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GEOTHERMAL RESERVOIR INSURANCE STUDY

FINAL REPORT

PREPARED FOR THE

UNITED STATES DEPARTMENT OF ENERGY

CONTRACT NO. DE-AC03-81SF11501

Coopers
&Lybrand

DISCLAIMER

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October 9, 1981

Mr. Kenneth M. Bromberg
Contract Monitor
United States Department of Energy
San Francisco Operations Office
1333 Broadway
Oakland, California 94612

Dear Mr. Bromberg:

Coopers & Lybrand and our subcontractor, GeothermEx, Inc., are pleased to submit this final report on the results of the Geothermal Reservoir Insurance Study. In accordance with the contract specifications, we have conducted a comprehensive and independent study of the need for and feasibility of establishing a geothermal reservoir insurance program.

This report contains an executive summary followed by an introduction to the study, the perception of risk by major market sectors, status of private sector insurance programs, analysis of reservoir risks, alternative government roles and our recommendation.

Coopers & Lybrand has appreciated this opportunity to provide assistance to the Department of Energy in the establishment of policies affecting the future energy security of the United States. If we can be of further service, please contact either E. Michael Shays or Donald M. Routh of our San Francisco office.

Very truly yours,

Coopers & Lybrand

PAC/DMR/kg

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I. EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

On June 11, 1981, an Executive Summary was delivered to the Department of Energy. The summary represented the preliminary findings of the Geothermal Reservoir Insurance Study and was subject to revision as a result of the final review process and the preparation of this final report. The Executive Summary, as revised, is presented herein. The summary is supported by the remainder of this report which should be considered as the definitive document representing the assumptions, findings and recommendations of Coopers & Lybrand.

The principal goal of this study has been to provide analysis of and recommendations on the need for and feasibility of a geothermal reservoir insurance program. One hypothesis is that a geothermal reservoir insurance program would be an incentive for increasing geothermal development and improving geothermal technology. The purpose of this study has been to analyze this potential incentive on its own merits -- not to attempt to determine the singular best incentive that might be provided to the geothermal industry.

The study involved five major tasks: (1) determine perception of risk by major market sectors, (2) determine status of private sector insurance programs, (3) analyze reservoir risks, (4) analyze alternative government roles, and (5) provide recommendations.

PERCEPTION OF RISK BY MAJOR MARKET SECTORS

Interviews with representatives of the developer, user and lender sectors of the geothermal industry were conducted. The objectives of the interviews were to:

- Identify major categories of geothermal risks to be utilized as the basis for subsequent analysis.
- Obtain the industry's perception of the need for a federal geothermal insurance program and its potential impact on geothermal development.

The perceived priority risks varied by size of firm, type of resource being developed, size of development and the respondent's role in the project. The priority risks commonly identified were:

- Reservoir decline;
- Well failure or damage;
- Environmental, legal and institutional delays;
- Physical damage to plant;
- Financial impediments; and
- Inability of developers and utilities to secure satisfactory long-term sales agreements.

Developers, users and lenders had differing opinions on the need for a federal geothermal insurance program and on its impact on geothermal development. Firms believing that increased availability of insurance coverage would have little positive impact on their plans to develop geothermal energy cited these reasons:

- Insurance might unnecessarily increase project costs.
- If insurance were available, lenders might require unwanted insurance.
- Subsidized insurance might facilitate unprofitable development.
- The Geothermal Loan Guaranty Program is similar to a form of insurance that provides coverage against default regardless of cause and is potentially less costly for the developer.

Firms believing that a federal geothermal insurance program would have a positive impact on their plans to develop geothermal energy cited these reasons:

- Insurance might reduce risks to utilities and thus accelerate development.

- A well-defined insurance program might substantially increase lender participation.

Larger firms had different perceptions than smaller firms regarding the role of insurance in encouraging geothermal development. Certain larger developers and utilities plan to proceed with development regardless of insurance. The smaller firms, because of their relative intolerance for risks, generally believe that increased availability of insurance would greatly facilitate development of geothermal energy.

Although the individuals interviewed had differing opinions on the appropriateness and need for an insurance program, they generally agreed that the availability of insurance would speed geothermal development. Insurance would address the uncertainty surrounding this resource and as a result would overcome some of the reluctance to become involved in geothermal projects.

Regarding the role of government, there is a consensus that the role of providing insurance would be best left to the private sector. The government role should be limited to encouraging and complementing private initiative. A government role that displaces the private market, with a resulting dependency on government, should be avoided.

STATUS OF PRIVATE SECTOR INSURANCE PROGRAMS

Interviews with representatives of the various segments of the private insurance community were conducted to determine the status of current insurance programs. Insurance brokers, primary insurers and reinsurance companies provided their perceptions of the insurability and appropriateness of coverages for the specific geothermal risks previously identified by the major market sectors.

A majority of the firms interviewed are knowledgeable of the risks associated with geothermal development. However, only one primary insurer has actively sought to provide reservoir performance coverage. Many of the firms interviewed indicated a willingness to provide insurance coverage for certain of the risks associated with geothermal projects. In particular, some insurers indicated a specific interest in writing coverage for reservoir performance.

The key reasons identified for the current lack of broad participation in insuring geothermal developments were:

- Lack of historical performance data;
- Questionable reliability of available data;
- Potential for unusually large loss;
- Unacceptibility of desired policy term; and
- Lack of communication between geothermal and insurance industries.

In considering the insurability of the priority risks identified by the major market sectors, certain specific risks were perceived as uninsurable (e.g. marketability). The remaining risks, although opinions differed widely as to insurability, comprise the set of geothermal risks considered for further analysis.

The insurance companies identified conventional and unconventional coverages that could apply to loss from geothermal risks. The conventional coverages include boiler and machinery, builder's risk and business interruption insurance while the unconventional forms of protection include coverage of reservoir inadequacy or depletion.

Currently there is only limited participation in providing insurance protection for geothermal risks. However, it is not unusual for developing technologies that have limited or unavailable data, to be served by only a few insurers. If some insurers gain positive experience in the geothermal industry other insurers have indicated they would be more willing to become involved, thereby increasing competition.

ANALYSIS OF RESERVOIR RISKS

The risks of geothermal development were analyzed to estimate the approximate level of insurance premiums necessary to cover potential losses. Prior to performing actuarial analyses resulting in premium estimates, specific risks were identified and their probability of occurrence and estimated cost consequences were determined.

Based on the results of the interviews, information provided by DOE data sources and geothermal reservoir engineering experts of GeothermEx, Inc., a comprehensive set of risks were identified. These risks comprise five major risk categories specific to geothermal developments:

- Well Risks - events leading to the unexpected replacement, addition, or abandonment of wells.
- Reservoir Performance Risks - events leading to significant reduction in reservoir productivity.
- Power Plant Risks - events leading to reduction in power plant performance.
- Surface Facility Risks - events leading to unexpected replacement of advanced design equipment and/or significant portions of the piping system.
- Acts of God - events such as landslides and volcanic eruptions.

Probabilities of occurrence and cost consequences were estimated based on available data and subjective probability assessments of geothermal reservoir experts. Subjective, rather than objective, probability assessments were necessarily utilized because adequate objective evidence based on repeated historical trials was not available. On the basis of the probabilistic analysis, an expected loss and loss distribution for each risk was estimated in terms of:

- Direct Cost to Developer - direct costs to replace or add wells, surface piping, etc.
- Indirect Cost to Developer - loss of revenue from reduced steam sales.
- Direct Cost to User - repair costs from physical damage to plant or turbines, as well as the unamortized value of a plant resulting from total or partial abandonment.
- Indirect Cost to User - excess cost of replacement power resulting from shut down or reduced capacity.

The expected losses and distributions were estimated for each of three different stages of development (field development, initial operation and full operation) and for each of seven geologic project types (e.g. vapor dominated). The expected losses and distributions are the principal data inputs used to estimate approximate levels of insurance premiums.

Premiums were estimated using appropriate actuarial methods as a function of the expected losses and loss distribution for each coverage category, along with a provision for administrative expenses. The risk loadings used in the premium calculations were determined statistically, rather than by a combination of underwriting judgment and competitive factors which would be the case in an actual market environment. Annual premiums were estimated assuming coverage in force for the entire project life under the assumption that the policy would be renewed annually.

At the time of a heat sales agreement there is likely to be limited data available on which to base judgments on risk, which will make it difficult to precisely assess premiums. As operational experience is gained and actual loss history observed, premiums could be calculated more accurately and should be readjusted.

ALTERNATIVE GOVERNMENT ROLES

After examining the range of possible programs, five alternatives were selected for detailed evaluation. These five alternatives represent viable options of federal support ranging from noninvolvement to a high level of support. The alternatives are:

(1) Private market insurance program exclusive of any government involvement.

(2) Private market insurance program with government providing excess catastrophe reinsurance.

(3) Private market insurance program with government making available specific excess reinsurance.

(4) Private market insurance program with primary government insurance to cover those risks not insured by the private sector.

(5) Government primary insurance program contracted to a third party for underwriting and administration.

Detailed analyses were performed on each alternative including (a) impact on private insurance sector, (b) financial impact on geothermal industry, (c) estimated cost to government, and (d) interaction with other government programs.

The level of federal support will have important consequences on the private insurance sector. A positive impact on the private insurance sector would be achieved if the government's role and level of involvement would support rather than compete with the private insurance sector. However, if the government's role and level of involvement extend beyond a support function, it would have a negative impact on the development of a viable private market insurance program. Therefore, Alternatives 1, 2 and 3 would have a positive impact on the private insurance sector's development of geothermal insurance programs and Alternatives 4 and 5 would have a negative impact.

The financial impacts of insurance costs were examined for each project type. The estimated premiums were significantly greater during the early stages of development and operation because of the initial uncertainties of reservoir characteristics. Although insurance premiums are higher in the early stages, the financial impact can be minimized through various methods such as federal cost support. However, even with the high initial premiums and no cost support, analysis indicates that the insurance burden would not be prohibitive to project economics. The financial impact to the insured will not significantly differ among the alternatives. However, Alternatives 2, 3 and 5 could provide somewhat lower cost because of the potential for federal cost support to the insured. Alternative 4 would result in somewhat higher cost because of the additional risks covered.

The cost to government of providing geothermal reservoir insurance depends on the potential government liability and administrative costs. If premiums are adequately assessed to cover liability and administrative costs the net cost to government would be zero. However, to adequately assess the possible cost consequences to government, the maximum potential government outlay, the expected government outlay and the uncertainty that premiums would not cover actual losses must be considered. Alternative 1 has the lowest cost to government. The government's potential and expected liability will increase with increasing levels of federal support; however, the possibility that premiums would not cover actual loss is greatest under Alternative 2.

There are a variety of government programs that provide incentives for geothermal development. These include price supports, tax incentives and loan guaranties. The Geothermal Loan Guaranty Program (GLGP) is the government program that is likely to have the most direct impact on the alternatives because it mitigates certain risks and serves as an incentive to develop geothermal energy. The continuation of the GLGP would likely decrease the demand for insurance for a limited number of potential insureds under each alternative.

In evaluating the alternatives the primary consideration was whether or not there is a need for a government role. In assessing alternative government roles consideration was given to the following primary criteria:

- Maximize availability of geothermal insurance from the private sector.
- Minimize cost to the geothermal industry.
- Minimize cost to government.

RECOMMENDATION

The recommended geothermal reservoir insurance alternative was determined on the basis of its responsiveness to the perceived need for geothermal reservoir insurance and its effectiveness in stimulating development of geothermal resources.

The study began with the fundamental assumption that it is advantageous to develop geothermal resources in the United States. There clearly are risks inherent in geothermal resource development. The study has detailed and analyzed these risks and found them to be significant. Reducing the financial uncertainty that stems from these risks can provide a strong incentive for the development of geothermal resources.

Although current means exist to reduce certain aspects of the financial uncertainty of loss to geothermal developers and users (e.g. Geothermal Loan Guaranty Program, tax incentives, etc.), there is room for complementing these programs. This study has shown that insurance would provide a means of protecting against the financial uncertainties of geothermal development. The study has also shown that insurance would most likely be a cost effective means of dealing with geothermal project financial uncertainties.

Interviews with members of the geothermal constituency showed that although there is some difference of opinion on the appropriateness of a federally supported reservoir insurance program, there is a widespread belief that such a program, if properly structured, would speed the development of geothermal resources. Those interviewed also believed that geothermal insurance would be most efficiently provided by the private insurance industry.

The willingness of the private insurance sector to commit a portion of their financial capacity to insuring geothermal development on a basis that is not prohibitive to project economics has been limited. This lack of broad participation has been due to unfamiliarity with the nature of the risks of geothermal projects and the limited number of projects which have been presented to the private insurance sector for consideration.

This study has served as a first step in identifying and classifying the risks associated with geothermal projects and has prompted discussion of the insurability of those risks by developers, users, lenders, and potential insurers. Information and intelligence have been gathered on probabilities of loss occurrence and estimates have been made of potential overall costs of loss. This information of itself will encourage further discussion and analysis within the private insurance sector. In addition, the number of projects of each type is projected to increase substantially over the next several years which will focus the attention of the private insurance sector on geothermal projects as a market for coverage.

Under these circumstances, it was determined that there is a viable role for the government to help accelerate the emergence of geothermal insurance supplied through the private sector. Given that:

- it is desirable to provide incentives for the development of geothermal energy as an alternative energy source,
- there are significant risks associated with geothermal development,

- insurance provides incentives for geothermal development by reducing the financial uncertainty of geothermal risks to the insured,
- the geothermal constituency believes that a properly structured insurance program would speed the development of geothermal resources, and
- the private insurance sector currently lacks broad participation in insuring geothermal development, this implies

there is a need for a temporary government role in a geothermal reservoir insurance program until such time as private insurers are actively providing adequate coverage on a broad basis. In addition, because (a) the significant risks associated with geothermal development can be insured, and (b) there is a historical precedence for the government playing a role in insuring highly technical or emerging industries, it is feasible for the government to have a role in a geothermal reservoir insurance program.

Based on the above summarization of, and the detailed findings reported in, Sections III, IV, V and VI of this report, it has been concluded that there is both the need for and the feasibility of a federally supported, and properly structured, geothermal reservoir insurance program.

Because of the previously established need for and feasibility of a federally supported geothermal reservoir insurance program and based on (a) the analysis of the perceptions of the major geothermal market sectors in Section III, (b) the analysis of the perceptions of the private insurance sector and existing geothermal reservoir insurance programs in Section IV, (c) a thorough analysis of geothermal risks in Section V, and (d) a detailed analysis of alternative government roles in Section VI, the recommended program is:

A private market insurance program for insurable risks underwritten by private insurers should be encouraged. The federal government should support this effort by making available limited excess reinsurance at a specified level decreasing over time. Additionally, through cost support, the price to insurers should be substantially less than what the private reinsurance market might provide.

The recommendation includes these provisions:

- The federal government will encourage broader participation by private insurers through facilitating communication between the geothermal industry and the private insurance sector.

- The specific details of the reinsurance program will be developed by the federal government in cooperation with the private insurance sector. This includes determination of the appropriate attachment point for federal involvement.

- The federal government reinsurance program will be structured to phase out in a specific period of time wherein adequate performance data can be obtained such that the insurance industry is able to make a determination of its commitment to underwrite the full program.

- The federal government's support of the program will be gradually reduced during the participation period.

- The administration of the government reinsurance program will be contracted to a third party having reinsurance expertise, thereby eliminating the need for the federal government to staff and administer the program.

This alternative is preferable because it:

- Addresses the primary constraints inhibiting the private insurance sectors' broad participation in geothermal projects, including the concern about the potential for unusually large loss.

- Places the primary burden of providing protection with private insurers who have the most expertise in managing risk.

- Permits each private insurer to select its level of participation, if any, in the geothermal reinsurance program.

- Encourages open competition and innovation between insurers.

- Provides cost support by removing risk loading and administrative costs from the federal reinsurance premium calculation, thereby reducing costs to the insurer and potentially to the insured and providing an incentive for early participation.

- Minimizes the federal government role and provides for an orderly phase-out as adequate performance data on geothermal risks are obtained.

- Encourages tailoring of protection to meet the specific needs of the insured.

- Has a positive impact on the private sector's development of geothermal insurance programs.

- Motivates the geothermal industry to utilize the best technology and management skills to reduce ultimate costs.

The cost to government for any reinsurance program will be dependant on numerous factors that are difficult to determine prior to the exact specification of a detailed program. For example, the cost to government depends on such factors as (1) the number of insured geothermal projects, (2) the government's scope of coverage, (3) the amount of reinsurance ceded to the government by insurers, (4) the actual loss experience of the developers and users, and (5) the duration of the program. Absent detailed program specifications, the cost parameters of the recommended program are based on the analysis of reservoir risks and the following primary assumptions:

- The government is providing the maximum level of reinsurance permitted by the program.

- The number of geothermal electric generation projects in existence in 1990 is estimated to approximate 100, which would generate approximately 5,000 megawatts of electrical capacity. This estimate includes the 16 projects (812 megawatts) that are currently operating and an annual addition of between 5 and 13 plants coming on line from 1982-1990.*

- The program is established January 1, 1982 and entirely phased out December 31, 1991 with the phase-out period beginning January 1, 1990.

- The attachment point for government reinsurance is equal to the expected loss plus five percent of the probable maximum loss during the first year of the program based on the loss distribution for all risks per project. The attachment point increases by five percent of the probable maximum loss in each successive year through 1989.**

- Premiums charged by the government are equal to expected government losses with no provision for loading administrative expenses and risk charges.

The estimated cost to government in 1981 dollars is based on the assumptions stated above. In reviewing the cost to government,

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*Based on estimates provided in Geothermal Progress Monitor: Progress Report, September 1980, DOE/RA-0051/4, P.1-7. The assumed number of geothermal electric generation projects approximates the mid-point between the operating and planned plants and the Interagency Geothermal Coordinating Council goal for cumulative geothermal electric power on line in 1990.

**An alternative method of expressing the attachment point may be necessary if reinsurance is obtained on a treaty basis (terms negotiated for all policies to be reinsured in advance of those policies being issued) rather than obtained for each individual policy when written. While the attachment point can be determined for each individual policy on the basis of variance, the use of a reinsurance treaty requires that the amount of coverage (and, therefore, the attachment point) be known prior to issuing a single policy. Therefore, the attachment point is expressed as a ratio to the expected losses for all policies to be reinsured through the treaty. Because the expected loss is generally assumed to be a percentage of premium, the attachment point for this type of treaty reinsurance would also be expressed as a percentage of the total premium reinsured under the treaty.

it is important to recognize that the amount paid out for claims (losses) would be offset by funds received from premiums. The expected amount of losses paid by the government would aggregate approximately $400 million with annual expected losses ranging from $20 million to $55 million*. As stated, premiums charged by the government are then assumed to equal the expected government losses. The government's total probable maximum loss, which by definition is significantly less likely to be attained than the expected loss, would aggregate approximately $1 billion during the period of the program. Because reinsurance premium income of $400 million would offset the total maximum loss, the net probable maximum loss exposure to the government would be $600 million. Administrative costs are estimated at ten percent of premium income during the period of the program.

The aggregate expected amount of losses of approximately $400 million (exclusive of premium income) paid by the government during the duration of the program represents approximately $100 million to cover direct loss (repair and/or replacement) and approximately $300 million to cover indirect loss (lost potential revenue). The $100 million expected government loss to cover direct loss is less than one percent of the estimated initial capital investment for all geothermal electric generation projects assumed to be in existence in 1990, and less than two percent of the initial capital investment for those projects assumed to participate in the geothermal reservoir insurance program.** Because the program would cover direct loss for total capital investment and not just the initial capital investment, the $100 million expected government loss for direct loss actually represents much less than two percent of the total capital investment for projects in the program.

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*The expected losses increase annually by an average of $5 million from approximately $20 million in 1982 to $55 million in 1989 and then decrease to zero by 1992 as the program is phased out.

**The total initial capital investment for all projects in existence in 1990 is estimated to be approximately $12.8 billion. This is based on the number of geothermal electric generation projects assumed to exist in 1990 and an assumed average initial capital investment of $60-65 million for well field and surface facility development and $66 million for plant and transmission lines.

The structure of the primary insurance program developed by the private sector could take the form of individual insurance company programs or an association or pool of insurers who develop a joint program. If a joint program is developed, the overall cost to the government, as estimated above, may be significantly different. The size of the geothermal insurance market, the available insurance capacity and the degree of specialized underwriting expertise required will affect the program structure selected.

Detailed guidelines must be developed for the recommended program. The remaining discussion highlights certain of the recommended guideline parameters.

Adequate authority should exist for the recommended program. This authority should be exercised in such a manner as to encourage the efforts of the private insurance sector. For the insurance industry, eligibility for the program would be based on providing insurance to candidates with at least a $1 million (1981 base) investment in a geothermal project.*

The nature of losses qualifying for coverage under this program should include both direct and indirect losses, for example, the loss of capital and loss of revenue resulting from an unexpected event. The availability of the coverage through private insurers in conjunction with this program should allow policyholders to protect the entire amount of their interest in a project subject to self-insured retention provisions. Evaluation of specific projects for the acceptability of the risk will depend heavily on the data obtained by primary insurers consistent with generally accepted industry underwriting practices. The premium received by the federal government for this reinsurance will be proportional to its participation and will be adjusted to reflect the amount of cost support. The recommendation anticipates that claims against this reinsurance program would be presented for reimbursement on the basis of claims paid by the primary insurers.

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*This minimum investment level should, however, remain somewhat flexible so as to not exclude sizeable direct-use commerical projects having a demonstrated need for insurance.

II. INTRODUCTION

INTRODUCTION

"Geothermal - earth heat - energy is one of our most plentiful resources. It results from the radioactive decay of rocks, which raises the earth's temperature an average of 25 degrees Celsius with each kilometer of depth. Experts estimate that 32 million quads of energy are simmering within ten kilometers of the surface of the United States.* Most can never be utilized, but interest in exploitable areas is quickening. Some 2,300,000 acres of federal land have been leased for exploration and development, and in 1979 drilling increased 25 percent over 1978. Development and refinement of technology are necessary to make geothermal energy economically competitive with conventional sources of energy. However, experts estimate that by the year 2020 geothermal could be adding 18.5 quads annually to the national energy pool."**

One hypothesis is that a geothermal reservoir insurance program would be an incentive for increasing geothermal development and improving geothermal technology. The purpose of this study has been to analyze this potential incentive on its own merits -- not to attempt to determine the singular best incentive that might be provided to the geothermal industry.

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*In 1975, the United States Geological Survey, ERDA-86, estimated the total heat content of the accessible geothermal resource base (depth less than ten kilometers) at 600,000 quads, excluding the highly diffuse "Normal gradient" resources. On the basis of conservative assumptions of extraction and conversion efficiencies the total recoverable energy from this base, with near term technology but without regard to cost, was estimated at 3,400 quads. This is the energy equivalent of 578 billion barrels of oil which is over 40 times the total U.S. energy consumed in 1980 and over 300 times the total imported crude oil in 1980.

**National Geographic Special Report, "Geothermal - Tapping the Earth's Furnace," February 1981, p. 64

BACKGROUND

On June 30, 1980, Public Law 96-294, referred to as the Energy Security Act, was enacted by the Congress of the United States. Subtitle B of Title VI (Geothermal Energy) of the Act requires that a reservoir insurance program study be conducted. Specifically, Section 621 of the Act directs the conduct of a detailed study of the need for and feasibility of establishing a reservoir insurance and reinsurance program incorporating the terms, conditions and provisions set forth in Section 622. The applicable sections of the Energy Security Act are contained in the Appendix.

On February 13, 1981, Coopers & Lybrand contracted with the United States Department of Energy to conduct a geothermal reservoir insurance study. An executive summary containing the preliminary findings and recommendations resulting from the study was submitted to the Department of Energy on June 11, 1981. The final report, as contained herein, is the definitive document representing the assumptions, findings and recommendations of Coopers & Lybrand.

OBJECTIVES

The primary objective of this study has been to provide an analysis of the need for and feasibility of a geothermal reservoir insurance program. In conjunction with the analysis of the need for and feasibility of such a program, the appropriate level of federal support, if any, was to be determined. The findings and recommendations resulting from the study are herein presented by Coopers & Lybrand to the United States Department of Energy. It is the intent of the Secretary of the Department of Energy to submit the results of this study to Congress for review in accordance with the requirements of Section 621 of the Energy Security Act.

SCOPE

The scope of the geothermal reservoir insurance study was comprised of five major areas: (1) analysis of reservoir risks, (2) perception of risk by major market sectors, (3) status of private sector insurance programs, (4) alternative government roles, and (5) recommendations. The detailed scope of work as prepared by the Department of Energy is presented below.

SCOPE OF WORK

Analysis of Reservoir Risks

A. Discuss insuring against inadequate initial temperature and flow rates during the short term as well as the following long-term risks:

- Temperature decline
- Pressure or production rate decline
- Scaling or corrosion of production wells
- Injection problems
- Operational problems in geothermal facilities on the surface or with downhole pumps
- Any other resource related problems that result in cost escalation adversely affecting project economics

B. Select a cross-sample of geothermal projects (both electric and direct-use) based on their expected development potential. Estimate the overall probability of project failure from the above risks that result in insurance claims.

C. Estimate the costs associated with such failure and the premiums required to support this level of failure.

D. How well can the above mentioned risks be evaluated for a specific project at the time a heat sales agreement is to be signed?

E. At what times during subsequent field development and exploitation can these risks be evaluated with sufficiently greater confidence to justify adjustment of the insurance premiums?

Perception of Risks by Major Market Sectors

The study should consider, to the maximum extent possible, the attitudes and viewpoints of the following major market sectors regarding the need, cost and impact of a reservoir insurance/reinsurance program on the geothermal industry.

A. Geothermal developers (direct-use)

B. Geothermal developers (field development leading to power plants)

C. Utilities

D. Major non-electric users of geothermal heat

E. Interim lenders (commercial banks)

F. Long-term lenders

G. Insurance industry

H. Reinsurance industry

Status of Private Sector Insurance Programs

Specify the companies, terms, costs, coverage and other relevant parameters associated with existing private sector insurance/reinsurance coverage. Identify any project types not likely to be covered.

Alternative Government Roles

Evaluate various levels of federal support ranging from non-involvement to a high level of support. Discuss alternative government roles such as providing insurance coverage, reinsurance coverage or some mix of the two. To the degree practical, consider other relevant government insurance programs. For each of the above, consider the probable cost, impact on private sector insurance/reinsurance programs, interaction with other government programs (e.g., Geothermal Loan Guaranty Program), and mechanisms for the phase out of federal involvement.

Recommendations

Provide recommendations for structuring a federal insurance/reinsurance program incorporating the terms, conditions, and provisions set forth in Section 622 of P.L. 96-294. Discuss the necessary legislative authority, program management (maximizing private sector involvement), scope of coverage (e.g., actual project losses vs. expected project revenues), methods of paying claims (e.g., continuous operating subsidies vs. lump sum payment), project qualification and premium structure, evaluation parameters and nature of losses qualifying for coverage.

* * * * *

To further clarify the intended scope of the study, representatives of Coopers & Lybrand met with Mr. Michael Harvey, Minority Counsel for the Senate Energy Committee. As a result of the meeting and discussions with representatives of the Department of Energy, the scope of the study was defined to include not only risks relative to the quantity and quality of the reservoir but also other hazards unique or nearly unique to geothermal development.

The scope of geothermal projects selected for risk analysis was limited to project sites within the United States. Although there are significant geothermal developments located in other parts of the world, it was determined that risk, probability and cost data from foreign sites would not be sufficiently applicable to the study because (1) the current state of technological development in the United States is sufficiently different, and (2) any federal program resulting from the study would apply only to domestic geothermal sites.

APPROACH

The objectives and scope of the geothermal reservoir insurance study required a multi-disciplined approach to the engagement. An engagement team was organized consisting of over 40 Coopers & Lybrand professionals representing the following disciplines:

- Actuarial Consulting
- Economic Services Consulting
- Finance and Management Consulting
- Government Services Consulting
- Insurance Consulting

Within these disciplines, individual members of the management team provided the study with experience and expertise in such areas as public policy analysis, decision theory, probability analysis, geothermal project financing, premium determination and insurance program development. In addition, GeothermEx, Inc., a geothermal reservoir engineering firm, was engaged as a sub-contractor to Coopers & Lybrand. GeothermEx provided the engagement team with professionals experienced as geothermal reservoir engineers, geologists, geophysicists and geochemists.

The five major areas comprising the scope of work were resequenced and utilized as the basis for detailing the approach to accomplishing the objectives of the study. The approach employed consisted of the following tasks.

TASK 1: Perception of Risk by Major Market Sectors

1. A cross-sample of geothermal project types was selected based on their expected development potential and range of geography, geology, resource characteristic, usage and environmental risks.

2. Separate and distinct stages of development, applicable across project types, were identified such that interviewees' responses could be more accurately categorized and compared.

3. The following major market sectors, from which interviewees would be selected, were identified:

   - Geothermal developers - power generation
   - Geothermal developers - direct-use
   - Utilities
   - Non-electric users
   - Interim lenders
   - Long-term lenders

4. Representatives of each of the major market sectors were selected and interviewed to determine their:

   - Experience with geothermal projects.
   - Perception of risks in geothermal development.
   - Estimates of risk probability and cost consequences.
   - Views on the need for and impact of a government sponsored geothermal insurance program.

TASK 2: Status of Private Sector Insurance Programs

1. The following principal insurance sectors, from which interviewees would be selected, were identified:

   - Insurance brokers
   - Primary insurers
   - Reinsurance companies

2. Representatives of each of the principal insurance sectors were selected and interviewed to determine their:

   - Energy industry experience.
   - Specific geothermal experience.
   - Terms, costs and coverages associated with any existing geothermal insurance policies.
   - Perception of risks in geothermal development.
   - Perception of insurability of the risks identified by the major market sectors.
   - Perception of appropriate types of coverages.
   - Views on preferred geothermal insurance program structures.

TASK 3: Analysis of Reservoir Risks

1. A comprehensive list of insurable risks was developed as a result of:

   - Interview results from the major market sectors involved with geothermal development and production.
   - Interview results from the principal insurance sectors.
   - Direction provided by a representative of the Senate Energy Committee.

- Information provided by Department of Energy data sources.
- Information provided by geothermal reservoir engineering experts.
- A thorough analysis by members of the engagement team.

2. The list of insurable risks was stratified by geologic project type and stage of development.

3. Probabilities of occurrence and cost consequences were estimated for each insurable risk.

4. An expected loss and loss distribution for each risk was estimated in terms of direct and indirect costs to both the developer and user for each stage of each project type.

5. Insurance coverage categories were defined.

6. Insurance premiums were estimated as a function of the expected loss and loss distribution for each coverage category.

7. Risk data availability and reliability at the time of heat sales agreement signing was evaluated.

8. Premium readjustment points, based on changes in the availability and reliability of data, were evaluated.

TASK 4: Alternative Government Roles

1. Other relevant government insurance programs were evaluated from an historical perspective.

2. Alternative government roles representing various levels of federal support were evaluated.

3. The following detailed analyses were performed on a selected number of alternatives representing viable options of federal support:

   - Impact on private insurance sector.
   - Financial impact on geothermal industry.
   - Estimated cost to government.
   - Interaction with other government programs.

TASK 5: Recommendations

1. The need for and feasibility of a government role in the development of a geothermal reservoir insurance program was evaluated.

2. Based on the evaluation of need and feasibility and the results of Tasks 1 through 4, a recommended program was developed.

3. The resulting estimated cost to government of the recommended program and its interaction with other government programs was evaluated.

4. Guideline parameters for the recommended program were developed, including:

   - Legislative authority
   - Program management
   - Project qualifications
   - Nature of losses qualifying for coverage
   - Scope of coverage
   - Evaluation parameters
   - Premium structure
   - Methods of paying claims

III. PERCEPTION OF RISK BY MAJOR MARKET SECTORS

PERCEPTION OF RISK BY MAJOR MARKET SECTORS
DETAILED TABLE OF CONTENTS

PERCEPTION OF RISK BY MAJOR MARKET SECTORS
TABLE OF EXHIBITS

PERCEPTION OF RISK BY MAJOR MARKET SECTORS

An analysis of the need for and feasibility of a geothermal reservoir insurance program requires, among other inputs, a thorough understanding of both the real and perceived risks inherent in geothermal projects. In order to gain this understanding, in-depth interviews were conducted with the major market sectors associated with the development, financing and use of geothermal energy. The results of these interviews, combined with the research of available geothermal risk data and the knowledge and experience of geothermal reservoir engineers, geophysicists and geologists, provide the base data for subsequent analyses.

Prior to the selection of interview candidates, a cross-sample of geothermal project types was determined and the major market sectors associated with geothermal projects were identified. Potential interview candidates were then selected such that a broad range of knowledge, experience and perspective would be provided. This section describes the selection criteria, selection process and interview process. It then focuses on the results of the interviews exclusive of the detailed perception of risks and perspective on the need for an insurance program. The detailed perception of risks resulting from the interviews are reported in Section V - Analysis of Reservoir Risks. The perspective on the need for an insurance program resulting from the interviews is reported in Section VI - Alternative Government Roles.

GEOTHERMAL PROJECT TYPES AND STAGES OF DEVELOPMENT

In order to assure input from a full representation of the geothermal constituency a cross sample of geothermal project types was selected. Special interests resulting from specific site situations were therefore considered in the overall analysis. Additionally, specific stages of development which apply across project type were identified and defined to aid in the consistency and comparibility of input data.

Cross-Sample of Geothermal Project Types

Recognizing that project data vary by the geologic structure of the various geothermal projects, a cross-sample of geothermal reservoirs was selected. The selection of project types covers the range of geography, geology, resource characteristics, usage and environmental risks of geothermal energy development in the United States. The selected geothermal project types and a definition of the associated terms are:

Project types

A. Vapor Dominated

B. Liquid Dominated, Fracture Permeability, Areally Extensive

C. Liquid Dominated, Fracture Permeability, Areally Restrictive, Leaky Fault

D. Liquid Dominated, Fracture Permeability, Areally Restrictive, Leaky Fault with an Associated Reservoir

E. Liquid Dominated, Fracture Permeability, Areally Restrictive, Volcanic Fissures

F. Liquid Dominated, Intergranular Permeability, Local Anomaly, Benign Chemistry

G. Liquid Dominated, Intergranular Permeability, Local Anomaly, Problem Chemistry

H. Liquid Dominated, Intergranular Permeability, Regional Aquifer

Definition of terms

Vapor Dominated: Saturated steam (typically at 465°F and 500 psi) exists in the reservoir. The fluid produced is dry steam.

Liquid Dominated: Either water only or water with a steam saturation exist in the reservoir. Temperatures and pressures can vary widely. Electricity generation under present technology is commercial only for resources above 300°F.

Fracture Permeability: Either fractured massive (impermeable) rock or fractured porous (permeable) formation. In the latter case fractures usually dominate over pores as fluid conduits.

Areally Extensive: The reservoir has considerable area extent and well-spacing and siting has considerable flexibility.

Leaky Fault: There is no reservoir as such. Production takes place from a fault which brings up fluid from great depths.

Leaky Fault With an Associated Reservoir: A reservoir directly fed by a fault.

Volcanic Fissures: Reservoir formed by fissures in volcanic rocks.

Intergranular Permeability: Flow takes place through pores, not fractures. Such reservoirs are easier to engineer.

Local Anomaly: The exploitable reservoir has finite limits.

Benign Chemistry: No serious operational or environmental problems due to fluid chemistry is expected.

Problem Chemistry: Serious operational or environmental problems need to be solved to exploit the resource.

Regional Aquifer: Wells produce from a vast aquifer, usually a low temperature resource.

Examples of project types

A sample site of either electric or direct-use generation for each of the selected project types has been identified to assist in the understanding of how the project types can be differentiated. A typical site, its location, geologic setting, resource characteristics, status of development and other relevant information is presented for each project type.

Project Type A:	Vapor Dominated
Typical Site:	The Geysers, California
Location:	Lake, Sonoma, and Mendocino Counties; T. 10-12 N., R. 7-9 W., Mt. Diablo B. and M.
Geologic Setting:	Geysers-Clear Lake area. Reservoir in meta-sedimentary rocks (Franciscan Formation graywacke) at depths 2,000 to 10,000 feet. Reservoir permeability due to pervasive fracturing of brittle rocks. Heat source mid-crustal magma body.
Resource Characteristics:	Dry steam produced from wells; water quality of condensate good ($\leq$500 TDS). Target temperatures >450°F. Wellhead pressures about 500 psi. Small quantity of noncondensible gases, including a small fraction of H_2S.
Status of Development:	Numerous wells drilled and producing power plants on line. Field developed in increments; production history ranges from 0-20 years. Current installed capacity: 920 MW, divided into 15 units each ranging from 12 to 135 MW.

Project Type A:	Vapor Dominated (continued)
Other Relevant Information:	Land surface especially prone to landslides. This and other factors restricts available sites for power plants and transmission facilities.
Project Type B:	Liquid Dominated, Fracture Permeability, Areally Extensive
Typical Site:	Baca Area (Valles Caldera), New Mexico
Location:	Baca Location No. 1, Sandoval County
Geologic Setting:	Rio Grande Rift geological province. Reservoir in fine-grained volcanic rocks (Pleistocene Bandelier Tuff). Reservoir permeability due to fracturing. Heat source not known; possibly youthful magma body.
Resource Characteristics:	Several hot water wells drilled, average well capable of flashing 35% steam at 200,000 lb/hr total mass. Reservoirs contain free steam saturation. Water quality moderate (about 7,000 ppm TDS). Target temperatures >400°F; downhole temperatures to 532°F observed. Small quantity of non-condensible gases, including small fraction of H_2S.
Status of Development:	Numerous producible wells drilled; a DOE-funded demonstration power plant (55 MW gross) is possible.

Project Type B: **Liquid Dominated, Fracture Permeability, Areally Extensive** (continued)

Other Relevant Information: Scaling in wells may be a problem. Other vapor-dominated reservoirs may be present in area but have not yet been delineated. Limited availability of plant sites and transmission lines. Environmentally sensitive area.

Project Type C: **Liquid Dominated, Fracture Permeability, Areally Restrictive, Leaky Fault**

Typical Site: Susanville, California

Location: Lassen County; T. 30 N., R. 12E.

Geological Setting: Transition between Cascade Range and Basin and Range Province. Reservoir in fine-grained lake sediments and volcanics. Reservoir permeability mainly due to fracturing. Heat source: Deep circulation of meteoric water.

Resource Characteristics: Hot water (100-185°F); subhydrostatic pressures; must be pumped. Water quality good (170-800 ppm TDS).

Status of Development: Water presently used for direct heat applications in greenhouses, swimming pool and space heating in public building. A DOE-sponsored project currently under way to provide hot-water for district residential heating system.

Project Type C: Liquid Dominated, Fracture Permeability, Areally Restrictive, Leaky Fault (continued)

Other Relevant Information: Possibility of communication between agricultural aquifers and geothermal aquifer.

Project Type D: Liquid Dominated, Fracture Permeability, Areally Restrictive, Leaky Fault with an Associated Reservoir

Typical Site: A typical northern Nevada electrical generation project. [Because all data on actual prospects remains proprietary, this entry represents a generalized case based on data from several reservoirs.]

Location: Various areas within Washoe, Churchill, Pershing, and Eureka Counties.

Geologic Setting: Basin and Range Province. Reservoir of typical prospect is in fractured granite and/or volcanic rocks at depth of 5,000-10,000 feet. Reservoir permeability due to pervasive shattering of brittle rocks. Heat source: Very deep circulation of meteoric water in region of higher-than-average heat flow.

Resource Characteristics: Hot water produced from wells, typically at 400°F. Well subhydrostatic but flow due to flashing. Percentage of flashed steam variable. Water quality good to moderate (500-7,000 ppm TDS). Small quantity of non-condensible gases.

Project Type D: **Liquid Dominated, Fracture Permeability, Areally Restrictive, Leaky Fault with an Associated Reservoir** (continued)

Status of Development: Two to five producible wells drilled in typical prospect; additional drilling going on. Also, negotiations being pursued concerning heat sales contract. Possible DOE loan guaranty applications.

Other Relevant Information: Make-up water scarce. High CO_2 - scaling potential.

Project Type E: **Liquid Dominated, Fracture Permeability, Areally Restrictive, Volcanic Fissures**

Typical Site: Puna Rift, Hawaii

Location: Puna District, Hawaii Island

Geologic Setting: Faulted and rifted zone on south flank of Kilauea volcano. Reservoir in fractured basalts at depths of 4,000-6,000 feet. Heat source: local magmatic heating.

Resource Characteristics: Wells produce very hot water (>420°F); 65-70% flash to steam. Post-flash brine of moderately good quality (<2,500 ppm). Small quantity non-condensible gases, including small fracture of H_2S.

Status of Development: Several deep wells drilled; one known to be producible. Three megawatt demonstration electrical plant under construction.

Project Type E: Liquid Dominated, Fracture Permeability, Areally Restrictive, Volcanic Fissures (continued)

Other Relevant Information: Hazards include volcanic eruption damaging facilities, natural seismicity and horizontal displacement of land surface associated with movement of rift zone.

Project Type F: Liquid Dominated, Intergranular Permeability, Local Anomaly, Benign Chemistry

Typical Site: East Mesa, California

Location: Imperial County, California; T. 15-16 S., R. 16-17 E.

Geologic Setting: Salton Trough geologic province. Reservoir in sedimentary and metasedimentary rocks (Colorado River Delta) at depths 5,000 to 8,000 feet. Reservoir permeability intergranular and possibly fractured. Heat source: Possible magmatic source.

Resource Characteristics: Hot water (320-380°F), produced from wells, water quality 2,000-2,800 (ppm TDS). Target temperatures for development $\geq$330°F; observed as high as 400°F.

Status of Development: 18 wells drilled. A 10 MW gross electrical power plant followed by a 48 MW net plant under design. Development partially financed by a DOE geothermal loan guaranty.

Project Type F: Liquid Dominated, Intergranular Permeability, Local Anomaly, Benign Chemistry (continued)

Other Relevant Information: High natural seismicity in region. Questions of land subsidence important.

Project Type G: Liquid Dominated, Intergranular Permeability, Local Anomaly, Problem Chemistry

Typical Site: Salton Sea, California

Location: Imperial County, California

Geologic Setting: Imperial Valley-Salton Trough. Sedimentary rocks of the Colorado River delta; depth 3,000-8,000 feet. Reservoir permeability: Intergranular porosity. Heat source: Probable magmatic.

Resource Characteristics: Hot water (572 to 617°F), several produceable wells in place. Water quality very poor (> 180,000 ppm TDS). Target temperature for development greater than 600°F; observed as high as 644°F.

Status of Development: More than 20 wells drilled to depths of 2,300 to 8,000 feet.

Other Relevant Information: Possibility of ground subsidence due to withdrawal of fluid is of particular concern. Because of severe fluid chemistry, scaling and corrosion in surface facility are potential problems.

Project Type H: Liquid Dominated, Intergranular Permeability, Regional Aquifer

Typical Site: Madison Group Thermal Aquifer

Location: Portions of central South Dakota and adjacent North Dakota.

Geologic Setting: Sedimentary rocks of the Great Plains Province. Porous and permeable limestones of the Madison Group; depth ranges from less than 2,000 feet to over 8,000 feet; intergranular porosity enhanced by solution channeling. Heat source: Deep circulation of meteoric water.

Resource Characteristics: Hot water at 100-160°F. Water quality good; often potable when cooled; temperature gradients of 2.5°F/100 feet in wells to 2,000 feet, and 2°F/100 feet to >3,500 feet. Highly permeable zones >3,000 feet may produce water at 120°-160°F.

Status of Development: Dozens of farm and municipal wells penetrate thermal aquifer at depths to 3,000 feet in two states. Drilling of thermal wells (accidentally or by intent) continues across the region.

Other Relevant Information: Aquifer system deepens to north and northwest into Williston Basin of North Dakota. Depth of development wells would exceed 3,000 feet in these areas, with corresponding increase in cost. Highly permeable zones at >5,000 feet might produce water at >160°F.

Identification of Stages of Development

Three distinct stages of development, applicable to all project types, were identified to aid in gathering consistent and comparable data. Analysis of risks during exploration are not within the scope of this study and are not intended to be implied as such. However, the concept of "reservoir discovery" is recognized as not being precisely defined and is subject to interpretation depending on context. From the viewpoint of the explorer or operator a discovery may exist which, in the opinion of a potential user or purchaser of energy, is still in the exploration stage and not a proven or insurable resource or reserve. For the purposes of this study, the term discovery may be taken to imply that there is sufficient definition of the resource to make it marketable, in the opinion of both the developer-operator and the potential or actual user.

The three stages of development applicable to the full life of each geothermal project and referred to throughout this report are:

- Stage 1 - Full field development; reservoir discovery to the first day of production (i.e. 3-5 years).
- Stage 2 - Initial operations; first day of production through solution of the transient problems (i.e. one year).
- Stage 3 - Full operation; solution of transient problems through remainder of project life (i.e. 25-30 year life of project).

DETERMINATION OF MAJOR MARKET SECTORS

The geothermal industry is, with notable exceptions, in its pioneering period of development. In these early times the various roles of the private and public sectors are being defined and redefined. A review of the geothermal constituency provides the following categorization of the geothermal market sector:

- Developers of geothermal resources
- Users of geothermal resources
- Lenders for geothermal development and production

Within each market sector there are finer distinctions of the roles each firm plays. The following describes the developer, user and lender sectors and the background for the selection of specific firms asked to provide their perceptions of the risks in geothermal projects.

Developers of geothermal energy typically initiate the production process. They initiate exploratory drilling and, if successful, complete the development process through delivery of energy to an end user. The developer market sector may be segregated into two areas:

- <u>Electric Developers</u>: delivery of geothermal energy in sufficient quantity and quality for generation of electricity.

- <u>Direct-use Developers</u>: delivery of geothermal energy in sufficient quantity and quality for use in direct heat applications.

Electric and direct-use heat development require significantly different levels of investment, quality of resource and user needs. For this reason, the developer's perception of risk may vary significantly. In certain cases, a single developer may be involved in both electric and direct-use heat generation. In these situations, the perceptions of risks have been carefully delineated by the two types of development thereby maintaining a distinction as to ultimate use of the resource.

Users of geothermal energy purchase the raw energy source and convert it to a usable form of energy. In most cases, users of geothermal energy are utilities. The users' contribution to geothermal energy development is normally related to significant investment in the power plant and distribution systems, concurrent with the developer's full field development. Users are faced with a number of risks related to long-term production and maintenance of the resource. Utilities also differ significantly in their perception of risks based on their size and ownership structure, e.g., municipal vs. private.

As in all development, lenders are often the facilitating institution. There is a natural distinction between lenders and their perceptions of risks by short-term lenders (usually banks) and long-term lenders (typically investment firms).

SELECTION OF INTERVIEWEES

Based on the determination of the cross-sample of geothermal project types and identification of the major market sectors associated with geothermal development and production, a comprehensive set of experience factor parameters was developed to aid in the interviewee selection process. The following primary parameters were utilized in developing the final list of interview candidates:

- Direct experience or knowledge of at least one of the eight project types with all project types represented.
- Direct experience with either direct-use or electric geothermal projects as either a developer or user.
- Direct experience with or knowledge of geothermal project financing as either an interim or long-term lender.
- Representatives of both publicly held and privately owned companies.
- Resource locations in representative domestic sites.

Within these parameters both business and technical experts were considered for participation in the study. The process resulted in the identification of 24 firms contacted for interviews.

Coopers & Lybrand senior personnel conducted in-depth, on-site, interviews with 43 executives representing 23 of the 24 firms contacted. The interest in the future of geothermal energy and in particular on this study is evidenced by the extraordinary response to the request for interviews with these firms. Most of the interviews consisted of 2-4 hour meetings with follow-up input and correspondence. The results of the interviews provided the engagement team with the base data for the entire study and was a critical input into the final recommendation.

The individuals interviewed and the firms they represent are listed in Exhibit III-1. Following the list is Exhibit III-2 which profiles the firms interviewed and their experience or working knowledge of the various geothermal project types.

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MAJOR MARKET SECTOR INTERVIEWEES

1. Developers

A. Geothermal Resource International, Inc.
Menlo Park, California

Person interviewed:

Mr. Bob Greider, President

B. Union Oil Company of California
Los Angeles, California

Persons interviewed:

Dr. Carel Otte, President, Union Geothermal Division

Mr. Vane E. Suter, Vice President-Operations

Mr. Neil J. Stefanides, Vice President-Exploration

Mr. Richard C. Lindwall, Manager of Planning and Valuation

C. Magma Power Company
Los Angeles, California

Person interviewed:

Mr. Joseph W. Aidlin, Vice President, Secretary, and General Counsel

D. Chevron Resources Company
San Francisco, California

Person interviewed:

Dr. Michael A. Lane, Senior Geologist

Mr. Basil D. Garrett, Operations Supervisor

E. Geothermal Energy Corporation
New York, New York

Person interviewed:

Mr. Paul Rodzianko, President

F. Republic Geothermal, Inc.
Santa Fe Springs, California

MAJOR MARKET SECTOR INTERVIEWEES

Persons interviewed:

Dr. Robert Rex, President

Mr. Lenny M. Targon, Vice President-Finance

Mr. Donald A. Campbell, Vice President-Engineering and Technology

G. Geoproducts Corporation
Oakland, California

Person interviewed:

Mr. Kenneth L. Boren, President

H. Phillips Geothermal Co.
Salt Lake City, Utah

Person interviewed:

Mr. Donald Harban, Director of Development

2. Users

A. Utah Power and Light Company
Salt Lake City, Utah

Persons interviewed:

Mr. J. Lynn Rasband, Manager of Advance Development

Mr. M. Blaine Hofeling, Manager-Risk and Insurance Services Department

Mr. Gary Chandler, Financial Analyst

Mr. John E. Droubay, Assistant Treasurer and Assistant Financial Officer

B. San Diego Gas and Electric Co.
San Diego, California

Persons interviewed:

Mr. Craig Hubble, Manager-Risk Management

Mr. James M. Nugent, General Manager

Mr. Robert G. Lacey, Manager-Heber Project

Mr. George Anastasi, Supervisor of Geothermal Program

MAJOR MARKET SECTOR INTERVIEWEES

C. Sacramento Municipal Utility District
Sacramento, California

Person interviewed:

Mr. Lee R. Keilman, Supervising Mechanical Engineer

D. Hawaiian Electric Company, Inc.
Honolulu, Hawaii

Persons interviewed:

Mr. Andrew T. F. Ing, Financial Vice President

Mr. Roy T. Uemura, Technical Advisor-System Planning Department

Mr. Harwood D. Williamson, Vice President-Planning

Mr. Richard E. Bell, Vice President-Engineering

Mr. Robert T. Pannabecker, Director Insurance and Claims

E. Southern California Edison Company
Rosemead, California

Persons interviewed:

Mr. Thomas R. Sparks, Engineer for Geothermal Programs

Mr. Thomas Noonan, Special Finance

Mr. Lawrence W. Yu, Administrator, Special Finance Treasurer's Department

F. Sierra Pacific Power Co.
Reno, Nevada

Person interviewed:

Mr. Richard Atkinson, Business Analyst

G. Eugene Water and Electric Board
Eugene, Oregon

Persons interviewed:

Mr. Herbert H. Hunt, Director Power Resources

Mr. John E. Brown, Treasurer, Director Accounting and Finance

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MAJOR MARKET SECTOR INTERVIEWEES

H. Eureka Energy Co., a subsidiary of
Pacific Gas and Electric Co.
San Francisco, California

Person interviewed:

Mr. Philip C. Watson, Geothermal Resource Geologist

3. Lenders

A. Bank of America
Los Angeles, California

Person interviewed:

Mr. Jeffrey B. Weinress, Vice President-Industries Office, Energy Group

B. The First Boston Corporation
New York, New York

Person interviewed:

Mr. Michael S. Gorman, Financial Analyst-Project Finance

C. The Idaho First National Bank
Boise, Idaho

Persons interviewed:

Mr. Charles B. Heavy, Vice President

Mr. Mark Fredback, Loan Officer

D. Bank of Montreal
San Francisco, California

Person interviewed:

Mr. John H. Woods, Vice President

E. Merrill Lynch White Weld Capital Markets Group
New York, New York

Person interviewed:

Mr. Andre A. Schwarz, Vice President

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MAJOR MARKET SECTOR INTERVIEWEES

F. Chase Manhattan Bank
New York, New York

Person interviewed:

Mr. Peter Roux, Vice President

G. Kidder, Peabody & Company
New York, New York

Person interviewed:

Mr. William P. Short III, Associate

EXHIBIT III-2

PROFILE OF FIRMS INTERVIEWED

Number of Firms with Experience or Working Knowledge of Projects by Type of Geothermal Resource

	Type of Resource								
		Liquid - Fracture				Liquid - Intergranular			
Type of Firm - Market Sector	Vapor (A)	Areally Extensive (B)	Leaky Fault (C)	Leaky Fault w/ Res. (D)	Volcanic Fissures (E)	Local, Benign Chem. (F)	Local, Problem Chem. (G)	Reg'l Aquifer (H)	General Knowledge Only
Developers									
. Electric	4	6	6	8	4	7	6	1	-
. Direct-use*	2	2	1	4	0	4	0	1	-
Users									
. Utilities	4	2	2	6	2	3	6	1	-
. Others*	0	0	1	0	1	0	1	0	-
Lenders									
. Interim	2	1	1	2	1	1	1	0	-
. Long-Term	0	0	0	0	0	1	0	0	3
TOTAL	12	11	11	20	8	16	14	3	3

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*A few developers and utilities reported experience in both electric and direct use of geothermal resources.

INTERVIEW PROCESS

The primary purpose of the interviews was to provide an in-depth understanding of the risks in geothermal development and production. The results of the interviews, supplemented with the engagement team expertise and research, provided the necessary base data for subsequent analyses. The hypothesis for the study which in part guided the development of the survey instrument can be stated as:

> If private industry and/or government increased the availability of insurance coverage (at a reasonable cost) for geothermal development and production, there would be a greater willingness (perhaps critical) for potential developers and users to become involved.

This hypothesis was tested in the interviews. The interviews and survey instrument were also developed to:

- Identify priority risks in geothermal development as perceived by major market sectors.
- Identify the probability of these priority risks occuring based on industry experience.
- Identify and understand the chain of subevents leading to priority risks and the likelihood of these subevents occurring.
- Identify the likely financial impact associated with the priority risks.
- Provide the study with an understanding of the perceptions of risks, the probability of their occurance, the losses to expect and the protection needs of the major market sectors.

As anticipated, in many instances the base data sought was neither readily available nor subject to precise quantification. It is also necessary to understand that industry responses may be influenced in large measure by each firm's goals and objectives with respect to future geothermal development. The analysis and conclusions reflect these considerations.

During the design phase of the interview process, the survey instrument was internally tested before interviewing the experts. There were three significant findings of the test interview:

- The questionnaire document was extremely comprehensive; it was anticipated that the interviewees would be required to make a significant contribution of their time.
- The questionnaire document was very detailed, especially as to the chain of risk events resulting in loss to the firm and the cost of that loss; considerable training of the interviewers was conducted in order to insure comparability of results.
- The nature of the questionnaire document was such that certain questions would apply more appropriately to one market sector than others; it was therefore anticipated that responses to certain questions could not be compared among market sectors.

Based on these findings, it was anticipated that the detail and quality of response would vary significantly by market sector and firm. The responses in the interviews, then, required careful interpretation and reinforcement from other sources -- the engagement team's own understanding of geothermal development and analysis of secondary research sources.

Questionnaire Format

The questionnaire was designed to elicit information from a broad perspective and to be supplemented with detailed data. There are four sections to the questionnaire:

- Interviewee Information: Facts relating to the name, title and position of respondents.
- Experience in Geothermal: Questions relating to the respondents' familiarity and experience with specific geothermal projects.
- Data Request: Questions relating to perceptions of priority risks based on the respondents' project experience; including discussions of priority risks of individual projects, subevents, probability of occurrence, and types of losses expected in relation to total project costs.
- Government Programs and Future of Geothermal: Questions probing the need for government involvement, current government incentives provided and their effect on development and needs for insurance protection.

The questionnaire asked for detailed and reiterative information based on respondent experience. In question II-1, the project types with which respondents had knowledge or experience were identified. For each reservoir identified in question II-1, separate responses to question II-2 probed the type of development (size of project, location of reservoir, cost, goals and objectives in development) for individual reservoirs.

In Section III - Data Request, the project types were further dilineated by stages of development in which the respondent had direct involvement or a good working knowledge. For each reservoir type and stage of development in question III-2, specific information was obtained as to perceptions of risks, risk subevents, probability of occurance and losses attendant.

The interviews were conducted during a three week period in March and April 1981. Coopers and Lybrand senior personnel were given two day-long training sessions prior to the interviews to help insure comparability of responses. The interviews were conducted at the respondents' offices which ranged across the United States from New York City to Honolulu, Hawaii. The firms were especially responsive in the interviews and contributed significantly to the study. A copy of the questionnaire is presented in Exhibit III-3.

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DEPARTMENT OF ENERGY
GEOTHERMAL RESERVOIR INSURANCE STUDY
INTERVIEW QUESTIONNAIRE

I. INTERVIEWEE INFORMATION

1. Name of Respondent ______________________________
2. Title of Respondent ______________________________
3. Company ______________________________
4. Class of Company: (may be more than one)
   a. Developer: Electric use ☐ and/or Direct-use ☐
      (1) Business Manager ☐ or (2) Technical Expert ☐
   b. User: Utility ☐ or Direct-use ☐
      (1) Business Manager ☐ or (2) Technical Expert ☐
   c. Lender: Short Term ☐ and/or Long Term ☐
5. Address ______________________________
6. Phone ________________

Others Attending:

Name ________________ Title ________________

Name ________________ Title ________________

Name ________________ Title ________________

Name ________________ Title ________________

7. Interviewers:

Name ________________ Office ________________

Name ________________ Office ________________

Name ________________ Office ________________

8. Date of Interview ______________________________

DEPARTMENT OF ENERGY
GEOTHERMAL RESERVOIR INSURANCE STUDY
INTERVIEW QUESTIONNAIRE, Continued

II. DESCRIPTION OF EXPERIENCE IN GEOTHERMAL ENERGY

1. We would like to understand your familiarity with geothermal projects. With what type of geothermal project, do you have knowledge or experience?

Project Type		Knowledge		Experience	
		Electric Use	Non-Electric Use	Electric Use	Non-Electric Use
I. Vapor Dominated	A.	☐	☐	☐	☐
II. Liquid Dominated					
A. Fracture Permeability					
1. Areally Extensive	B.	☐	☐	☐	☐
2. Areally Restrictive					
a. Leaky Fault	C.	☐	☐	☐	☐
b. Leaky Fault with Associated Reservoir	D.	☐	☐	☐	☐
c. Volcanic Fissures	E.	☐	☐	☐	☐
B. Intergranular Permeability					
1. Local Anomally					
a. Benign Chemistry	F.	☐	☐	☐	☐
b. Problem Chemistry	G.	☐	☐	☐	☐
2. Regional Aquifer	H.	☐	☐	☐	☐
III. Others ____________	I.	☐	☐	☐	☐

Comments on knowledge and experience: ____________________

____

____

____

____

EXHIBIT III-3

DEPARTMENT OF ENERGY
GEOTHERMAL RESERVOIR INSURANCE STUDY
INTERVIEW QUESTIONNAIRE, Continued

II. DESCRIPTION OF EXPERIENCE IN GEOTHERMAL ENERGY, continued

2. If you have had knowledge or experience, what was your experience?

   a. Project Discussed:

      (1) Project type: /__/ (A through I)

      (2) Location ______________________________

      (3) Size of Field Development:

         No. of wells /______/
         Your investment $______
         Total investment $______

         Size of Power Plant Development:

         MW generated /______/
         Your investment $______
         Total investment $______

      (4) What was your role in this project?

         ____

      (5) Was this with your current company? __________
         If not, what company? ______________

      (6) Narrative Discussion of your goals and objectives in this project (i.e. ROI, turnaround time to sell-out, premiums for bankers, rate base and capacity change for utilities):

         ____
         ____
         ____
         ____

      (7) Narrative discussion of your problems and risks:

         ____
         ____
         ____
         ____
         ____

DEPARTMENT OF ENERGY
GEOTHERMAL RESERVOIR INSURANCE STUDY
INTERVIEW QUESTIONNAIRE, Continued

III. DATA REQUEST

1. We want to discuss your perceptions of the priority risks in geothermal development and production. We have defined priority risks as those risks which would become a major impediment to the project. Because risks can vary from project to project, we would like to begin focusing this discussion on particular types of projects and their stages of development.

   We have identified three distinct stages of development:

   - Stage 1 - Full Field Development, reservoir discovery to the first day of production (i.e. 5 years).
   - Stage 2 - Initial Operations; first day of production through solution of the transient problems (i.e. one year).
   - Stage 3 - Full Operation; solution of transient problems to payback (i.e. 25-30 year life of project).

2. Let's explore further the types of projects and stages of development with which you have had direct involvement or a good working knowledge.

Project Type		Stage of Development		
		1	2	3
I. Vapor Dominated	A.	☐	☐	☐
II. Liquid Dominated				
A. Fracture Permeability				
1. Areally Extensive	B.	☐	☐	☐
2. Areally Restrictive				
a. Leaky Fault	C.	☐	☐	☐
b. Leaky Fault with Associated Reservoir	D.	☐	☐	☐
c. Volcanic Fissures	E.	☐	☐	☐
B. Intergranular Permeability				
1. Local Anomaly				
a. Benign Chemistry	F.	☐	☐	☐
b. Problem Chemistry	G.	☐	☐	☐

DEPARTMENT OF ENERGY
GEOTHERMAL RESERVOIR INSURANCE STUDY
INTERVIEW QUESTIONNAIRE, Continued

		Stage of Development		
Project Type		1	2	3
B. Intergranular Permeability				
2. Regional Aquifer	H.	☐	☐	☐
III. Others ______________	I.	☐	☐	☐

3. Discussion of Priority Risks:

a. Type ☐ Stage ☐ Use ☐

b. What events do you consider to be priority risks?

(1) ____
(2) ____
(3) ____
(4) ____

c. What are the major sub events (Risks), if any, leading to each of the priority risks described in (b.) above.

Priority Risk (1):
1st Sub Event ______________________________
2nd Sub Event ______________________________
3rd Sub Event ______________________________
4th Sub Event ______________________________

Priority Risk (2):
1st Sub Event ______________________________
2nd Sub Event ______________________________
3rd Sub Event ______________________________
4th Sub Event ______________________________

Priority Risk (3):
1st Sub Event ______________________________
2nd Sub Event ______________________________
3rd Sub Event ______________________________
4th Sub Event ______________________________

Priority Risk (4):
1st Sub Event ______________________________
2nd Sub Event ______________________________
3rd Sub Event ______________________________
4th Sub Event ______________________________

EXHIBIT III-3
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INTERVIEW QUESTIONNAIRE, Continued

d. What are the chances that the priority risks or events will occur during this particular stage of development?

Risk (listed in b)	Probability Per Time/Well, etc.		
(1) ________	________	Per	________
(2) ________	________	Per	________
(3) ________	________	Per	________
(4) ________	________	Per	________

e. What is the probability of occurrence for each sub event and is that a conditional probability?

	Probability Per Time Period/Well, etc.			Conditional on?
Priority Risk (1)				
1st Sub Event	________	Per	________	________
2nd Sub Event	________	Per	________	________
3rd Sub Event	________	Per	________	________
4th Sub Event	________	Per	________	________
Priority Risk (2)				
1st Sub Event	________	Per	________	________
2nd Sub Event	________	Per	________	________
3rd Sub Event	________	Per	________	________
4th Sub Event	________	Per	________	________
Priority Risk (3)				
1st Sub Event	________	Per	________	________
2nd Sub Event	________	Per	________	________
3rd Sub Event	________	Per	________	________
4th Sub Event	________	Per	________	________
Priority Risk (4)				
1st Sub Event	________	Per	________	________
2nd Sub Event	________	Per	________	________
3rd Sub Event	________	Per	________	________
4th Sub Event	________	Per	________	________

DEPARTMENT OF ENERGY
GEOTHERMAL RESERVOIR INSURANCE STUDY
INTERVIEW QUESTIONNAIRE, Continued

f. You gave me your estimated probability, what is your confidence interval for each of these probabilities?

Risk/	Confidence Interval						
Sub Event	± 5%	±10%	±15%	± 20%	±25%	±30%	>±30%
(1)	☐	☐	☐	☐	☐	☐	☐
(1st)	☐	☐	☐	☐	☐	☐	☐
(2nd)	☐	☐	☐	☐	☐	☐	☐
(3rd)	☐	☐	☐	☐	☐	☐	☐
(4th)	☐	☐	☐	☐	☐	☐	☐
(2)	☐	☐	☐	☐	☐	☐	☐
(1st)	☐	☐	☐	☐	☐	☐	☐
(2nd)	☐	☐	☐	☐	☐	☐	☐
(3rd)	☐	☐	☐	☐	☐	☐	☐
(4th)	☐	☐	☐	☐	☐	☐	☐
(3)	☐	☐	☐	☐	☐	☐	☐
(1st)	☐	☐	☐	☐	☐	☐	☐
(2nd)	☐	☐	☐	☐	☐	☐	☐
(3rd)	☐	☐	☐	☐	☐	☐	☐
(4th)	☐	☐	☐	☐	☐	☐	☐
(4)	☐	☐	☐	☐	☐	☐	☐
(1st)	☐	☐	☐	☐	☐	☐	☐
(2nd)	☐	☐	☐	☐	☐	☐	☐
(3rd)	☐	☐	☐	☐	☐	☐	☐
(4th)	☐	☐	☐	☐	☐	☐	☐

EXHIBIT III-3
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GEOTHERMAL RESERVOIR INSURANCE STUDY
INTERVIEW QUESTIONNAIRE, Continued

III. DATA REQUEST, continued

g. What are the kinds of losses that you would expect with each of these risk occurances?

	Priority Risks					
	1	2	3	4	5	6
(1) Cost consequences of total or partial abandonment						
• $ gross: Mid (50%)	$	$	$	$	$	$
Low (25%)						
High (75%)						
Max (100%)						
• Year of $ (1981?)	19	19	19	19	19	19
• % of total capital cost	%	%	%	%	%	%
(2) Increase in O&M						
• $ per year gross: Mid (50%)	$	$	$	$	$	$
Low (25%)						
High (75%)						
Max (100%)						
• Year of $ (1981?)	19	19	19	19	19	19
• % of total O&M/year	%	%	%	%	%	%
(3) One time cost (i.e. penalty, clean-up, default), specify ______ ______ ______						
• Gross: Mid (50%)	$	$	$	$	$	$
Low (25%)						
High (75%)						
Max (100%)						
• Year of $ (1981?)	19	19	19	19	19	19
• % of total capital proj.	%	%	%	%	%	%
(4) Loss of revenue						
• $ or kwh; mid (50%)						
Low (25%)						
High (75%)						
Max (100%)						
• Year of $ or kwh (1981?)	19	19	19	19	19	19
• % of total rev/kwh/year	%	%	%	%	%	%
(5) Cost to replace capital $						
• $ gross: Mid (50%)	$	$	$	$	$	$
Low (25%)						
High (75%)						
Max (100%)						
• Year of $ (1981?)	19	19	19	19	19	19
• % of total capital cost	%	%	%	%	%	%

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GEOTHERMAL RESERVOIR INSURANCE STUDY
INTERVIEW QUESTIONNAIRE, Continued

III. DATA REQUEST, continued

4. When responding to the previous questions regarding percent of total capital costs, what are you considering to be included in the capital base? (i.e. wells, surface facilities, plant) ____________________________________

5. What is your (or what would you expect to be the) total capital cost base for this stage of development in this type of project.

$__________ gross, year $__________.

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GEOTHERMAL RESERVOIR INSURANCE STUDY
INTERVIEW QUESTIONNAIRE, Continued

IV. GOVERNMENT PROGRAMS AND FUTURE OF GEOTHERMAL

1. What impact would an insurance protection program have on your involvement in the future of geothermal development, assuming it were available? ____________________

2. How critical is the cost of that protection in view of your answer to the last question? ____________________

3. Is this answer dependent on what other government incentives are available? (i.e. with or without Geothermal Loan Guaranty Program). ____________________

4. Would government involvement in a geothermal reservoir insurance program have a positive impact on your involvement in such a program __________ Why? ____________________

5. a. For developers and users: What impact would a reservoir insurance program have on your contractual obligations? ____________________

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GEOTHERMAL RESERVOIR INSURANCE STUDY
INTERVIEW QUESTIONNAIRE, Continued

IV. GOVERNMENT PROGRAMS AND FUTURE OF GEOTHERMAL, continued

b. For lenders: What impact would the availability of various types of protection have on your willingness to lend? ______

6. What protection have you been able to secure?

a. Conventional Insurance: What coverages, what terms?

______

b. Contractual Negotiations: project capital structuring (i.e. Heat Sales Agreement, specify)

______

c. Other government programs (see glossary of selected terms at end of questionnaire)?

- Depletion Allowance............................... ☐
- Intangible Drilling Costs Write-offs............ ☐
- 15% Energy Tax Credit........................... ☐
- DOE Geothermal Loan Guaranty Program.. .... ☐
- DOE User Coupled Drilling Program............... ☐
- PURPA: 80 MW Power Plant Regulatory Exclusion.... ☐
- Utilities Purchase at Avoided Cost.............. ☐
- Forced Wheeling On Behalf of Utilities.......... ☐
- Grants, R&D Assistance.......................... ☐
- Others, specify______ ☐

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GEOTHERMAL RESERVOIR INSURANCE STUDY
INTERVIEW QUESTIONNAIRE, Continued

IV. GOVERNMENT PROGRAMS AND FUTURE OF GEOTHERMAL, continued

d. What types of protection will you need in the future in order to continue or increase your involvement in geothermal energy development/production (i.e. insurance protection, government programs..specify)

e. What do you see as the future of geothermal energy? Roles of various players?

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GEOTHERMAL RESERVOIR INSURANCE STUDY
INTERVIEW QUESTIONNAIRE, Continued
GLOSSARY OF SELECTED TERMS
GOVERNMENT PROGRAMS

- DOE User Coupled Drilling Program

Objective is to stimulate geothermal development by reducing reservoir confirmation risk to the developer. DOE will cost share surface exploration drilling and flow testing of exploration wells to confirm low-to-moderate-temperature hot water resources. The amount of DOE cost share will be based on the degree of success, but will be between 90% for an unsuccessful project and 20% for a successful project.

- PURPA: 80 MW Power Plant Regulatory Exclusion

The exemptions under Section 210(e)(2) of PURPA (Public Utility Regulatory Policy Act of 1978) relating to the Public Utility Holding Company Act of 1935, the Federal Power Act, and state regulation were limited to projects of 30MW or less, while most geothermal projects fall in the 50MW range. This meant that under existing law the exemption benefits of Section 210(e)(2) were seldom available for geothermal projects.

In June, 1980, Congress passed the Energy Security Act. Section 643 of Title VI of the Act authorizes the Federal Energy Regulatory Commission to exempt "geothermal small power production facilities of not more than 80MW capacity" under PURPA.

Geothermal projects of 80MW or less capacity, then, are not subject to severe regulation from state or federal agencies.

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INTERVIEW QUESTIONNAIRE, Continued
GLOSSARY OF SELECTED TERMS
GOVERNMENT PROGRAMS

- Utilities Purchase Electricity at Avoided Cost

  PURPA encourages small power production from renewable energy sources by requiring utilities to buy power from small producers at their avoided cost of power, e.g. the cost of their highest power source. PURPA was amended by the Energy Security Act to define a small power producer as a geothermal power producer of up to 80 MW.

- Forced Wheeling

  Requires the utilities to wheel, or carry on their transmission lines, electricity generated from geothermal energy.

RESULTS OF INTERVIEWS

This section presents the results of the major market sector interviews. The results focus on responses to specific questions in the questionnaire. Most interviews were wide-ranging and covered additional topics that related to the geothermal industry in general. The results of the interviews are divided into three general categories:

- Experience in Geothermal Energy -- Part II of the questionnaire.
- Summary of Priority Risks* -- Part III of the questionnaire.
- Analysis of Government Programs and Future of Geothermal -- Part IV of the questionnaire.

Experience in Geothermal Energy - Developers

Developers provided their answers from experience with fifteen different geothermal resources. Projects ranged in size from a projected 1,000 Megawatt (MW) capacity and 200 wells to five MW capacity with two wells. Most developers preferred not to disclose their investment or the total investment in each project. The roles of the developers related primarily to the exploration and development of the fields for electric and direct heat uses. A few developers were also operators, project managers, owners of leases or designers of the proposed power plants.

Exhibit III-4 presents a summary of the developers' experience in geothermal development at specific sites. Exhibit III-5 presents a summary of the developers' goals and objectives as well as the problems and risks associated with each site. It is apparent that the developers' first objective is to secure a greater return on investment based on their perception of greater risk accompanying field development. Developers also agree on the need for alternative energy sources and believe that development of geothermal

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*The detailed priority risks by project type and stage of development as perceived by the interviewees appear in Section V - Analysis of Reservoir Risks.

EXHIBIT III-4

SUMMARY OF EXPERIENCE IN GEOTHERMAL ENERGY -- DEVELOPERS

Location	Size*		Roles
	Field Wells	Plant (MW)	
Salton Sea, CA			
• Niland	-	20	Drilled and tested wells, power plant design
• Niland & Westmorland	4	-	Explore and develop field
• Niland & N. Brawley	12	-	Owner of lease
Lassen, CA	2	55	General Partner, Operator
East Mesa, CA			
• Company A	-	10	Drill and test, built binary cycle plant
• Company B	10	10	Explore and develop field
Geysers, CA			
• Company A	-	1,000	Explore and develop first commercial well
• Company B	200	746	Field Operator
Heber, CA	10	50-100	Developer, Operator, Owner
Long Valley, CA	-	-	Explore and develop for direct use
Brady Hot Springs, NV			
• Company A	2	-	Explore and develop field
• Company B	2	-	Project manager
Beowawe, NV	4	10	Explore and develop field for hot water
Utah (unspecified)	2	-	Explore and develop, Project Manager
Roosevelt Hot Springs, UT	10	20	Explore and develop, Operator
Desert Peak, NV	4	-	Explore and develop
Humboldt, NV	2	-	Explore and develop
Baca, NM	20	50	Developer, Field Operator
Vale, OR	5	-	Project Manager

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*Includes data on both existing and planned projects.

EXHIBIT III-5

SUMMARY OF GOALS AND OBJECTIVES AND PROBLEMS AND RISKS FOR DEVELOPERS AT SPECIFIC SITES

Stated Goals and Objectives	Location of Development
1. Greater return on investment, based on greater risk	All
2. Develop alternative energy and diversify company assets	All
3. Increase knowledge of geothermal (research and development)	Beowawe, Salton Sea
4. Increase knowledge of direct heat application	Brady Hot Spring, Vale
5. Enhance public credibility	Heber, Salton Sea

Stated Problems and Risks	
1. Decline in resource productivity and associated problems	East Mesa, Beowawe, Humboldt, Utah, Roosevelt, Heber
2. Scaling and corrosion	Brady Hot Springs, Salton Sea
3. Permit delays and other environmental concerns	Geysers, Long Valley, Lassen, Baca
4. Marketing of resource	Utah, Brady Hot Springs
5. Higher then expected capital and operating costs	East Mesa, Salton Sea, Geysers
6. Skilled labor	Lassen, Beowawe

energy would serve to enhance their public credibility while increasing their knowledge of this energy source.

Most problems and risks are related to the uncertainty of resource productivity before completion of full field development. Another problem with development is the environmental concerns and accompanying permit delays. Certain developers stated concern over the competitive price of geothermal energy in the near future, given higher drilling costs. They question their ability to profitably market the steam given the current rates for alterative energy sources.

Experience in Geothermal Energy - Users

The users of geothermal energy (primarily utilities) provided their answers from experience with eight different geothermal resources. Projects ranged in size from 55 MW and $100 million investment to 3 MW and $9 million investment. Exhibit III-6 presents a summary of the users' experience in geothermal development at specific sites. The roles of various utilities are more divergent than those of developers. In addition to buying steam from developers and operating power plants, utilities have acted as advisors to developers and joint venture partners with developers.

Exhibit III-7 presents a summary of the utilities' goals and objectives as well as the problems and risks associated with each project. The primary goals of utilities are to advance geothermal energy as an alternative energy source while diversifying their resource base. Privately held utilities have the goal of structuring construction of their power plants to maximize return on investment. Utilities were generally enthusiastic about the potential for geothermal development to provide lower cost energy in the future. They expect other energy sources to become increasingly expensive in comparison to geothermal.

Because most power plants are under construction prior to completion of full field development, an important risk for utilities in geothermal development is reliance on unproven reservoirs.

EXHIBIT III-6

SUMMARY OF EXPERIENCE IN GEOTHERMAL ENERGY -- USERS

Location	Size* Field Wells	Size* Plant (MW)	Roles
Salton Sea, Niland, CA	6	20	Owner of wells, buy steam
Heber, CA			
. Company A	-	50	Exploration, research, and development, buy steam
. Company B	-	50	Operate power plant, buy steam
N. Brawley, CA	-	10	Operate power plant, buy steam
Geysers, CA	9	55	Built power plant, buy steam
Northern Nevada			
. Company A	20	30	Interim Coordinator, build plant, buy steam
. Company B	-	10	Joint Venture Partner, build plant, buy steam
. Company C	-	55	Joint Venture Partner, build plant, buy steam
. Company D	20	50	Joint Venture Partner, build plant, buy steam
Puna, HI	-	3	Technical Advisor, operate plant, buy steam
Roosevelt H. S., UT	14	20	Builder of conversion facility, buy steam
Cascades, OR	-	-	Research and development

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*Includes data on both existing and planned projects.

EXHIBIT III-7

SUMMARY OF GOALS AND OBJECTIVES AND PROBLEMS AND RISKS FOR USERS AT SPECIFIC SITES

Stated Goals and Objectives	Location of Development
1. Advance geothermal as alternative energy source	All
2. Broaden and diversify resource base	All
3. Research and development, gain experience	Puna, Heber, Northern Nevada, N. Brawley
4. Invest in energy source with low cost potential	All
5. Structure construction and sales agreement to maximize tax advantage and rate of increase	Privately held utilities

Stated Problems and Risks	
1. Permit delays and other environmental concerns	Puna, Heber, Cascades
2. Reliance on unproven reservoir, technology	Northern Nevada, Roosevelt
3. No significant problems	Geysers, N. Brawley

Experience in Geothermal Energy - Lenders

Lenders have focused increasing attention on geothermal development. The long-term lenders interviewed have yet to finance a geothermal project, but expect to become directly involved soon. Exhibit III-8 presents a summary of the lenders' stated goals and objectives as well as problems and risks associated with specific sites. Lenders believe that their support of geothermal projects would enhance their public image while assisting an alternative energy source. They also see geothermal as a means of diversifying their loan portfolios while servicing preferred customers.

Lenders expressed a need for a better operating history in each reservoir. Smaller lenders were reluctant to commit too many resources to geothermal projects where there is no in-house expertise in risks or precedence with default.

Summary of Priority Risks - Developers

The perceived priority risks of geothermal developers varied by size of firm, type of resource being developed, and size of development. The priority risks which all developers agreed on were:

- Reservoir Decline: Unexpected depletion of reservoir or less than expected realization of capacity.
- Failure of Mitigating Systems: Failure of mitigating measures such as corrosion protection to maintain production.
- Environmental, Legal and Institutional Delays: Unexpected delays in development due to environmental concerns, legal questions regarding ownership and use of the resource and permit delays.

All of the developers interviewed expressed concern over the high cost of development. Developers were confident that the risks in development could be overcome. However, delays in development and the cost of mitigating measures severely impacted project economics.

EXHIBIT III-8

SUMMARY OF GOALS AND OBJECTIVES AND PROBLEMS AND RISKS FOR LENDERS AT SPECIFIC SITES

Stated Goals and Objectives	Location of Development
1. Support alternative energy, enhance public image	Geysers, Boise, Baca
2. Invest time and research and development, service to preferred customer, future business	Geysers, Salton Sea, Baca, Vale, Boise,
3. Return on loan portfolio (diversification)	Geysers
Stated Problems and Risks	
1. Lack of information, history of reservoir capacity	All
2. Increased cost of mitigating measures	Geysers, Salton Sea
3. Lack of experience, no precedence with default	Vale, Boise
4. Regulatory and environmental concern	Salton Sea, Geysers, Boise
5. Ability to market direct heat product	Vale

Smaller developers expressed concerns about the availability of financing, especially during the exploratory stages of development. Smaller developers also voiced concern over an unexpected drop in the price of competitive energy. These concerns relate to the continued market for energy and the smaller developer's ability to locate buyers.

Summary of Priority Risks - Users

The perceived priority risks of users often differed between publically and privately held utilities. The priority risks which all utilities agreed on were:

- Reservoir Decline: Unexpected depletion of reservoir or less than expected realization of capacity and subsequent inability of developer to deliver steam to the power plant.
- Physical Damage to Plant: Damage resulting from earthquake, flood, or volcano. The utilities' considerable investments in plant and equipment are especially vulnerable to natural disasters.
- Financial Impediments: Delays in production due to inability of developer to finance additional mitigating measures.
- Environmental, Legal and Institutional Delays: Local residents are often opposed to power plants and municipalities may not be able to handle increased discharges from power plants.

In addition to these priority risks, municipal utilities are cautious about their ability to raise funds for geothermal development. With utility rates regulated and considered high, certain utilities expressed difficulties in passing along "venture" development costs in yet unproven geothermal resources. Conversely, utilities stated a commitment towards diversifying their energy sources and expect increased public acceptance of placing seed capital in geothermal energy.

Private utilities are becoming involved in geothermal development as joint venture partners with resource developers. A joint venture partnership is seen as a method of reducing the risks of overreliance on a developer's ability to provide steam in the face of unexpected mitigating costs.

Summary of Priority Risks - Lenders

Lenders have expressed a growing interest in geothermal development in recent years. In the past, geothermal development has been financed through significant equity participation of developers and utilities. In recent years, lender participation has been coupled with the Department of Energy's Geothermal Loan Guaranty Program (GLGP). Changes in the developers' equity participation or the GLGP will directly affect the lenders' perceptions of risks in geothermal development. In addition to the priority risks of reservoir capacity and decline and regulatory delays, lenders also perceive the following priority risks in geothermal development:

- Ability of Developers and Utilities to Secure Satisfactory Long-Term Sales Agreements: Lenders voiced concern over the industry's ability to successfully market geothermal energy under fluctuating market conditions.
- Sustained Reservoir and Power Plant Performance: Overdevelopment of the field in early stages of production often leads to costly mitigating measures and reduction in power generation.

Banks stated a few obstacles to lending for geothermal development. For local banks, there is often no in-house geothermal staff which is expert in the engineering design and geological factors involved in development. Local banks believe that the risks attendant to geothermal are sufficiently different from their more conventional projects, such as oil and natural gas drilling, that they warrant the scrutiny of in-house experts. Certain larger banks mentioned a reluctance to lend for geothermal development except as an accommodation to preferred customers.

Analysis of Government Programs and the Future of Geothermal

This section focuses on the major market sectors' need for protection. The results of this portion of the interview reflect the broad cross-sample of firms interviewed and their specific needs.

Impact of insurance on future involvement

Developers had differing opinions on the need for insurance coverage and on its impact on geothermal development. Several developers believe that insurance coverage would have little impact on their plans to develop geothermal energy. They cite these reasons:

- Insurance might unnecessarily drive-up costs; if it were available, banks might require insurance.
- Insurance might facilitate unprofitable development.
- Established developers already assume risks themselves and plan to proceed with development; because equity venture partners do not expect insurance, there is little need.

However, most developers, including those with no need for additional protection, agree that insurance would speed the development process. Utilities believe they would find a greater degree of comfort with insurance. Insurance would help a utility to be comfortable with an operator, thus removing some obstacles in negotiating a heat sales agreement.

Utilities also disagree on the impact of insurance coverage. Those that believe insurance would have a major positive impact cited the need to have a secured reservoir in order to decide to build their power plant. Others stated that insurance would reduce the uncertainty of loss and thus allow for better contingency planning.

Those utilities that believe insurance would have little positive impact cited the fact that developers have assumed most risks to date. A developer's guarantee, combined with flexible engineering design, was adequate assurance for a few utilities.

Most banks stated that a well-defined insurance program would substantially increase their participation in geothermal development. A few stated that insurance was essential for electric use projects.

Many of these responses paralled the line drawn between large developers and utilities and smaller companies. Some larger firms plan to proceed with development regardless of insurance. The smaller firms generally believe that insurance, in some form, would greatly facilitate development of geothermal energy.

Several developers, utilities and lenders prefaced their responses by stating that the Department of Energy's Geothermal Loan Guaranty Program is, in their opinion, insurance. Many believe that continuation of the GLGP is essential.

Insurance secured and protection needed for future involvement

Developers and utilities have secured only standard property, casualty and liability coverage for their projects, e.g., fire, catastrophe and extended coverage on equipment.

Some developers and utilities stated that they need coverage for recapture of tax benefits and business interruption costs. Certain utilities stated that some form of coverage for the reservoir and their investment in the power plant would be helpful.

Banks are concerned that loss coverage should be well-defined: (1) clear as to guarantee, (2) known price, and (3) long-term to cover payment of debt. One bank said that a federally-supported insurance program should not be structured similiar to FHA loans where the guaranty is in the form of government bonds rather than cash to pay the outstanding loan.

Importance of cost

Developers believe that insurance costs would be of significant importance to their development. Any cost over two percent of the project, they stated, would become critical to project economics.

Utilities also believe that insurance costs would be extremely important. Most utilities are concerned that insurance coverage could push the cost of producing energy (and thus their rates) above alternative energy sources.

Dependence on and use of other government programs

Exhibit III-9 presents a summary of the planned and actual use of government programs by the firms interviewed. As the exhibit shows, the four government programs or incentives which are of greatest use to firms are:

- Depletion Allowance
- Intangible Drilling Costs Write-Offs
- 15% Energy Tax Credit
- DOE Geothermal Loan Guaranty Program

Perceived future of geothermal energy

Developers, utilities and lenders are cautiously optimistic about geothermal energy's future. Most growth will remain localized in the Western United States -- especially California, Nevada and Hawaii. In Hawaii, for example, there is the potential for complete energy independence through the development of the geothermal resource.

While the major market sectors do not expect geothermal energy to become especially significant in the overall mix of energy sources, it is seen as becoming an increasingly attractive source of energy. For the near future, the major market sectors believe that while geothermal energy will remain an economically feasible industry, it will be at the upper-end cost range of energy sources.

EXHIBIT III-9

PLANNED AND ACTUAL USE OF GOVERNMENT INCENTIVES FOR DEVELOPMENT OF GEOTHERMAL ENERGY

Government Incentives	Number of Firms Likely to Qualify	Number of Firms Using or Plan to Use
Depletion Allowance	10	10
Intangible Drilling Costs Write-Offs	10	10
15% Energy Tax Credit	10	10
DOE Geothermal Loan Guaranty Program	12	9
DOE User Coupled Drilling Program	10	3
PURPA: 80 MW Power Plant Regulatory Exclusion	10	9
Utilities Purchase at Avoided Cost	13	7
Forced Wheeling On Behalf of Utilities	13	6
Grants, R&D Assistance	13	7

IV. STATUS OF PRIVATE SECTOR INSURANCE PROGRAMS

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STATUS OF PRIVATE SECTOR INSURANCE PROGRAMS
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STATUS OF PRIVATE SECTOR INSURANCE PROGRAMS

DETERMINATION OF PRINCIPAL INSURANCE SECTORS

Prior to selecting companies as candidates for interviews it was necessary to obtain a clear understanding of the functions performed by the various participants in the private insurance market. These participants include brokerage firms, primary property-casualty insurers, reinsurance companies and insurance/reinsurance pools. The following provides a general definition of each of the market sectors:

- Broker: A soliciter of insurance who represents the insured in negotiations with insurance companies to obtain insurance coverage for the insured's particular needs; is often the initiator in working with insurance organizations to arrange for protection of unusual or extremely large risks.
- Insurance Company: An organization chartered and regulated under state laws to indemnify another (the insured) for loss caused by designated hazards or perils; the company assumes by contract (the policy) financial responsibility for the specified risks of its policyholders.
- Reinsurance Company: An insurance company which accepts all or a specified portion of the risk of loss of another insurer; this is a mechanism for spreading the risk of loss between two or more insurance companies; the two principal types of reinsurance are treaty reinsurance based on a previously agreed to contract between the companies and facultative reinsurance where individual risks are accepted at the option of the two companies.

- Insurance Pool: A group of insurance companies that have joined together for the purpose of sharing certain risks on an agreed upon basis; usually structured to underwrite similar risks for a group of insurers with similar characteristics.

Each of the above sectors of the private insurance market was considered to have knowledge and experience in dealing with insurance risks for emerging industries. It was, therefore, determined that representatives of each of the above sectors should be included in the insurance interview process.

SELECTION OF INTERVIEWEES

Method of Selection

Efforts to obtain a representative cross-sample of the insurance industry began with the analysis of several industry summaries such as the Fire, Casualty & Surety Lines Aggregate Financial Report, Best's Insurance Management Reports and other insurance publications. This analysis identified a preliminary list of insurers, reinsurers and other underwriting organizations from which the final list of interviewees would be selected. The preliminary list included insurers whose commercial lines of business represented a significant portion of their total book of business underwritten, the principal reinsurance companies and organizations and other underwriting groups with experience in energy industries. A list of more than fifty potential interviewees was prepared through this process.

The final list of interviewees was prepared following more extensive analysis of the commercial lines of business written by the companies including some direct experience with energy related hazards. Telephone contacts were made with companies and organizations on the list when questions existed regarding the organization's experience relative to this study. Among the individuals and organizations contacted but not formally interviewed were

Mr. Al J. Borris, C.P.C.U., Manager of Client Services for EBASCO Risk Management Consultants, Inc. and Mr. Michael Ovens of the London brokerage firm of Harris & Dixon. EBASCO, which manages a mutual insurance company established in Bermuda in response to the casualty insurance needs of the United States public utility industry, declined to be interviewed because they had no property insurance expertise and there was no apparent interest in covering property risks. The firm of Harris & Dixon has worked through Lloyds Underwriters in London to provide property insurance on some foreign geothermal power plants not including coverage on the reservoir performance.

After completion of the analysis, a list of twenty-one final interview candidates was prepared. These included two primary insurance carriers with known geothermal experience, nine other primary insurers, eight of the largest reinsurers operating in the United States, one reinsurance pool with property insurance experience and two of the major brokerage firms. This final list of interview candidates was reviewed and approved by insurance personnel of Coopers & Lybrand. Seventeen of the twenty-one interview candidates were formally interviewed by the project team.

Composite Profile of Interviewees

Though it is difficult to precisely detail all of the characteristics represented by the interviewees, some of the common characteristics of the organizations interviewed are described below. Many of these characteristics are reflective of the size and diverse interest and expertise of the organizations.

Among the characteristics of the organizations interviewed for this study are:

- The organizations generally ranked within the top twenty-five property and casualty insurers in the United States, the top fifteen reinsurers or the top five insurance brokerage firms.

- Commercial lines of insurance constitute a significant portion of the companies' total book of insurance written.

- Each of the organizations had knowledge and experience with insuring against the hazards of several energy fields, including petroleum, gas and coal.

- Most of the organizations had knowledge or experience in providing insurance protection for unusually large risks or risks where historical data was difficult to secure; this protection was provided individually or through pooling arrangements such as the nuclear energy liability pools.

- Many of the insurance organizations interviewed have direct experience in the emerging energy technologies, such as, solar, synfuels, coal gasification, wind and waste recovery.

- Seven of the seventeen companies indicated specific knowledge or experience with geothermal energy risks.

- Many of the respondents have or are currently providing insurance coverages under standard forms, such as property damage to power plants, workers compensation, boiler and machinery and builder's risks for energy industries including geothermal.

Exhibit IV-1 lists the twenty-one interview candidates who were contacted requesting their participation in the interview process. A total of 61 executives representing seventeen firms agreed to participate and were formally interviewed by senior insurance consultants of Coopers & Lybrand. By category, those companies contacted by Coopers & Lybrand are listed with the company representatives who participated in the interviews.

EXHIBIT IV-1
Page 1 of 4

INSURANCE SECTOR INTERVIEWEES

1. Geothermal Energy Insurance

A. INA Underwriters Insurance Company
New York, New York

Person interviewed:

Mr. Akos Swierkiewiez, Vice President - Property

B. American Home Assurance Company and AIG Energy
New York, New York

Persons interviewed:

Mr. Michael I. D. Morrison, President

Mr. Charles Force, Executive Vice President, AIG Energy

Mr. Kirk Mellen, Senior Casualty Officer

2. Commercial Insurers

A. Continental Insurance Companies
New York, New York

Persons interviewed:

Mr. Charles L. Rueff, Senior Vice President

Mr. Robert M. Menninger, Vice President, Continental Risk Services

Mr. George S. Zacharkow, Marine Office of America

Ms. Beverley B. Wadsworth, Vice President International & Reinsurance

Mr. David R. Sheppard, Swett & Crawford

Mr. Robert F. Nabors, Executive Vice President, Underwriters Adjustment Company

Mr. Tom Coleman, Assistant Vice President, Continental Boiler & Machinery

Mr. Robert F. Lowry, President, All American Marine Slip

Mr. W. F. Warm, President, Cargo Surveyer Inc.

Mr. Harold Culler, Vice President, Continental Technical Services

Mr. Stan S. Roblin, Director of Underwriting, Continental Special Risks Underwriters

Mr. Richard Pflager, Commercial Property Underwriting

INSURANCE SECTOR INTERVIEWEES

B. Highlands Insurance Company
Houston, Texas

Persons interviewed:

- Mr. James A. Terry, President
- Mr. Harold F. Duble, Executive Vice President
- Mr. D. W. McGillicuddy, Senior Vice President
- Mr. B. J. Phillips, Senior Vice President
- Mr. Norris Krieg, Vice President
- Mr. J. E. Smith, Vice President
- Mr. Jim West, Assistant Vice President
- Mr. Charlie Martin, Vice President

C. Kemper Insurance Companies
Long Grove, Illinois

Persons interviewed:

- Mr. Warren T. Boyce, Vice President
- Mr. Robert A. Garwood, Assistant Manager Commercial Casualty Underwriting
- Mr. Forest S. Paddock, Assistant Manager Boiler and Machinery Underwriting

D. Maryland Casualty Company (American General Group)
Baltimore, Maryland

Persons interviewed:

- Mr. L. L. Lucas, Senior Vice President Underwriting
- Mr. James Krafft, Vice President Casualty
- Mr. George Cass, Vice President Property
- Mr. John Russell, Vice President Loss Control
- Mr. Gene Cavey, Assistant Vice President Casualty

E. Travelers Corporation
Hartford, Connecticut

Persons interviewed:

- Mr. George Ramsdel, Senior Vice President
- Mr. Thomas Jackson, Secretary, Product Manager Commercial Underwriting

EXHIBIT IV-1
Page 3 of 4

INSURANCE SECTOR INTERVIEWEES

Persons interviewed, continued:

Mr. Roger Faulk, Supervising Market Analyst,
Boiler and Machinery

Mr. Frank Young, Associate Director Engineering

Mr. Henry Elliott, Associate Director Engineering

F. United States Fire Insurance Company (Crum & Forster Group)
Morristown, New Jersey

Persons interviewed:

Mr. George L. Yeager, Senior Vice President

Mr. Roger A. Quigley, Vice President

Mr. Donald J. Prudhomme, Vice President

Mr. Harry T. Matt, Vice President

Mr. Edward J. Ritter, Assistant Vice President

3. Reinsurance Companies

A. General Reinsurance Corporation
Greenwich, Connecticut

Persons interviewed:

Mr. Bruce Hayden, Assistant Vice President
Facultative - Casualty

Mr. Thomas McCarthy, Vice President
Facultative - Property

B. American ReInsurance Company
New York, New York

Persons interviewed:

Mr. Herbert W. Shaw, Jr., Senior Vice President

Mr. James Pearce, Vice President

Mr. William McGill, Assistant Vice President

C. Munich American Reinsurance Company
New York, New York

Person interviewed:

Mr. Michael A. Pero, Vice President

EXHIBIT IV-1
Page 4 of 4

INSURANCE SECTOR INTERVIEWEES

D. North American Reinsurance Corporation
New York, New York

Persons interviewed:

Mr. C. W. Price, Secretary

Mr. James E. Baxendale, Vice President

Mr. Robert N. Wanglund, Vice President

Mr. Robert Mirabile, Assistant Vice President

Mr. Hans Gfeller, Assistant Manager, Engineering Risks Department

E. Prudential Reinsurance Company
Newark, New Jersey

Person interviewed:

Mr. John Spoonauer, Director

F. Industrial Risk Insurers
Hartford, Connecticut

Person interviewed:

Mr. Blinn McClelland, Vice President

G. SCOR Reinsurance
Dallas, Texas

Persons interviewed:

Mr. Marcus Corbally, MICE, Vice President Technical Risks

Mr. Larry F. Bachel, PE, Assistant Manager Technical Risks

Mr. Karl Hauenstein, Casualty Department

4. Brokerage Firms

A. Corroon & Black of Pennsylvania
Philadelphia, Pennsylvania

Person interviewed:

Mr. Norman K. Barrett, Senior Vice President

B. Marsh & McLennan
San Francisco, California

Persons interviewed:

Mr. John R. Taylor, Senior Vice President

Mr. Michael Enfield, Vice President

INTERVIEW PROCESS

To obtain consistent information from the interviews, a detailed questionnaire was prepared. The questions included knowledge and experience in energy industries, specific experience with geothermal energy and assessment of the risks associated with geothermal reservoir insurance as identified earlier in the project. The questionnaire was designed to provide each of the interviewers a uniform approach to the collection of both the objective and subjective data required. For those questions seeking subjective information the questionnaire was designed to obtain the interviewees' perspective.

Questionnaire Format

The questionnaire was divided into five principal sections with the first section used to profile the interview respondent. The second section of the report profiled the respondent company's knowledge and experience in providing insurance protection for energy industries. Among the eight energy types included were petroleum, gas and geothermal. This section was intended to gather information on the extent of coverage provided by each company to other energy industries for risks that were similar to those experienced in the geothermal field, such as drilling risks and underground storage reservoirs. Also identified in this section were the types of coverage written and any limitations on the company's capacity. For those respondents who had specific experience with geothermal energy, this section contained a series of questions to ascertain the interviewees' geothermal experience. The questions included a description of coverage quoted/issued, pre-issue underwriting information, specific problems encountered and types of coverage requested that the company declined to provide. This series of questions on specific geothermal experience was completed for each prospect or insured that the company had dealt with. Those companies with no geothermal experience were asked if they had ever declined to quote on a geothermal risk and, if so, the reasons for the declination.

The third section of the questionnaire covered the respondent company's perception of the geothermal risks and the company's assessment of the insurability of those risks. The list of risks was prepared for this questionnaire following analysis of the priorty risks identified in prior interviews with geothermal developers, geothermal energy users and lenders and analysis of additional risk information. The section identified eight principal risk categories with more than forty individual risk types. The questions on the insurability of specific risks focused on each particular respondents reaction. A negative reaction to insurability did not signify that the risk is necessarily uninsurable but rather than that respondent would not want to insure that risk at this time. This section also sought information on the appropriateness of limiting insurance protection only to specific project types and/or stages in the development and production process.

The fourth section of the interview questionnaire was designed to determine the types of coverage the interviewee would consider appropriate for those risks identified as insurable in the previous section. The questions in this section would also provide a general sense of the company's willingness and capacity to provide protection against these risks. Specific information requested included coverage limits, policy conditions, policy term, deductibles and renewal guarantees. It was recognized that obtaining this specific information might prove difficult because of the potential variability of limits, conditions, underwriting requirements, etc., by the different project types, the lack of risk information on which the interviewee could conduct an evaluation and the constraints of the interview process which limited the time available for understanding and evaluating risks. It was also anticipated that certain information requested in this section would be considered proprietary by the respondants and therefore unavailable.

The last section of the questionnaire asked for general responses to narrative questions on the potential role of the federal government in providing insurance for geothermal risks. The questions sought the interviewees' opinion of the impact on their company's willingness to ensure geothermal risks if government insurance/reinsurance existed and sought the respondant's perception of the pros and cons of government involvement in a geothermal insurance/reinsurance program. The appropriate roles of the private insurance sector and the government in a geothermal insurance program were covered in this section of the questionnaire. Additionally, the questionnaire sought to determine the interviewees perception of the impact of a pooling arrangement by the private sector.

The questionnaire, utilized by the insurance consultants of Coopers & Lybrand in the interview process, is presented in Exhibit IV-2.

EXHIBIT IV-2
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DEPARTMENT OF ENERGY
GEOTHERMAL RESERVOIR INSURANCE STUDY
INSURANCE/REINSURANCE
INTERVIEW QUESTIONNAIRE

I. Interview Profile

A. Name of Respondent ____________________
B. Title of Respondent ____________________
C. Company ____________________
D. Address ____________________
____
E. Telephone ____________________

F. Others Atttending:

Name ____________________ Title ____________________
Name ____________________ Title ____________________
Name ____________________ Title ____________________
Name ____________________ Title ____________________

G. Interviewers:

Name ____________________ Office ____________________
Name ____________________ Office ____________________

H. Date of Interview ____________________

EXHIBIT IV-2
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DEPARTMENT OF ENERGY
GEOTHERMAL RESERVOIR INSURANCE STUDY
INSURANCE/REINSURANCE
INTERVIEW QUESTIONNAIRE, Continued

II. Description of Experience with Geothermal or Other Energy Types

1. We would like to understand your familiarity with the geothermal energy industry and with the production and use of other types of energy. Please indicate the types of energy in which you have knowledge or experience.

Energy Type	Knowledge	Experience	Level
A. Coal	☐	☐	
B. Geothermal	☐	☐	
C. Natural Gas	☐	☐	
D. Nuclear	☐	☐	
E. Petroleum	☐	☐	
F. Solar	☐	☐	
G. Synfuels	☐	☐	
H. Other	☐	☐	

2. Comments on Knowledge and Experience:

EXHIBIT IV-2
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DEPARTMENT OF ENERGY
GEOTHERMAL RESERVOIR INSURANCE STUDY
INSURANCE/REINSURANCE
INTERVIEW QUESTIONNAIRE, Continued

3. If you had specific experience with geothermal, what was your experience?

   A. Request for quote or policy issued? ____________________

   B. Name of prospect or insured and description of project/facility. ______________________________

   ____

   ____

   ____

   C. Description of coverage quoted/issued, including type, limits, conditions, term, and premium basis. __________

   ____

   ____

   ____

   D. What types of pre-issue information did you require?

   ____

   ____

   ____

   E. What specific problems did you encounter in quoting on these coverages or issuing these policies?

   ____

   ____

   ____

DEPARTMENT OF ENERGY
GEOTHERMAL RESERVOIR INSURANCE STUDY
INSURANCE/REINSURANCE
INTERVIEW QUESTIONNAIRE, Continued

F. Where there types of coverage desired by the prospect/ insured that you would not provide? Please identify the coverage and specific reasons.

____
____
____
____

4. If you have not had any specific experience with geothermal, have you ever declined to quote on coverage for geothermal risks? ____________________

Why did you decline?

1. ____________________________________
2. ____________________________________
3. ____________________________________
4. ____________________________________
5. ____________________________________

EXHIBIT IV-2
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DEPARTMENT OF ENERGY
GEOTHERMAL RESERVOIR INSURANCE STUDY
INSURANCE/REINSURANCE
INTERVIEW QUESTIONNAIRE, Continued

III. Risk Assessment

1. In an earlier part of this study we interviewed a sample of geothermal energy developers, users and lenders and obtained their perceptions of the priority risks in geothermal energy. With the assistance of our engineering subcontractor, we were able to prepare a list of these risks. We would like your reaction to this list, including specific insurability.

Priority Risks	Insurable		Comments
	Y	N	
A. WELL RISKS			
1) Events leading to a reduction in useful well life--for both production and injection wells.			
a) Scaling			
b) Corrosion			
c) Well-face plugging			
d) Mechanical damage			
2) Drilling and completion problems			
a) Mechanical problem			
b) Other			
3) Success ratio less than expected			
B. SURFACE FACILITY RISKS			
1) Failure of advanced design equipment			
a) Pumps			
b) Other			

EXHIBIT IV-2
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DEPARTMENT OF ENERGY
GEOTHERMAL RESERVOIR INSURANCE STUDY
INSURANCE/REINSURANCE
INTERVIEW QUESTIONNAIRE, Continued

Priority Risks	Insurable	Comments
2) Failure of standard design equipment (major unplanned consequences)		
3) Scaling and corrosion --management related (Improper handling and treatment)		
4) Scaling and corrosion -- Greater than expected		
C. PLANT RISKS		
1) Power plant performance		
2) Transmission		
a) Availability of lines		
b) Accidents		
c) Other		
D. RESERVOIR PERFORMANCE RISKS		
1) Interference of other wells (adjacent development)		
2) Improper well siting (within particular development)		
- Pressure decline		
- Flashing in reservoir		
3) Production/Injection strategy - Including premature cooling due to injection well siting		
4) Adverse change in		
a) Chemistry (including non-condensable gas effect)		
b) Temperature		
c) Pressure		
d) Enthalpy		
e) Permeability		

EXHIBIT IV-2
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DEPARTMENT OF ENERGY
GEOTHERMAL RESERVOIR INSURANCE STUDY
INSURANCE/REINSURANCE
INTERVIEW QUESTIONNAIRE, Continued

Priority Risks	Insurable	Comments
5) Reservoir characteristics adversely different than originally expected		
a) Temperature		
b) Reservoir size		
c) Chemistry		
d) Enthalpy		
e) Permeability		
E. ACTS OF GOD		
1) Landslides		
2) Volcanic hazards		
F. DELAYS		
1) Water rights disputes (Stage 1)		
2) Social acceptance		
G. MARKETABILITY		
1) Regulatory rate treatment		
2) Limited market size		
3) Difficulty in negotiating a sales contract		
4) Alternative energy costs		
5) Long-term market for end-product		
H. ENVIRONMENTAL		
1) Access to water--long run drought		
2) Subsidence caused by net fluid withdrawal - liability issue		

Should insurance protection be limited to certain types of projects and/or certain stages of development?

____

____

____

DEPARTMENT OF ENERGY
GEOTHERMAL RESERVOIR INSURANCE STUDY
INSURANCE/REINSURANCE
INTERVIEW QUESTIONNAIRE, Continued

IV. Protection Against Loss

For each of the risks that you identified as insurable, we would like to obtain more specific information on your willingness and capacity to provide protection against these risks.

1. Identification of risk

Code ____ Risks ______________________________

2. What coverages do you currently offer or would you consider offering to protect against loss from this risk?

____

____

3. What do you consider appropriate for this risk:

A. Coverage Limits ______________________________

B. Policy Conditions ______________________________

C. Policy Term ______________________________

D. Deductible ______________________________

E. Guaranteed Renewal ______________________________

F. Other ______________________________

____

____

Comments: ______________________________

____

____

____

DEPARTMENT OF ENERGY
GEOTHERMAL RESERVOIR INSURANCE STUDY
INSURANCE/REINSURANCE
INTERVIEW QUESTIONNAIRE, Continued

4. What types of pre-issue requirements would you consider necessary?

   A. Projected costs for field development and facilities construction and estimated time span for each. ________

   B. Copies of pertinent contracts among involved parties ________

   C. Technical information:

      - Geothermal reservoir ________
      - Individual wells ________
      - Proposed facilities ________
      - Testing results ________
      - Environmental impact ________
      - Other technical (specify) ________

   D. Other ____

   ____

5. What level of reinsurance would you consider appropriate?

   ____

   ____

6. Other Comments: ____

   ____

   ____

   ____

   ____

DEPARTMENT OF ENERGY
GEOTHERMAL RESERVOIR INSURANCE STUDY
INSURANCE/REINSURANCE
INTERVIEW QUESTIONNAIRE, Continued

V. General Considerations

1. How would the existence of a government-backed reinsurance program impact your willingness to provide coverage for protection against loss from geothermal risks?

2. What would you consider to be the advantages and disadvantages of a government-backed insurance/reinsurance program for geothermal risks?

3. What would you consider to be the appropriate roles for private insurers, reinsurers and government in a geothermal insurance/reinsurance program?

4. Would the existence of a private geothermal insurance pool impact your consideration of providing protection against loss from geothermal risks?

Conduct of Interviews

Interviews with the insurance organizations identified earlier were conducted by senior insurance consulting personnel from Coopers & Lybrand's New York, Boston, Dallas and Chicago offices. The interviews were conducted in the interviewees offices during a three week period in April and May, 1981. When contact was made with the interview candidates the interviewers outlined the background of the study and offered an advance copy of the questionnaire such that the interviewee could become familiar with the material. A glossary of the geothermal risks and a description of project types was also included with the advance material.

RESULTS OF INTERVIEWS

Energy Industry Experience

Those interviewed generally had extensive knowledge of and experience in dealing with the risks associated with various energy production industries, including the petroleum, natural gas, coal and nuclear industries. This knowledge and experience extends to some smaller insurance companies through participation in pools such as Industrial Risk Insurers and the nuclear energy liability pools. Exhibit IV-3 illustrates the background of the interviewees in the various energy industries. Knowledge of an energy industry by an insurer means the completion of research and analysis into the hazards faced by a particular energy industry. Experience with an energy industry means either the issuance of an insurance policy covering some portion of the energy industry's hazards or the desire to issue a policy through transmittal of a quote on a particular coverage or coverages.

EXHIBIT IV-3

PROFILE OF KNOWLEDGE AND EXPERIENCE IN ENERGY INDUSTRIES

Energy Industry	Knowledge	Experience
Petroleum	100%	100%
Natural Gas	100%	100%
Coal	93%	93%
Synfuels	80%	73%
Nuclear	73%	73%
Solar	67%	57%
Geothermal	53%	46%
Other*	60%	60%

It is important to note that most of the insurance protection provided to the energy industries, including geothermal, by the companies interviewed have been provided under standard forms of coverage such as property damage to plants, boiler and machinery, builder's risk and completed operations. Some companies have conducted extensive research and, in a few cases, have written unconventional coverages on energy risks. At least three primary insurers and two reinsurers have conducted significant research in order to provide protection for underground storage reservoirs for oil and natural gas. The principal difference in underwriting these storage reservoirs and a geothermal resource reservoir is the ability to determine the value, quantity and quality of the resource in the reservoir. Other companies interviewed had pioneered insurance protection for many of the emerging energy fields. Companies have provided insurance protection to both energy developers and energy users.

---

*Other energy industries include wind, coal gasification, hydro and waste recovery.

Specific Geothermal Experience

Through the interview process, four primary insurers and five reinsurers who have direct experience in providing protection to the geothermal energy industry were identified. Of the three primary insurers, one company's experience occured approximately 10 years ago and the company declined any specific comments on that experience. Another primary insurer has been actively involved in a geothermal energy resource insurance program and, although they have quoted on eight different geothermal projects, no policy has yet been issued. One other company is currently writing standard form coverages for a geothermal project but is not providing any protection for the reservoir. The remaining company provided only physical damage on drilling rigs.

Those reinsurers with geothermal energy industry experience include four who have participated with one of the above primary insurers either on quotes for specific projects or support for the primary insurer's program. One of these reinsurers is also providing reinsurance protection on a floater policy with standard coverages for pipes, drilling and underground lines. One other reinsurer has issued a reinsurance contract to a west coast insurer for a principal geothermal developer. This is an all risk policy covering physical damage and contingent business interruption but specifically excluding claims from loss of steam or pressure.

There was some reluctance among companies with specific geothermal experience to offer more than general information on that experience. There were three principal reasons for this reluctance:

- Some of the information requested on the company's experience such as project name, coverage limits, exclusions and premium basis was considered proprietary.

- Certain specific data requested varied substantially by project type and coverage limits, exclusions and policy term were to be individually negotiated with the prospective insured based on general underwriting guidelines.

- The reinsurers would negotiate the specifics of the reinsurance coverage provided to the primary insurer on the basis of a specific proposal made by the primary insurer and therefore a standard reinsurance arrangement for geothermal projects did not exist.

The information that was provided, though usually general in nature, was sufficient to produce a valid overview of the companies' willingness to meet what they perceived to be the insurance needs of the geothermal energy industry. Two primary insurers and four reinsurers agreed in principal that protection of the geothermal resource reservoir can be achieved in addition to the more standard forms of coverage. One of the primary insurers is currently developing its geothermal reservoir insurance program and underwriting guidelines. The remaining primary insurer has a general program developed and has obtained the support of the four reinsurers. The following points summarize this company's program:

- The program is designed to insure the long-term availability of the geothermal resource at levels of quantity and quality established prior to policy issuance.

- Insurance protection is offered on an all-risk* basis for loss arising out of project termination and/or reduction of project capability because of resource inadequacy. (*except those specifically excluded in the policy).

- Coverage is offered for a noncancellable policy period encompassing the construction phase (21-42 months) plus an operational period of up to seven years.

- The program provides indemnification to indirect users (e.g. electric generation plants) in the form of payment of the sunk costs of the project in the event of project termination prior to project completion (construction phase) or the unamortized sunk costs if the project is terminated in the operation phase; for reduced capability the program provides indemnification of agreed amounts to assure continuation of the debt service and payment of fixed amounts.

- The program can also include coverage for loss of earnings because of project termination or reduced capacity.

- The program can provide indemnification to direct users of the geothermal resource in the form of the actual cost of an alternatively fueled steam boiler sufficient to produce the temperature level and quantity of heat requried for the project; the actual cost of the alternative fuel required; the annual cost of redrilling or reworking the geothermal well.

- The program is specifically tailored to each project and directly reflects the insurable interest of the insured.

- The company has quoted on coverage for eight different projects, with total exposure ranging from more than $700,000 to approximately $66 million.

This company and its reinsurers have been willing to assume full capacity for these exposures and it is the only company actively marketing this coverage. Through its pre-issue underwriting requirements, the company attempts to confirm the existance of the geothermal resource to an 80% - 100% reliability level based on the current state of geothermal technology.

Though insurance protection of the geothermal reservoir is evolving, several problems have hampered the efforts of the insurance industry. These problems were cited by the companies attempting to market the coverage and by companies who have not been involved in protecting the geothermal energy industry. Among the problems encountered and reasons for non-involvement are:

- Lack of historical data on the geothermal resource.

- Reliability of available data.

- Catastrophe possibility limited the companies' willingness to accept that exposure.

- Insurance company involvement occured too late in the project financing structure making it difficult to superimpose insurance.

- Desired term of coverage was unacceptable.

- Difficulty in determining the specific insurance needs of an individual project.

- Inability to determine appropriate retention levels.

Whether these problems are real or perceived, they do in fact present a substantial barrier to the full participation of the insurance industry in providing protection for the geothermal reservoir. One of the points that emerged from the interview process was the apparent limited communication between the geothermal energy industry and the insurance industry on the depth of these problems and limited efforts to jointly resolve these problems.

One of the key findings of the interviews was that, of the primary insurance companies that have been approached, only one declined to provide any coverage for the protection desired by the prospective insured. The requested coverage included protection against loss of market and the effects of government regulations. However, this company also was willing to negotiate a buy back of these exclusions with the prospective insured.

Perception of Risk

This subsection of the report reviews the portion of the interview questionnaire that deals with the respondent's assessment of the principal geothermal resource risks identified earlier in the study. Although seventeen insurance organizations were formally interviewed, the questions in this section were not applicable to the two brokerage firms, thereby, reducing the maximum cumulative responses to fifteen. The following paragraphs and exhibits analyze the companies' perception of the insurability of those risks, the appropriate coverages and evaluation of the possible differences in protection by project type and stage of development. It is important to recognize that while some companies reached similar conclusions on insurability, they did so for varying reasons reflecting their own underwriting guidelines and policy. Even those who agree that a particular risk is insurable often disagree on the precise coverage needed to protect against loss. Also, the fact that a respondent identified a particular event as uninsurable does not necessarily imply that it is an uninsurable risk but rather that the particular insurer would not want to provide coverage for it at this time. Whatever else may be learned from this portion of the questionnaire, the lack of uniformity in the responses is indicative of the varied and competitive nature of the insurance industry.

Prior to analyzing the interview results, it is important to understand the generally accepted characteristics of an insurable risk:

- There must be a large group of homogeneous exposure units.
- The loss produced must be definite.
- The occurrence of the loss in individual cases must be accidental or fortuitous.
- The chance of loss must be calculable.

Other characteristics often included in the definition of insurable risk are that the potential loss must be of sufficient size to cause a hardship, the cost of insuring must be economically feasible and the risk must be unlikely to produce loss to a great many insured units at the same time.

On the following pages, the analyses of risk insurability from the interviewees perception are divided into general risk categories including a definition of both the categories and the specific risks. The numbers next to each of the risks on the exhibits represent the number of companies who view the particular risk as insurable or uninsurable.

The first risk catagory to be considered are the risks that arise in the drilling, operations and maintenance of geothermal wells. The useful well life is the scheduled or expected number of years during which a well is economically operable. Though well life varies from field to field, the expected life usually ranges from 5 - 20 years. This catagory includes both production and injection wells. The specific definitions of risks as provided to the interviewees are:

Scaling - Chemical precipitate from the geothermal fluid. Most common kinds in geothermal system: calcium carbonate ($CACO_3$) and silica (SiO_2).

Corrosion - Rusting or dissolving of downhole casing, surface fluid-handling lines, and other metal components of the geothermal system.

Well-face plugging - Chemical precipitate forms where water moves through slotted casing into or from the well, or in permeable zones immediately adjacent to hole. Most common in injection wells.

Mechanical damange or mechanical problems - Loss of equipment or tools in hole, casing collapse, cement failure, casing leaks, etc. Specifically excludes scaling and corrosion.

Drilling and completion problems - Completion of a well by installation of a casing or a liner which partially or totally seals off the production zone(s). A liner (casing which is hung from its top and not cemented in place) may be pre-slotted to allow entry of formation fluids. A liner supports the hole and prevents sloughing or cave-ins. Incorrect location of the slots or an insufficient number of slots may prevent or limit production. Slots may also become sealed by sand or clay from the formation or scaling. Correction may be attempted by shooting new holes through the liner or through the cemented casing using special tools lowered downhole.

<u>Success ratio less than expected</u> - The number of successful (production) wells drilled divided by the total number of wells drilled. In all reservoir developments a certain fraction of the wells drilled will be unsuccessful. Prediction of the location of permeable zones in the reservoir may be difficult and "dry" holes may be drilled even within areas of known production. Increased drilling experience is likely to establish a fairly well-known success ratio, but initial estimates based on the drilling of only a few wells may be highly erroneous. More likely to be high in heavily drilled parts of a field than on the margins where the lateral extent of the reservoir is uncertain.

From Exhibit IV-4, it is apparent that only certain of the well risks were considered insurable by a majority of the respondents. These were the reduction in useful well life and drilling and completion problems caused by mechanical damage/problems. Less than a third of the interviewees also believed that the risk of well success ratio less than expected would also be insurable. Though each of the other individual risks were viewed as uninsurable by most respondents, at lease one company indentified each of these risks as insurable.

EXHIBIT IV-4
INSURABILITY OF WELL RISKS

Risk	Insurable	Uninsurable
1. Events leading to a reduction in useful well life		
a. Scaling	1	14
b. Corrosion	1	14
c. Well-face plugging	2	13
d. Mechanical damage	9	6
2. Drilling and Completion Problems		
a. Mechanical problems	8	7
b. Other	1	5
3. Success ratio less than expected	4	11

Generally the interviewees considered these risks to be of the maintenace, wear and tear and housekeeping variety, controllable by project management and therefore uninsurable. Even those who identified these risks as insurable did so with the caveat that only the loss caused by a sudden and accidental occurrance would qualify as an insurable loss. Coverage that the companies believed would generally apply to those risks viewed as insurable would include boiler and machinery (for damage/failure to the vessel), standard business interruption protection and physical damage to the equipment. The cost of the removal of scaling and corrosion and other evolutionary type risks were seen as an integral part of the risk of doing business for the project. Only one company believed any of the risks would be covered by protection against the reduction of the resource capability and that was limited to the risk of the well success ratio being less than expected.

The next risk category evaluated by the interviewees is the surface facility risks, including accidents to or failure of downhole pumps, steam or water gathering lines, auxiliary values and piping and geothermal water disposal lines. Specific definitions of risks in this category are:

Advance design equipment - Items for which design principles and operating histories are not well established. For geothermal systems, downhole pumps for high temperature (300-450°F) applications are the main such items.

Standard design equipment - Example: Large diameter steam or hot water gathering lines.

Scaling and corrosion - improper handling - Improper equipment design, designed pressure decline in system, designed temperature decline in system, incorporation of atmospheric oxygen in fluid and/or mixing of brines causes unnecessary degree of scaling or corrosion.

Scaling and corrosion - greater than expected - Even though optimum equipment design and fluid handling procedures are followed, the rate of scaling and/or corrosion is excessive.

Exhibit IV-5 displays that accidental damage to and in some cases failure of equipment of both advanced and standard design is considered insurable by a sizeable number of interviewees. The damage to or failure of pumps was viewed as insurable by more than two-thirds of the respondents if caused by accident. Without exception these companies would exclude design failure and limit mechanical breakdown. Some companies indicated they would not provide coverage during the initial period of use of the equipment because they believed this should be covered by the manufacturer's warranty. Only one insurer indicated that they might offer standard business interruption coverage for loss while the facility is down from one of these risks, otherwise those responding would apparently limit coverage to physical damange protection for the equipment. Those companies who viewed these risks as uninsurable did so because they viewed the risks as the responsibility of the equipment manufacturer's warranty program, as failure of the manufacturer's design and thereby a liability issue with the manufacturer or simply a risk of conducting business.

EXHIBIT IV-5
INSURABILITY OF SURFACE FACILITY RISKS

Risk	Insurable	Uninsurable
1. Failure of advance design equipment		
a. Pumps	11	4
b. Other	7	3
2. Failure of Standard Design	7	8
3. Scaling & Corrosion - management related	2	13
4. Scaling & Corrosion -greater than expected	2	13

The next category of risk is the plant risks. This category includes accidents to or failure of equipment in the electrical power generating facility or heat consuming process (for direct use projects). The two specific risks within this category are the power plant performance and the availability of transmission facilities. Specific definitions of risk in this category are:

Power plant performance - Failure of equipment, such as turbines in an electrical generating facility due to damage from particulate matter or dissolved solids.

Transmission availability - The availability of transmission facilities from the island of Hawaii to the other islands in the Hawaiian chain.

For the risks associated with power plant performance a majority of the respondents viewed the risk as insurable, though for a variety of reasons and only for certain coverages. Most of the insurers would only cover the physical damage to the plant caused by an accident and would consider loss of performance caused by other factors. Only one insurer viewed standard business interruption insurance as appropriate for this type of loss. All but two respondents viewed the accidential loss of transmission facilities as an insurable risk while only four of the respondents believed that the availability of transmission lines was insurable. Companies were divided on the appropriate coverages for the transmission risks. Some believed that they would provide physical damage coverage on the lines while others believed that standard business interruption coverage could be provided. Only one company believed that both coverages would be appropriate. Those companies responding negatively to the insurability of these risks generally believed that performance risks were a hazard of doing business.

EXHIBIT IV-6
INSURABILITY OF PLANT RISKS

Risk	Insurable	Uninsurable
1. Power Plant Performance	8	7
2. Transmission		
a. Availability of lines	4	10
b. Accident	13	2
c. Others	2	3

The next category of risks are those dealing with reservoir performance. The category includes those problems which affect the entire subsurface structure which yields the geothermal fluid and excludes those problems in individual wells that can be solved by drilling a new well at that site. The key definitions of individual risks in this category are:

Interference of other wells (adjacent development) - Pressure and/or temperature drops within one project because the same subsurface reservoir also is being tapped for a nearby, independent project.

Improper well siting (particular development) - Pressure and/or temperature drops because the wells within a single project are spaced too closely, causing the reservoir to be depleted more rapidly than necessary.

Premature cooling due to production/injection well siting - Injection wells are improperly placed too close to production wells, causing cold water to invade the production zones leading to lower net productivity.

Adverse change - Reservoir characteristics over long-term exploitation are different from those projected to occur in this long-term phase. The projected characteristics were based on experience gained early in the project.

Reservoir characteristics adversely different than expected - Reduced reservoir performance in the early stages of develoopment (Stages 1 & 2) because the reservoir characteristics (chemistry, temperature, pressure, enthalpy and permeability) are worse than originally expected based on limited experience with the development.

This is the risk category where the interviewees were most divided in their opinions. For the first three items the majority of companies viewed the risks as uninsurable. The reasons given for these responses include:

- Interference from other wells
  - a business risk
  - a liability issue for the other party
  - impossible to determine probability of loss
- Improper well citing
  - a business risk
  - a matter of professional liability on the part of the geologist/engineer
- Production/injection strategy
  - a business risk

Those companies who identified these three risks as insurable belived that they were all causes of resource inadequacy which they were willing to protect against. As Exhibit IV-7 shows, the respondents were divided on the insurability of risks included under the items of adverse change in reservoir characteristics or the reservoir characteristics found to be adversely different than expected.

EXHIBIT IV-7

INSURABILITY OF RESERVOIR PERFORMANCE RISKS

Risk	Insurable	Uninsurable
1. Interference from other wells	1	14
2. Improper well citing	2	13
3. Production/Injection strategy	2	12
4. Adverse change		
a. Chemistry	7	7
b. Temperature	7	7
c. Pressure	7	8
d. Enthalpy	7	8
e. Permeability	7	8
5. Characteristics adversely different than expected		
a. Chemistry	5	9
b. Temperature	5	10
c. Pressure	5	10
d. Enthalpy	5	10
e. Permeability	5	10

Unlike the earlier risks in this category, the respondents who determined that the last two risk items were insurable believed that before a final determination on insurability could be made a clear understanding of the amount of change expected would be required and agreed on prior to policy issuance. Some insurers believed that this could be covered by protection against diminished reservoir capacity while others believed that only losses from damage to or failure of equipment, caused by these factors, should be provided.

While many of the same companies viewed the particulars of the last item, reservoir characteristics adversely different than expected, as insurable, they were hesitant to be fully committed to provide such coverage. Companies anticipated very large exposure in the area of professional liability for the geologist and engineers.

The next risk category, acts of god, was viewed by most respondents as insurable. As indicated in Exhibit VI-8, a total of twelve companies believed that loss caused by landslides and volcanic erruptions would be insurable though perhaps under a separate policy for physical damage. Some interviewees indicated that a final determination would be made on each situation based on detailed underwriting analysis.

EXHIBIT IV-8
INSURABILITY OF ACTS OF GOD

Risk	Insurable	Uninsurable
1. Landslides	13	1
2. Volcanic erruption	13	1
3. Earthquakes*	4	1

The sixth risk category is the risk of delays. There were two specific items in this category: water rights disputes and social acceptance. The definitions of these risks as used in the interviews are:

> Water rights disputes - Good quality, cold water is necessary for the cooling tower in electrical power generation, in addition to the geothermal hot water or steam. In arid parts of the western United States, an appropriation for groundwater would be necessary from the respective state government. In some areas, there could be conflicts with preexisting appropriations.
>
> Social acceptance - In this context, a qualitative assessment of the likelihood that any particular project will meet with exceptional opposition on aesthetic, environmental, historical or other grounds not directly correlatable with the physical characteristics of the resource.

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*This risk was added to the list by some interviewees, and is discussed in more detail in Section V.

EXHIBIT IV-9

INSURABILITY OF DELAYS

Risk	Insurable	Uninsurable
1. Water rights disputes	1	14
2. Social acceptance	0	15

As indicated on the above exhibit, only one of the companies participating in the interviews viewed these risks as insurable. Those companies commenting on the question of insurability strongly believed that these were risks of doing business and therefore unacceptable to an insurance company.

The next risk category, marketability, was similarly viewed by all respondents as uninsurable. Exhibit IV-10 identifies the specific risks in the marketability category. One company is currently offering protection to direct users of geothermal energy for the retrofit to an alternative energy source if the reservoir is inadequate but will not insure against the cost of geothermal energy becoming greater than expected relative to alternative energy costs. Most interviewees saw these as risks of doing business.

EXHIBIT IV-10

INSURABILITY OF MARKETABILITY

Risk	Insurable	Uninsurable
1. Regulatory rate treatment	0	15
2. Limited market size	0	15
3. Difficulty in negotiating sales contract	0	15
4. Alternative energy costs	0	15
5. Long-term market for end-product	0	15

The last risk category considered by interviewees was environmental risks. The two specific items within this are access to water and subsidence caused by net fluid withdrawal. For the purposes of the interview process these items were defined as:

Access to water - drought - In those areas where ground water is awarded by appropriation, the earliest appropriation has seniority. Therefore, if groundwater supplies become depleted as a result of drought, an agricultural use might temporarily have precedence over even a capital-intensive use such as geothermal power generation in a local area.

Subsidence caused by net fluid withdrawal - Depending on local geology, removal of the large volume of hot water needed for geothermal power production could result in small but widespread changes in the topography of the land surface. For example, in the Imperial Valley of California, the land surface is nearly flat but there is a widespread network of irrigation systems. A small change in slope could result in local reversal of water flow.

Less than a third of the interviewees viewed the first item, access to water, as an insurable risk. Those who responded in the insurable column believed that this might activate contingent business interruption coverage or would directly contribute to loss caused by reservoir inadequacy. Though more than half of the companies interviewed believed that the risk of subsidence caused by net fluid withdrawal was insurable, there were different coverages viewed as appropriate. Most companies believed this would be covered under a liability insurance policy if the insured is held responsible for damages caused to others. Four of the companies indicated a willingness to provide property damage coverage for the insured's property. Exhibit IV-11 below illustrates the interviewees perception of the insurability of these risks.

EXHIBIT IV-11

INSURABILITY OF ENVIRONMENTAL PROBLEMS

Risk	Insurable	Uninsurable
1. Access to water - long-run drought	4	11
2. Subsidence caused by net fluid withdrawal	9	6

Most of the insurers and reinsurers interviewed indicated that there probably would not be any significant variance in the coverage across the stages of development. One reinsurer believed that the coverage would vary from Stage 1 (full field development and construction phase) to Stage 2 (beginning with on-line through resolution of the transient problems) to Stage 3 (operational period). However, this does not mean that the insurers would expect to approach coverage in each stage exactly the same way. Many of the insurers and reinsurers believed that the first two stages would be most critical for insurers. This would be the periods when insurers would limit potential exposure through the use of high deductibles or perhaps limit coverage only to certain risks. This may also be the period when insurers most closely monitor the performance of the project through data supplied by the insured and from frequent on-site inspections by their own engineers or by geothermal experts retained by the company. Entering the third stage, the project would have accumulated sufficient data for most insurers to more accurately assess the risks, thereby increasing their comfort and willingness to assume a greater share of the risk of loss. The key to the risks in Stage 3 is the accummulation of reliable data on the performance of the project and the characteristics of the risks which forecast the probability of loss.

There were no indications by any of the interviewees that the insurability or acceptability of the risks would change based on the project type. Some companies did believe the approach to coverage, pre-issue requirements and some of the policy provisions might vary by type of project, especially for those projects relying on the extensive use of new technology. Most companies believed that while some general guidelines would be used to define their particular approach to geothermal energy risks, most policies would be manuscript in nature and specifically tailored to the insured project.

Perception of Appropriate Types of Coverages

Based on their perception of the risks identified as insurable the companies identified some of the standard forms of coverages offered by the industry as appropriate. These include:

- <u>Business Interruption Insurance</u>: Protection for the owner from losses which would be sustained during a period when the business is not operating due to the occurance of a covered hazard. This insurance may provide reimbursement for salaries, taxes, rents and other necessary expenses plus net profits which would have been earned during the period of interruption and subject to the policy limits.

- <u>Boiler and Machinery Insurance</u>: Protection for the insured from losses caused by stated damage to property and legal liability for damages caused by accidents of boilers, pressure vessels or related machinery.

- <u>Commercial Multi-Peril Insurance</u>: Protection against loss, generally in a single combination package, caused by both property and casualty hazards and generally includes protection for physical damage to the insured property.

In addition to the above, two of the (primary insurance) respondents believed that a form of protection against loss caused by the inadequacy or reduced capacity of the geothermal reservoir was appropriate for some of the insurable risks. Four reinsurers also agreed with this conceptual coverage and were supporting the primary insurers efforts. At this point, however only one of the two primary insurers has initiated a program to offer this coverage to the geothermal industry.

Analysis of Preferred Program Structure

The last section of the questionnaire determined the respondents' attitude toward the federal government's involvement in a geothermal insurance program and the private insurance sector's ability to provide the required capacity for geothermal reservoir risks. Nearly all of the interviewees believed that the federal government should not play a role in an insurance program because private insurers/reinsurers had, in their opinion, demonstrated the capacity and willingness to provide this protection. Most of the interviewees also discounted the need for an insurance pool for the same reason. A few primary insurers indicated that a government-backed reinsurance or catastrophe reinsurance program or a private insurance pool would positively influence their willingness to write geothermal reservoir insurance. Those insurers currently providing geothermal reservoir insurance would continue to do so with or without a government program.

V. ANALYSIS OF RESERVOIR RISKS

ANALYSIS OF RESERVOIR RISKS

DETAILED TABLE OF CONTENTS

ANALYSIS OF RESERVOIR RISKS

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ANALYSIS OF RESERVOIR RISKS

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ANALYSIS OF RESERVOIR RISKS

The commercial scale developer and user of geothermal energy, either for generation of electricity or for direct-use, face a number of significant risks that can inhibit development. In the early stages of field development the size and character of the reservoir are highly uncertain, yet the costs to the developer and user in terms of initial wells, surface facilities and power plants are significant. Even after commercial operations have begun, reservoir performance over the lifetime of the project is still an uncertainty.

One principal aim of this study has been to identify and analyze the major risks associated with geothermal projects, for the purpose of estimating the approximate level of insurance premiums necessary to cover these risks. The term "risk", as used throughout this section, denotes both the probability of a hazardous event occurring and the cost consequences of such occurrence.

This section presents a detailed analysis of major geothermal reservoir risks. First, a comprehensive set of broadly defined risks are identified based largely on the responses to the interviews previously discussed in Section III. Second, the specific risks that were perceived as (a) insurable and (b) posing unique problems to geothermal developments, are described and analyzed in detail for the purpose of estimating insurance premiums. Third, the methodology followed to estimate the probabilities and cost consequences of specific events that define each risk is discussed. The methodology is based on the subjective probability assessments of geothermal reservoir experts. These data are translated into expected losses over time, along with loss distributions that reflect the range of possible losses. The expected loss and distribution of loss for each major risk are combined to estimate insurance premiums for major coverage categories. The resulting premiums are examined in terms of their sensitivity to different risk loadings and how they could be recalculated over time as additional operating experience is obtained.

RISK IDENTIFICATION

Approach

Three main sources of data were relied on to develop an initial set of broadly defined perils or hazards that pose major risks to geothermal development. These three sources were:

(1) Interviews with principal geothermal developers, users, and lenders (discussed in Section III);

(2) DOE data sources (principally DOE geothermal reservoir data); and

(3) Geothermal reservoir engineering experts of GeothermEx, Inc.

Risks were identified by any or all of the above sources as posing major impediments to the development of different types of geothermal projects. Seven major geologic types of projects were considered. These types of projects were defined in Section III and are referenced throughout this Section as Type A through Type G.*

Further, risks were identified by the stage of development in which they were particularly significant. As discussed in Section III, three stages of development were selected to reflect periods in which the probability of a hazardous event occurring and the cost consequences of that occurrence might be significantly different. These stages are:

- Stage 1 - Full Field Development; wells are drilled and tested, pipeline system and power plant are built. Lasts

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*Some minor changes, however, were made to the original interpretations of each project type as defined in Section III. First, because of insufficient geologic data to differentiate responses for a Type C (Leaky Fault) from those for a Type D (Leaky Fault with Associated Reservoir), Type C was redefined as "Leaky Fault Non-Electric Use" and Type D as "Leaky Fault Electric Use." Also, because of insufficient geologic data to differentiate responses for a Type C from those of a Type H (Regional Aquifer Non-Electric Use), Type H was considered to fall within Type C.

until the first day of production (approximately 3-5 years from initial agreement to develop).

- Stage 2 - Initial Operations; first day of production through solution of transient problems (approximately one year duration).
- Stage 3 - Full Operations; solution of transient problems through remainder of project life (approximately 30 year life of project).

Comprehensive List of Risks

Exhibit V-1 and the glossary of risks that follows, presents the results of the analysis of (a) interviews with geothermal developers, users, and lenders, (b) DOE data sources, and (c) geothermal reservoir engineering data. The exhibit represents a comprehensive set of broadly defined significant risks to geothermal projects and depicts how these risks vary by specific geologic project type and stage of development.

Each of the risks, identified by any or all of the above sources, was categorized into one of the following ten major risk categories:

- Well Risks
- Reservoir Performance Risks
- Plant Risks
- Surface Facility Risks
- Acts of God
- Legal Liability Risks
- Delays
- Environmental Risks
- External Cost Escalation
- Marketability

In Exhibit V-1, a dot is placed in the appropriate cell to indicate the specific project type and stage of development for which the risk was identified as posing a major impediment to development.

EXHIBIT V-1
Page 1 of 4

COMPREHENSIVE SET OF GEOTHERMAL RISKS

RISK CATEGORY / PROJECT TYPE ►	A			B			C			D			E			F			G		
STAGE ►	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3
I. **Well Risks**																					
1) Drilling and completion problems	●			●			●			●			●								
2) Events leading to reduction in useful well life			●	●	●	●				●	●	●				●	●	●	●	●	●
3) Success ratio less than expected										●											
II. **Reservoir Performance Risks**																					
1) Interference of other wells (adjacent development)	●	●	●																		
2) Reduced reservoir performance due to improper well siting (within particular development)			●			●						●									
3) Premature cooling due to poor production/ injection strategy				●	●	●				●	●	●				●	●	●	●	●	●
4) Reservoir characteristics worse than originally expected	●	●		●	●		●	●		●	●		●	●		●	●		●	●	
5) Adverse change from expectations in reservoir model			●			●			●			●			●			●			●

EXHIBIT V-1
Page 2 of 4

COMPREHENSIVE SET OF GEOTHERMAL RISKS

RISK CATEGORY	A			B			C			D			E			F			G		
PROJECT TYPE ➤ / STAGE ➤	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3
III. **Plant Risks**																					
1) Power Plant performance			●			●						●									
2) Transmission availability													●								
IV. **Surface Facility Risks**																					
1) Failure of advanced design equipment												●	●	●					●	●	
2) Failure of standard design equipment											●	●							●	●	
3) Scaling and corrosion -- management related due to improper handling and treatment						●												●			●
4) Scaling and corrosion -- greater than originally expected						●												●			●
V. **Acts of God**																					
1) Earthquakes			●						●			●			●			●			●
2) Floods																			●	●	●
3) Landslides			●																		
4) Volcanic Hazards															●						

EXHIBIT V-1
Page 3 4

COMPREHENSIVE SET OF GEOTHERMAL RISKS

RISK CATEGORY	PROJECT TYPE ➤ STAGE ➤	A			B			C			D			E			F			G		
		1	2	3	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3
VI. Legal Liability Risks																						
1) Legal liability due to interfering with adjacent well development				●							●	●	●							●	●	●
VII. Delays																						
1) Construction delays					●			●			●			●			●			●		
2) Water rights disputes											●			●						●		
3) Regulatory delays		●	●	●	●						●						●			●		
4) Social acceptance														●	●	●						
VIII. Environmental Risks																						
1) Access to water -- long run drought													●									●
2) Pollution -- air and ground water			●	●		●	●		●	●		●	●	●	●	●	●	●	●	●		
3) Subsidence caused by net fluid withdrawal																					●	●

COMPREHENSIVE SET OF GEOTHERMAL RISKS

RISK CATEGORY	PROJECT TYPE ➤	A			B			C			D			E			F			G		
	STAGE ➤	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3
IX. External Cost Escalation																						
1) Labor costs		●																				
2) Financing costs				●	●						●						●			●		
3) Other external cost escalation											●			●	●	●						
X. Marketability																						
1) Limited market size for sale of heat		●						●			●						●			●		
2) Difficulty in negotiating a sales contract					●												●					
3) Costs of alternative energy sources											●	●	●				●					
4) Long-term market for end-product								●			●	●	●									

Exhibit V-2
Page 1 of 7

GLOSSARY OF GEOTHERMAL RISKS

I. Well Risks - Problems of successfully drilling and operating geothermal wells over the project-life.

A. Drilling and completion problems

1. Blow-out - Sudden, violent expulsion of formation fluid (mud, hot water, steam, gas) from a drilling well displacing the drilling fluid and followed by an uncontrolled flow from the well.

2. Lost Circulation - The loss of substantial quantities of drilling fluid (mud or water) to a fractured or highly porous rock formation encountered downhole. Evidenced by the complete or partial loss of drilling returns.

3. Fishing - Seeking to recover or extract from the well bore tools, cables, pipe, casing or rods which have become detached while in the well or which have been accidently dropped into the well.

4. Sloughing formations - Rock units being drilled that exhibit a tendency to slough or cave into the hole due to excessive fracturing.

5. Swelling formations - Rock units being drilled which exhibit a tendency to swell due to absorption of drilling fluid, resulting in a decrease in hole diameter following penetration by the drill bit. May result in an inability to withdraw drill string from the hole.

6. Hard formations - Rock units particularly hard and resistive to penetration by the drill bit.

7. Well deviation - Deviation of the direction of a drill hole from the vertical or from another desired orientation. May result in failure to encounter expected production zones at depth.

8. Formation damage - The sealing off, partially or completely, of potentially productive zones downhole by entry of drilling mud.

9. Poor completion - Completion of a well by installation of a casing or a liner which partially or totally seals off the production zone(s).

Exhibit V-2
Page 2 of 7

GLOSSARY OF GEOTHERMAL RISKS

B. Events leading to reduction in useful well-life

1. Scaling - Chemical precipitate from the geothermal fluid. Most common kinds in geothermal systems: calcium carbonate ($CaCO_3$) and silica (SiO_2).

2. Corrosion - Rusting or dissolving of downhole casing, surface fluid-handling lines and other metal components of the geothermal system.

3. Well-face plugging - Chemical precipitate forms where water moves through slotted casing into or from the well or in permeable zones immediately adjacent to hole. Most common in injection wells.

4. Mechanical damage or mechanical problems - Loss of equipment or tools in hole, casing collapse, cement failure, casing leaks, etc. Specifically excludes scaling and corrosion.

C. Success ratio less than expected - In all reservoir developments a certain fraction of the wells drilled will be unsuccessful. Prediction of the location of permeable zones in the reservoir may be difficult and "dry" holes may be drilled. Inadequate knowledge of geological and/or hydrological conditions may lead to worse than expected success ratios causing more than expected numbers of wells to be drilled.

II. Reservoir Performance Risks - Problems which affect the entire subsurface unit which yields the geothermal fluid.

A. Interference of other wells (adjacent development) - Pressure and/or temperature drops within a reservoir because the same subsurface reservoir also is being tapped from a nearby, independent project.

B. Improper well siting - Pressure and/or temperature drops because the wells within a single project are spaced too closely, causing the reservoir to be depleted more rapidly than necessary.

GLOSSARY OF GEOTHERMAL RISKS

C. Premature cooling due to production/injection strategy - Injection wells are placed too close to production wells, causing cold water to invade the production zone leading to lower net productivity.

D. Reservoir characteristics worse than originally expected - Reduced reservoir productivity in the early stages of development (Stages 1 and 2) because reservoir characteristics (discussed below) are worse than originally expected based on limited experience with the development.

1. Temperature - The temperature of hot water and/or steam extracted from the reservoir.

2. Pressure - The fluid pressure in a reservoir that drives the fluid from the reservoir to the well.

3. Chemistry - The quantity (concentration) and kinds (composition) of naturally-occurring chemical species that are included in the geothermal water.

4. Enthalpy - Synonomous with heat energy content and different from temperature. For example, a pound of steam at a given temperature will contain much more heat energy (enthalpy) than a pound of water at the same temperature.

5. Permeability - The property or capacity of a porous or fractured rock for transmitting a fluid. Permeability may vary within different parts of a reservoir and be subject to changes with time. Insufficient permeability results in inadequate production rates.

6. Reservoir Size - That portion of the identified geothermal resource from which a valuable energy commodity can be economically and legally extracted.

E. Adverse change from expectations in reservoir model -A detailed reservoir model is based on geological, hydrological and chemical data gained throughout the early life of a project (Stages 1 and 2). Long-term forecasts of the behavior of the reservoir throughout Stage 3 are based on this model. Reservoir characteristics (same as those defined above) are worse than expected over long-term exploitation (Stage 3) based on projections of the reservoir model developed through Stages 1 and 2.

GLOSSARY OF GEOTHERMAL RISKS

III. Plant Risks - Geothermal related hazards that impact on the performance of the power plant and availability of transmission lines.

A. Power plant performance - Failure of equipment, such as turbines in an electrical generating facility, due to damage from particulate matter or dissolved solids.

B. Transmission availability - The availability of transmission facilities from the island of Hawaii to the other islands in the Hawaiian chain.

IV. Surface Facility Risks - Problems related to the operations and life of surface facility equipment, such as surface fluid-handling and gathering lines.

A. Failure of advanced design equipment - Items for which design principles and operating histories are not well established, such as downhole pumps for high temperature (300-450°F) applications.

B. Failure of standard design equipment - Example: Large diameter steam or hot water gathering lines.

C. Scaling and corrosion (management related due to improper handling) - Improper equipment design, designed pressure decline in system, designed temperature decline in system, incorporation of atmospheric oxygen in fluid and/or mixing of brines causing unnecessary degree of scaling or corrosion.

D. Scaling and corrosion (greater than expected) - Even though optimum equipment design and fluid handling procedures are followed, the rate of scaling and/or corrosion is greater than originally expected causing damage to surface facilities.

V. Acts of God

A. Earthquakes - A sudden motion or trembling in the earth caused by the abrupt release of slowly accumulated strain (by faulting or volcanic activity). Extent of damage to geothermal facilities depends on the severity of a given quake. Damage is to a general area.

GLOSSARY OF GEOTHERMAL RISKS

B. Floods - A rising and overflowing body of water onto normally dry land. Prevalent in desert areas due to heavy rainfall. May be triggered by earthquakes. Damage is to a general area.

C. Landslides - A general term covering a wide variety of mass-movement of landforms and processes involving the moderately rapid to rapid (on the order of one foot per year or greater) downslope transport, by means of gravitational body stresses, of soil and rock material en masse. Landsliding is usually preceded, accompanied by, and followed by perceptable creep deformation along the surface of sliding and/or within the slide mass. Damage is highly site-specific. Much of the Geysers geothermal installation (Type A project) is on landslide terrain.

D. Volcanic hazards - The ejection of volcanic materials (lava, pyroclastics, and volcanic gases) onto the earth's surface. Usually a violent phenomenon, but an eruption along a fissure may be relatively calm. A highly site-specific risk, present only in regions of known recent volcanic activity. For example, may be significant at geothermal installations in Hawaii, yet virtually need not be considered at sites in Nevada.

VI. Legal Liability Risks

A. Legal liability due to interfering with adjacent well development - Damage to the injured party as a result of inadvertently tapping the reservoir of a nearby, independent project.

VII. Delays

A. Construction delays - Any of a number of events which would lead to significant delays in development (including labor strikes).

B. Water rights disputes - Good quality, cold water is necessary for the cooling tower in electrical power generation. In certain situations, an appropriation for ground-water might be necessary from the state government. In some areas, there could be conflicts with preexisting appropriations.

C. Regulatory delays - Any of a number of regulatory/licensing requirements which could take much longer than expected to fulfill.

GLOSSARY OF GEOTHERMAL RISKS

D. Social acceptance - In this context, a qualitative assessment of the likelihood that any particular project will meet with potential opposition on aesthetic, environmental, historical or other grounds not directly correlatable with the physical characteristics of the resource.

VIII. Environmental Risks

A. Access to water due to long run drought - In those areas where ground water is awarded by appropriation, the earliest appropriation has seniority. Therefore, if groundwater supplies become depleted as a result of drought, an agricultural use might temporarily have precedence over even a capital-intensive use such as geothermal power generation.

B. Pollution - Pollution from accidental fluid or gas release into the air, ground water or surface water.

C. Subsidence caused by net fluid withdrawal - Depending on local geology, removal of the large volume of hot water needed for geothermal power production could result in small but widespread changes in the topography of the land surface. For example in the Imperial Valley of California, the land surface is nearly flat but there is a widespread network of irrigation systems. A small change in slope could result in local reversal of water flow.

IX. External Cost Escalation

A. Labor cost - Escalating costs for all forms of labor, especially, the cost of maintaining the services of geothermal experts.

B. Financing costs - Rapidly rising interest rates and the availability of financing at reasonable rates.

C. Other escalating costs - A general category including greater than expected escalation in drilling costs and costs for particular materials, such as steel.

GLOSSARY OF GEOTHERMAL RISKS

X. Marketability

A. Limited market size for sale of heat - Developer's risk of not finding utilities or direct-heat users for the purchase of the geothermal product.

B. Difficulty in negotiating a sales contract -Developer's risk of not finalizing an agreeable contract after significant expenses have been incurred.

C. Costs of alternative energy sources - Risk that the future costs of alternative energy sources would make geothermal energy an unattractive energy option.

D. Long-term market for end-product - Developer's risk that the user's product of a direct-use geothermal project would not be economically attractive over the long-term or that the geothermal electric utility would not remain financially stable over the life of the geothermal development.

CONSOLIDATION OF RISKS

Approach

Exhibit V-1 defined a comprehensive set of significant risks to geothermal developments. This set of risks is therefore important for all segments of the geothermal industry to consider for general business planning. However, not all of these risks would be useful to consider for inclusion into a geothermal insurance program.

In this subsection, each of the risks in the ten major risk categories are examined for the purpose of consolidating the list to those risks that are perceived as (a) insurable and (b) posing unique problems to geothermal development. First, several risks were excluded that were not considered to pose unique problems for geothermal development, in the sense that these risks are also common in other types of industries and insurance to cover such risks either is, or would not be, generally available. Having identified geothermal specific risks, numerous private-sector insurers (as discussed in Section IV) were interviewed to ascertain their perceptions of which of these risks would be considered insurable. The resulting consolidated set of risks serves as the basis of the detailed risk analysis to estimate possible insurance costs described later in this section.

Rationale For Exclusion

Uniqueness

All risks in the category of "External Cost Escalation" were excluded because they are not unique problems faced by the geothermal industry. Increased financing and labor costs are risks common to all major industries. Furthermore, insurance is generally not available to cover such risks as they are considered to be standard risks of doing business.

Within the "Delays" category, construction delays and regulatory delays were excluded on the basis of not being unique risks to geothermal development. Water rights disputes and social acceptance, however, were not excluded because these risks pose unique problems for specific geothermal sites.

Air and ground water pollution were excluded from the "Environmental Risks" category because these are common environmental risks in many industries, and insurance in different forms to cover such risks is available. However, limited water availability because of drought and subsidence caused by net fluid withdrawal were not excluded because of the unique nature of these risks for specific geothermal projects.

Similarly, earthquakes and flood hazards were excluded from the "Acts of God" category because these are general hazards to all facilities and industries in a region and as such, insurance in different forms to cover these risks is available. However, volcanic hazards in a specific area of Hawaii and landslides in the Geysers region of Northern California were not excluded from consideration because the geothermal developments in these areas are the only major facilities in the high-risk zone. In this sense these hazards were considered unique to the geothermal developments in those specific areas.

The "Legal Liability Risks" category, specifically the risk of legal liability due to interfering with an adjacent well development, was also excluded from further consideration. The rationale was that this risk would likely be covered under existing forms of liability insurance.

Insurability

After making the previously mentioned exclusions, the remaining set of risks were those identified in Section IV. These risks were presented to representatives of the private-insurance sector for their consideration as to the insurability of each risk.

On the basis of the insurance interviews, all risks within the category "Marketability" were considered uninsurable. These risks were considered to be normal business risks for the geothermal industry. Similarly, the remaining risks within the "Delays" category were considered uninsurable.

Within the category "Surface Facility Risks", failure of standard design equipment along with management related scaling and corrosion problems were also excluded. Management related scaling and corrosion caused by improper handling and treatment was considered uninsurable because of moral hazard.* Scaling and corrosion greater than originally expected was not excluded from further analysis. There were mixed responses regarding the insurability of standard design equipment. However, because the likelihoods of such losses would be small compared to those of advanced design equipment, only loss of the later type of equipment was considered for further analysis.

"Power Plant Performance Risks" were generally considered insurable. However, the risks of not being able to transmit power from the island of Hawaii to the other Hawaiian islands were excluded from further analysis. This risk was generally considered uninsurable and would likely be resolved before Stage 1 of a major project would begin.

Within the "Reservoir Performance Risks" category, reduced reservoir performance due to improper well siting and poor production/injection strategy were excluded on the basis of being perceived as uninsurable. The primary reason cited was the moral hazard problem introduced by insuring against such risks. Interference by other wells of an adjacent development was considered for further analysis for Type A projects because of the specific problems already evidenced in the Geysers region and the fact that not all insurers considered this risk as uninsurable.

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* Moral hazard is defined as increasing the incentive, because of insurance, to not take appropriate measures to reduce the chances of adverse consequences.

All risks within the "Well Risks" category were considered for further analysis. Scaling, corrosion and well-face plugging problems greater than expected were generally considered as uninsurable in the interviews because they were primarily perceived as continuous maintenance problems controllable by management. However, these risks were not excluded from the detailed risk analysis because, in further analysis these risks were much more specifically defined to include only the need to replace more than an expected number of wells due to excessive and unforeseen scaling, corrosion or well-face plugging that could not have been controlled through normal maintenance measures.

There were mixed responses to the insurability of risks within the "Environmental Risks" category. Such risks as limited water availability because of drought and subsidence caused by net fluid withdrawal may in fact be insurable risks. However, these risks were excluded from further analysis because of the lack of information on which to base probabilities as to the likelihoods and potential costs of such events.

The resulting set of risks comprise five major risk categories. Four of the categories correspond to the four major components of any geothermal project -- wells, reservoir, plant and surface facilities. The five categories are:

- Well Risks
- Reservoir Performance Risks
- Plant Risks
- Surface Facility Risks
- Acts of God

These categories and the specific risks considered within each category are depicted by type of project and stage of development in Exhibit V-3. These risks comprise a consolidated set of risks to geothermal projects that, based on the interviews discussed previously, are perceived as (a)insurable and (b) posing significant and unique problems to geothermal development. This consolidated

EXHIBIT V-3
Page [illegible] of 2

CONSOLIDATED SET OF GEOTHERMAL RISKS

RISK CATEGORY	PROJECT TYPE ➤	A			B			C			D			E			F			G		
	STAGE ➤	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3
I. Well Risks																						
1) Drilling and completion problems		●			●			●			●			●								
2) Events leading to reduction in useful well life				●	●	●	●				●	●	●				●	●	●	●	●	●
3) Success ratio less than expected											●											
II. Reservoir Performance Risks																						
1) Interference of other wells (adjacent development)		●	●	●																		
2) Reservoir characteristics worse than originally expected		●	●		●	●		●	●		●	●		●	●		●	●		●	●	
3) Adverse change from expectations in reservoir model				●			●			●			●			●			●			●
III. Plant Risks																						
1) Power plant performance				●			●						●									

CONSOLIDATED SET OF GEOTHERMAL RISKS

PROJECT TYPE ➤	A			B			C			D			E			F			G		
RISK CATEGORY / STAGE ➤	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3
IV. **Surface Facility Risks**																					
1) Failure of advanced design equipment												●				●	●		●	●	
2) Scaling and corrosion -- greater than originally expected						●												●			●
V. **Acts of God**																					
1) Volcanic hazards															●						
2) Landslides			●																		

set of risks served as the basis of the detailed risk analysis performed to estimate possible insurance premiums, which is described in detail in the following subsection.

ANALYSIS OF INSURABLE RISKS

In this subsection the detailed risk analysis performed to estimate possible insurance costs is described. The consolidated set of risks served as the base set of risks that were analyzed. As stated earlier, the term "risk" denotes both the probability of a hazardous event occurring and the cost consequences of such occurrence.

First, the general methodology employed for estimating risks is described. Second, for each risk (a) the specific events considered, (b) the cost consequences of such events, and (c) the method of estimating the probabilities associated with each event are described. Third, a detailed analysis of each risk for one project type is provided. The detailed results for all project types, along with detailed descriptions of all major input data, are presented in the Appendix. The results of the analysis are an expected loss and loss distribution by type and stage of development for each risk, which serve as the primary inputs for estimating insurance premiums. A summary table of expected losses and loss distributions (as measured by their variance) is presented at the conclusion of this subsection.

General Methodology

A variety of risks, conceptually at least, can be shifted from the developer or user to an insurer for a price. This is the essence of insurance, whereby a person can substitute a certain cost (the insurance premium) for the risk of being exposed to uncertain events having a range of cost consequences. Before insurance premiums can be set by an insurance company, data on the probability and cost consequences of specific events are required. These data are usually obtained through historical observations. However, when there is limited operational history with which to assess risks, as is the case for large scale commerical geothermal projects in the United States, alternative methods must be employed.

The probabilities and cost consequences of events that define risks to geothermal development depend largely on the specific type of project and stage of development. To estimate the probabilities and cost consequences of such events, reliance was placed on available historical data and on the subjective probability assessments of geothermal reservoir experts.

A subjective probability reflects an expert's judgment based on his current state of information. It is a number between zero and one that represents an individual's belief in the outcome of an uncertain event. It is a much different concept than an objective probability, which can be observed from repeated historical trials. The use of objective probabilities for assessing risks is naturally preferable. However, when objective evidence is not available the next best alternative is to turn to an expert for his judgment, measured in terms of subjective probabilities.

Subjective probabilities, if properly assessed, should reflect an expert's current state of information regarding the likelihood of an event and its cost consequences. Where little information exists, very wide probability distributions should be assessed to incorporate this uncertainty. Narrower distributions should be obtained for variables about which there is greater current knowledge.

Subjective probability statements can be very valuable for decision making and risk assessment. For example, given the current uncertainty regarding future geothermal well costs, it is much more valuable to assume, based on the best information available, that these costs will range from $1 million to $3 million with specific probabilities, than it is to assume with certainty that wells will cost $1.5 million.

This then brings forth the practical problem of measurement. Intuitive judgments must be based on one's current state of information translated into probability statements. Properly assessing subjective probabilities is more of an art than a science. There are many potential sources of bias that the analyst must be aware of and take into account when posing questions to the expert.* However, there are basically two general methods of assessing probabilities.** One method is to directly ask the expert for a number. Another method is to indirectly derive the probabilities by asking the expert to make choices between two uncertain events. The second method is more preferable to minimize potential sources of bias. To aid in this process and help mitigate bias, there are a number of reference devices that assist the respondent to think about probabilities.***

The most important aspect in properly assessing subjective probabilities, regardless of the method employed, is to define a very specific event that does not require additional information for the expert to be able to make certain judgments. For example, consider the question, what is the probability of a specific project experiencing scaling and corrosion problems? A geothermal expert may very well answer (a) "I could not even begin to guess", or (b) "It is impossible to say." Both these responses reflect the fact that the question is far too general to state a meaningful probability. To be able to state a meaningful probability the expert must at least be able to specifically define the event. A valid and meaningful response from the expert is much more likely if the more specific question were asked:

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*See D. Kahneman and A. Tversky, "Judgment Under Uncertainty: Hueristics and Biases," Science, Vol. 185, Sept. 1974; and R. Fallon, "Subjective Assessment of Uncertainty," The Rand Corporation, Santa Monica, California, p-5581, Jan. 1976.

**See C. A. Holloway, "Decision Making Under Uncertainty: Models and Choices," Prentice-Hall, Inc., 1979, p. 290-310.

***See C. S. Spetzler and C. Stael Von Holstein, "Probability Encoding in Decision Analysis," Readings in Decision Analysis, Stanford Research Institute, 1974, p. 291-320.

> What is the probability next year of project X suffering scaling and corrosion problems in production wells to the extent that they can not be mitigated by normal maintenance and, as such, require the replacement of more producer wells than were originally expected or scheduled to be replaced?

Because of the importance of event definition, specific events for each of the broadly defined risks identified in Exhibit V-3 were developed. For example, the risk of drilling and completion problems under the "Well Risks" category was defined in terms of events that would lead to the need to replace one or more wells. Each event definition is described in detail later in this section where the specific probabilities and cost consequences that were estimated for each major risk category are discussed. In general, risks were defined as:

- Well Risks - events leading to the unexpected replacement, addition or abandonment of wells.
- Reservoir Performance Risks - events leading to significant reduction in reservoir productivity.
- Power Plant Risks - events leading to reduction in power plant capacity.
- Surface Facility Risks - events leading to unexpected replacement of advanced design equipment and/or significant portions of the piping system.
- Acts of God - events leading to significant damage to wells, power plant and/or surface facilities.

Subjective probability estimates were assessed from geothermal reservoir experts regarding (a) the occurrence of numerous events that comprise the major risk categories outlined above, and (b) the cost consequences given an event has occurred. Probability estimates of cost were necessary because of the current uncertainty regarding many of the major cost categories, such as well costs and steam revenue.

To estimate probabilities, both the direct and indirect probability assessment methods were utilized depending on the nature of the variable being estimated. To estimate the probabilities of specific events occurring, the indirect method of having the expert make choices between two lotteries with the aid of a probability reference wheel was used.*

Events were generally defined in terms of exceeding a certain value ($X \geq x$). For example, scaling and corrosion problems were defined to be extensive enough to require one or more wells to be replaced. Therefore, for the most part the probability reference wheel was used to estimate points on a continuous cummulative distribution $P(X \geq x)$, as opposed to discrete probabilities $P(X=x)$.

To estimate the continuous probability distributions for different cost variables, such as well costs, the direct interval method was used.** This technique is to ask the expert for the different values of X such that there is a .01, .25, .50, .75, and .99 probability respectively of the true value being less than or equal to X.

On the basis of this probabilistic analysis of events and cost consequences, an expected loss and loss distribution for each risk considered for insurance was estimated. The expected loss and loss distribution are the principal data inputs utilized to estimate insurance premiums and are discussed in more detail in the context of the analysis of specific risks. Expected losses and loss distributions for each risk were estimated for each of the three different stages of development and for each of the seven geologic project types to which they are applicable.

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*For a detailed discussion of the use of a probability reference wheel for indirect probability assessment, see C. A. Holloway, op. cit., p. 290-310.

**Ibid.

Losses were estimated in terms of four major cost categories that later served as the basis for insurance coverage. These cost categories, which are described in more detail later in the context of the analysis of specific risks, are:

- Direct Cost to Developer - direct costs to replace or add wells, surface piping, etc.
- Indirect Cost to Developer - loss of revenue from reduced steam sales.
- Direct Cost to User - repair costs from physical damage to plant or turbine, as well as the unamortized value of plant resulting from total or partial abondonment.
- Indirect Cost to User - excess cost of replacement power resulting from shut down or reduced capacity.

As an example of the previously described methodology, consider the following event for a particular type of project during a specific stage of development:

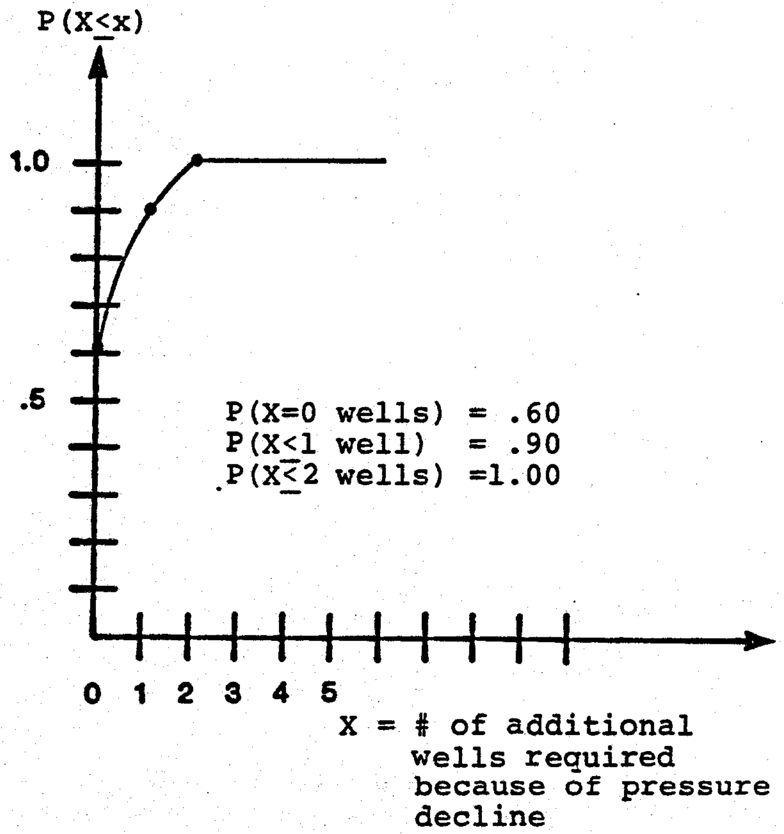
> Reservoir pressure decline greater than expected, to the extent that one or more unplanned producer wells need to be drilled in order to supply original design flow of the project.

Assume that the cumulative probability distribution for the probability of the number of wells needed to be drilled because of unexpected pressure decline, is estimated as depicted in Exhibit V-4.

In the expert's judgment there is a 60 percent chance of never having to add wells because of pressure decline, a 90 percent chance of having to add one or less wells, and a 100 percent chance (certainty) that the number of wells would be less than or equal to two.

EXHIBIT V-4

PROBABILITY OF PRESSURE DECLINE IN RESERVOIR CAUSING NEED FOR ADDITIONAL WELLS



On the basis of this cumulative distribution $P(X \leq x)$, the discrete probability $P(X = x)$ of any one number of wells needed to be drilled can be derived. The probabilities are:

$P(X = 0 \text{ wells}) = .60$
$P(X = 1 \text{ wells}) = .30$
$P(X = 2 \text{ wells}) = .10$
$P(X \geq 3 \text{ wells}) = .00$

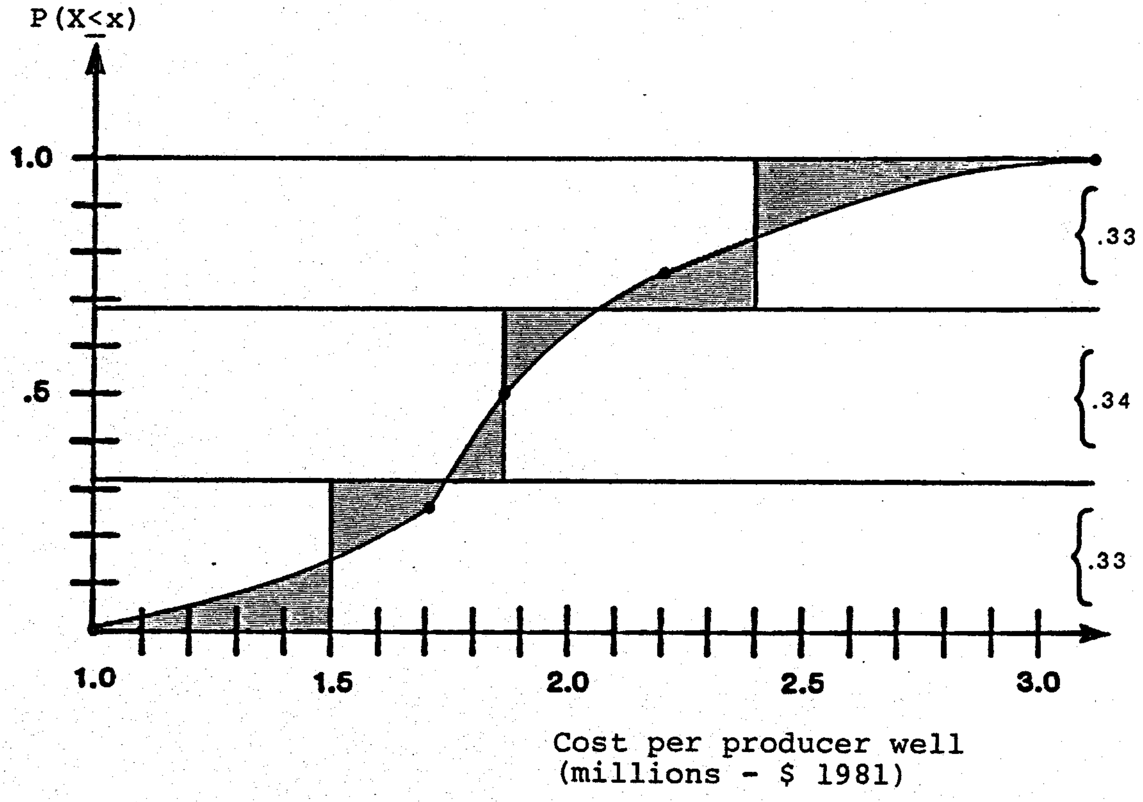
Furthermore, assume that the only cost consequence for this example is the cost of additional wells. These costs are estimated to range from $1.0 million to $3.0 million per well, with the associated cumulative probability distribution curve depicted in Exhibit V-5.

This curve was derived using the direct interval technique discussed earlier. It was estimated that there is approximately only a one percent chance of well costs being less than $1.0 million, a 25 percent chance of less than $1.7 million, a 50 percent chance of less than $1.85 million, a 75 percent chance of less than $2.2 million and virtual certainty (greater than a 99 percent chance) of well costs being less than $3.0 million per well ($1981).

This is a continuous distribution in the sense that every dollar amount between $1.0 million and $3.0 million is possible. Therefore, for computational reasons it is necessary to approximate this distribution into a discrete distribution of a finite number of points. For this example the continuous distribution was approximated by a discrete distribution of three points. To do this, the continuous distribution was divided into three segments, each having approximately a 33-percent chance of the true well costs falling within that segment. The expected value of each segment was estimated as the point of the curve where the area above the curve equals the area below the curve within that particular segment.

EXHIBIT V-5

PROBABILITY OF COST PER PRODUCER WELL



Discrete Approximation

P(X=1.5) = .33

P(X=1.85) = .34

P(X=2.4) = .33

The expected value of each segment is a discrete approximation for all values falling within the segment. Therefore, this approximation implies:

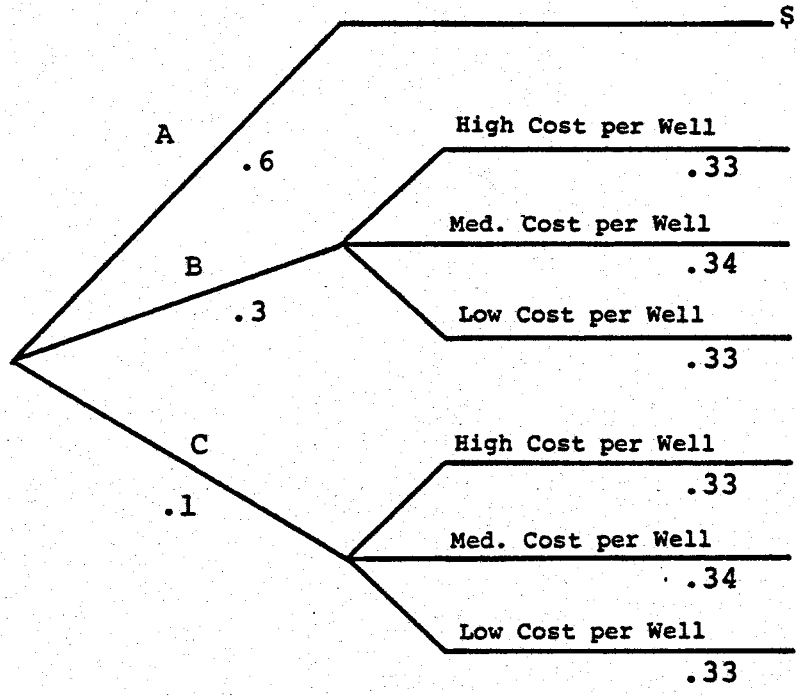
- A 33-percent chance of well costs equaling $1.5 million;
- A 34-percent chance of well costs equaling $1.85 million; and
- A 33-percent chance of well costs equaling $2.4 million.

Based on the above assumptions, the expected cost of additional producer wells because of reservoir pressure decline and the loss distribution of this risk is derived utilizing the probability tree diagram depicted in Exhibit V-6.

The tree depicts the range of possible losses from $0.00 to $4.80 million with the associated probability for each loss. The expected loss of $.96 million is the probability of each loss multiplied by each loss amount and summed over all losses. This value represents the best estimate, in a statistical sense, of the cost of additional wells because of pressure decline in the reservoir. This value and the spread of the loss distribution as measured by its variance are the two principal components needed to estimate an insurance premium necessary to cover the risk.

EXHIBIT V-6

EXAMPLE RISK ANALYSIS FOR PRESSURE DECLINE IN RESERVOIR CAUSING NEED FOR ADDITIONAL WELLS



Loss Distribution	
Additional Well Cost (millions-$1981)	Scenario Probability
$0.00	.600
2.40	.099
1.85	.102
1.50	.099
4.80	.033
3.70	.034
3.00	.033

Expected Cost of Additional Wells: $0.96 (millions - $ 1981)

A: Zero Additional Wells Needed.
B: One Additional Well Needed.
C: Two Additional Wells Needed.

Well Risks

These risks address the problems of successfully drilling and operating geothermal wells over the project life. The specific risk subcategories considered are:

- Drilling and completion problems.
- Events leading to a reduction in useful well life.
- Success ratio less than expected.

Significant risks were defined to include only those problems leading to the need to replace wells or the decision to abandon wells late in the project life. Also, it was defined that this risk category would not include damage to the reservoirs as a whole. For example, it was defined that even for events leading to well-face plugging (or other problems having to do with the well-reservoir interface) a useful replacement well could be successfully completed moderately close to the original well.

Drilling and completion problems

Event Definition: This risk category includes drilling and completion problems in Stage 1, which are extensive enough to cause loss of one or more producer and/or injector wells. Drilling and completion problems are considered to include (see Exhibit V-2 for definitions):

- Blow-outs
- Lost circulation
- Fishing
- Sloughing/swelling formations
- Hard formations
- Well deviation
- Formation damage
- Poor completion

These problems are considered significant risks only in Stage 1 of any project because most of the drilling would be accomplished during this time and presumably later drilling would benefit from the experience gained during Stage 1.

Cost Consequences: The cost impacts of these problems affect only the developer. They primarily consist of the capital cost for replacement wells. No steam revenue is lost because no revenue is generated during Stage 1 of development.

Probability Estimation: The events in this category were considered as independent events with a certain probability of occurring at random to any well during Stage 1. The independent probability of any one well of a project needing to be replaced because of drilling and/or completion problems was subjectively assessed. The probability of any specific number of wells needing to be replaced during Stage 1 was determined assuming a binomial distribution with n number of trials and p being the probability of failure per trial; where in this case n equals the number of wells per project during Stage 1 and p equals the subjective probability of any one well needing to be replaced during Stage 1.

Analysis of Project Type D: Exhibit V-7 presents the risk analysis for drilling and completion problems for project Type D during Stage 1. Detailed results of the risk analysis, for each geologic project type where this risk was considered significant, are presented in the Appendix along with detailed descriptions of the major input data.

The probabilities for any specific number of wells requiring replacement during Stage 1 are provided in Exhibit V-7, for both producer and injector wells. These probabilities are based on the binomial distribution with n equal to the number of wells in the entire field, and p equal to the probability of any one well needing replacement. A probability tree diagram is provided for each event which depicts the probability of any number of wells needing replacement during Stage 1, along with the cost consequences of each scenario. The expected value of the well replacement costs for each event, because of drilling and completion problems, is presented at the bottom of each tree.

WELL RISKS
DRILLING AND COMPLETION PROBLEMS
TYPE D - STAGE 1
EVENT 1

Description:	Drilling and/or completion problems in Stage 1 cause loss of one or more producer wells requiring an equivalent number of holes to be drilled.

Cost Consequences:

Developer:	Capital cost of replacement producer wells.
User:	None.

Input Data:

Cost Per Well:	\$1.8 (millions - \$1981)*

Probability: n = 11; p = .10 (binomial parameters)

p(X=0) = .31
p(X=1) = .39
p(X=2) = .21
p(x=3) = .07
p(X=4) = .02

X = number of producer wells requiring replacement

---

*For computational reasons, the expected value of cost per well was used throughout the analysis as an approximation of the continuous cost distribution. The estimated cost distributions and their expected values for each project type are presented in the Appendix.

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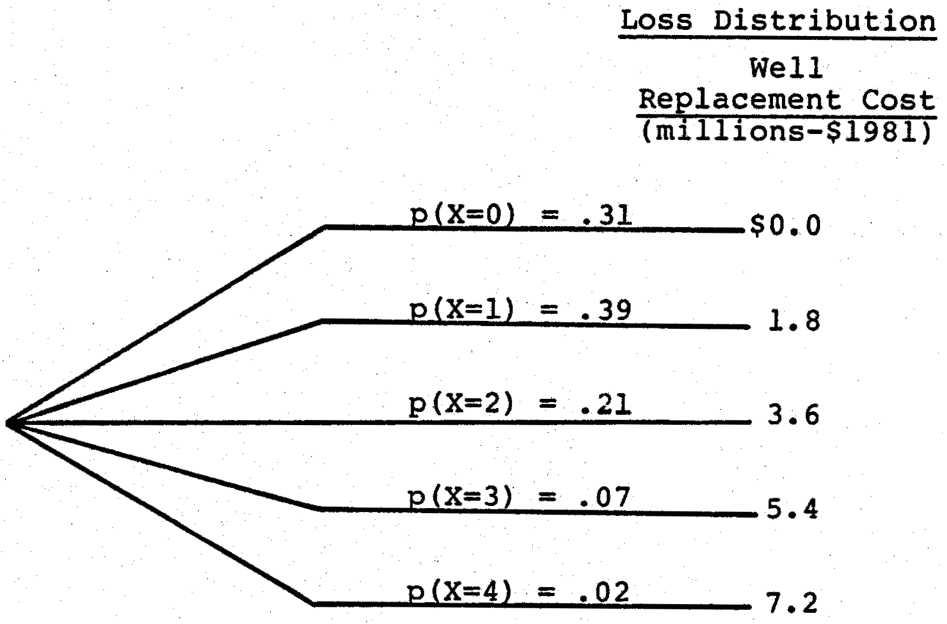
WELL RISKS
DRILLING AND COMPLETION PROBLEMS
TYPE D - STAGE 1
EVENT 1



Expected Well Replacement Cost: $2.0 (millions - $1981)*

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*This value represents the best estimate, in a statistical sense, of the cost of replacing wells due to drilling and completion problems in Stage 1. As discussed in the previous example, (Exhibit V-6), the expected value of a loss distribution is calculated as the probability of each loss multiplied by each loss amount and summed over all losses. Expected values for each of the loss distributions estimated throughout this analysis were calculated in this fashion.

WELL RISKS
DRILLING AND COMPLETION PROBLEMS
TYPE D - STAGE 1
EVENT 2

Description:	Drilling and/or completion problems in Stage 1 cause loss of one or more injector wells requiring an equivalent number of holes to be drilled.
Cost Consequences:	
Developer:	Capital cost of replacement injector wells.
User:	None.
Input Data:	
Cost Per Well:	$1.7 (millions - $1981)
Probability:	n = 6; p = .10 (binomial parameters)

p(X=0) = .53   X = number of injector wells requiring replacement
p(X=1) = .36
p(X=2) = .09
p(X=3) = .02

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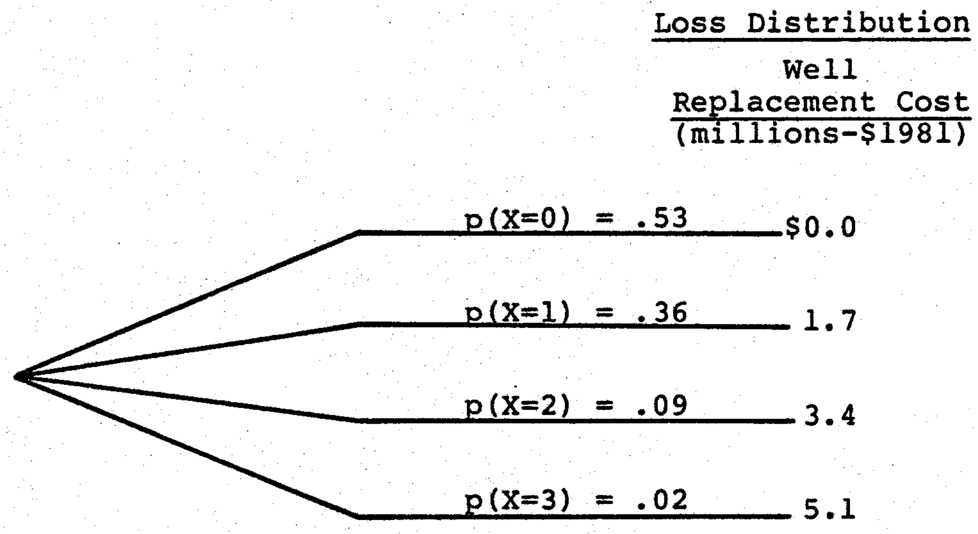
WELL RISKS
DRILLING AND COMPLETION PROBLEMS
TYPE D - STAGE 1
EVENT 2



Expected Well Replacement Cost: $1.0 (millions - $1981)

Events leading to reduction in useful well life

Event Definition: These events apply to wells which were successfully completed and capable of producing geothermal fluid at commercial quantities. However, later accidents or developing conditions cause formerly productive wells to become uneconomic. Possible events include (see Exhibit V-2 for definitions):

- Scaling
- Corrosion
- Well-face plugging
- Mechanical damage or problems

The relative importance of different events varies between reservoirs depending on local geological conditions and the stage of the particular development. Events are considered for Stages 1, 2, and 3.

Cost Consequences: Cost consequences from the events affect both the developer and user. To the developer, costs include the capital cost of replacing wells along with the temporary loss of revenue, if any, while a well is down and being replaced. Furthermore, it is assumed that it is not economical to replace a well during the last five years of the operating life of a project, because for most projects the discounted value of future revenue generated by the well does not offset its cost during this period. Therefore, it is further assumed that the developer will choose to loose the future revenues from wells that are shut-down during years 26-30 of Stage 3.

The user, which for this risk subcategory is assumed to be an electric utility, may suffer (a) the excess cost of replacement power during the time a well or wells are being replaced, and (b) a proportionate amount of the unamortized value of its plant in the event a producing well is abandoned during the last five years of Stage 3.

If (1) a significant portion of a utility's fuel source is geothemal energy and (2) there is insufficient excess generating capacity to make-up for any shortfall in geothermal energy during the time a well or wells are being replaced, then the utility would have to buy temporary replacement power from other utilities at possibly higher costs. The differential between what it costs the utility to generate electricity from geothermal and what it costs to buy the replacement power on a short-term temporary basis is a cost to the utility due to a well or wells needing replacement.

The precise cost differential of replacement power to a utility is highly dependent on numerous factors specific to that utility, such as its location, size, mix of fuel sources, contractual relationships with other utilities, etc. Thus, it is impossible to precisely estimate this cost for the six electric generation project types considered in this study (Types A, B, D, E, F, and G). Although data in this area are extremely limited, indications are that the cost of replacement power for most utilities will be on par with the cost of generating electricity from geothermal for the conceivable future.* This implies that the cost differential of replacement power, in the short-term and long-term, to a utility is approximately zero, which is what has been assumed for all electric generation type projects with the exception of Type A. Type A represents projects in the Northern California Geysers region where geothermal energy can be more efficiently produced because of the high quality dry steam nature of the resource. In this area, the steam price is projected to be about one half of what it is projected to be in other regions.** Therefore, for Type A, a positive cost differential for replacement power is assumed.

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*Based on (a) data provided by the Department of Energy's Energy Information Office regarding projections of the cost of generating electricity at the busbar for different fuel sources, and (b) interviews with representatives of utilities discussed previously in Section III.

**Estimated steam prices for Types A, B, D, E, F, and G are presented in the Appendix.

Because the cost of replacement power for Type A would be approximately twice the Type A steam price, the differential cost of replacement power is assumed equivalent to the current steam price per Type A.

If a producer well is abandoned during the last five years of the project life a certain percentage of the normal operating capacity of the plant is lost. Therefore, if a straight-line depreciation of the plant is assumed, there is a proportionate share of the unamortized value of the plant, due to the loss of the well, that is a cost to the user.

Probability Estimation: Subjective probability distributions were assessed regarding the number of producer or injector wells requiring replacement during Stages 1 and 2. Stage 3 was divided into two periods (1) years 1-25 and (2) years 26-30, to differentiate those periods in which producer wells would be replaced and in which they would be abandoned. Subjective probability distributions were then assessed for the number of producer wells requiring replacement in Stage 3 years 1-25, and the number of producer wells abandoned in Stage 3 years 26-30. The probability of injector wells requiring replacement was assessed considering all of Stage 3 (years 1-30) with the assumptions:

(1) During years 1-25 of Stage 3 any injector well that is shut-down is replaced.

(2) During years 26-20 of Stage 3 the number of required injector wells may decrease as producer wells are abandoned. This may result in not requiring replacement for every injector well that is shut-down.

Analysis of Project Type D: Exhibit V-8 presents the risk analysis for events leading to reduction in useful well life for project Type D during Stages 1, 2, and 3. Detailed results of the risk analysis, for each geologic project type where this risk was considered significant, are presented in the Appendix along with detailed descriptions of the major input data.

As will be the common format throughout the rest of this subsection, first the discrete probabilities P(X = x) for the number of wells requiring replacement, which were derived from the cumulative distribution $P(X \leq x)$, are presented. This cumulative distribution is what was subjectively assessed. The dots on the graph of the cumulative distribution represent those specific probabilities which were subjectively assessed. These specific probabilities are presented along with the graph of the cumulative distribution. In this particular example, for Event 1 of Stage 1, these probabilities are:

$P(X \leq 0) = .25$
$P(X \leq 1) = .50$
$P(X \leq 3) = .75$
$P(X \leq 10) = 1.00$

The Exhibit concludes with a probability tree diagram for each event considered, that relates each possible scenario with its cost consequences. The expected cost for each cost category is presented at the bottom of the diagram.

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WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE D - STAGE 1
EVENT 1

Description: Mechanical damage, scaling or corrosion cause loss of one or more producer wells (before field is in production). Well is replaced.

Cost Consequences:

Developer: Capital cost of replacement producer wells.

User: None.

Input Data:

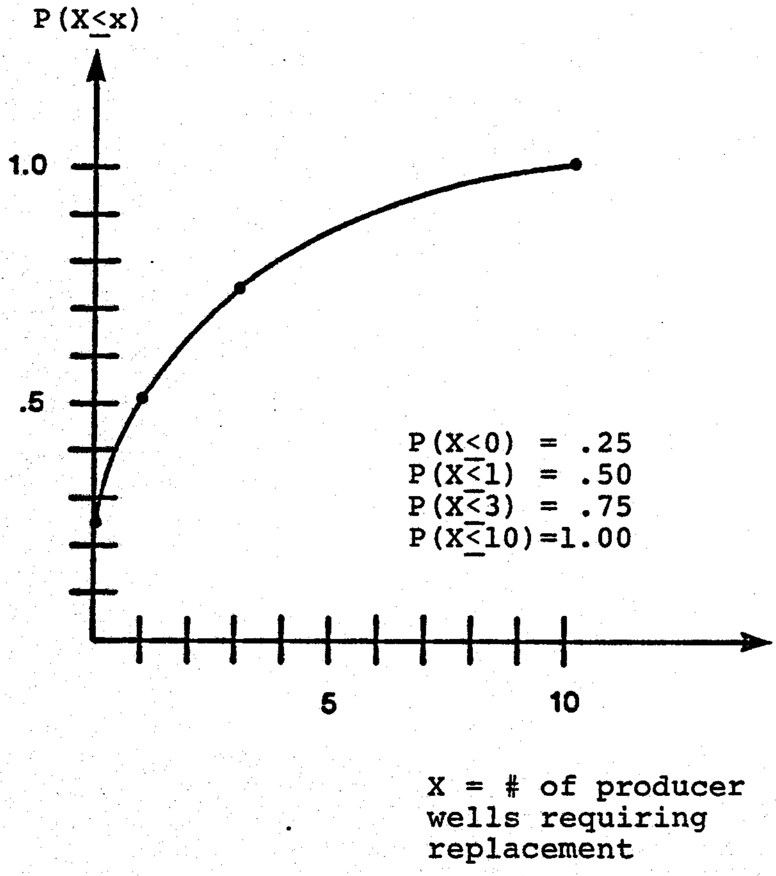
Cost Per Well: $1.8 (millions - $1981)

Probability:

$p(X=0) = .25$
$p(X=1) = .25$
$p(X=2) = .15$
$p(X=3) = .10$
$p(X=4) = .07$
$p(X=5) = .05$
$p(X=6) = .04$
$p(X=7) = .03$
$p(X=8) = .03$
$p(X=9) = .02$
$p(X=10) = .01$

X = number of producer wells requiring replacement

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE D - STAGE 1
EVENT 1



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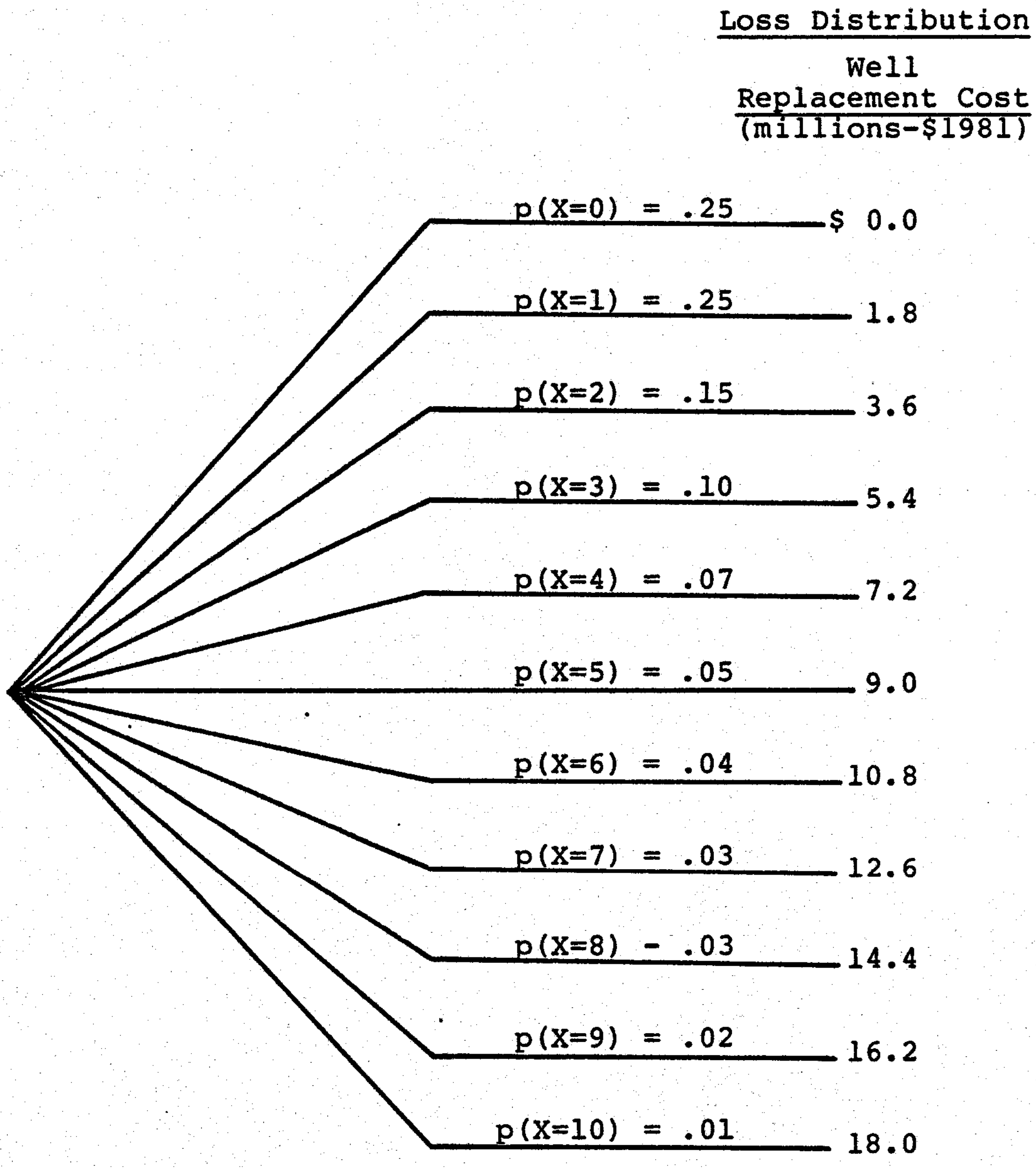
WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE D - STAGE 1
EVENT 1



Expected Well Replacement Cost: $4.23 (millions - $1981)

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE D - STAGE 2
EVENT 1

Description: Mechanical damage, scaling or corrosion cause loss of one or more producer wells. Well is replaced.

Cost Consequences:

Developer: (a) Capital cost of replacement producer wells.

(b) Revenue loss while each producer well (beyond reserve capacity) is replaced.

User: None.

Input Data:

Delay Time: 5 months.

Well Replacement Cost: $1.8 (millions - $1981)

Number of Wells: 10 producers/1 reserve

Revenue Loss Per Producer Well Per Month: $0.069 (millions - $1981)

Probability:

$p(X=0) = .25$
$p(X=1) = .25$
$p(X=2) = .15$
$p(X=3) = .10$
$p(X=4) = .07$
$p(X=5) = .05$
$p(X=6) = .04$
$p(X=7) = .03$
$p(X=8) = .03$
$p(X=9) = .02$
$p(X=10) = .01$

X = number of producer wells requiring replacement

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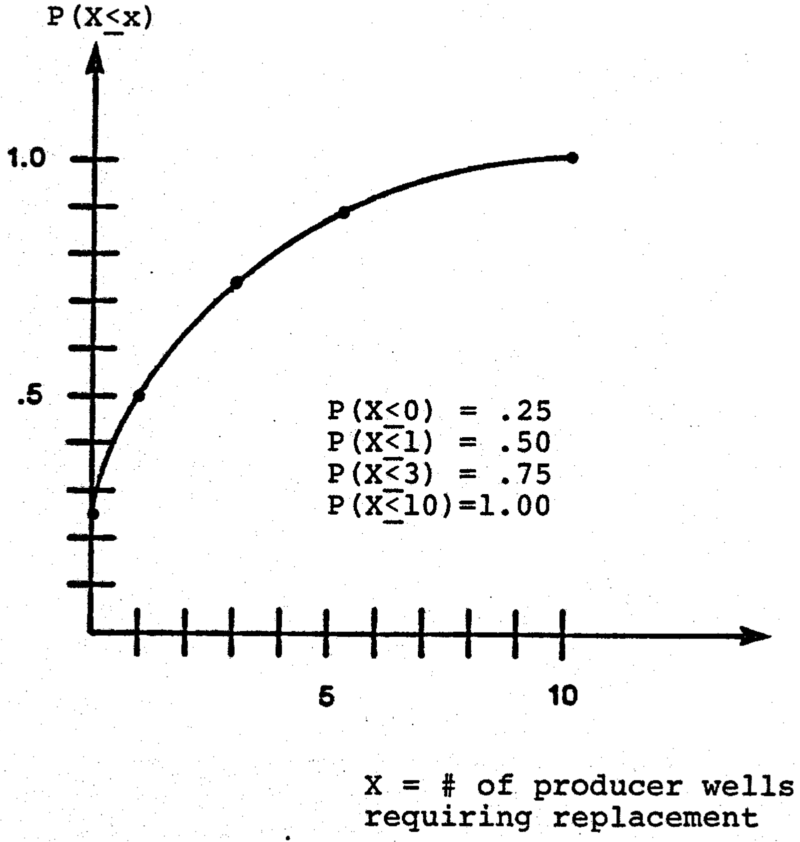
WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE D - STAGE 2
EVENT 1



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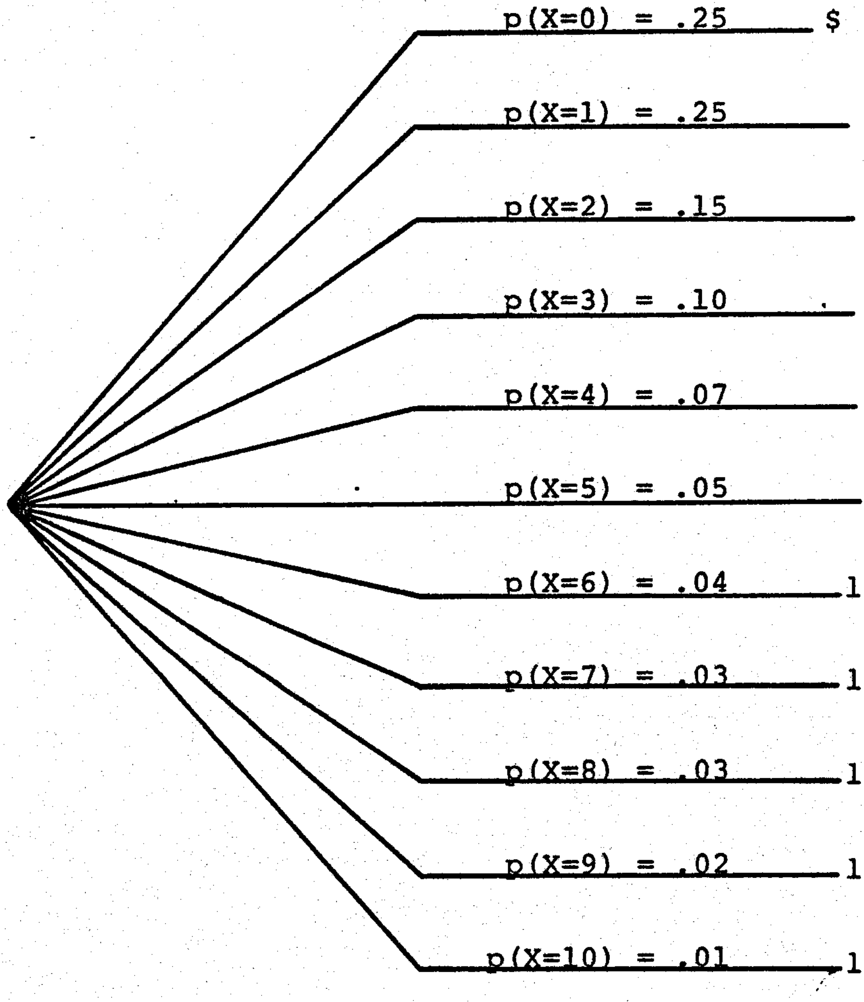
WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE D - STAGE 2
EVENT 1



	Loss Distribution	
	Well Replacement Cost (millions-$1981)	Revenue Loss (millions-$1981)
p(X=0) = .25	$ 0.0	$0.00
p(X=1) = .25	1.8	0.00
p(X=2) = .15	3.6	0.35
p(X=3) = .10	5.4	0.69
p(X=4) = .07	7.2	1.05
p(X=5) = .05	9.0	1.38
p(X=6) = .04	10.9	1.75
p(X=7) = .03	12.6	2.07
p(X=8) = .03	14.4	2.45
p(X=9) = .02	16.2	2.76
p(X=10) = .01	18.0	3.15

Expected Well Replacement Cost: $4.23 (millions - $1981)
Expected Revenue Loss: $0.56 (millions - $1981)

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE D - STAGE 2
EVENT 2

Description: Mechanical damage, scaling, corrosion or well-face plugging cause loss of one or more injector wells. For each injector well (beyond reserve capacity) that is shut down two producer wells must be taken off-line. Injector well is replaced.

Cost Consequences:

Developer: (a) Capital cost of replacement injector wells.

(b) Revenue loss while each injector well beyond reserve capacity is replaced.

User: None.

Input Data:

Delay Time: 5 months.

Well Replacement Cost: $1.7 (millions - $1981)

Revenue Loss Per Injector Well Per Month: $0.138 (millions - $1981)

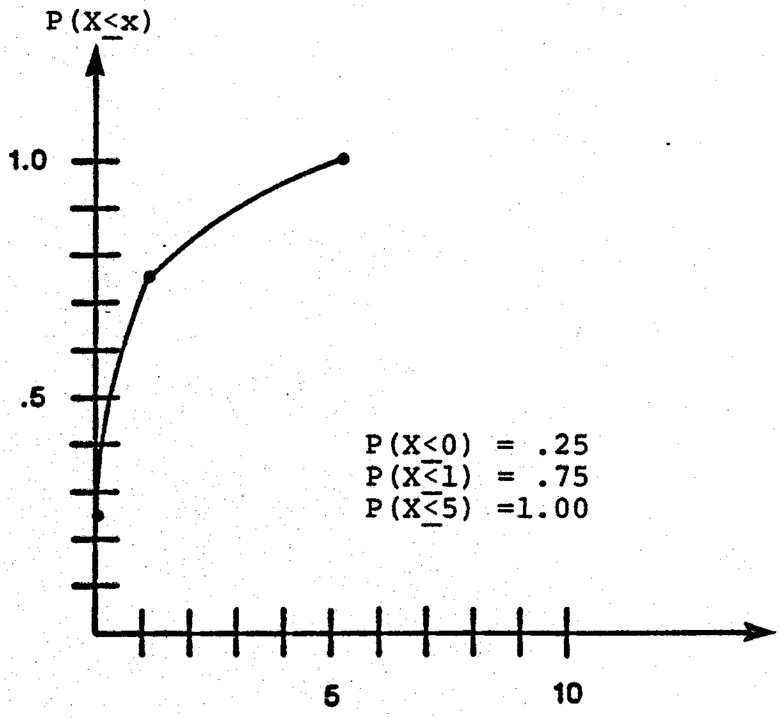
Probability:

$p(X=0) = .25$
$p(X=1) = .50$
$p(X=2) = .10$
$p(X=3) = .07$
$p(X=4) = .05$
$p(X=5) = .03$

X = number of injector wells requiring replacement

EXHIBIT V-8

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE D - STAGE 2
EVENT 2



X = # of injector wells requiring replacement

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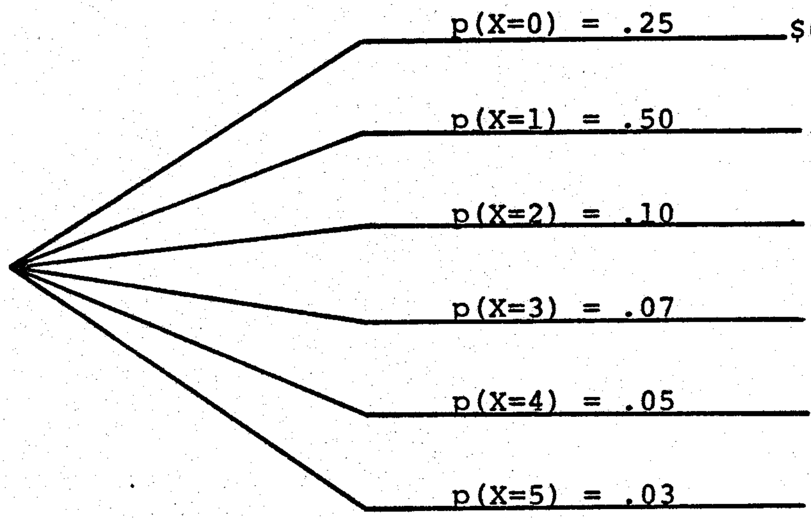
WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE D - STAGE 2
EVENT 2



	Loss Distribution	
	Well Replacement Cost (millions-$1981)	Revenue Loss (millions-$1981)
p(X=0) = .25	$0.0	$0.00
p(X=1) = .50	1.7	0.00
p(X=2) = .10	3.4	0.69
p(X=3) = .07	5.1	1.38
p(X=4) = .05	6.8	2.07
p(X=5) = .03	8.5	2.76

Expected Well Replacement Cost: $2.18 (millions - $1981)
Expected Revenue Loss: $0.35 (millions - $1981)

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE D - STAGE 3 (YEARS 1-25)
EVENT 1

Description:	Mechanical damage, scaling, corrosion or well-face plugging cause loss of one or more producer wells beyond original expectations. Well is replaced.

Cost Consequences:

Developer:	(a) Capital cost of replacement producer wells. (b) Revenue loss while well is replaced. Assumes that reserve wells are occupied while dealing with expected replacement.
User:	None.

Input Data:

Delay Time: 5 months.

Well Replacement Cost: $1.8 (millions - $1981)

Revenue Loss Per Producer Well Per Month: $0.0602 (millions - $1981)

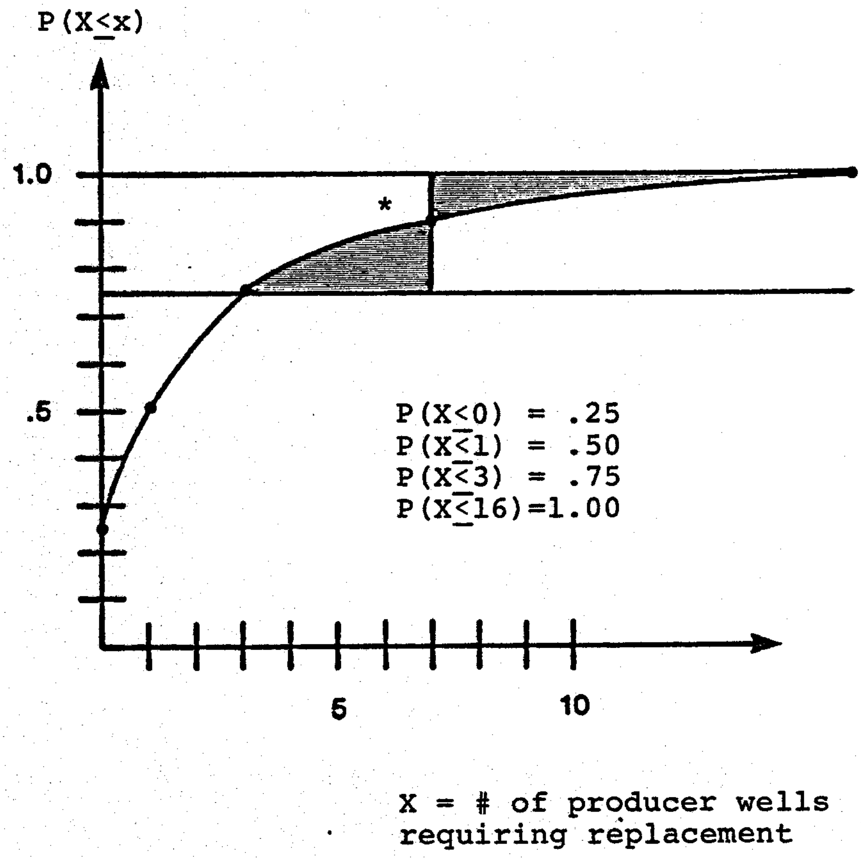
Probability:

$p(X=0) = .25$ X = number of producer wells requiring replacement
$p(X=1) = .25$
$p(X=2) = .15$
$p(X=3) = .10$
$p(X=7) = .25$*

---

*For computational reasons, the tail of the distribution $p(4 \leq X \leq 16)=.25$ was truncated and approximated by X=7 wells.

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE D - STAGE 3 (YEARS 1-25)
EVENT 1



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*tail of distribution truncated, approximated by 7 wells with probability of .25

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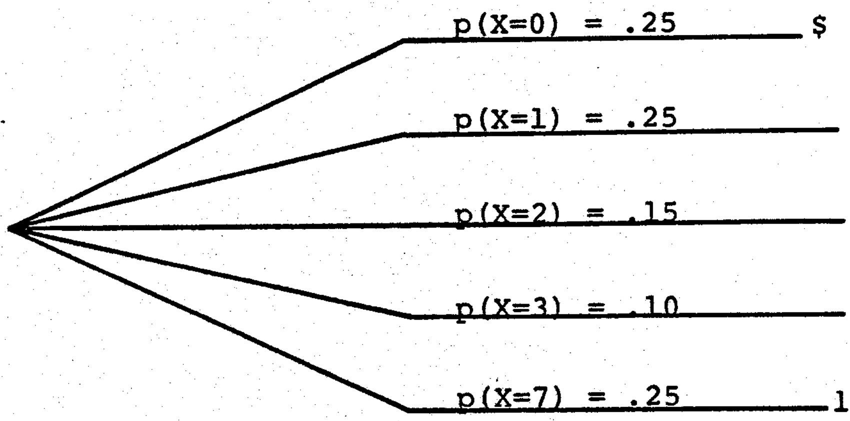
WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE D - STAGE 3 (YEARS 1-25)
EVENT 1



	Loss Distribution	
	Well Replacement Cost (millions-$1981)	Revenue Loss (millions-$1981)
p(X=0) = .25	$ 0.0	$0.00
p(X=1) = .25	1.8	0.30
p(X=2) = .15	3.6	0.60
p(X=3) = .10	5.4	0.90
p(X=7) = .25	12.5	2.10

Expected Well Replacement Cost: $4.68 (millions - $1981)
Expected Revenue Loss: $0.78 (millions - $1981)

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE D - STAGE 3 (YEARS 26-30)
EVENT 1

Description: Mechanical damage, scaling, corrosion or well-face plugging cause loss of one or more producer wells in excess of original expectations during years 26-30. Lost well(s) is abandoned.

Cost Consequences:

Developer: Loss of revenue per producer well over the remainder of project life.

User: Unamortized value of plant from loss of wells.

Input Data:

Developer's Revenue Loss Per Well:
Range: $0 - $2.1 (millions - $1981)
Expected Value: $1.05 (millions - $1981)

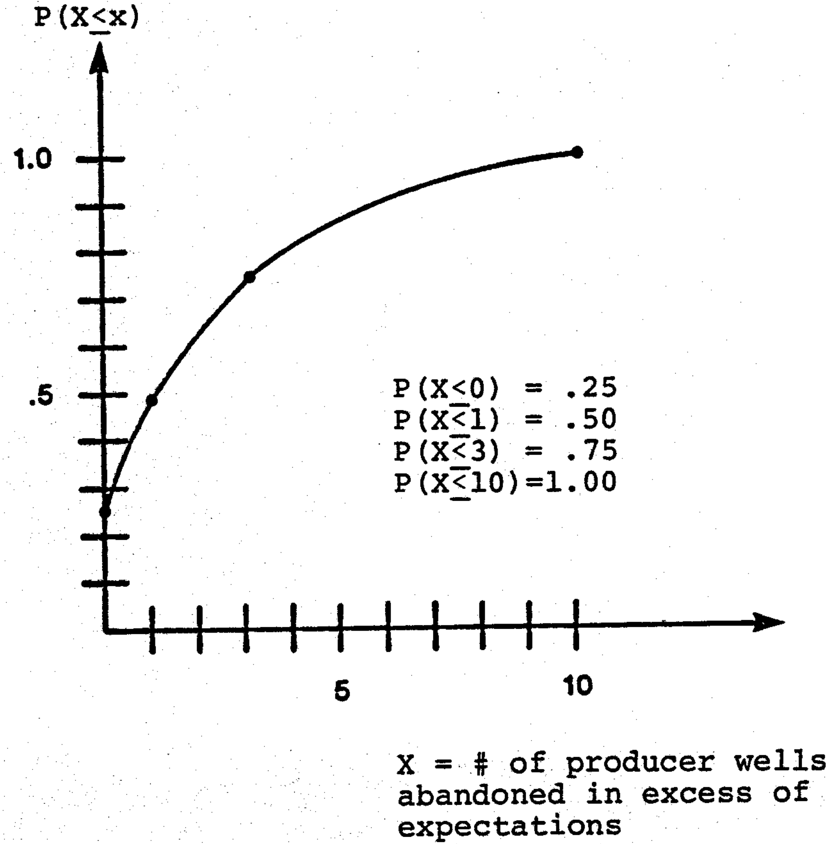
Expected Unamoritzed Value of Plant
Due to Loss of One Well: $0.16 (millions - $1981)

Probability:

$p(X=0) = .25$
$p(X=1) = .25$
$p(X=2) = .15$
$p(X=3) = .10$
$p(X=4) = .07$
$p(X=5) = .05$
$p(X=6) = .04$
$p(X=7) = .03$
$p(X=8) = .03$
$p(X=9) = .02$
$p(X=10)= .01$

X = number of producer wells abandoned in excess of expectations

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE D - STAGE 3 (YEARS 26-30)
EVENT 1



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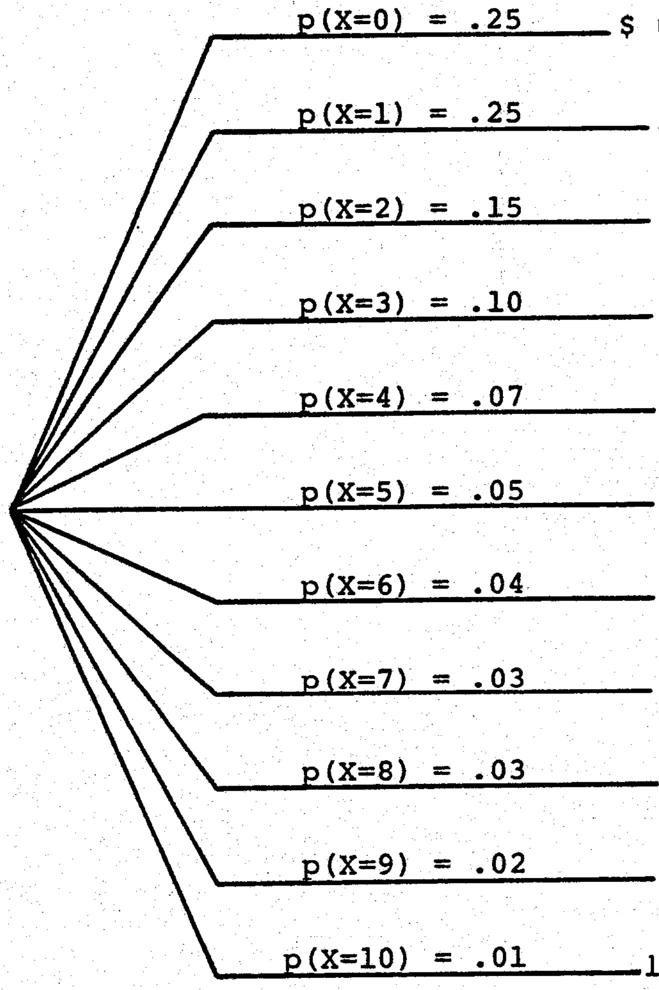
WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE D - STAGE 3 (YEARS 26-30)
EVENT 1



	Loss Distribution	
	Revenue Loss (millions-$1981)	Unamortized Value of Plant (millions-$1981)
p(X=0) = .25	$ 0.00	$0.00
p(X=1) = .25	1.05	0.16
p(X=2) = .15	2.10	0.32
p(X=3) = .10	3.15	0.48
p(X=4) = .07	4.20	0.64
p(X=5) = .05	5.25	0.80
p(X=6) = .04	6.30	0.96
p(X=7) = .03	7.35	1.12
p(X=8) = .03	8.40	1.28
p(X=9) = .02	9.45	1.44
p(X=10) = .01	10.50	1.60

Expected Revenue Loss: $2.47 (millions - $1981)
Unamortized Value of Plant: $0.47 (millions - $1981)

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE D - STAGE 3 (YEARS 1-30)
EVENT 1

Description:	Mechanical damage, scaling, corrosion or well-face plugging cause loss of one or more injector wells requiring replacement. For every such injector well that is replaced two producer wells must be taken off-line temporarily.

Cost Consequences:

Developer:	(a) Capital cost of replacement injector wells. (b) Revenue loss while each injector well is replaced and two producer wells are off-line.
User:	None.

Input Data:

Delay Time: 5 months.

Well Replacement Cost: $1.7 (millions - $1981)

Revenue Loss Per Injector Well Per Month: $0.120 (millions - $1981)

Probability:

p(X=0) = .25
p(X=1) = .50
p(X=2) = .10
p(X=3) = .05
p(X=4) = .04
p(X=5) = .02
p(X=6) = .02
p(X=7) = .02

X = number of injector wells requiring replacement.

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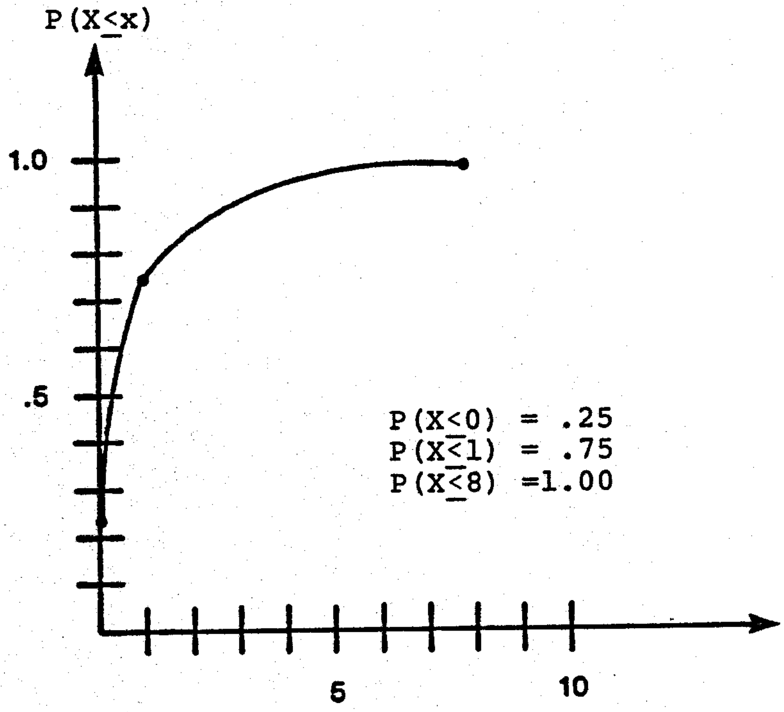
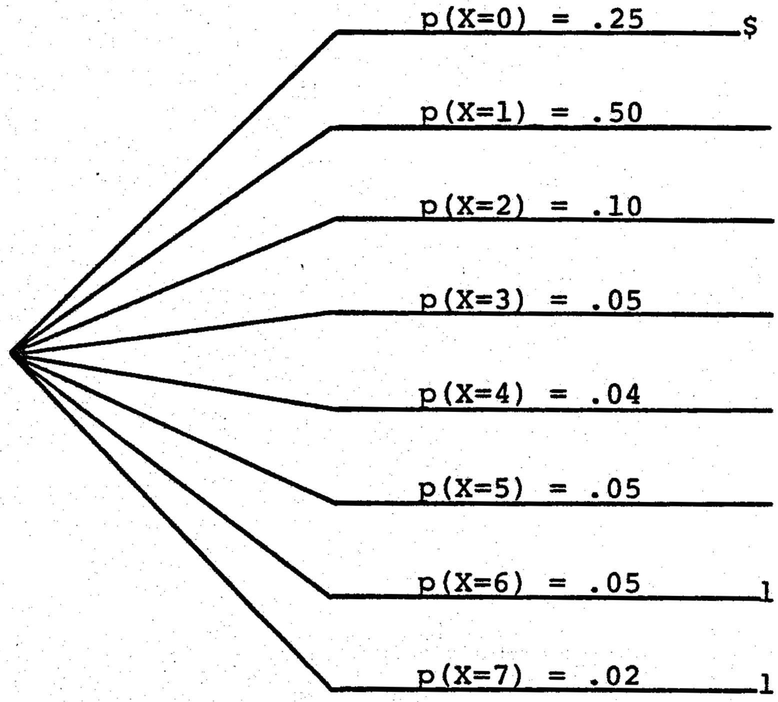
WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE D - STAGE 3 (YEARS 1-30)
EVENT 1



$P(X<0) = .25$
$P(X\leq 1) = .75$
$P(X\leq 8) =1.00$

X = # of injector wells requiring replacement

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE D - STAGE 3 (YEARS 1-30)
EVENT 2



	Loss Distribution	
	Well Replacement Cost (millions-$1981)	Revenue Loss (millions-$1981)
p(X=0) = .25	$ 0.0	$0.0
p(X=1) = .50	1.7	0.6
p(X=2) = .10	3.4	1.2
p(X=3) = .05	5.1	1.8
p(X=4) = .04	6.8	2.4
p(X=5) = .05	8.5	3.0
p(X=6) = .05	10.2	3.6
p(X=7) = .02	11.9	4.2

Expected Well Replacement Cost:	$2.33 (millions - $1981)
Expected Revenue Loss:	$0.82 (millions - $1981)

Success ratio less than expected

Event Definition: This risk subcategory is significant in areas of especially complicated geology. Here, inadequate knowledge of geological and/or hydrological conditions may lead to worse than expected success ratio during Stage 1 requiring additional producer wells to be drilled. It is assumed that adequate experience will be gained as a result of this drilling and that there will not be a significant risk during subsequent stages.

Cost Consequences: The only significant cost consequence considered for this risk is the capital cost to the developer of drilling more wells than originally expected.

Probability Estimation: A subjective probability distribution was assessed for the number of additional producer wells needed to be drilled because of the success ratio being less than expected for Type D during Stage 1. Type D was the only project type where this risk was considered significant (see Exhibit V-3).

Analysis of Project Type D: Exhibit V-9 presents the risk analysis for success ratio less than expected for project Type D during Stage 1. This risk was not considered significant for any of the other project types. Detailed descriptions of all major input data are provided in the Appendix.

EXHIBIT V-9
Page 1 of 3

WELL RISKS
SUCCESS RATIO LESS THAN EXPECTED
TYPE D - STAGE 1
EVENT 1

Description: Inadequate knowledge of geological and/or hydrological model leads to worse than expected success ratio during Stage 1 drilling; additional producer wells must be drilled.

Cost Consequences:

Developer: Capital cost of replacement producer wells.

User: None.

Input Data:

Cost Per Well: $1.8 (millions - $1981)

Probability:

p(X=0) = .25
p(X=1) = .25
p(X=2) = .15
p(X=3) = .10
p(X=4) = .07
p(X=5) = .05
p(X=6) = .04
p(X=7) = .03
p(X=8) = .03
p(X=9) = .02
p(X=10)= .01

X = number of additional producer wells required

EXHIBIT V-9
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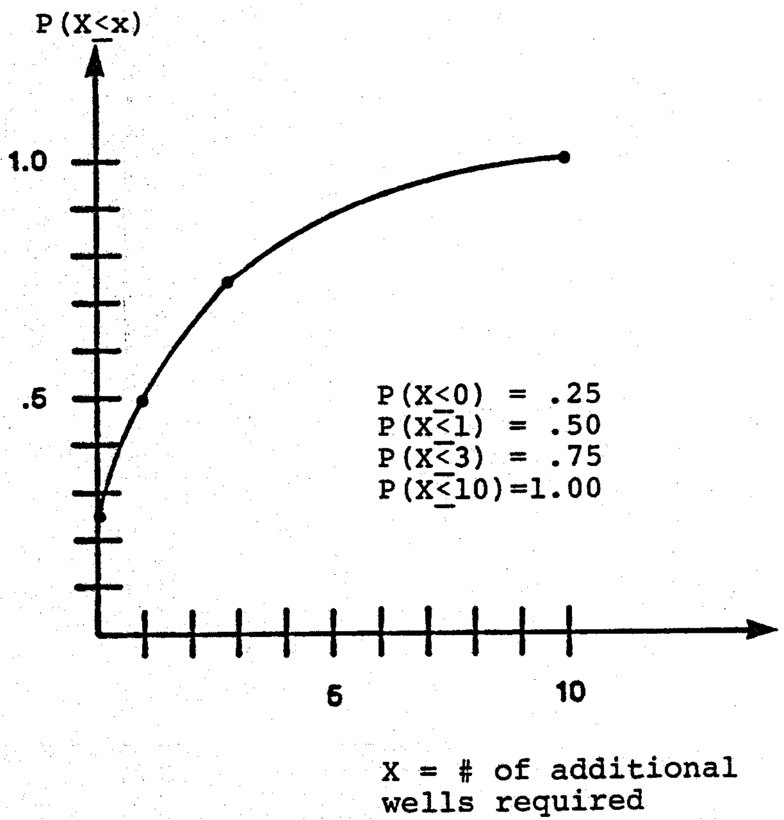
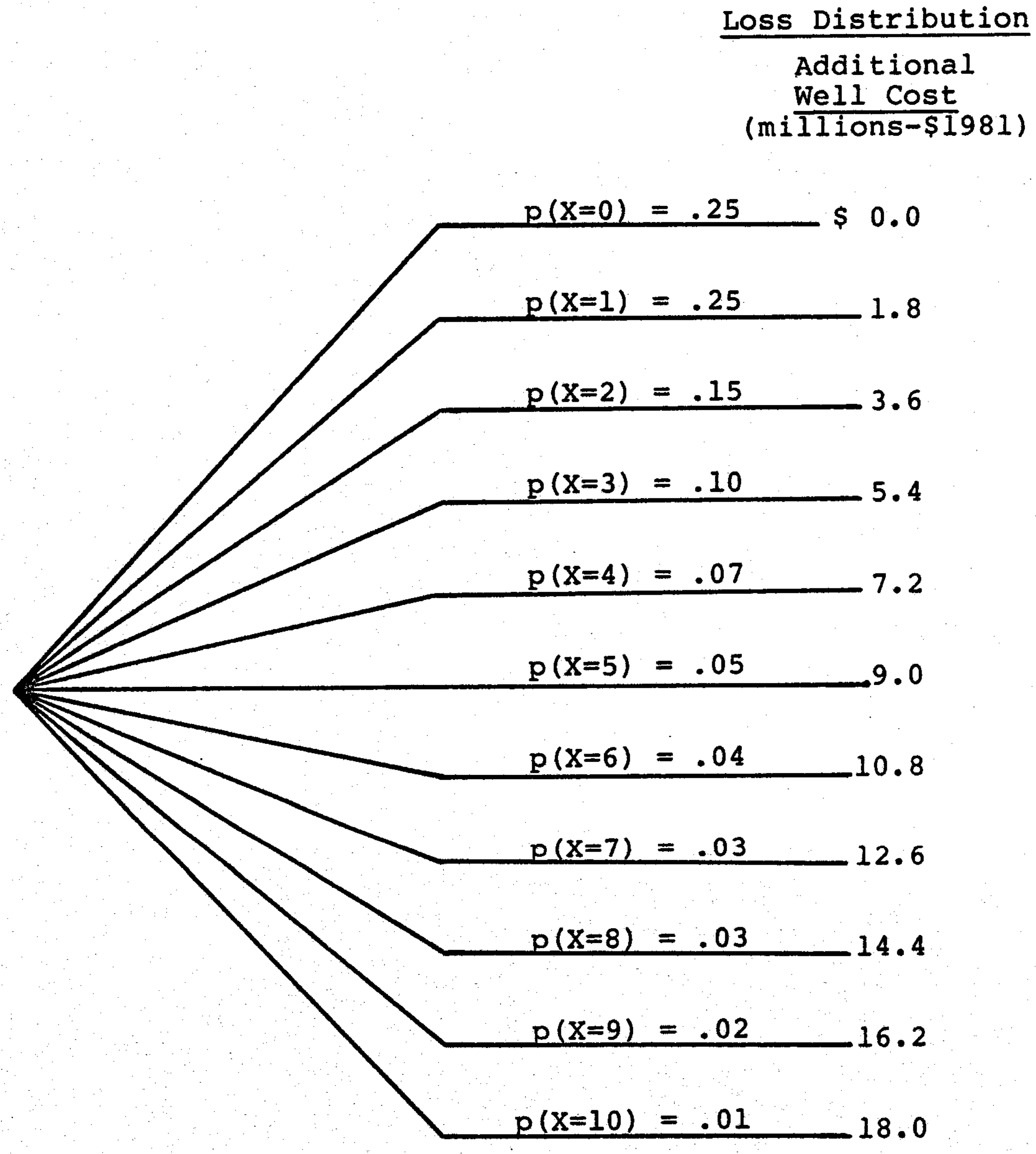
WELL RISKS
SUCCESS RATIO LESS THAN EXPECTED
TYPE D - STAGE 1
EVENT 1



$P(X \leq 0) = .25$
$P(X \leq 1) = .50$
$P(X \leq 3) = .75$
$P(X \leq 10) = 1.00$

EXHIBIT V-9
Page 3 of 3

WELL RISKS
SUCCESS RATIO LESS THAN EXPECTED
TYPE D - STAGE 1
EVENT 1



Expected Additional Well Cost: $4.23 (millions - $1981)

Reservoir Performance Risks

These risks include problems which affect the entire surface unit that yields the geothermal fluid. The specific risk subcategories considered are:

- Interference caused by wells in an adjacent development.
- Initial reservoir characteristics worse than expected.
- Adverse changes from expectations in reservoir model.

Excluded from consideration in this section are those problems in individual wells that can be solved by drilling a new well close to the original location (these risks were considered under Well Risks).

Interference of other wells (adjacent development)

Event Definition: These events occur when temperature, pressure or productivity of wells within a particular project declines because the same subsurface reservoir is also being tapped from a nearby, independent project. Risks were considered significant only in a Type A reservoir (see Exhibit V-3).

Cost Consequences: Costs will depend on the stage of development in which the interference takes place. During Stages 1 and 2 it is assumed that sufficient flexibility remains in the production/injection strategy for the project such that lower productivity can be largely mitigated by adding more wells. However, in Stage 3 most of the wells for the project are assumed to be in place and the full reservoir volume available to the project is being exploited, therefore, additional wells will not solve the problem. Instead, the lower flow rates will persist throughout the remainder of project life, which implies (1) a loss of revenue for the developer, (2) the excess cost of replacement power for the user, and (3) the proportionate amount of unamortized value of a plant due to reduction in the normal operating capacity.

Probability Estimation: For Stages 1 and 2 a cumulative distribution $P(X \leq x)$ was assessed for the number of additional producer wells required to mitigate any interference. Discrete probabilities $P(X = x)$ were then derived from each of these distributions regarding the probability of any specific number of wells being required. For Stage 3 a cumulative distribution was assessed for the percentage of normal operating capacity lost as a result of the lower flow rates.

Analysis of Project Type A: Exhibit V-10 presents the risk analysis for interference of other wells (adjacent developement) for project Type A, Stages 1, 2, and 3. Detailed descriptions of all major input data are provided in the Appendix.

EXHIBIT V-10
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RESERVOIR PERFORMANCE RISKS
INTERFERENCE OF OTHER WELLS (ADJACENT DEVELOPMENT)
TYPE A - STAGE 1
EVENT 1

Description:	Wells in an adjacent development commence full production, causing declines in pressure and/or productivity of wells within project. Reservoir engineering calculations indicate that additional wells must be drilled in order to supply full design steam flow to plant, and sufficient excess project area and/or reservoir volume is present within the project to make this feasible.

Cost Consequences:

Developer:	Capital cost of additional producer wells. (Additional injector wells not considered because adequate injection capacity is assumed always present for this type of project).
User:	None.

Input Data:

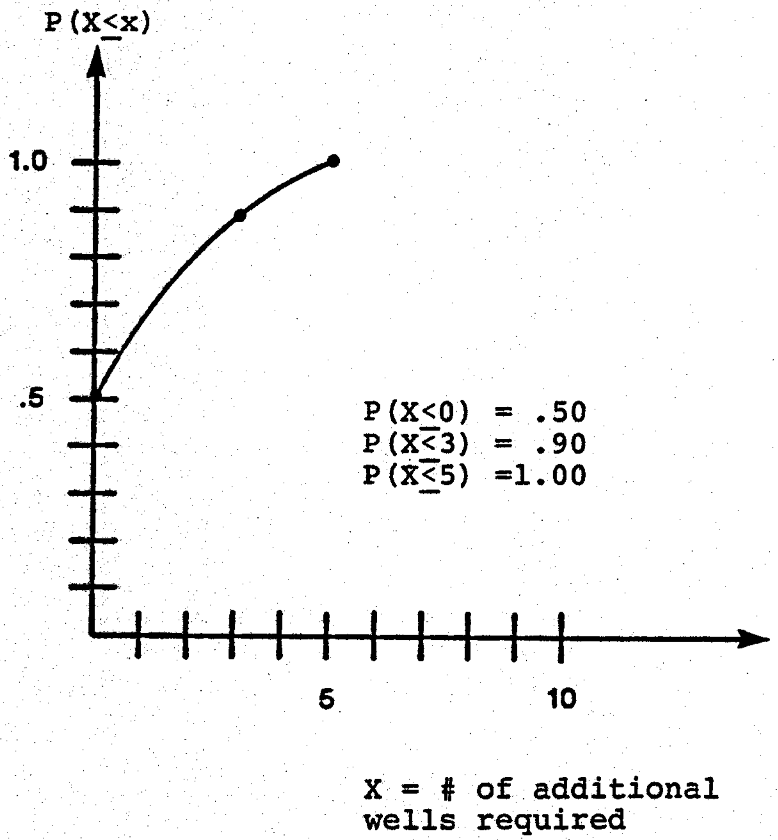
Cost of Additional Producer Well: $1.8 (millions - $1981)

Probability:

$p(X=0) = .50$ X = number of additional producer wells required
$p(X=1) = .20$
$p(X=2) = .11$
$p(X=3) = .09$
$p(X=4) = .07$
$p(X=5) = .03$

EXHIBIT V-10
Page 2 of 9

RESERVOIR PERFORMANCE RISKS
INTERFERENCE OF OTHER WELLS (ADJACENT DEVELOPMENT)
TYPE A - STAGE 1
EVENT 1



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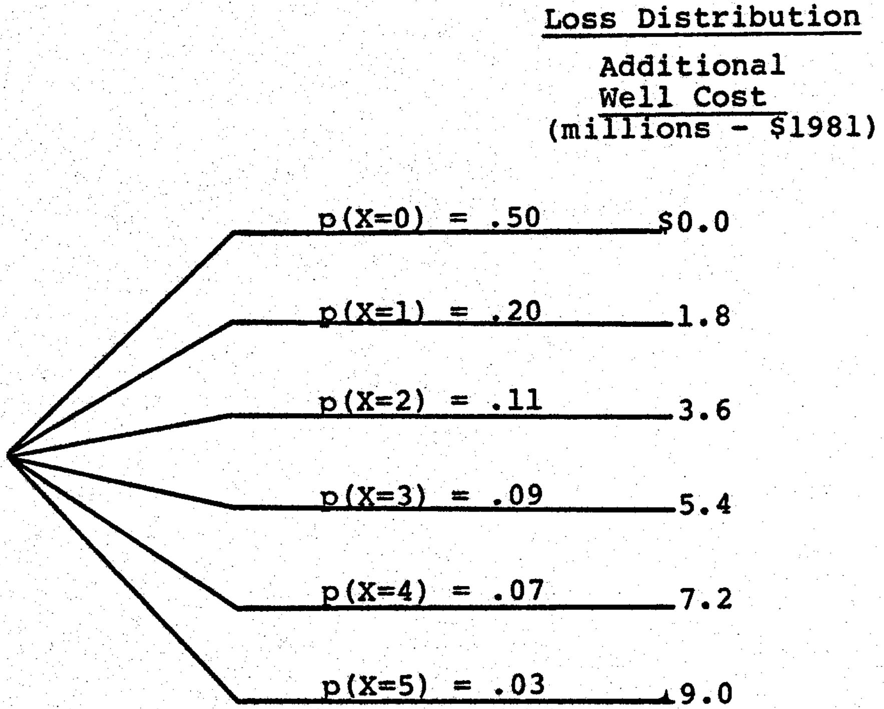
RESERVOIR PERFORMANCE RISKS
INTERFERENCE OF OTHER WELLS (ADJACENT DEVELOPMENT)
TYPE A - STAGE 1
EVENT 1



Expected Cost of Additional Wells: $2.02 (millions - $1981)

RESERVOIR PERFORMANCE RISKS
INTERFERENCE OF OTHER WELLS (ADJACENT DEVELOPMENT)
TYPE A - STAGE 2
EVENT 1

Description: Wells in an adjacent development commence full production, causing declines in pressure and/or productivity of wells within project. Reservoir engineering calculations indicate that additional wells must be drilled in order to supply full design steam flow to plant, and sufficient excess project area and/or reservoir volume is present within the project to make this feasible.

Cost Consequences:

Developer:
(a) Capital cost of additional producer wells.
(b) Diminished revenue until new wells (in excess of reserve capacity) come on-line.

User: Cost differential of replacement power until new wells come on-line.

Input Data:

Delay Time in Adding a Well: 5 months

Cost of Additional Producer Well: \$1.80 (millions - \$1981)

Revenue Loss Per Producer Well Per Month: \$0.084 (millions - \$1981)

Excess Cost of Replacement Power Per Producer Well Per Month: \$0.084 (millions - \$1981)

Number of Wells: 18 producers/2 reserves

Probability:

p(X=0) = .50
p(X=1) = .20
p(X=2) = .11
p(X=3) = .09
p(X=4) = .07
p(X=5) = .03

X = number of additional producer wells required

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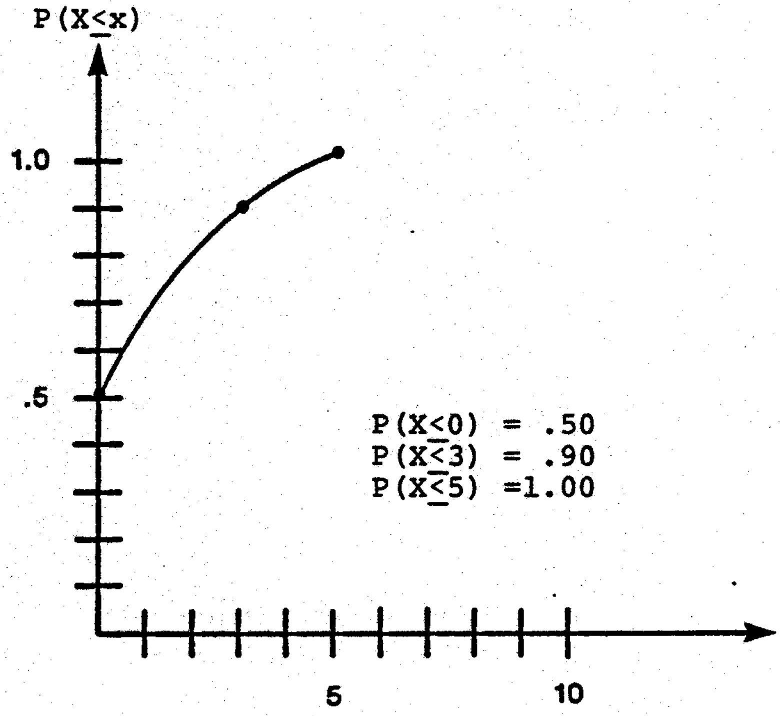
RESERVOIR PERFORMANCE RISKS
INTERFERENCE OF OTHER WELLS (ADJACENT DEVELOPMENT)
TYPE A - STAGE 2
EVENT 1



$P(X\leq 0) = .50$
$P(X\leq 3) = .90$
$P(X\leq 5) =1.00$

X = # of additional producer wells required

EXHIBIT V-10
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RESERVOIR PERFORMANCE RISKS
INTERFERENCE OF OTHER WELLS (ADJACENT DEVELOPMENT)

TYPE A - STAGE 2
EVENT 1

	Loss Distribution		
	Additional Well Cost (millions-$1981)	Revenue Loss (millions-$1981)	Excess Cost of Replacement Power (millions-$1981)
p(X=0) = .50	$0.0	$0.00	$0.00
p(X=1) = .20	1.8	0.00	0.00
p(X=2) = .11	3.6	0.00	0.00
p(X=3) = .09	5.4	0.42	0.42
p(X=4) = .07	7.2	0.84	0.84
p(X=5) = .03	9.0	1.26	1.26

Expected Cost of Additional Wells: $2.020 (millions - $1981)
Expected Revenue Loss: $0.134 (millions - $1981)
Expected Cost of Replacement Power: $0.134 (millions - $1981)

EXHIBIT V-10
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RESERVOIR PERFORMANCE RISKS
INTERFERENCE OF OTHER WELLS (ADJACENT DEVELOPMENT)
TYPE A - STAGE 3
EVENT 1

Description:	Wells within project show declines in pressure and/or productivity; reservoir engineering calculations show that interference by wells in adjacent development has caused the declines. Because the project's reservoir already is fully developed during this stage, producing from additional wells within the project would only cause intensified reservoir decline. The diminished productivity will persist throughout the remainder of the project life.

Cost Consequences:

Developer:	Revenue loss from reduced design flow of project over the remainder of the project life.
User:	(a) Cost differential of replacement power over the remainder of project life. (b) Unamortized value of plant.

Input Data:

Field Revenue - Stage 3: $572.0 (millions - $1981)
Plant Cost: $67.8 (millions - $1981)

Probability:

p(X=0) = .70
p(X=5) = .20
p(X=10)= .07
p(X=15)= .03

X = percentage of normal operating capacity lost

EXHIBIT V-10
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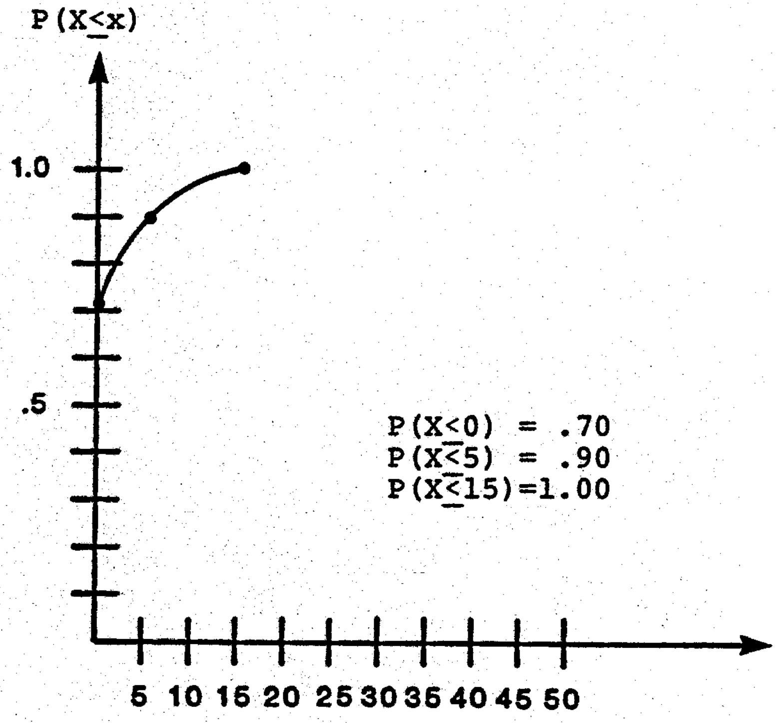
RESERVOIR PERFORMANCE RISKS
INTERFERENCE OF OTHER WELLS (ADJACENT DEVELOPMENT)
TYPE A - STAGE 3
EVENT 1



$P(X<0) = .70$
$P(X \leq 5) = .90$
$P(X \leq 15) = 1.00$

X = Percentage of normal operating capacity lost

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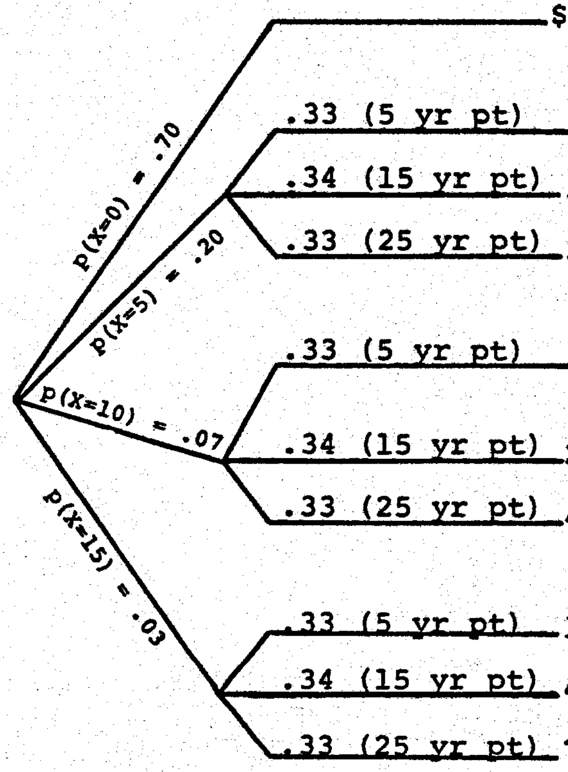
RESERVOIR PERFORMANCE RISKS
INTERFERENCE OF OTHER WELLS (ADJACENT DEVELOPMENT)
TYPE A - STAGE 3
EVENT 1



Loss Distribution*			
Revenue Loss (millions-$1981)	Unamortized Value of Plant (millions-$1981)	Excess Cost of Replacement Power (millions-$1981)	Scenario Probability
$ 0.0	$0.0	$ 0.0	.7000
4.7	0.56	4.7	.0660
14.3	1.70	14.3	.0680
23.9	2.84	23.9	.0660
9.4	1.12	9.4	.0231
28.6	3.40	28.6	.0238
47.8	5.70	47.8	.0231
14.1	1.68	14.1	.0099
42.9	5.08	42.9	.0102
71.7	8.52	71.7	.0099

Expected Revenue Loss: $6.15 (millions - $1981)
Expected Unamortized Value of Plant: $0.73 (millions - $1981)
Expected Cost of Long-Term Replacement Power: $6.15 (millions - $1981)

---

*Cost consequences will depend upon when reduction in capacity initially takes place. Assume equally likely to take place during Stage 3 (years 1-30). Continuous loss distribution can then be discretized and approximated by three points: (1) 33 percent chance of loss occurring at the 5-year point, (2) 34 percent chance of loss occuring at the 15-year point, and (3) 33 percent chance of loss occuring at the 25-year point.

Reservoir characteristics worse than originally expected

Event Definition: These events are concentrated in the early stages of development. Here, a contract has been entered into between the developer/producer and user in which the steam price is based on data regarding geothermal fluid characteristics learned during exploration and early development drilling and testing. A large number of wells are drilled during Stage 1 and the first large-scale production data ordinarily are obtained during Stage 2. Therefore, it is possible that experience during Stages 1 and 2 will show that one or more of the following reservoir characteristics are worse than those interpreted from early data (for definitions see Exhibit V-2):

- Temperature
- Chemistry
- Pressure
- Enthalpy
- Permeability
- Reservoir size

The relative importance of various physical characteristics varies between reservoirs. Events are considered for Stages 1 and 2.

Cost Consequences: Costs will affect both the developer and user as a result of adverse changes in initial reservoir characteristics. With the exception of smaller reservoir size, it is assumed that these changes can be mitigated by additional producer wells because sufficient project area and/or reservoir volume should be available during Stages 1 and 2 for additional drilling. The cost effects would be (a) the cost of additional wells to the developer along with some temporary loss of revenue to the developer during Stage 2, and (b) possible excess cost of replacement power to the user (siginificant for Type A projects only) during Stage 2 until sufficient numbers of wells can be added.

If the reservoir size is found to be smaller than expected then additional wells will not mitigate the problem. In this case the developer will experience loss of anticipated revenue for the remainder of the project. The user will experience the excess cost of replacement power (significant for Type A projects only) and a proportionate amount of the unamortized value of the plant due to loss of normal operating capacity. Therefore, these particular cost consequences are considered under the category of adverse changes from expectations in reservoir model, where long-term implications of reduced reservoir performance having cost consequences in Stage 3 are considered.

Probability Estimation: For both Stages 1 and 2 a cumulative probability distribution $P(X \leq x)$ was assessed for the number of additional producer wells required to mitigate any reduced productivity because of changes in reservoir characteristics. Discrete probabilities $P(X = x)$ were then derived from each of these distributions regarding the probability of any specific number of wells being required.

Analysis of Project Type D: Exhibit V-11 presents the risk analysis for reservoir characteristics worse than originally expected for project Type D, Stages 1 and 2. Detailed results of the risk analysis, for each geologic project type where this risk was considered significant, are presented in the Appendix along with detailed descriptions of the major input data.

EXHIBIT V-11
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RESERVOIR PERFORMANCE RISKS
RESERVOIR CHARACTERISTICS WORSE THAN ORIGINALLY EXPECTED
TYPE D - STAGE 1
EVENT 1

Description:	Temperature, chemistry, enthalpy, pressure or permeability are found to be lower than expected, such that additional producer wells must be drilled in order to supply design flow of project. Sufficient project area and/or reservoir volume is available during this stage.

Cost Consequences:

Developer:	Capital cost of additional producer and injector wells. One additional injector well is needed for each two additional producer wells.
User:	None.

Input Data:

Cost of Additional Producer Well:	\$1.8 (millions - \$1981)
Cost of Additional Injector Well:	\$1.7 (millions - \$1981)

Probability:

$p(X=0) = .40$
$p(X=1) = .25$
$p(X=2) = .15$
$p(X=3) = .08$
$p(X=4) = .05$
$p(X=5) = .04$
$p(X=6) = .03$

X = number of additional producer wells required

EXHIBIT V-11
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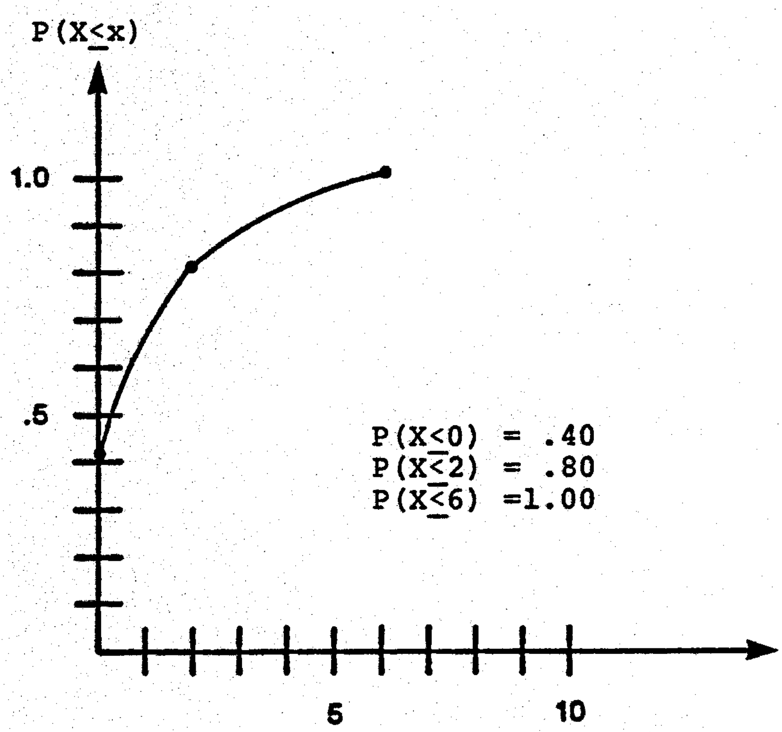
RESERVOIR PERFORMANCE RISKS
RESERVOIR CHARACTERISTICS WORSE THAN ORIGINALLY EXPECTED
TYPE D - STAGE 1
EVENT 1



$P(X<0) = .40$
$P(X\leq 2) = .80$
$P(X\leq 6) = 1.00$

X = # of additional producer wells required

EXHIBIT V-11
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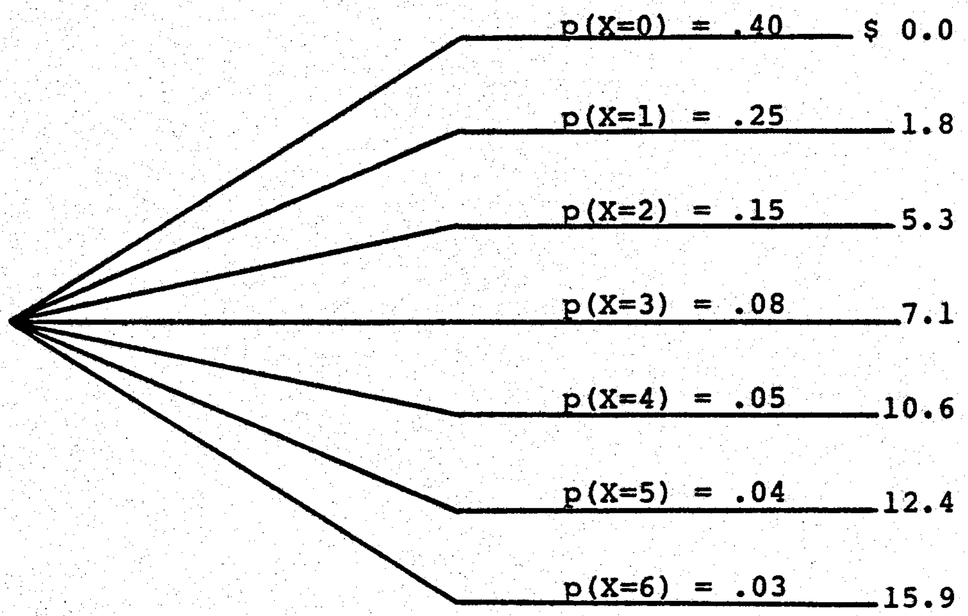
RESERVOIR PERFORMANCE RISKS
RESERVOIR CHARACTERISTICS WORSE THAN ORIGINALLY EXPECTED
TYPE D - STAGE 1
EVENT 1

Loss Distribution

Cost of
Additional
Producer and
Injector Wells
(millions-$1981)



Expected Cost of Additional Wells: $3.32 (millions - $1981)

EXHIBIT V-11
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RESERVOIR PERFORMANCE RISKS
RESERVOIR CHARACTERISTICS WORSE THAN ORIGINALLY EXPECTED
TYPE D - STAGE 2
EVENT 1

Description: Temperature, chemistry, enthalpy, pressure or permeability are found to be lower than expected, such that additional producer wells must be drilled in order to supply design flow of project. Sufficient project area and/or reservoir volume is available during this stage.

Cost Consequences:

Developer:
(a) Capital cost of additional producer and injector wells. One additional injector well needed for each two additional producer wells.
(b) Diminished revenue until new wells (in excess of reserve capacity) come on-line.

User: None.

Input Data:

Delay Time in Adding a Well: 5 months
Cost of Additional Producer Well: $1.8 (millions - $1981)
Cost of Additional Injector Well: $1.7 (millions - $1981)
Revenue Loss Per Producer Well Per Month: $0.069 (millions - $1981)
Number of Producer Wells: 10 producers - 1 reserve

Probability:

p(X 0) = .30
p(X=1) = .35
p(X=2) = .15
p(X=3) = .08
p(X=4) = .05
p(X=5) = .04
p(X=6) = .03

X = number of additional producer wells required

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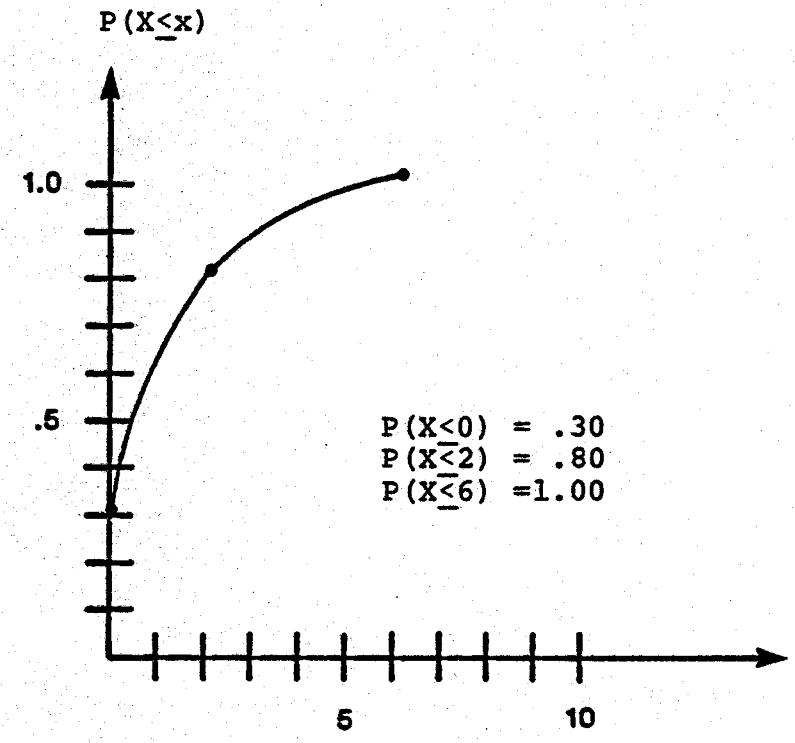
RESERVOIR PERFORMANCE RISKS
RESERVOIR CHARACTERISTICS WORSE THAN ORIGINALLY EXPECTED
TYPE D - STAGE 2
EVENT 1



$P(X<0) = .30$
$P(X \le 2) = .80$
$P(X \le 6) = 1.00$

X = # of additional producer wells required

EXHIBIT V-11
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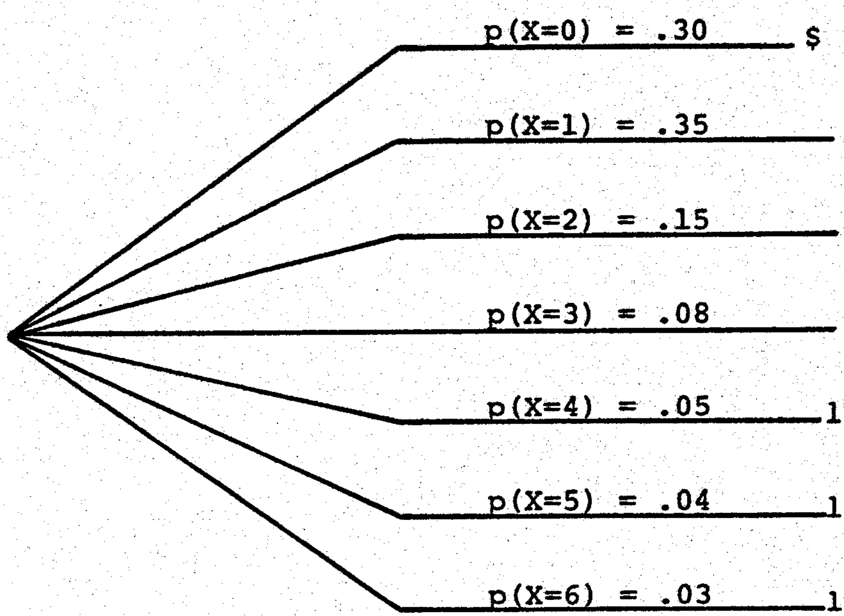
RESERVOIR PERFORMANCE RISKS
RESERVOIR CHARACTERISTICS WORSE THAN ORIGINALLY EXPECTED
TYPE D - STAGE 2
EVENT 1



	Loss Distribution	
	Cost of Additional Producer and Injector Wells (millions-$1981)	Revenue Loss (millions-$1981)
p(X=0) = .30	$ 0.0	$0.000
p(X=1) = .35	1.8	0.000
p(X=2) = .15	5.3	0.345
p(X=3) = .08	7.1	0.690
p(X=4) = .05	10.6	1.035
p(X=5) = .04	12.4	1.380
p(X=6) = .03	15.9	1.725

Expected Cost of Additional Wells: $3.5 (millions - $1981)
Expected Loss of Revenue: $0.27 (millions - $1981)

Adverse changes from expectations in reservoir model

Event Definition: The detailed reservoir model is based on geological, hydrological and chemical data gained and analyzed throughout the early life of the project, but mostly in Stages 1 and 2. Detailed forecasts of the behavior of the reservior for all stages through Stage 3 are based on this model. The reservoir characteristics which may be different than predicted are (for definitions see Exhibit V-2):

- Temperature
- Chemistry
- Pressure
- Enthalpy
- Permeability
- Reservoir size

Cost Consequences: Events considered in this risk subcategory have long-term cost consequences to the developer and user. During Stage 3 adverse changes in reservior characteristics will lead to a reduction from design steam flow and lower overall productivity. Because additional project area and/or reservoir volume would not likely be available during this stage for additional drilling, lowered productivity is assumed to persist throughout the remainder of the project life. If during Stages 1 or 2 the reservior size is found to be less than originally expected, leading to lower than expected productivity, the reservoir will be operated at lower than original design flow throughout the project life with cost consequences resulting primarily in Stage 3.

Specific cost consequences to the developer and user occur only in Stage 3 and are (a) loss of revenue to developer due to lowered productivity (b) excess cost of replacement power to the user (significant only for Type A projects), and (c) the proportionate amount of the unamortized value of the plant due to reduction in normal operating capacity.

Probability Estimation: For Stage 1 a cumulative probability distribution was assessed for the percentage reduction in normal operation capacity as a result of reservoir size being found smaller than expected. For Stage 2, the same probability distribution was assessed under two different conditions: (1) no reduction in reservoir size was discovered in Stage 1; and (2) reservoir size had been found smaller than originally expected during Stage 1. For Stage 3, a cumulative probability distribution was assessed for the percentage reduction in normal operating capacity as a result of any or all of the reduced reservoir characteristics described above, under three different conditions regarding reservoir size: (1) no reductions in reservoir size were discovered in either Stage 1 or 2; (2) reductions in reservoir size were discovered in Stage 1 but not in Stage 2; and (3) reductions in reservoir size were discovered in Stage 2 but not in Stage 1.

Analysis of Project Type D: Exhibit V-12 presents the risk analysis for adverse changes from expectations in reservoir model for project Type D. Detailed results of the risk analysis, for each geologic project type where this risk was considered significant, are presented in the Appendix along with detailed descriptions of the primary input data.

EXHIBIT V-12
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RESERVOIR PERFORMANCE RISKS
ADVERSE CHANGES FROM EXPECTATIONS IN RESERVOIR MODEL
TYPE D - STAGES 1-3
EVENT 1

Description:

Stages 1-2:	Reservoir size is smaller than expected, leading to lower than expected productivity. Reservoir must be operated at lower than design flow throughout project life.
Stage 3:	Change in reservoir characteristics from expectations leads to a reduction from design steam flow and overall lower productivity. Because additional project area and/or reservoir volume is not available during this stage, lowered productivity will persist throughout the remainder of the project life.

Cost Consequences:

Developer:	Loss of revenue from lowered productivity during stages 2 and 3.
User:	Unamortized value of plant.

Input Data:

Field Revenue - Stage 2: $8.4 (millions - $1981)

Field Revenue - Stage 3: $264.0 (millions - $1981)

Plant Cost: $28.6 (millions - $1981)

RESERVOIR PERFORMANCE RISKS
ADVERSE CHANGES FROM EXPECTATIONS
IN RESERVOIR MODEL
TYPE D - STAGES 1-3
EVENT 1

EXHIBIT V-12
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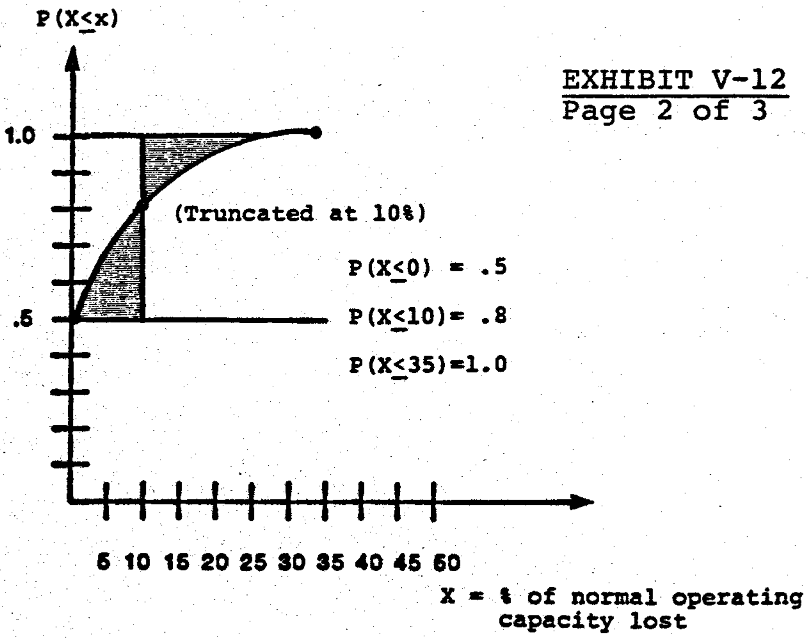
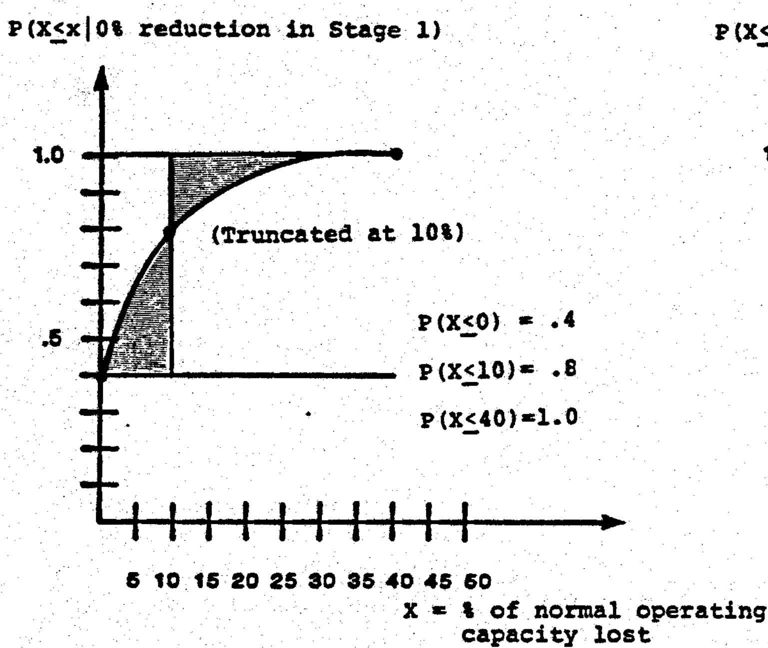
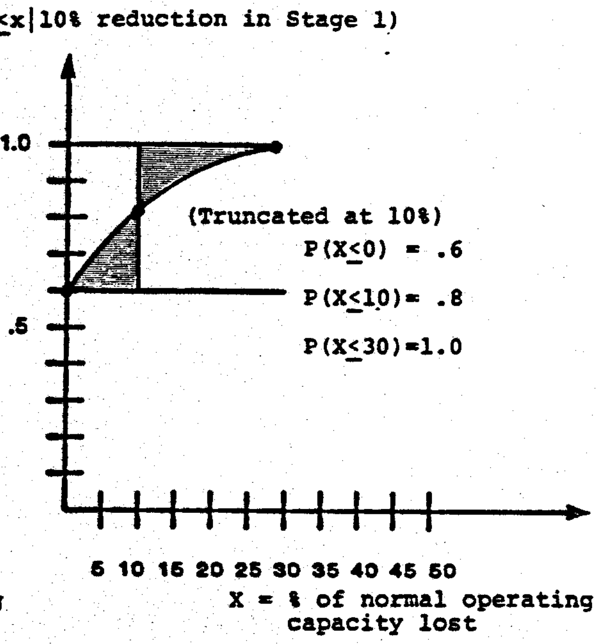
Probability:

Stage 1:

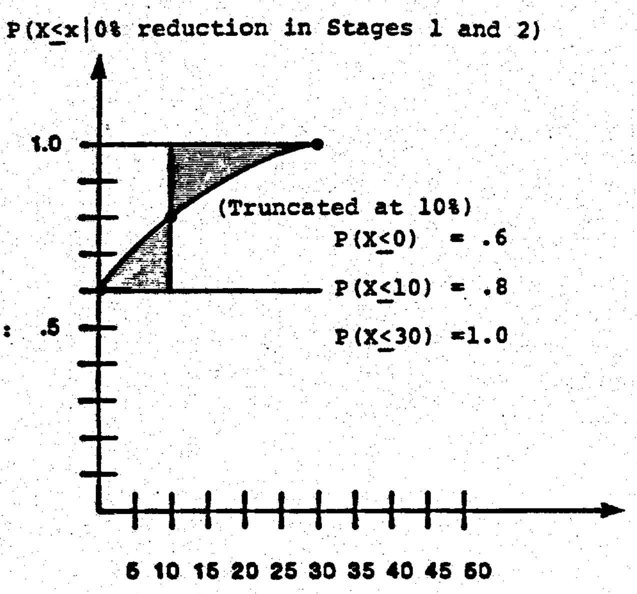


Stage 2:





Stage 3:



X = % of normal operating capacity lost

P(X=0%|10% reduction in Stage 1 and/or Stage 2) = .90

P(X=5%|10% reduction in Stage 1 and/or Stage 2) = .10

EXHIBIT V-12
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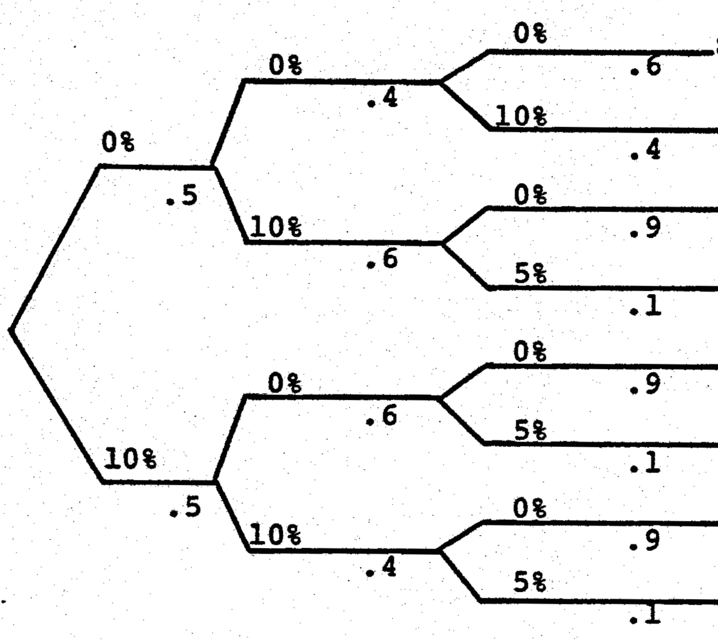
RESERVOIR PERFORMANCE RISKS
ADVERSE CHANGES FROM EXPECTATIONS IN RESERVOIR MODEL
TYPE D - STAGES 1-3
EVENT 1



Revenue Loss (millions-$1981)	Unamortized Value of Plant (millions-$1981)	Scenario Probability
$ 0.0	$0.00	.12
13.2	1.43	.08
26.8	2.86	.27
32.7	3.50	.03
27.2	2.86	.27
33.1	3.50	.03
51.3	5.72	.18
56.6	6.29	.02

Expected Revenue Loss: $28.0 (millions - $1981)
Expected Unamortized Value: $3.02 (millions - $1981)

---

*Probability distribution for Stage 1 was discretized and approximated by two points: (1) 50 percent chance of zero reduction in capacity, and (2) 50 percent chance of 10 percent reduction in capacity.

**Probability distributions for Stage 2 were discretized and approximated by two points. Losses during Stage 2 assumed to occur at the mid-point and continue throughout project life.

***Probability distributions for Stage 3 were discretized and approximated by two points. Losses during Stage 3 assumed to occur at the mid-point (year 15) and continued throughout project life.

Plant Risks

Risks considered in this category are those geothermal related hazards which impact on the performance of the power plant.

Power plant performance

Event Definition: Geothermal steam is more likely than steam in coal-fired or other closed system generators to carry fine particulate matter or dissolved solids (such as silica) that may significantly damage the turbine blades. The events considered in this risk category are the specific instances where turbines need to be rebladed. Complete replacement of the turbine was considered too remote a circumstance to analyze in detail.

Cost Consequences: Three main cost consequences are considered: (a) the cost to the user of reblading the turbine, (b) the user's excess cost of replacement power while the turbine is shut-down, and (c) the developer's loss of steam revenue during the downtime.

Probability Estimation: Discrete probabilities were assessed for the number of times a turbine would require reblading during Stage 3 for each type of project where this risk was considered significant.

Analysis of Project Type D: Exhibit V-13 presents the risk analysis for power plant performance for project Type D. Detailed results of the risk analysis, for each geologic project type where this risk was considered significant, are presented in the Appendix along with detailed descriptions of the primary input data.

EXHIBIT V-13
Page 1 of 2

PLANT RISKS
POWER PLANT PERFORMANCE
TYPE D - STAGE 3
EVENT 1

Description:	Reblading -- Mechanical damage to turbine requires reblading and consequent shutdown.

Cost Consequences:

Developer:	Loss of steam revenue while plant is down.
User:	Cost of reblading to user.

Input Data:

Cost of Reblading: $0.75 (millions - $1981)
Downtime: 1 month
Revenue Loss Per Month: $0.74 (millions - $1981)

Probability:

p(0 reblades) = .80
p(1 reblade) = .15
p(2 reblades) = .05

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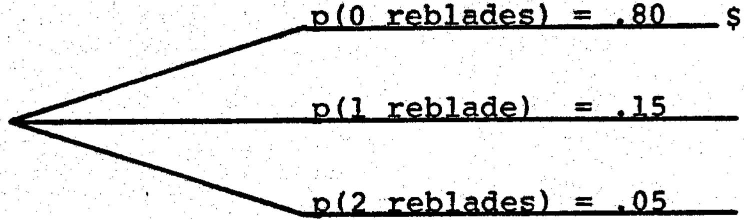
Page 2 of 2

PLANT RISKS
POWER PLANT PERFORMANCE
TYPE D - STAGE 3
EVENT 1



	Loss Distribution	
	Cost of Rereblading (millions-$1981)	Revenue Loss (millions-$1981)
p(0 reblades) = .80	$0.00	$0.00
p(1 reblade) = .15	0.75	0.74
p(2 reblades) = .05	1.50	1.48

Expected Loss of Reblading: $0.19 (millions - $1981)
Expected Revenue Loss: $0.18 (millions - $1981)

Surface Facility Risks

Risks related to the operations and usable-lives of the surface facilities of geothermal projects are considered in this category. These facilities consist of retrievable downhole equipment (such as pumps), surface fluid-handling and gathering lines, and steam separators. The specific risk sub-categories considered are:

- Failure of advanced design equipment.
- Scaling and corrosion in fluid handling and gathering lines greater than expected.

Failure of advanced design equipment

Event Definition: Two sets of problems are considered for this risk sub-category:

- Failure of downholes pumps.
- Failure of steam separators.

Downhole pumps for geothermal well applications are advanced design equipment because the combination of high temperature environment and chemical properties of the water are more severe than usually experienced by such pumps and completely reliable equipment has not yet been developed.

Failure of downhole pumps is considered for Stages 1 and 2 of reservoir Type F because (a) pumping would be necessary throughout the project life for this project type and (b) experience should be gained during this time such that the hazard would be greately diminished by Stage 3. Stage 3 risks are considered for Type D reservoirs only because pumping would only become necessary later in the project life for this type of reservoir. Steam separators are also considered advanced design equipment for Type G where geothermal fluid of extreme composition exists.

<u>Cost Consequences</u>: The cost of advanced design equipment failure affects primarily the developer (unless the failure is in a Type A project where the user will also face a significant excess cost for replacement power). The developer incurs the cost of replacing the equipment and the revenue loss, if any, during the time the downhole pump or steam separator is being replaced.

<u>Probability Estimation</u>: Cumulative probability distributions were assessed and converted into discrete probabilities for (a) the number of downhole pumps requiring replacement greater than expected, and (b) the number of steam separators requiring replacement greater than expected (Type G only).

<u>Analysis of Project Type F</u>: Exhibit V-14 presents the risk analysis for failure of advance design equipment for project Type F. Detailed results of the risk analysis, for each geologic project type where this risk was considered significant, are presented in the Appendix along with detailed descriptions of the primary input data.

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Page 1 of 6

SURFACE FACILITY RISKS
FAILURE OF ADVANCED DESIGN EQUIPMENT
TYPE F - STAGE 1
EVENT 1

Description: Greater than expected failure of downhole pumps requiring replacement.

Cost Consequences:

Developer: Cost of replacement pumps.

User: None.

Input Data:

Cost of Pump: \$0.17 (millions - \$1981)

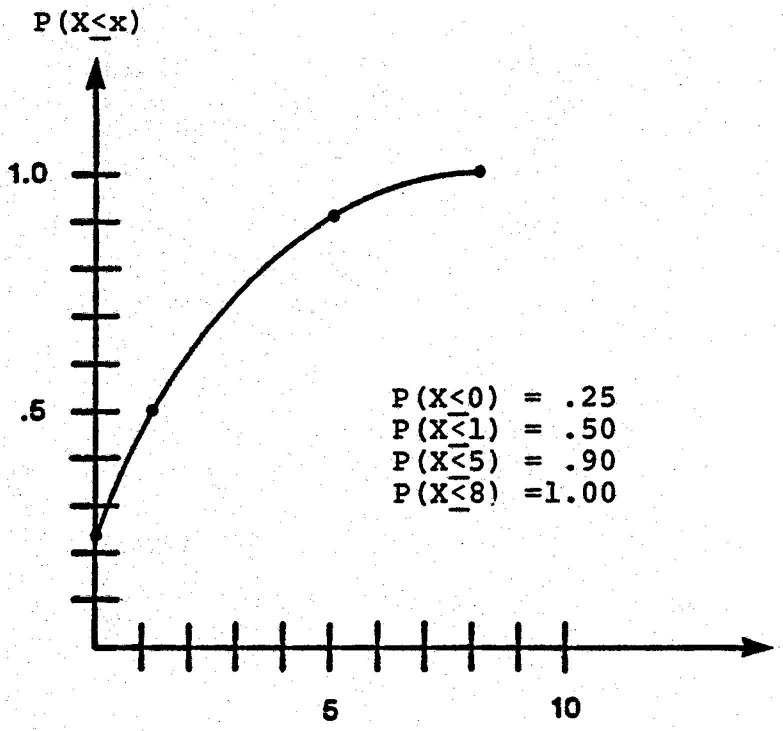
Probability:

$p(X=0) = 0.25$
$p(X=1) = 0.25$
$p(X=2) = 0.15$
$p(X=3) = 0.10$
$p(X=4) = 0.08$
$p(X=5) = 0.07$
$p(X=6) = 0.05$
$p(X=7) = 0.03$
$p(X=8) = 0.02$

X = number of downhole pumps requiring replacement greater than expected

EXHIBIT V-14
Page 2 of 6

SURFACE FACILITY RISKS
FAILURE OF ADVANCED DESIGN EQUIPMENT
TYPE F - STAGE 1
EVENT 1

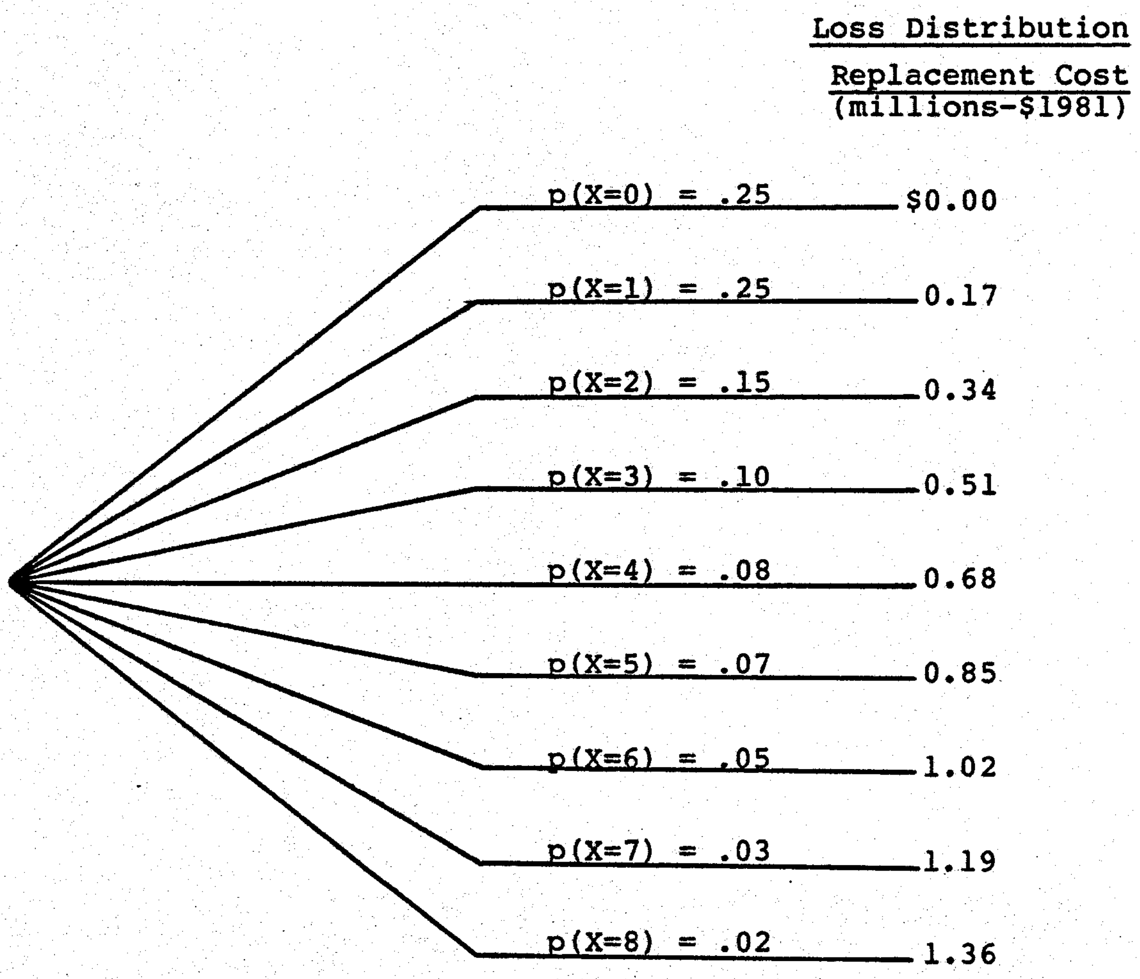


$P(X<0) = .25$
$P(X\leq1) = .50$
$P(X\leq5) = .90$
$P(X\leq8) = 1.00$

X = # of downhole pumps requiring replacement greater than expected

EXHIBIT V-14
Page 3 of 6

SURFACE FACILITY RISKS
FAILURE OF ADVANCED DESIGN EQUIPMENT
TYPE F - STAGE 1
EVENT 1



Expected Loss:

Expected Replacement Cost: $0.37 (millions - $1981)

EXHIBIT V-14
Page 4 of 6

SURFACE FACILITY RISKS
FAILURE OF ADVANCED DESIGN EQUIPMENT
TYPE F - STAGE 2
EVENT 1

Description: Greater than expected failure of downhole pumps requiring replacement.

Cost Consequences:

Developer:
(a) Replacement cost of pumps.
(b) Revenue loss during downtime for well (in excess of reserve capacity) associated with faulty pump.

User: None.

Input Data:

Cost of Pump: $0.17 (millions - $1981)
Revenue Loss Per Pump Per Month: $0.053 (millions - $1981)
Downtime: 1.5 months
Number of Reserve Wells: 4

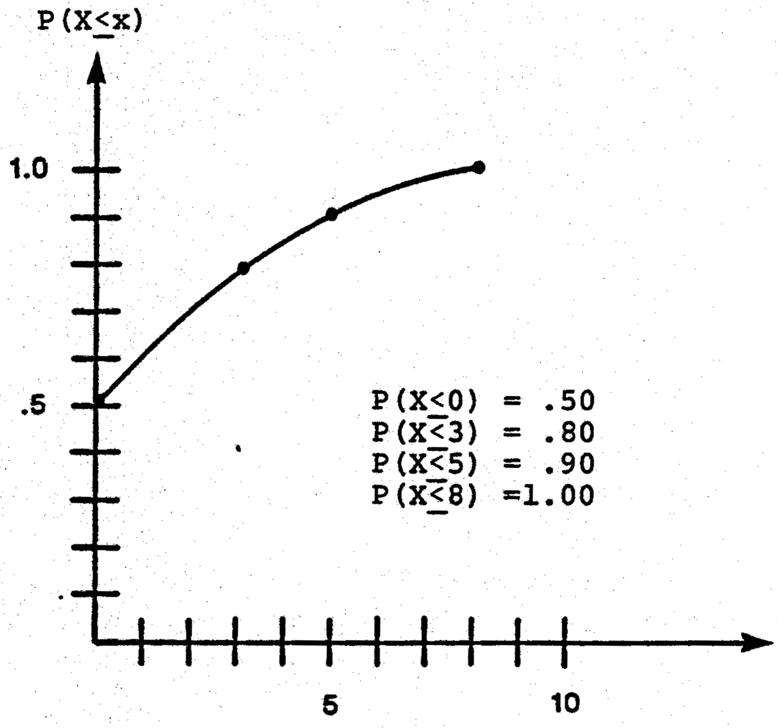
Probability:

$p(X=0) = 0.50$
$p(X=1) = 0.12$
$p(X=2) = 0.10$
$p(X=3) = 0.08$
$p(X=4) = 0.05$
$p(X=5) = 0.05$
$p(X=6) = 0.05$
$p(X=7) = 0.03$
$p(X=8) = 0.02$

X = number of downhole pumps requiring replacement greater than expected

EXHIBIT V-14
Page 5 of 6

SURFACE FACILITY RISKS
FAILURE OF ADVANCED DESIGN EQUIPMENT
TYPE F - STAGE 2
EVENT 1

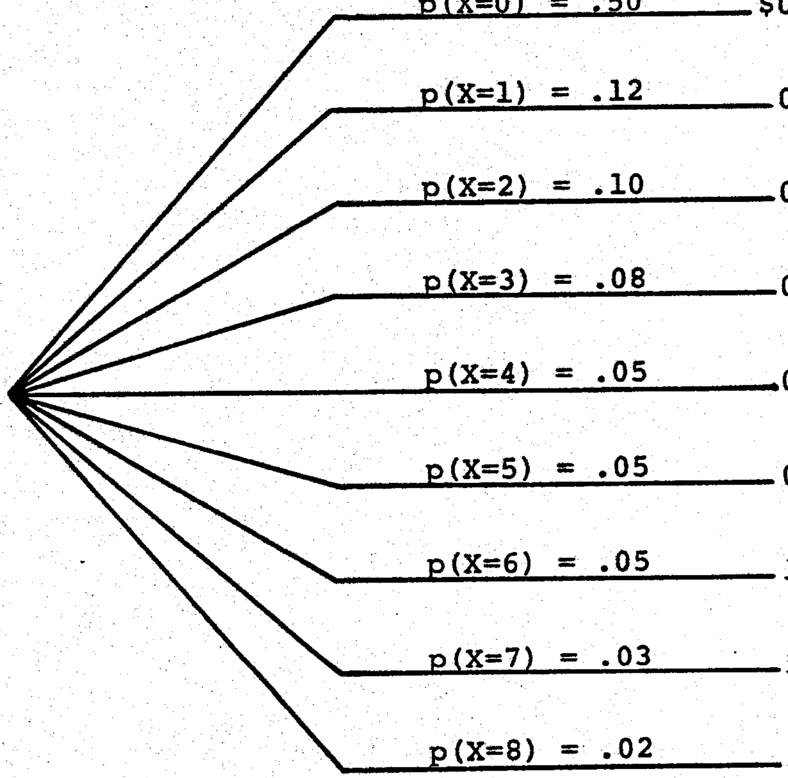


$P(X<0) = .50$
$P(X \leq 3) = .80$
$P(X \leq 5) = .90$
$P(X \leq 8) =1.00$

X = # of downhole pumps
requiring replacement
greater than expected

EXHIBIT V-14
Page 6 of 6

SURFACE FACILITY RISKS
FAILURE OF ADVANCED DESIGN EQUIPMENT
TYPE F - STAGE 2
EVENT 1



	Loss Distribution	
	Replacement Cost (millions-$1981)	Revenue Loss (millions-$1981)
p(X=0) = .50	$0.00	$0.00
p(X=1) = .12	0.17	0.00
p(X=2) = .10	0.34	0.00
p(X=3) = .08	0.51	0.00
p(X=4) = .05	0.68	0.00
p(X=5) = .05	0.85	0.08
p(X=6) = .05	1.02	0.16
p(X=7) = .03	1.19	0.24
p(X=8) = .02	1.36	0.32

Expected Loss:

Expected Replacement Cost: $0.29 (millions - $1981)
Expected Revenue Loss: $0.03 (millions - $1981)

Scaling and corrosion greater than expected

Event Definition: Two possible series of events can lead to significant hazards of scaling and corrosion in surface gathering and handling lines. In one scenario, fluid chemistry actually experienced is worse than expected to the extent that normal maintenance procedures are inadequate to prevent serious damage to the pipelines, thereby resulting in the need to replace siginificant portions of the system. In the other scenario, scaling and corrosion are caused by improper handling and treatment procedures. Only the likelihoods and cost consequences of the first scenario were considered. As discussed earlier, improper handling and treatment procedures were excluded from further analysis because they were perceived as uninsurable because of the moral hazard situation that insurance might present.

Because pipelines would have to be operated for some period of time before a significant level of damage could occur, only events in Stage 3 were considered significant risks.

Cost Consequences: Costs are considered only for the owner of the pipeline system (ordinarily the developer) and consist of the capital costs of replacing portions of the pipeline system. This is because problems with the pipeline system, unlike problems with wells, are likely to develop relatively slowly. If it is decided that the expenditure of replacing a significant portion of the pipeline must be made, then provisions would most likely have been previously made for adequate redundancy in the system to maintain full flow to the power plant. Thus, interruptions to revenue will most likely be avoided.

Probability Estimation: First, discrete probabilities for the number of occurrences of scaling and corrosion problems leading to the replacement of portions of the pipeline system were assessed. Second, a cumulative probability distribution was assessed for the percentage of the pipeline system requiring replacement given that the event occurs.

Analysis of Project Type B: Exhibit V-15 presents the risk analysis for scaling and corrosion for project Type B. Detailed results of the risk analysis, for each geologic project type where this risk was considered significant, are presented in the Appendix along with detailed descriptions of the primary input data.

EXHIBIT V-15
Page 1 of 3

SURFACE FACILITY RISKS
SCALING AND CORROSION
TYPE B - STAGE 3
EVENT 1

Description:	Scaling and corrosion greater than expected leading to the replacement of portions of the pipeline system.

Cost Consequences:

Developer:	Capital cost of replacing portions of the pipeline system. Revenue loss is considered zero because adequate redundancy is likely to exist to maintain full flow to the power plant.
User:	None.

Input Data:

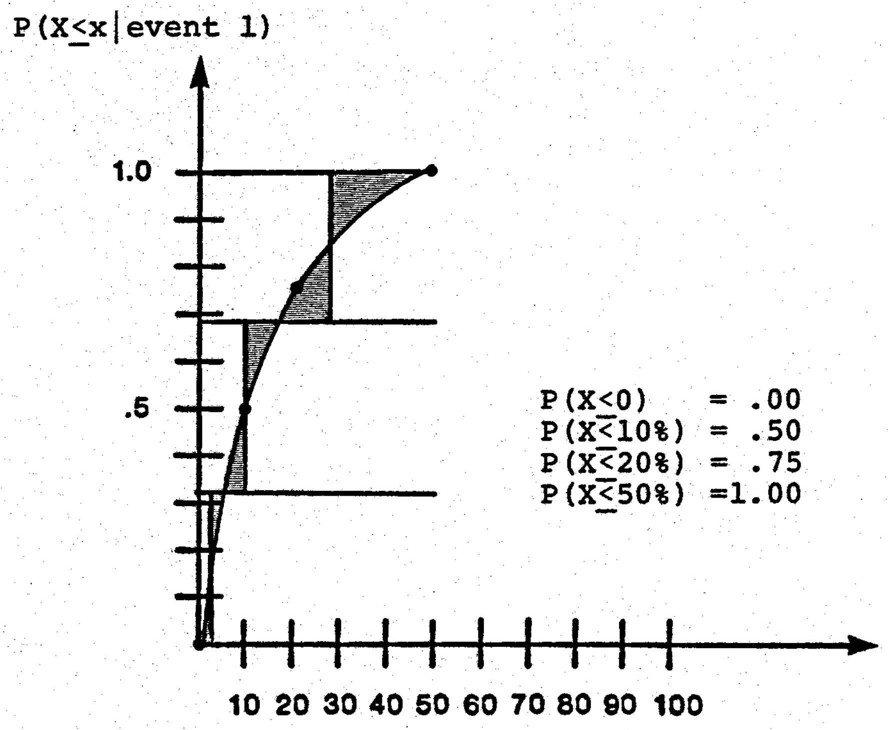
Cost of Piping System: $9.0 (millions - $1981)

Probability:

P(event 1 never occurs) = .50
P(event 1 occurs once) = .40
P(event 1 occurs twice) = .10

EXHIBIT V-15
Page 2 of 3

SURFACE FACILITY RISKS
SCALING AND CORROSION
TYPE B - STAGE 3
EVENT 1



$P(X<0) = .00$
$P(X \le 10\%) = .50$
$P(X \le 20\%) = .75$
$P(X \le 50\%) = 1.00$

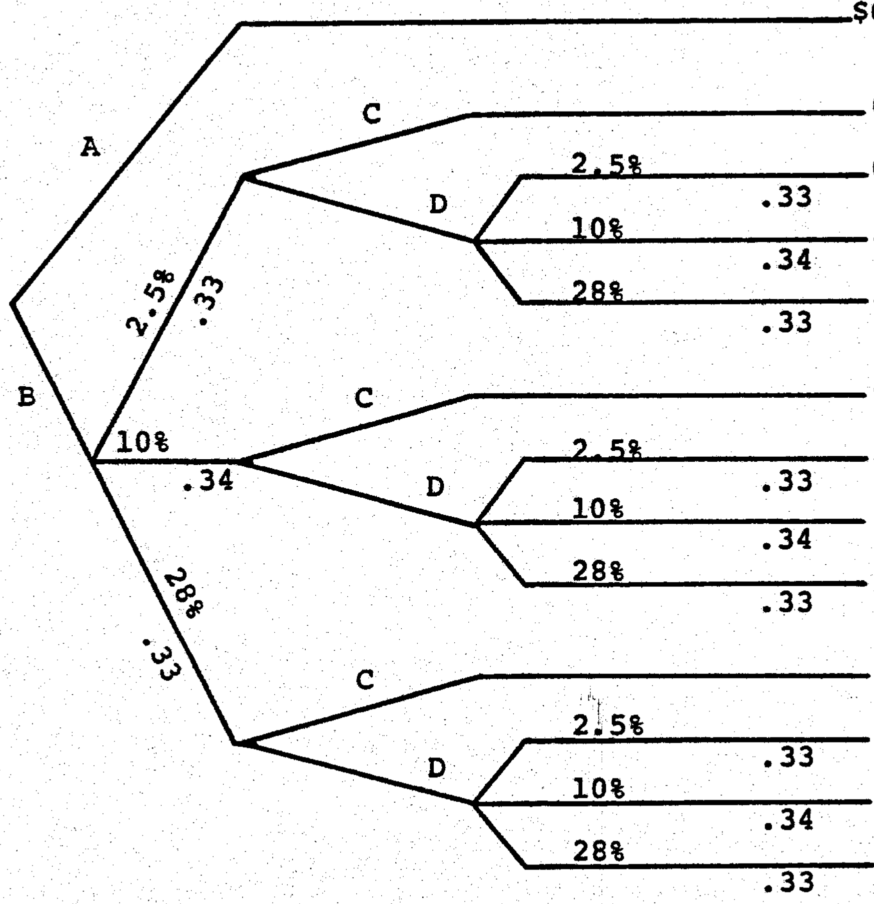
X = % of pipeline system requiring replacement given that event 1 has occurred

Discrete Approximation:

$P(X = 2.5\%) = .33$
$P(X = 10\%) = .34$
$P(X = 28\%) = .33$

EXHIBIT V-15
Page 3 of 3

SURFACE FACILITY RISKS
SCALING AND CORROSION
TYPE B - STAGE 3
EVENT 1



Loss Distribution	
Replacement Cost of Portions of the Piping system (millions-$1981)	Scenario Probability
$0.000	.500
0.225	.132
0.450	.011
1.125	.011
2.745	.011
0.900	.136
1.125	.011
1.800	.011
3.420	.011
2.520	.132
2.745	.011
3.420	.011
5.040	.011

A: Event 1 never occurs.
B: Event 1 occurs first time.
C: Event 1 never occurs again after having occurred once.
D: Event 1 occurs second time.

Expected Cost of Replacing Portions of the Piping System:
$0.73 (millions - $1981)

Acts of God

Included for consideration in this risk category are (a) volcanic hazards in a specific area of Hawaii (Type E), and (b) landslides in the Geysers region of Northern California (Type A). These risks are analyzed because the geothermal developments in these areas are the only major facilities in the high-risk zone. As discussed earlier, other natural disasters were excluded from consideration because they represent hazards to all facilities and industries in a region and as such insurance in different forms to cover those risks is generally available.

Volcanic hazards

Event Definition: The specific volcanic hazards considered are lava flows from volcanic eruptions that cause significant damage to wells, power plant, and/or surface facilities. Damage to wells is defined as either (a) slight damage or burial of well-head resulting basically in clean-up costs, or (b) heavy damage resulting in clean-up and significant repair. Very severe damage to wells causing replacement and/or blowouts (see Exhibit V-2 for definition) was not considered as having significant probability in this case. Damage to the power plant is defined as being severe enough to cause temporary shut-down while repairs take place. Damage to surface facilities is defined as severe enough to cause temporary shut-down of the development and replacement of a percentage of the piping system.

Cost Consequences: The developer is assumed to incur most of the cost of damages to wells and surface facilities. These costs include (a) clean-up and repair costs for wells, as well as revenue loss while each well is temporarily shut-down for repairs, and (b) replacement costs for portions of the piping system, along with revenue loss while replacement is taking place and the development is temporarily shut-down. The user's costs result from damage to the power plant measured as a percentage of the total replacement cost of the plant. Further, the developer is assumed to temporarily lose steam revenue as a result of power plant shut-down.

Probability Estimation: First, discrete probabilities were estimated for the number of occurrences of each of the events described above for wells, power plant and surface facilities. Second, cumulative probability distributions were assessed for the extent of damage given that an event has occurred, in terms of numbers of wells damaged, the percentage of the power plant's replacement cost required for repair, and the percentage of the piping system requiring replacement.

Analysis of Project Type E: Exhibit V-16 presents the risk analysis for volcanic hazards for project Type E. Detailed descriptions of all primary input data are provided in the Appendix.

EXHIBIT V-16
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ACTS OF GOD
VOLCANIC HAZARDS
TYPE E - STAGE 3
EVENT 1

Description:

Lava flow from a volcanic eruption damages one or more wells (either producers or injectors) leading to, for each well damaged, either:

(a) slight damage or burial of well-head resulting in basically clean-up costs; or

(b) heavy damage resulting in clean-up and significant repair to well.

(Note: Very severe damage to wells causing replacement and/or blowouts not considered as having significant probability in this case).

Cost Consequences:

Developer:
(a) Clean-up expense.
(b) Repair cost of wells.
(c) Revenue loss while each well is down for repairs.

User: None.

Input Data:

Clean-up Expenses in the Event of Slight Damage: $0.1 (millions - $1981); 1 month delay

Repair Costs in the Event of Heavy Damage: $1.0 (millions - $1981); 3 months delay

Revenue Loss Per Well Per Month: $0.06 (millions - $1981)

Probability:

Event 1:
P(event 1 never occurs) = .90
P(event 1 occurs once) = .10
P(event 1 occurs more than one) = .00

Damage:
P(slight damage given event 1 occurs) = .50
P(heavy damage given event 1 occurs) = .50

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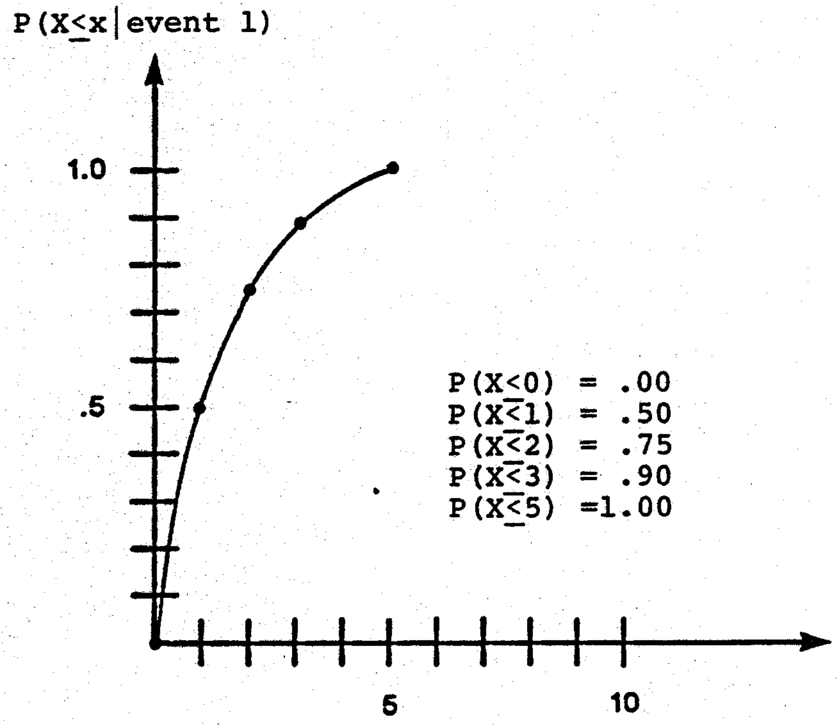
ACTS OF GOD
VOLCANIC HAZARDS
TYPE 3 - STAGE 3
EVENT 1



$P(X<0) = .00$
$P(X \leq 1) = .50$
$P(X \leq 2) = .75$
$P(X \leq 3) = .90$
$P(X \leq 5) = 1.00$

X = # of wells damaged
given event 1 has occurred

$P(X=0) = .00$
$P(X=1) = .50$
$P(X=2) = .25$
$P(X=3) = .15$
$P(X=4) = .07$
$P(X=5) = .03$

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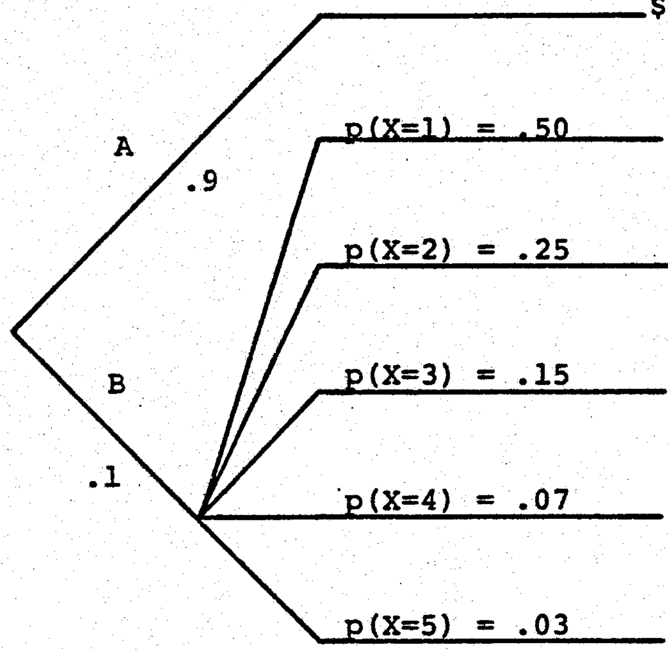
ACTS OF GOD
VOLCANIC HAZARDS
TYPE E - STAGE 3
EVENT 1



Loss Distribution		
Repair Cost (millions-$1981)	Revenue Loss (millions-$1981)	Scenario Probability
$0.00	$0.00	.900
0.55	0.12	.050
1.10	0.24	.025
1.65	0.36	.015
2.20	0.48	.007
2.75	0.60	.003

A: Event 1 never occurs.
B: Event 1 occurs once.

Expected Well Repair Cost: $0.10 (millions - $1981)
Expected Revenue Loss: $0.02 (millions - $1981)

EXHIBIT V-16
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ACTS OF GOD
VOLCANIC HAZARDS
TYPE E - STAGE 3
EVENT 2

Description:	Lava flow from a volcanic eruption causes significant damage to the power plant (as measured by a percentage of replacement cost required to repair plant), severe enough to cause shut-down while repairs take place.

Cost Consequences:

Developer:	Loss of revenue while plant is shut-down.
User:	Cost of repairing power plant measured as a percentage of total replacement cost. 100% of replacement cost corresponds to total destruction of the plant. Total destruction considered extremely unlikely (<.0001) and therefore only repair costs were considered.

Input Data:

Cost of Power Plant: $33.63 (millions - $1981)

Revenue Loss Per Month While Plant is Shut-Down: $0.61 (millions - $1981)

Probability:

Event 2: P(event 2 never occurs): .90
P(event 2 occurs once): .10

EXHIBIT V-16
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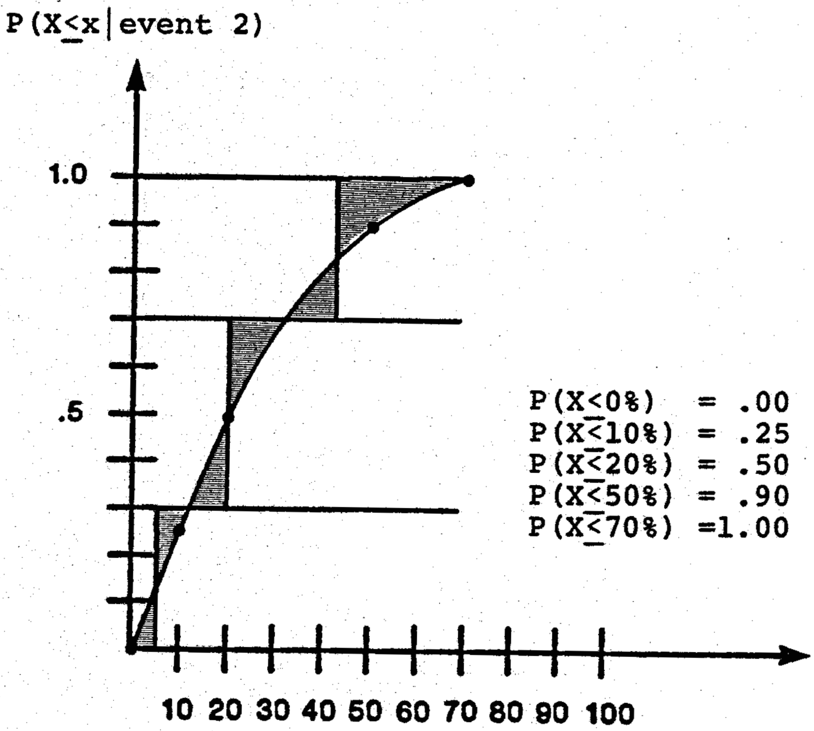
ACTS OF GOD
VOLCANIC HAZARDS
TYPE 3 - STAGE 3
EVENT 2



$P(X<0\%)\ \ = .00$
$P(X\leq 10\%) = .25$
$P(X\leq 20\%) = .50$
$P(X\leq 50\%) = .90$
$P(X\leq 70\%) =1.00$

X = % of replacement cost
required for repair given
that event 2 has occurred

Discrete Approximation:

P(X = 6% replacement cost) = .33/Downtime = 1 month
P(X = 20% replacement cost) = .34/Downtime = 6 months
P(X = 44% replacement cost) = .33/Downtime = 12 months

EXHIBIT V-16
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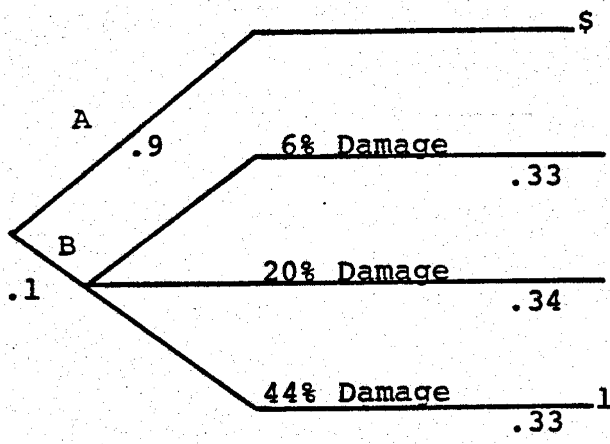
ACTS OF GOD
VOLCANIC HAZARDS
TYPE E - STAGE 3
EVENT 2



Loss Distribution Repair Cost (millions-$1981)	Revenue Loss (millions-$1981)	Scenario Probability
$ 0.0	$0.00	.900
2.0	0.61	.033
6.7	3.66	.034
14.8	7.32	.037

A: Event 2 never occurs.
B: Event 2 occurs once.

Expected Loss:

User's Expected Repair Costs: $0.78 (millions - $1981)
Developer's Expected Revenue Loss: $0.37 (millions - $1981)

ACTS OF GOD
VOLCANIC HAZARDS
TYPE E - STAGE 3
EVENT 3

Description:	Lava flow from a volcanic eruption causes significant damage to surface facilities, severe enough to cause temporary shut-down of project and replacement of a percentage of the piping system.

Cost Consequences:

Developer:	(a) Cost of replacing a portion of piping system (measured as a percentage of the replacement cost of the system). (b) Revenue loss while replacement is taking place and the project is shut-down.
User:	None.

Input Data:

Cost of Surface Piping System: $4.0 (millions - $1981)

Revenue Loss Per Month while Project Is Down: $0.61 (millions - $1981)

Probability:

Event 3: P(event 3 never occurs): .90
P(event 3 occurs once): .10

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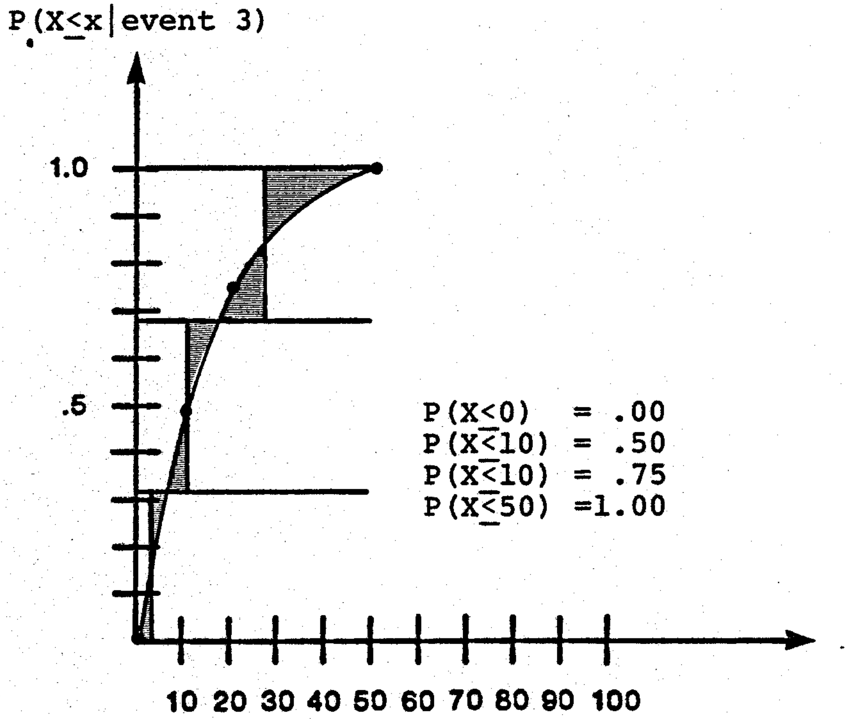
ACTS OF GOD
VOLCANIC HAZARDS
TYPE E - STAGE 3
EVENT 3



X = % of piping system requiring replacement given that event 3 has occurred

Discrete Approximation:

P(X = 2.5% replacement) = .33/Downtime = 1 month
P(X = 10% replacement) = .34/Downtime = 4 months
P(X = 28% replacement) = .33/Downtime = 6 months

EXHIBIT V-16
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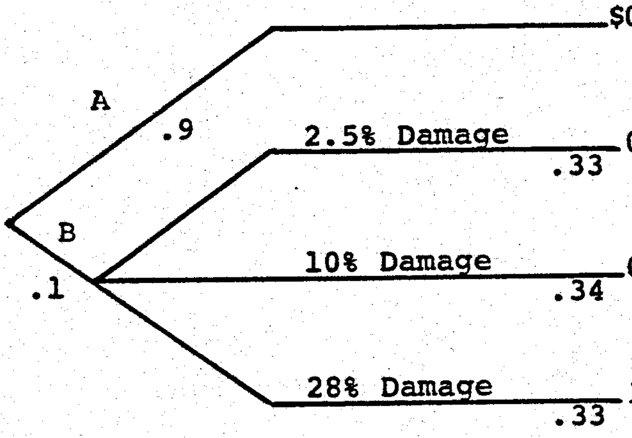
ACTS OF GOD
VOLCANIC HAZARDS
TYPE: E - STAGE 3
EVENT 3



Loss Distribution		
Replacement Cost (millions-$1981)	Revenue Loss (millions-$1981)	Scenario Probability
$0.00	$0.00	.900
0.10	0.61	.033
0.40	2.44	.034
1.12	3.66	.033

A: Event 3 never occurs.
B: Event 3 occurs once.

Expected Loss:

Developer's Expected Replacement Cost: $0.05 (millions - $1981)
Developer's Expected Revenue Loss: $0.22 (millions - $1981)

Landslides

Event Definition: The specific events considered are landslides that cause significant damage to wells, power plant, and/or surface facilities. Damage to wells is defined as either (a) slight damage or burial of well-head resulting basically in clean-up costs, or (b) heavy damage resulting in clean-up and replacement of well, or (c) very severe damage causing blow-out, which results in remedial work (usually a remedial well), clean-up and a replacement well. Damage to the power plant is defined as being severe enough to cause temporary shut-down while repairs take place. Damage to surface facilities is defined as severe enough to cause temporary shut-down of the development and replacement of a percentage of the piping system.

Cost Consequences: The developer's cost of well damage include (a) clean-up and repair costs for wells, (b) cost of replacement wells if necessary, (c) cost for remedial wells and/or other measures needed to control blow-out, and (d) revenue loss while each well is temporarily shut-down for repairs or replacement. The user's excess cost of replacement power while a well is being repaired or replaced is considered for this risk because this cost is significant for Type A projects where the risk of landslide is present.

As a result of power plant damage the users are assumed to incur (a) the costs of repair measured as a percentage of the replacement cost, and (b) the excess cost of replacement power during the time the plant is shut-down. Also, the developer is assumed to lose steam revenue during the time the power plant is shut-down.

For surface facilities damages, the developer's costs include (a) replacing portions of the piping system, and (b) revenue loss while replacement is taking place and the project is shut-down. Also, the user is assumed to incur the excess cost of replacement power while the project is temporarily shut-down.

Probability Estimation: As with volcanic hazards, first, discrete probabilities were estimated for the number of occurrences of each of the events described above for wells, power plant and surface facilities. Second, cumulative probability distributions were assessed for the extent of damage given that an event has occurred, in terms of numbers of wells damaged, the percentage of the power plant's replacement cost required for repair, and the percentage of the piping system requiring replacement.

Analysis of Project Type: Because of the almost exact similarity between the analysis carried out for landslides and that of volcanic hazards, in terms of the nature of the events, probabilities and costs that were considered, a detailed presentation of the landslides risk analysis is not needed in order to depict the steps carried out. However, as with all the other major risk subcategories, the detailed results of this specific analysis are provided in the Appendix, along with detailed descriptions of the primary input data.

Summary of Expected Losses and Variances

Exhibit V-17 presents a summary of the estimated expected losses and loss distributions (as measured by their variances) for all risks analyzed in this section, aggregated by geologic project type, cost category and stage of development. These expected losses and variances serve as the principal inputs for estimating insurance premiums, to be discussed in the next subsection. As discussed earlier, all expected losses are categorized in terms of four major cost categories:

- Direct Cost to Developer - direct costs to replace or add wells, surface piping, etc.
- Indirect Cost to Developer - loss of revenue from reduced steam sales.
- Direct Cost to User - repair costs from physical damage to plant or turbine, as well as the unamortized value of plant resulting from total or partial abondonment.
- Indirect Cost to User - excess cost of replacement power resulting from shut down or reduced capacity.

EXHIBIT V-17

AGGREGATE EXPECTED LOSSES AND VARIANCES*
(Millions - $ 1981)

	PROJECT TYPE	A			B			C**			D			E			F			G		
COVERAGE CATEGORY	STAGE	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3
Developer Direct Loss																						
- Expected Loss		7.4	4.6	3.4	9.7	8.7	6.23	.17	.13	-	14.8	9.9	7.3	7.0	3.4	0.2	8.7	13.1	13.4	3.5	6.5	6.7
- Variance		18.6	14.5	6.8	32.8	36.5	23.8	.03	.02	-	61.3	40.4	29.9	21.7	15.3	0.2	36.6	45.5	39.5	7.1	11.6	18.4
Developer Indirect Loss																						
- Expected Loss		-	0.3	52.7	-	0.8	62.1	-	-	-	-	1.2	32.4	-	0.3	23.8	-	2.0	114.5	-	0.4	40.3
- Variance		-	0.2	697.3	-	0.7	828.0	-	-	-	-	1.3	236.0	-	0.2	158.3	-	1.7	2594.0	-	2.3	438.4
User Direct Loss																						
- Expected Loss		-	-	9.0	-	-	6.7	-	-	-	-	-	3.6	-	-	4.3	-	-	9.3	-	-	5.7
- Variance		-	-	102.5	-	-	10.0	-	-	-	-	-	3.2	-	-	12.2	-	-	18.5	-	-	9.9
User Indirect Loss																						
- Expected Loss		-	0.3	52.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
- Variance		-	0.2	697.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

* Cells without expected losses reflect areas where no significant loss was indicated.

** Only limited data for estimating Developer's Direct Loss were available for this type.

ESTIMATED INSURANCE PREMIUMS

An insurance premium can be separated into three components: (1) a portion to pay losses, (2) a portion to pay the administrative expenses, and (3) a portion for profit and contingencies. This last component, profit and contingencies, can also be considered a "risk charge" because it is a payment to the insurer for assuming the risk of the insurance policy.

For the most common lines of insurance, the ratemaking methodologies are well established. They rely on the analysis of recent experience to determine the necessary provision for losses and expenses to be included in the premium. The provision for profit and contingencies, or risk charge, is usually expressed as a percentage, or loading, to be added to the provision for losses and expenses. The size of this charge should, ideally, reflect the risk inherent in the insurance. The risk in question is the possibility that losses will be more than expected and, therefore, the insurance premiums collected will be insufficient to pay the losses. This would require the insurer to pay the losses with its own capital and surplus funds.

Methodology

The determination of an appropriate insurance premium to ensure the risks of geothermal energy development and production requires the determination of the three insurance premium components described above. However, there is not sufficient prior insurance history and experience in the geothermal area. Therefore, the expected losses and variance of those losses, as estimated earlier in this section, were used to estimate appropriate insurance premiums.

The expected value of losses was used as the best estimate of the provision for losses needed in the insurance premium. The provision for administrative expenses was assumed to be 25% of expected losses. This amount for expenses was considered reasonable for premiums of the size under consideration given the current marketplace. The final component of the insurance premium, the risk charge, was calculated as a percentage of the variance of loss dollars. As mentioned above, the risk charge should reflect the inherent risk of the particular insurance. Because the variance of the loss dollars is a measure of the inherent variability of the expected losses, a risk charge that is a percentage of the variance satisfies this requirement. Annual premiums were estimated, for each stage of each project type, assuming coverage in force for the entire project life under the assumption that the policy would be renewed annually.

To calculate an annual premium, for a given stage and project type, the sum of the expected losses, the administrative expense provision and the risk charge were divided by the number of years in the stage of the project for the policy in question, or:

$$\text{Annual Premium} = \frac{\text{EL} + (.25 \times \text{EL}) + (\text{R} \times \text{Var})}{\text{years in stage}}$$

Where EL is the expected loss dollars, Var is the variance of the loss dollars and R is a percentage of the variance. For purposes of these calculations the length of each stage of development was assumed to be 5 years for Stage 1, one year for Stage 2 and 30 years for Stage 3.

The R values were chosen separately for each type of policy and stage of development but are the same for all geologic project types. For each type of policy, for each stage of development, the expected value and variance of the loss dollars were computed for all geologic projects types combined. Using these results, the R values were chosen such that the overall risk charge (R x Var) is 15% of the total provision for losses and administrative expenses. The R values, so computed, were used in the premium equation utilizing the expected losses and variance for each geologic project type for each type of insurance policy.

The 15% risk charge is higher than is found in most insurance rates. However, it is believed that a risk charge of this magnitude is necessary in this situation for two reasons: 1) to compensate the insurer for assuming an unusual and new type of risk, and 2) to provide a safety margin in the insurance premium to protect against unexpected adverse loss experience.

All of the annual premiums so calculated are in 1981 dollars, as were the expected losses reported earlier in this section. Neither inflation nor investment income to the insurer is considered. If, instead of annual premiums, the entire insurance cost (or a significant portion thereof) were paid at the beginning of development, then the insurer would receive substantial benefit from investment income. However, annual premiums in this situation may not generate as much investment income because the insurer expects to use each year's premium income to pay that year's losses and expenses and cannot invest long-term. The fact that premiums would be paid annually allows insurers to adjust premiums for inflation.

The loss estimates and resulting premiums were calculated for typical projects of specific geologic types. In developing premium quotations for actual geothermal installations, differences in size should be recognized through the use of an appropriate exposure base. Such a base should have the following characteristics:

- The base should vary as does the size of the potential loss.
- The base should be practical and, preferably, already in use (usually by the insured for another purpose).

The most desirable base is the one possessing a combination of these two properties to the largest degree.*

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*Dorweiler, P., "Premium and Exposure Bases," Proceedings of the Casualty Actuarial Society, 1971, p. 61.

Definition of Coverage Categories

The proposed insurance policies are identified by two characteristics: (1) the type of losses, and (2) the stage of development for which they provide coverage. The various potential losses discussed in the analysis of insurable risks were separated into four types:

- Direct Cost to Developer
- Indirect Cost to Developer
- Direct Cost to User
- Indirect Cost to User

Direct losses to the developer include all costs to the developer for repair, replacement or addition to the wells or piping system caused by any of the risks discussed earlier in this section. Indirect losses to the developer include potential lost revenue caused by any of the risks discussed. Direct losses to the user are those that involve repair or replacement of the physical plant. This category also includes the appropriate proportionate share of the unamortized value of the user's physical plant if the installation is abandoned earlier than originally planned or operated at lower than expected production levels. Indirect losses to the user include the excess cost to the user of purchasing power to replace that which would be lost if the installation had to be shut down or operated at reduced capacity for some period of time (significant for a Type A project only).

In all, there could possibly be twelve different types of insurance policies covering four loss categories and three stages of development. However, in Stage 1, the only significant loss is the direct loss to the developer, while in Stage 2 there were no significant risks identified for direct loss to the user. Therfore, there are eight types of policies for which annual premiums are estimated.

Premium Estimates

Estimated premiums were calculated for each type of geothermal installation for each of the eight policy types. For example, consider the following to determine the premium for developer direct losses for a Type A project in Stage 3. For this stage of this project type the expected losses are $3.4 million and the variance is $6.8 million (see Exhibit V-17). The R value for developer direct losses in Stage 3 is 6.23%. The annual premium during Stage 3 is therefore:

$$\frac{3.42 + (.25 \times 3.42) + (.0623 \times 6.75)}{30 \text{ years}} = \$0.157 \text{ million}$$

Exhibit V-18 shows the estimated annual premiums for each geologic project type and for each policy type. It is important to note that the estimated premiums are assumed to cover the entire loss amount for all risks analyzed in the previous section. In actual practice, both the insured and the insurer would have the option of insuring all or only some of the risks. Also, there are no deductible provisions assumed for purposes of this calculation. The existence of deductible provisions in the actual policies should, however, lower the premiums.

In actual practice it is likely that either the insurer or insured would decline full coverage for the entire developer indirect loss because of the high premium and high dollar loss potential. The possible loss would usually be limited by deductibles, waiting periods before the coverage was effective and/or time restrictions on the loss. None of these provisions were included in these calculations because they would normally be negotiated on a project-by-project basis. The above provisions would reduce the amount of premium charged the insured.

As shown in Exhibit V-18, the estimated premiums vary most significantly by the stage of development that the policies would cover. During Stages 1 and 2 average annual premiums for developer's direct loss, for example, approximates $3.9 million per year, whereas these premiums approximate only $300 thousand during Stage 3. This is due to two factors: (1) risks are high during the initial stages, and (2) the duration of Stages 1 and 2 are on the order of six years as compared to 30 years for Stage 3. There

EXHIBIT V-18

ANNUAL PREMIUM ESTIMATES*
15% RISK CHARGE
(Millions - $ 1981)

PROJECT TYPE	A			B			C**			D			E			F			G		
COVERAGE CATEGORY / STAGE	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3
Developer Direct Loss	2.1	6.5	0.2	2.8	12.8	0.3	0.04	0.2	-	4.4	14.5	0.4	2.0	5.1	0.01	2.6	18.8	0.7	1.0	8.7	0.3
Developer Indirect Loss	-	0.4	2.5	-	1.1	3.0	-	-	-	-	1.7	1.5	-	0.4	1.1	-	2.8	5.9	-	3.4	1.9
User Direct Loss	-	-	0.5	-	-	0.3	-	-	-	-	-	0.2	-	-	0.2	-	-	0.4	-	-	0.3
User Indirect Loss	-	0.4	2.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

* Cells without premium estimates reflect areas where no significant loss was indicated.

** Only limited data for estimating Developer Direct Loss were available for this type.

are many ways to spread the initial costs out over time and also to lower these insurance costs through a variety of special provisions or through federal cost support. The financial impacts of these potential costs and methods of spreading the costs over time are discussed and analyzed in Section VI, where a variety of alternative government roles are examined.

Sensitivity Analysis

The estimated premiums presented in this section are dependent on two things: (1) the estimated expected losses and variances and (2) the assumptions as to expenses and risk loading.

As stated previously, one of the reasons for the relatively high risk loading used here was to protect against adverse loss experience. The assumptions as to expenses and risk loading are estimates of the factors that would be used in the insurance marketplace. However, it is possible that larger expense and risk loading may be necessary in order to make geothermal reservoir insurance attractive to the insurance industry.

Exhibit V-19 displays estimated annual premiums with a 10% rather than 15%, risk loading factor. The difference in annual premiums as compared to those presented in Exhibit V-18 averages less than 8%.

Exhibit V-20 displays estimated annual premiums with a 20% risk loading. The difference in annual premiums as compared to those with a 15% risk loading averages less than 5%. A 20% risk loading may be necessary to induce the insurance industry to insure these risks.

The sensitivity analysis indicates that the estimated premiums are subject to variation according to the choice of risk charges. More importantly, this variation is of a predictable size. While the risk charge is important in determining the premiums, the accuracy of the expected losses and variances in terms of approximating actual losses over time is more critical.

EXHIBIT V-19

ANNUAL PREMIUM ESTIMATES*
10% RISK CHARGE
(Millions - $ 1981)

	PROJECT TYPE	A			B			C**			D			E			F			G		
COVERAGE CATEGORY	STAGE	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3
Developer Direct Loss		2.0	6.2	0.2	2.7	12.1	0.3	0.04	0.2	-	4.1	13.8	0.4	1.9	4.8	0.01	2.4	18.0	0.6	0.9	8.5	0.3
Developer Indirect Loss		-	0.5	2.4	-	1.0	2.8	-	-	-	-	1.6	1.4	-	0.4	1.0	-	2.7	5.5	-	3.2	1.8
User Direct Loss		-	-	0.5	-	-	0.3	-	-	-	-	-	0.2	-	-	0.2	-	-	0.4	-	-	0.3
User Indirect Loss		-	0.4	2.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

* Cells without premium estimates reflect areas where no significant loss was indicated.

** Only limited data for estimating Developer Direct Loss were available for this type.

EXHIBIT V-20

ANNUAL PREMIUM ESTIMATES*
20% RISK CHARGE
(Millions - $ 1981)

	PROJECT TYPE	A			B			C**			D			E			F			G		
COVERAGE CATEGORY	STAGE	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3
Developer Direct Loss		2.1	6.7	0.2	2.9	13.4	0.3	0.04	0.2	-	4.6	15.2	0.4	2.1	5.4	0.01	2.7	19.6	0.7	1.0	8.9	0.3
Developer Indirect Loss		-	0.5	2.6	-	1.1	3.0	-	-	-	-	1.8	1.5	-	0.4	1.1	-	2.9	6.2	-	3.5	1.9
User Direct Loss		-	-	0.6	-	-	0.3	-	-	-	-	-	0.2	-	-	0.2	-	-	0.4	-	-	0.3
User Indirect Loss		-	0.5	2.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

* Cells without premium estimates reflect areas where no significant loss was indicated.
** Only limited data for estimating Developer Direct Loss were available for this type.

EVALUATION OF RISK IDENTIFICATION AT HEAT SALES AGREEMENT

The development of geothermal energy resources presents the developer with significant financial risks from the outset. It is therefore necessary, if insurance is to be purchased, to have a method of evaluating the risk of loss at the time of execution of the heat sales agreement.

The proposed insurance premiums were calculated separately for each geologic project type and for each stage of development. This two-way risk classification plan is the basic rating criterion for the insurance. However, the premiums were calculated based on certain assumptions regarding each project type. To the extent that a given type presents an exposure that differs from these assumptions, the premium may have to be adjusted. Therefore, insurance premiums would probably be calculated according to the project type, number of wells planned, amount of piping and the amount and type of surface facilities and equipment. In addition dollar values should be ascertained for these items and for projected revenues of the project.

The exposure measured above should be compared to the exposure contemplated in the premium estimates to determine if more or less premium is required. Additional underwriting data should be obtained and evaluated prior to the issuance of a policy. Such data would include the latest statistics from similar projects and the results of engineering and geological tests performed at the project site. Further, consideration should be given to the developer's contingency plans, general experience and competence and financial strength.

A final piece of underwriting data involves deductibles. The estimated premiums shown in the report are for "first dollar" coverage (i.e., the insurer pays the entire loss). Premiums can, and usually are, reduced by the use of a deductible (i.e., some first portion of the loss is assumed by the insured). Such a deductible can be in the form of a flat dollar amount or can be expressed in terms of time for indirect losses. A dollar amount deductible could be applied to any of the coverages contemplated in this study. The time-type deductible is best suited to the insurance protection for lost revenue where the size of the loss depends on the period of time involved.

The system just described is an example of a manual type rate structure where premiums are set for certain pre-determined classes and are adjusted for differences in exposure. The predetermined classes in this case are the project type and stage of development. Using the same basic rate structure it would also be possible to construct a schedule rating plan. In a schedule rating plan, predetermined percentage credits and surcharges are added to the manual premium according to the presence or absence of certain characteristics that can affect the loss potential of a project. Such a plan could affect the final premium by as much as 25%.

The final consideration to be noted at this time is the keeping of adequate statistics regarding the insurance plan. On a regular basis, perhaps annually, the insured should supply the insurance company with updated information on the data initially required by the company. By using this data, the rates can be regularly examined to determine if a change is necessary.

IDENTIFICATION OF PREMIUM READJUSTMENT POINTS

This subsection of the report discusses what data can be used to determine if a rate adjustment is indicated and the suggested timing of such adjustments. The discussion is directed towards premium adjustments for insurers in the program, not the determination of premium for new insureds.

There are two reasons to consider a premium adjustment in a geothermal insurance plan: (1) changes in the basic ratemaking data, and (2) changes in the rating data pertaining to a particular insured. The difference between these two items is that ratemaking data pertain to all insureds, while rating data pertains to an individual insured. Adjustments based on changes in ratemaking data are discussed first.

One type of overall rate adjustment is an adjustment for increased loss costs due to inflation (these would be rate increases). Rates can be adjusted on a periodic basis by a price index for the items for which the insurance plan may pay. This index can be monitored and rate adjustments can be made based on inflationary trends in the index. For example, a price index of the cost of steam would be appropriate for adjusting the cost of insurance for developer's revenue losses caused by an insured event. In the interest of stability (to facilitate financial planning by developers and users) it may be appropriate to limit inflation-based rate increases to some maximum percentage per year.

Overall rate adjustment may also be caused by changes in the probability/severity estimates that were used to compute the estimated premiums. In the case where the insured has some guaranty of coverage and price, a rate change based on new probability/severity estimates would probably be used only if rates decreased significantly. Such a decrease would be passed along to the insured to prevent the insured from cancelling his present coverage in favor of cheaper, new coverage elsewhere.

Premium adjustments based on changes in rating data also fall into two categories. The first of these is premium adjustments related to proper exposure analysis. As discussed previously, one of the criteria for determining the proper premium is to know the exposure (number and value of wells, extent of piping system, type and value of surface facilities, etc). It is equally important that the insurer keep up to date on current exposure levels throughout the term of the policy, such that appropriate premium adjustments can be made.

The second category of adjustments based on rating data involves the particular experience of an individual insured. New engineering data could lead to a change in schedule rating credits or debits. Schedule rating debits or credits can also be affected by the cumulative loss experience of the insured. In addition to these items which affect an insured's premium, it may be desirable to use a retrospective rating plan or a dividend plan, either of which can be used to return excess premium dollars to an insured whose loss experience has been better than expected. In particular, a one-way retrospective rating plan that allows return of excess premium, but not assessment of additional premium, or some other plan that holds the promise of return premiums in exchange for favorable loss experience may be an incentive to the geothermal insurance program. Such a plan might lessen buyer resistance to an initial premium that is high enough to make insurers want to sell this insurance and increase the desirability of sound risk management techniques.

Engineering data on the insured project (including operating statistics) should be available to the underwriter in order to properly assess exposure and hazard. Premium and loss data should be well maintained, with all losses having date of payment statistics.

The data described in the preceding paragraph refers to the geothermal industry itself. However, engineering and insurance data from other fields should also be examined.

Time for Reevaluation

The frequency of premium reevaluation depends on how the insurance program is initially established. If one entity underwrites the entire program (non-competitive), changes will probably come more slowly, but they might be more sound. In a competitive environment, repricing would probably occur at each policy anniversary date. Furthermore, the manual of rates (such as is presented in the section on estimated premium) would be updated as often as the probability/cost information is updated as a result of actual experience, inflation or new technology.

An annual reevaluation of premium levels seems appropriate. However, each reevaluation may not actually result in new premiums. Considering the three reasons cited above for revision, inflation seems to be the one most likely to influence premiums in the early years of the program. New technology is unpredictable in its appearance and usually occurs in response to problems. The actual experience will eventually be the basis of ratemaking. However, it is possible that the body of actual experience will not be large enough to affect premium for many years.

VI. ALTERNATIVE GOVERNMENT ROLES

ALTERNATIVE GOVERNMENT ROLES

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ALTERNATIVE GOVERNMENT ROLES

This section investigates federal involvement in a geothermal reservoir insurance program and identifies program alternatives relative to the different levels of federal support. The possible government roles are addressed in terms of the following topics:

- The role of government and the private sector.
- Historical perspective of relevant government insurance programs.
- Perspective of the geothermal constituency.
- Identification of program alternatives.
- Analysis of the program alternatives.

The analysis of program alternatives serves as the basis for the recommendation discussed in Section VII of this report.

THE ROLE OF GOVERNMENT AND THE PRIVATE SECTOR

From an economic perspective, the private sector market provides the most efficient means of allocating goods and services. There is, however, a valid role for the government to serve national goals which may not be properly addressed in the market place, such as national security or energy independence. Geothermal development has been limited by several factors including the high level of technical risk and uncertainty that characterizes large scale geothermal projects. If it is believed to be desirable from a national perspective to provide incentives to accelerate geothermal development as an alternative energy source, then there is a valid role for the government to play in attempting to reduce the risk that confronts potential developers. A reservoir insurance program is one possible vehicle for reducing this level of risk.

In choosing among the alternatives to support and promote geothermal energy, the study has developed a set of guidelines to ensure that federal involvement has its intended impact with minimum disruption to the role and responsibility of local participants in project development and implementation. It should be the intent of any program to encompass a range of insurable risks and to accelerate a large number of projects. A federal program for geothermal insurance should be premised on obtaining the maximum amount of energy production as soon as possible for economically, technically and environmentally sound geothermal projects. It is assumed to be in the national interest to obtain as much energy as possible from this resource in a cost effective manner with minimal environmental disruption. Further, federal emphasis should be on supporting the private sector in developing an insurance program without the need for long range federal involvement. The current availability of demonstrated technologies, rising energy costs and the need to develop alternative energy sources should combine to encourage private initiative to use the energy value in geothermal sources. While government programs might be needed to support geothermal development, the type of assistance provided should encourage private business and industry to consider opportunities to sponsor and develop geothermal projects. Rather than encouraging and creating a dependence on the federal programs, the government role should stimulate private initiative and investment in developing this energy resource.

It is important to point out that the choice of the appropriate government role is crucial. Not every conceivable government program will solve the problems of geothermal development. Experience has shown that an incorrect policy choice can bring about inefficiency and can actually inhibit market initiative. This study attempts to assess the nature of the need for government involvement, if any, and to structure a program that is best tailored to address that need.

HISTORICAL PERSPECTIVE OF RELEVANT GOVERNMENT INSURANCE PROGRAMS

One objective of this report is the determination of the feasibility of federal government support for a geothermal reservoir insurance program. It is therefore appropriate to review other federal insurance programs from an historical perspective.

Historically there have been several occasions where government insurance programs have been initiated to meet real or perceived imperfections in the marketplace. These programs, at both the state and federal levels, have involved government as a partner with the private insurance sector, a competitor with the private insurance sector and as a provider of insurance benefits exclusive of the private sector. A cross-sample of these government insurance programs is:

- <u>Partners with private insurance sector</u>
  - federal crop insurance
  - nuclear energy liability
  - riot reinsurance
  - export credit insurance
  - emergency disaster relief
- <u>Competitors with private insurance sector</u>
  - federal crime insurance
  - OASDHI (Social Security, etc.)
  - non-occupational disability insurance plans
  - worker's compensation funds
  - automobile insurance fund (Maryland)
- <u>Exclusive of private insurance sector</u>
  - war risk aviation and marine
  - unemployment insurance
  - federal loan guaranty
  - federal flood insurance*

The federal insurance programs selected for review were chosen because of their varied relationships with the private insurance sector and the range of experiences each of these insurance programs have produced. The specific programs selected for this review include the crop insurance, flood insurance, riot reinsurance, nuclear energy liability co-insurance and crime insurance programs.

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* federal flood insurance program began as a partnership with the private insurance sector.

Exhibit VI-1 summarizes each of these five federal insurance programs in several areas including the year authorized, type of insurance program, involved agency/department and financial results. A narrative review of each of the five programs appears following the Exhibit.

Federal Crop Insurance Corporation

Originally thought of as an experiment, this program was first enacted as Title I of the Agricultural Adjustment Act of 1938 to provide all-risk economic protection of a farmer's required investment to produce covered crops. This legislation was enacted following disastrous economic results caused by severe droughts. The insured amount was established at the time of planting and represented the potential cash value of the crop. Following heavy losses during the program's early years, operations were discontinued in 1944. The program was reinstated during 1945 with coverage for specified national and regional crops. Additional periods of loss caused further restrictions to be imposed in 1947.

The federal government tried for many years to get private insurance companies to provide all-risk protection for crop hazards by providing a reinsurance market. While private insurance carriers have provided hail and fire coverage on crops since 1899, attempts to provide all-risk coverage by the private sector have been unsuccessful and the government received an unethusiastic reception to its reinsurance incentive.

Modifications to the crop insurance program made as a part of the Federal Crop Insurance Act of 1980 places the relationship with the private sector into a partnership arrangement. Crop insurance is now offered to farmers through independent insurance agents and provides an opportunity to exclude hail and fire coverage at a reduced rate if the farmer has purchased this coverage through the private market. The 1980 Act also mandates a pilot reinsurance program by 1982.

EXHIBIT VI-1

GOVERNMENT INSURANCE PROGRAMS

SUMMARY ANALYSIS

	CROP	CRIME	RIOT	NUCLEAR	FLOOD
Year Authorized	1938	1968	1968	1957	1968
Phased In	yes	yes	no	no	no
Primary Insurance/ Reinsurance/ Other	Primary	Primary	Reinsurance	Co-insurance	Primary
Agents	yes	yes	no	no	yes
Government Organization[a]	FCIC	FIA	FIA	NRC	FIA
Compete with Private	no	yes	no	no	no
Partner with Private	yes	no	yes	yes	no
Operations Continuing	yes	yes[c]	yes[c]	yes	yes
Expenses, including losses in excess of revenues (millions-$1977)	+65.9	+8.7	-5.9[b]	+254.0	+81.1

a) FCIC = Federal Crop Insurance Corporation
FIA = Federal Insurance Administration
NRC = Nuclear Regulatory Commission (inspection, regulation, no administration)

b) Amount revenues exceed expenses.

c) Legislation has been introduced that would significantly alter these programs.

Federal Crime Insurance Program

This program was authorized by Congress in 1968 in the same act with the authorization for riot reinsurance. In contrast with the riot reinsurance program, Congress authorized the federal government to provide primary insurance protection to customers rather than reinsuring losses. Crime insurance was initially offered in ten states during 1971. Policies were distributed through normal channels of agents and brokers. The original intent of the program was to compete with private insurers where government believed that the private insurers were not providing an adequate level of available coverage or coverage at affordable rates.

The federal government had expectations for substantial volumes of business but had relatively few sales. A number of incentives were utilized by the government to promote sales of crime insurance policies including easing requirements for protective devices, using advertising campaigns and providing finder's fees to agents in addition to commissions. Though the program is continuing, overall results have been less than successful.

Agents have been reluctant to actively market this coverage because they believe it is difficult to sell other coverages to these high risks. Sales also suffered because of the strict safety and loss prevention measures needed to qualify for federal coverage. If a potential insured can meet the federal guidelines, they can very often meet the requirements of private insurers. This program will expire September 30, 1981 unless extended by Congress.

Federal Riot Reinsurance Program

In 1968 legislation, Congress authorized the establishment of state property insurance plans (FAIR Plans) which would qualify for federally sponsored riot reinsurance. This riot reinsurance was considered necessary because of private insurers' unwillingness to insure property considered high risk because of condition or location in urban areas.

Riot reinsurance was used by the federal government to encourage the restoration of private insurance, particularly in urban areas. Recent suggestions by private insurance representatives point to the continued need for FAIR plans as an essential supplement to private insurance programs but support the phase out of the riot reinsurance program. This program will also expire in September 1981 unless extended by Congress.

Nuclear Energy Liability Insurance

With the planning and building of thermal reactors following World War II, two nuclear energy liability insurance pools were developed to provide the necessary insurance protection. Because the capacity of the private sector to accommodate the growing needs of the nuclear industry was limited, the Price-Anderson Act was passed in 1957. The Act established $560 million as the maximum amount for which a private corporation could be held liable for a single incident.

It is expected that the private insurance sector will eventually be able to provide full capacity for nuclear energy liability losses and the government program would be phased out. Historically few incidents have occurred and the principal cost to government has been for inspection and safety activities.

Federal Flood Insurance Program

This program began as a joint venture between private insurers and the federal government (Federal Insurance Administration division of HUD) to provide flood insurance protection for insureds in designated flood plain areas. Initial response to the program was slow because of limited development in flood plain areas and administrative requirements for qualification. Changes were made to encourage participation including a major change which made flood insurance mandatory on property receiving various forms of federal financial assistance. In 1978 the federal government assumed complete underwriting and administrative responsibility for the flood insurance program including total risk of loss.

The flood insurance program has not been particularly successful in some financial and administrative areas. The program has had recurring problems with improper underwriting and claims administration, questionable validity of risk information received, verification of agent's rates and use of rates which are not actuarially sound. Despite these problems the flood insurance program currently protects more than two million policyholders.

PERSPECTIVE OF THE GEOTHERMAL CONSTITUENCY

A successful geothermal reservoir insurance program must be sensitive to the needs and desires of the groups it is designed to serve. In developing such a program, it is important to determine what type of program the target groups would like to see and what specific factors they would oppose. This determination process helps ensure that a program will be accepted and, consequently, enhances its chances for success.

The project staff conducted forty interviews selected from a sample of business entities that potentially would be affected by a geothermal reservoir insurance program. Nearly all have had significant experience with geothermal projects. Those sampled were divided into four groups:

- Insurers
- Developers
- Lenders
- Users

The interviews were conducted with senior personnel of the various companies. Each interview followed a standard format that included questions on the types of projects the company has been involved with, the nature of the involvement and problems that had been encountered (Sections III and IV). An important part of the interviews dealt with government programs and how they might affect geothermal energy. Questions were asked to determine the respondents' reactions to the general need for an insurance program, how it should be structured and the role of the government and other players. The responses were summarized for each of the four groups.

Because of the sample size, it is not possible to state that the responses represent all points of view of each of the four groups. However, the responses are useful for determining some of the major concerns of those most likely to be affected by a geothermal insurance program. Following are summaries of the responses for each of the four groups.

Insurers

The basic theme that emerges from these comments is that the private insurance market is fully capable of and thus should be responsible for providing geothermal reservoir insurance. Of the seventeen insurers sampled, nearly half responded that the goverment should not be involved. Those remaining believed that the government should play only a minor role.

The insurers argue that there is sufficient capacity within the current insurance market and imply that those risks that they do not or would not cover should be regarded as uninsurable. If a role for government is appropriate, it should be limited to providing insurance over and above the capacity of the private market or to covering very large losses. A few insurers believe that the government might protect against uninsurable risks while others believe that doing this would only encourage poorly planned or marginally successful developments, and as such they are opposed to the idea.

A number of insurers expressed cynicism about the ability of the government to administer an effective insurance program. One insurer stated that government insurance programs already provided do not offer favorable testimony of the government's ability to effectively handle this type of program. Others equate government sponsorship with inefficiency and excessive administrative burdens. They believe this can only result in insurance being more costly than necessary.

Many insurers indicated that the existence of a government program would contribute little to the insurers' willingness to insure geothermal projects. There appears to be a clear preference among insurers for assessing each project on its own merits without "government interference." However, given some willingness to insure geothermal projects, a government program might, in some cases, facilitate tailoring coverage to the individual needs of each developer.

Among those sampled, the idea of a private geothermal insurance pool is more acceptable than a government program. However, a number of respondents qualified their support with statements that their own interests would have to be consistent with the guidelines for the pool. Some would only participate in a pool if it would forestall a government program.

The following points summarize the comments of the insurers:

- Insurers would prefer, and believe they have the ability, to handle geothermal insurance themselves.
- They believe that there is sufficient capacity for such a program within the industry.
- Any government role should be limited to providing coverage which exceeds existing or wanted capacity.

Developers

It is not surprising that the fundamental theme that emerged from the comments of the developers was a basic optimism about geothermal energy and a belief that further development should be encouraged. The developers disagreed, however, over whether an insurance program would provide a proper incentive for geothermal development.

Reactions to geothermal reservoir insurance differed based in large measure on the size of the company and the percentage of its total resources involved in geothermal projects. The larger, more diversified companies attached less importance to insurance than their smaller, more specialized counterparts.

Of the nine developers sampled, more than half indicated that an insurance program would encourage further development and allow projects to proceed more quickly. Reasons cited include:

- Insurance would reduce financial uncertainties thereby making geothermal projects more attractive to developers.
- Insurance would facilitate utility participation and provide a stimulus for them to enter negotiations earlier.
- Insurance would provide assurances for lenders.

Companies that do not advocate insurance cited problems of project responsibility and costs. With regard to responsibility, some developers fear that an insurance program would encourage poor or marginal projects. Regarding cost, there is some fear that if an insurance program existed, banks would require it in all cases. This might actually increase costs for low risk developments. Supporters of insurance, however, are sensitive to these concerns and emphasized that any insurance program (a) must be structured such that it does not encourage irresponsible development, and (b) must not be so costly that it would discourage projects with a high potential for profitability.

The developers sampled were virtually unanimous in their position that the government should not be involved in a geothermal reservoir insurance program unless the result would be reduced costs. All things being equal, the developers interviewed prefer to deal with private sources.

Many developers stressed the importance of a stable government policy. Geothermal developers see a role for the government, but those sampled limit it to providing start-up incentives in the form of seed money and tax breaks. They stressed that the government should not act independently of private enterprise and cautioned the government against providing assistance to projects likely to require permanent support. The Geothermal Loan Guaranty Program

(GLGP) was regarded by a number of developers as an appropriate role for government. Several suggested that the government might focus its efforts on improving the program.

The comments of the developers can be summarized as follows:

- There is a need for incentives in favor of geothermal development and an insurance program might serve as one.
- Any insurance program must be structured to encourage only truly viable projects and its costs must be in line with its perceived benefits.
- Government role should be limited to assisting with start-up of new projects.

Lenders

The tone of the lenders' responses about geothermal reservoir insurance can be summarized by stating that the greater the protection available, the greater the willingness to lend. Insurance would increase lender confidence and consequently could have a major impact on lending.

Based on the comments of the seven lenders sampled, it is clear that the consensus among lending institutions is that some sort of protection from loss is necessary before lending for geothermal developments will be considered. The lenders stressed that they desire "clean guarantees", i.e., no waiting, no conditions, no loopholes. It is important that any insurance program be structured using a format they are familiar with and trust. A structure similar to those used by the Small Business Administration and the MARAD guaranteed loan program for shipbuilding were cited as possible models. A structure such as that used by the Federal Housing Administration (where guarantees are in the form of government bonds rather than cash) was mentioned as something to be avoided.

More than half of the lenders sampled indicated that they believe the Geothermal Loan Guaranty Program is a good program, and some suggested that the government might focus its efforts on improving that program. One banker, elaborating on the point, expressed a belief that reservoir insurance is only appropriate in the final operating phase of a geothermal project where any major problem would most likely be a reservoir problem. In the preceding exploration and development phases, problems with technology, engineering and construction might also be factors. A loan guarantee would offer better protection under these circumstances. According to this banker, even this limited third phase reservoir insurance program would still have to meet three conditions to be able to substitute for a loan guarantee program:

- Guaranteed availability,
- Known price, and
- Long term (until debt is repaid).

The lenders were sensitive to overall costs and benefits of any insurance program. Insurance costs should not serve as a major disincentive to development. However, an insurance program should not encourage developments of questionable viability.

Generally, the lenders sampled have a positive reaction to potential government involvement in geothermal insurance. Some point out that there has been little in the way of demonstrable results from private insurers. They believe that it would not be as difficult to get insurance from the government and that the government would be more willing to insure over a longer term.

Even with an extensive network of guarantees and insurance programs, it is difficult to conclude that lenders would readily fund geothermal projects. As one banker pointed out, lenders tend to seek the "biggest possible deals." They perceive much more profit in oil and gas and, therefore, might not be as willing to invest time and resources in geothermal projects which are relatively smaller and more complicated.

The comments of the lenders can be summarized in the following points:

- Insurance would increase confidence and potentially would have a major impact on lending.
- Lenders desire clean guarantees structured along a familiar and acceptable format.
- The GLGP might provide better protection than insurance, especially in the first stages of project development.
- Costs should be in line with benefits.
- Insurance should not encourage marginal projects.
- Government can play a valuable role given lack of results from the private sector.
- Guarantees alone do not ensure increased lender participation in projects.

Users

The focus of the comments of users regarding geothermal insurance was on how it would affect costs in terms of (a) the utility's price or cost for power, and (b) the overall economics of geothermal projects. The users sampled all stressed that geothermal energy will become and remain a viable energy source only if it can compete effectively in price with other energy sources.

The users did not have a clear preferences for whether there should be a geothermal insurance program. Some stressed that it would have a definite positive impact because it reduces financial uncertainty. Others, however, implied that the responsibility for insurance should rest with project developers and operators, who are not necessarily the users. Still others indicated that their opinion would depend on the nature of the insurance. For example, an all-risk policy might prove helpful for a utility whereas reservoir capacity insurance might be of little interest.

All of the users attached great importance to the cost of any program, primarily because of the implications it would have for their operating costs. As one utility pointed out, insurance cost is very critical because of its impact on costs per kilowatt hour versus alternative sources. Insurance could cause costs to go either way. On the one hand, it is another project expenditure, but on the other hand, it might result in lower financing costs for geothermal developments.

Approximately one-half of the utilities sampled indicated that the existence of an insurance program might facilitate their contract negotiations. It would be easier to accept transfers of risk because the utility would have the option of passing it on to an insurer. Further, it might add incentives for lenders to come forward.

Regarding the role of the government, nearly all the users stated that they would prefer to see the private sector handle any insurance program. One utility expressed the opinion that government involvement in other similar programs "has been disastrous." The majority, however, would be willing to work with the government in the absence of tangible results from the private market. They believe that there are many uncertainties in dealing with the private sector and pointed out that utilities are used to dealing with the government. Nevertheless, the users would evaluate and consider the merit of a government sponsored program. They expect "substance and stability" and will oppose perceived government attempts to affect or influence management.

To summarize the comments of the users regarding a geothermal insurance program:

- Cost effectiveness of an energy source is an overriding concern.
- Insurance is important but utilities are interested in its impact on operating costs.

- Users would prefer to see an insurance program administered by the private sector; however, they would be willing to work with the government within certain limits in the absence of results from the private market.

Summary

Although the individuals interviewed had differing opinions on the appropriateness and need for an insurance program, they generally agreed that the availability of insurance would speed geothermal development. Insurance would address the uncertainty surrounding this resource and as a result would overcome some of the reluctance to become involved in geothermal projects. There is, however, a common concern that was voiced by a large number of those interviewed that unprofitable development should be avoided. It is in no one's interest to encourage projects of marginal feasibility given the magnitude of investment required and long run economic consequences.

Regarding the role of government, there was a consensus that the role of providing insurance would be best left to the private sector. The government role should be limited to encouraging and complementing private initiative. A government role that displaces the private market, with a resulting dependency on government, should be avoided.

IDENTIFICATION OF PROGRAM ALTERNATIVES

Evaluation of the role of government in providing federal support of geothermal reservoir insurance is best done through analysis of specific alternatives. This lends focus to what would otherwise be a rather broad subject area and makes it possible to compare various potential government roles with one another.

Selection Process

Two points were considered when developing the list of alternatives for consideration. First, it is desirable to consider as wide and diverse a scope of programs as possible. Second, it is necessary that the number of alternatives being considered be small enough to be sufficiently manageable. One means of achieving both conditions is to develop alternatives as distinct policy choices as opposed to specific and detailed plans. Such an approach would define the basic parameters of a potential program without specifying details such as coverage levels and premium calculation methodologies. Alternatives designed in terms of policy are more useful from an analytical standpoint because their comparison considers fundamental differences without becoming involved with specifics.

In developing the list of alternatives for providing geothermal reservoir insurance, a large number of potential insurance programs were first considered. The purpose of this process was to gain an understanding of the range of possibilities available. These were then distilled to five alternatives representing various levels of federal support and a range of types of insurance coverage.

Definition of Alternatives

The five alternatives selected for detailed analysis represent a wide range of possibilities for government involvement. The alternatives present various levels of federal support ranging from no support at all to a very high level. Further, they offer a choice as to the nature of government involvement either as a primary insurer or as a reinsurer. Finally, the alternatives consider possibilities of providing coverage for "insurable" versus "uninsurable" risks.

The alternatives should not be regarded as inflexible programs. Rather they are intended to represent distinct policy choices within which a detailed insurance program may be designed and implemented. In Chapter VII, a specific program recommendation is described in detail.

Of the five alternatives, four call for some degree of federal involvement in geothermal reservoir insurance. For the purpose of comparative analysis, these four alternatives are assumed to have the following common characteristics:

- A definition of "insurable" risks consistent with the list of insurable risks identified in Chapter V.
- Premium charges sufficient to cover expected losses.
- Some provision for orderly phase-out of government involvement.
- Delegation of responsibility for administrative functions of the program to a third party under contract to the federal government.

An important point regarding these characteristics is that they are the same for all the alternatives. This allows the comparison of the alternatives to focus on the fundamental policy differences without becoming involved with program specifications. The characteristics themselves were chosen to maintain consistency with the findings and conclusions of the report.

Insurable risks were defined in Chapter V as the set of risks of concern to geothermal developers that the private insurers interviewed indicated that they might insure. Because four of the alternatives call for the private market to provide coverage for insurable risks, it is necessary that they be defined in a way that is acceptable to the private insurers.

Premium charges are assumed in all cases to be at least sufficient to cover expected insurance claims payments. Most alternatives further assume that premiums would be adequate, i.e., sufficient to cover expected insurance claims, administrative costs, and a contingency for actual insurance claims payments exceeding their expected level.

The alternatives all assume that a provision for orderly phase-out is included to avoid the development of a dependence on government. The research and analysis for this study indicate that dependent relationships should be avoided. Consequently, any government program should be temporary and designed to stimulate rather than replace private enterprise.

It is desirable to delegate responsibility for administrative functions to a third party. This is consistent with the belief in government involvement on a temporary basis; but more important, administration by a third party would avoid the appearance and problems of a federal bureaucracy. Interviews with individuals in the geothermal constituency indicated a lack of confidence in the ability of the federal government to efficiently manage an insurance program's administrative functions. Administration by a third party would alleviate that concern and eliminate the need for the government to staff the program with the specialized insurance knowledge required.

The next several paragraphs are devoted to generally defining each of the five geothermal reservoir insurance alternatives. For each alternative the definition includes level of government support, type of coverage offered and relationship with the private insurance sector.

<u>Alternative 1</u> - A private market insurance program* for "insurable" geothermal reservoir risks in a competitive insurance environment.

The important characteristic of this alternative is a conscious absence of government involvement in providing insurance for geothermal projects. The policy choice of the federal government would be to provide no support to an insurance program because there would be no perceived need or use for such support. Necessary coverage for "insurable" risks of geothermal energy would be provided entirely by the private insurance market and without federal assistance.

<u>Alternative 2</u> - A private market insurance program for "insurable" risks underwritten by insurers/reinsurers in an open competitive environment supplemented by the federal government providing excess catastrophe reinsurance.

Like Alternative 1, this alternative anticipates that the bulk of coverage for "insurable" risks of the geothermal reservoir would be covered by the private sector through primary coverage. However, this alternative calls for a low level of federal support in that the federal government would provide only excess catastrophe reinsurance. By "excess", it is meant that insurance would be provided for losses exceeding a defined high threshold. The term "catastrophe" means that losses would have to be caused by a single defined event to be eligible for claims payments. Payment on claims would be the amount by which the loss exceeded the threshold level up to a stated maximum level. Coverage of losses below the threshold level

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*The use of the term "private market insurance program" refers to any one or combination of three possible methods of writing insurance. These are:

1. Currently established property-casualty insurance and reinsurance companies.
2. Self-insurance by corporations in the geothermal energy industry.
3. A captive insurance company for a segment or group within the geothermal energy industry.

would be covered by the private sector. Further, because this is a reinsurance program, the government provided coverage would be available only to private insurers and reinsurers, not individual policyholders.

Alternative 3 - A private market insurance program for "insurable" risks underwritten by insurers/reinsurers with the federal government making available limited excess reinsurance at a cost to insurers that is less than what the private market will provide.

Like Alternative 2, this alternative calls for the government to provide a form of excess reinsurance. Private insurers would be responsible for providing primary coverage and the government would make available reinsurance to private insurers and reinsurers for losses exceeding a defined threshold. This alternative is broader than Alternative 2 in that it does not have the catastrophe provision. Moreover, this alternative calls for the premium of government provided reinsurance to be set at a level below that which the private market would charge.

Alternative 4 - A private market insurance program for "insurable" risks underwritten by private insurers/reinsurers with the federal government providing primary insurance protection for risks not insured by the private sector.

This alternative depends on the private market to provide insurance coverage for risks that they are willing to insure ("insurable" risks). The role of government would be to provide insurance coverage for certain other risks not designated by the private market as "insurable".

This alternative calls for the government to provide primary insurance meaning that the coverage would be sold directly by the government to the individual policyholder. Consequently, there would be two separate insurance markets, a private market and a government market. The geothermal constituency could purchase insurance in both markets.

Alternative 5 - A primary insurance program covering "insurable" risks of the geothermal reservoir sponsored by the federal government.

The essence of this alternative is that it calls for primary geothermal reservoir insurance against "insurable" risks to be provided through a government program. There would be no defined role for the private insurance market in providing this coverage and consequently, this represents the maximum possible level of federal support for geothermal insurance. Although this alternative does not expressly call for federal price support, it does allow for that possibility.

ANALYSIS OF PROGRAM ALTERNATIVES

The five geothermal reservoir insurance program alternatives were analyzed and compared in terms of six basic criteria:

- Rationale for federal support.
- Impact on the private insurance sector.
- Financial impact on the geothermal industry.
- Estimated cost to government.
- Phase-out considerations.
- Interaction with other government programs.

The following discussion compares the alternatives according to each of these considerations. Following that is a summary section that discusses the advantages and disadvantages of each of the alternatives.

Rationale for Federal Support

Traditional economic theory contends that competitive market forces bring about a distribution of economic activity that results in an optimum allocation of resources. Because it is this doctrine that guides the free-enterprise system in the United States, a question is raised about why there is a need for any type of government sponsored insurance program. This section provides a discussion of the possible rationale for government involvement in providing geothermal reservoir insurance assuming a certain scenario for each alternative. The rationale is discussed in the context of the five alternative geothermal reservoir insurance programs and the specific needs to which they are designed to respond.

Alternative 1 would respond to circumstances of no perceived need for government involvement in providing geothermal reservoir insurance. This scenario presupposes that necessary insurance protection is therefore available from the private sector and there is no rationale for government involvement. Consequently, no government sponsored insurance program is proposed.

Alternative 2 would respond to particular circumstances requiring a relatively low level of government involvement. Specifically, under this scenario, the circumstances are that catastrophe reinsurance coverage is unavailable in the private market due to reluctance on the part of private reinsurers to provide this coverage. The lack of catastrophe reinsurance would imply significant risk for a private insurer with a sizable volume of geothermal business. While the existence of catastrophe reinsurance may not be a sufficient condition for the development of a private-sector insurance market, reinsurance of some sort is a necessary condition.

The lack of at least a catastrophe reinsurance market could thus be considered a basis for government intervention. This alternative calls on the government to address the market needs by making available catastrophe reinsurance. The availability of this reinsurance would provide encouragement for private insurers to underwrite geothermal risks.

Alternative 3 calls for a moderate level of federal support. This alternative responds to a scenario in which the private sector is not providing a sufficient level of primary coverage for the "insurable" risks of the geothermal reservoir. Further, the price of insurance/ reinsurance is high because the uncertainty surrounding geothermal reservoir risks has led to a large risk loading factor* being incorporated into the premium. This alternative envisions a government program that would offer reinsurance to primary insurers at a cost below what the private market will provide. The reduction in cost would be accomplished by removing the risk loading factor and administrative costs from the reinsurance premium calculation. This would bring the cost of insurance/reinsurance down to a more acceptable level and provide a needed incentive for early participation, until such time as adequate performance data on geothermal risks can be obtained.

Alternative 4 also represents a need for a moderate level of federal support but in response to different circumstances than Alternative 3. In this scenario, the private market is willing to provide adequate coverage for "insurable" risks. However, geothermal project development is being inhibited by certain risks that fall outside the defined "insurable" risks. Under this alternative the government has a rationale for providing coverage for some of these

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* The risk loading factor is a percentage added into the premium calculation to cover the contingency that actual insurance claims payments will exceed their expected level. The size of the risk loading factor is related to the level of uncertainty surrounding the probability of loss.

risks. This would require a determination on the part of the government of exactly what other risks are inhibiting geothermal development and a decision to provide coverage for some of these risks. It is important to note that the government would not necessarily insure every risk. Rather, this alternative is sensitive to a belief that certain risks (e.g., something that would increase the possibility of moral hazard) should not be insured under any circumstance.

Alternative 5 responds to circumstances requiring a very high level of federal support. In this scenario, the private market has demonstrated a complete inability, at the present time, to provide any level of geothermal reservoir insurance. Without any insurance, geothermal development is severely handicapped. If coverage could be provided for the defined "insurable" risks of the geothermal reservoir, developers would be more likely to invest in developing this resource. Given these circumstances, the government has a rationale for providing the necessary insurance. This alternative envisions a government insurance program to cover the defined "insurable" risks of the geothermal reservoir. This program would not depend on private sector participation given the assumed inability of private insurers to provide any measure of this type of insurance. The federal government would thus have full responsibility for providing geothermal reservoir insurance.

Impact on Private Insurance Sector

The role taken by the federal government in a geothermal reservoir program is likely to have important consequences for those private insurers attempting to market reservoir insurance to the geothermal industry. Based on the particular role assumed by government, these consequences can range from a positive impact to restricting the private insurance sector's ability to compete in the geothermal energy marketplace. For each of the alternatives defined, the impact on the role of the private insurance sector has been analyzed. Self-insurance and captive insurance mechanisms have been considered in analyzing the impact on the private insurance sector. Among the areas analyzed for each alternative are availability of necessary protection, the affordability of that protection and competition in the marketplace.

Alternative 1 stipulates that the federal government would not involve itself in any geothermal insurance program because of the lack of perceived need or utility of such investment. This alternative would be appropriate when marketplace factors are such that previous uncertainties regarding the performance characteristics of the geothermal resource are being understood and resolved by the private sector and necessary insurance protection will be available for the resource risks. Within this alternative, private insurance companies offering protection against geothermal reservoir risks are able to specifically evaluate the probability of loss arising from these hazards and the potential amount of loss and then structure both appropriate premiums and coverages for these individual risks. Projects that are economically viable will find that insurance protection is readily available at a price that is affordable. On the other hand, those projects that are marginal will encounter greater difficulty in obtaining insurance protection, except at a higher price. The latter projects may find this price of protection to be prohibitive. However, those direct and indirect use projects in the former group can expect better coverage at a reduced rate, brought about by a better understanding of the geothermal energy industry and a competitive insurance market. From the private insurance sector's viewpoint this alternative would be preferable.

A supportive role for the federal government is considered in Alternative 2. The scenario for this alternative indicates that some private insurers have demonstrated confidence that the uncertainties regarding the performance characteristics of the geothermal resource can be overcome with the accumulation and analysis of historical data. This supportive role, in the form of a partnership between the federal government and private insurers/reinsurers, would enable the private sector to make available necessary insurance protection without fear of a catastrophic event severely reducing capacity. One method of structuring this catastrophic protection would allow voluntary purchase by private insurers/reinsurers which would encourage private sector participation to the fullest extent possible within the insurance industry's capacity. Although the historical experience of partnership insurance programs with the federal government has not been altogether favorable, this period of data collection and analysis should generally have a positive impact on those private insurers marketing geothermal reservoir insurance.

Alternatives 3 and 4 identified two possible active roles for the federal government to assist the private sector. Alternative 3 is excess reinsurance provided to private insurers at a cost less than the cost of excess reinsurance provided by the private reinsurance sector. The comments for Alternative 2 are also generally applicable here. The major difference between the alternatives is the level of federal support proposed. In Alternative 3 the federal government's involvement will be triggered at a lower dollar level and for losses including those from other than catastrophic events. The insurance industry can avoid the possible impediment of unusually large losses while still playing the primary role in protecting against the risks of geothermal energy. This role could encourage more primary insurers to participate actively in the area of geothermal reservoir insurance and could somewhat reduce the premium to the insured for that protection. It may, however, have some negative impact on private reinsurers who may desire to provide these high levels of coverage on their own.

Alternative 4 presents a scenario in which the federal insurance program insures those risks classified as uninsurable. This alternative role would allow private insurers/reinsurers to gain the experience needed to develop the necessary insurance programs while the government provided coverage for those risks that the private insurance market was not willing to cover. Though there are some potential negative aspects of this role, the overall impact on the private insurance sector would be positive.

Alternative 5 assumes that a high level of federal support for providing geothermal reservoir protection is required because the private sector probably will not overcome the uncertainties regarding the performance characteristics of the geothermal resource in the short term. This alternative places the federal government in direct competition with the various private sector insurance mechanisms and would essentially eliminate private insurers from the geothermal reservoir insurance market because they could not individually compete with the federal government. The impact on the private insurance sector of this alternative is decidedly negative.

Financial Impact on the Geothermal Industry

This section examines the financial impact on the geothermal industry as a result of the insurance premiums estimated in Section V. The purpose of the analysis is to examine the economic feasibility of the estimated premiums with regards to specific geologic project types.

As discussed in Section V, the estimated premiums vary most significantly by the stage of development that the policies would cover. Annual premiums are much higher in Stages 1 and 2 because (a) the risks are greater during the initial stages of development and operation and (b) the duration of each stage is much shorter than Stage 3. Also, it is important to emphasize that the estimated premiums depicted in Exhibit V-18 are assumed to cover the expected loss amount for all the risks analyzed. In actual practice both the insurer and the insured would have the option of insuring all or only some of the risks, or perhaps other risks in addition to those considered in Section V. Further, self insured retention levels (or deductibles) were not considered for purposes of estimating premiums. If included, they could substantially lower premiums, particularly the large premiums necessary to cover developer's indirect loss (i.e., loss of potential steam revenue). This approach of assuming a maximum level of risks and no self-insured retentions was used for purposes of conservatism in premium estimation (i.e., higher premiums than would be expected in actual practice).

Although there are many ways to reduce the estimated premiums through a variety of deductible provisions or through federal cost support, the gross premium levels estimated in Section V were utilized to examine the feasibility of these added costs for each of six geologic project types considered in detail.* One method of spreading insurance costs over time is examined whereby annual premiums are calculated to cover risks for Stages 1 and 2 combined.

Before discussing the analysis of insurance costs for each project type, it is important to note that the financial impacts on the geothermal industry will not differ significantly by the alternative programs considered throughout this section. The premiums estimated in Section V include risk and administrative expense loadings which were judged reasonable for the private sector insurance marketplace. Therefore, these premiums can be regarded as those that would result from Alternative 1. Alternatives 2 through 5 all involve some level of government participation. The ultimate cost to the insured would not be significantly affected by any of these programs unless the government specifically provided cost support through risk and administrative loadings lower than those charged by the private sector.

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*A detailed analysis of the financial impacts on a Type C project "Leaky Fault Non-Electric Use" was not perfomed because only limited data for estimating Developer's Direct Loss was available.

Federal cost support is possible under each of the alternatives and is assumed to exist in Alternative 3. However, because Alternative 3 implies a reinsurance role for the government, whether or not the lower than market costs to the primary insurer will be passed on to the insured will depend on the degree of competition in the primary insurance market. Alternative 4 would perhaps result in somewhat higher insurance costs to the insured because of the possibility of additional risks being covered.

In order to examine the financial impacts of the premiums depicted in Exhibit V-18, extensive use was made of the Geothermal Loan Guaranty Cash Flow Model (GCFM)*. This model was used to examine the effects of insurance costs on the developers cash flows for each of the geothermal projects for which insurance premiums were estimated.**

In general the cash flow analysis indicated that, even with the high initial premiums and no deductible or self insured retention provisions, the financial burden imposed by the insurance costs would not appear to be prohibitive to project economics. Further, when annual insurance premiums were calculated so as to cover Stages 1 and 2 combined, initial costs were spread more evenly over time with predictably better results on project economics.

The insurance premiums and their financial impacts will vary by the size of each particular project. Before discussing the cash flow analysis for each type of development, it is instructive to note the total capital cost of each development and how annual insurance premiums varied by the size of each development. Exhibit VI-2

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* For a detailed description of the model see "Geothermal Loan Guaranty Cash Flow Model - Description and User's Manual", The MITRE Corporation, McLean, Virginia, MTR-80W160, Nov. 1980.

** Impacts of insurance premiums on electric utilities were not considered because the costs are relatively small and are judged not likely to impose a significant burden on utilities.

compares the estimated annual premiums for Stage 3 that cover (a) developer's direct loss and (b) developer's direct and indirect loss, to the total capital cost for each of the six electric-generation geothermal projects analyzed. The exhibit shows that insurance premiums generally increasely with the size of development, as should be expected because more wells, surface facilities and revenue potential are at risk. For each project type considered, the annual premium to cover developer's direct loss during Stage 3 is estimated at less than one percent of total project costs. To cover both developer's direct and indirect losses, the annual premium would average approximately 6 percent of the total project cost.

The remainder of this subsection will briefly describe the approach followed in examining the effects on project cash flows as a result of increased insurance costs. In addition, there will be a brief description of the model inputs used for the analysis. This is followed by a sample analysis for one specific project type. A summary of the results of the analysis for all project types is then provided.

Approach

The basic approach employed in examining the financial impacts was to compare a basecase cashflow analysis for each project type to alternative scenarios where increased annual costs were imposed to reflect either insurance premiums or estimated annual expected losses as determined in Section V. Comparisons were made on the basis of three criteria: (1) the Internal Rate of Return (IRR) of each project, (2) the Present Discounted Value (PDV)* of each project, and (3) the levelized breakeven price for each project.

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* This value is also known as Net Present Value (NPV).

Exhibit VI-2

ANNUAL INSURANCE PREMIUMS AS A PERCENTAGE OF TOTAL COST

Project Type	(1) Capital Cost of Development* (millions-$1981)	(2) Stage 3 Annual Premium Direct Coverage ** (millions-$1981)	(3) Stage 3 Annual Premium Direct and Indirect Coverage ** (millions-$1981)	Column (2) as a % of (1)	Column (3) as a % of (1)
A	$52.4	$.157	$ 2.64	.30	5.0
B	58.1	.309	3.24	.50	6.0
D	42.7	.366	1.81	.90	4.0
E	30.1	.007	1.06	.02	4.0
F	93.7	.638	6.48	.70	7.0
G	31.9	.316	2.18	1.00	7.0
Average	-	-	-	.60	5.5

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* Estimates derived from input data provided by DOE data sources used in the GCFM to conduct financial analyses.

** From Exhibit V-18.

The basecase cashflows, which will be described in more detail shortly, reflect all significant revenues and costs exclusive of possible losses resulting from the risks defined and analyzed in Section V. Therefore, both estimated annual insurance premiums (from Exhibit V-18) and estimated annual expected losses (derived from Exhibit V-17) were separately considered as additional operating expenses and compared to the basecase for each project type. This analytic framework allows the comparison between the IRR, PDV and breakeven price for each project with insurance costs compared to (a) the basecase results, and (b) the results of the basecase with additional expenses added that approximate the expected losses from risk events. The latter comparison is, perhaps, a more important benchmark with which to evaluate the financial effects of insurance, because the differential between insurance premiums and expected losses can be viewed as the price being paid to transfer risks.

The internal rate of return of any project is defined as the discount rate for the cashflow stream of the project which results in a net present value of the cashflow equal to zero. This is a useful measure of evaluating the profitability of alternative projects, because in general the higher the IRR the more profitable the project.

The present discounted value is another useful measure with which to evaluate the profitability of a project. It is defined as the project cashflow stream appropriately discounted to the present time. It can be interpreted as the present value to an investor of the future revenues and costs of a project. In a theoretical sense it represents the current price at which a reasonable investor would be willing to buy or sell the project.

The levelized breakeven price is defined as the steam sales price in mills per kilowatt-hour ($1981) that is required to achieve a specified equity rate of return.* This is a useful measure with

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* For a detailed description of how the levelized breakeven price is calculated within the GCFM see "Geothermal Loan Guaranty Cash Flow Model - Description and User's manual, _op. cit._, pg. A-12.

which to examine the effects of insurance costs, because it reflects the extent to which the steam sales price would have to be increased in order to maintain a specified equity rate of return given the additional insurance costs to the project.

Basecase

The basecase cashflows for each project type reflect all major revenues and costs over the lifetime of the development, exclusive of possible losses due to the risks defined and analyzed in Section V. For example, expected well-lives and success ratios were inputs to the GCFM to establish a basecase for each project type, but these values reflect current planning estimates and not the added costs of unexpected reductions in useful well-life or success ratio, which were risks analyzed in detail in Section V. The following is a list of some of the major inputs that are taken into account in generating cashflows for each year of a project.*

- Field Data
  - Field Output (MW)
  - Brine Flow Required
  - Well Flow Rates
  - Total Cost of Wells
  - Cost per Downhole Pump
  - Book Lives of Wells and Downhole Pumps
  - Tax Lives of Wells and Downhole Pumps
  - Intangible Drilling Cost Rates
  - Drilling Success Ratio
  - Cost per Makeup Well
  - Number of Makeup Wells (for normal field decline)

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* Values for these and other variables supplied by DOE data sources and GeothermEx Inc. Values by project for the major variables appear in the Appendix.

  - Field Plant Capital Cost (surface facilities)
  - Book Lives for Field Capital Accounts
  - Tax Lives for Field Capital Accounts
  - Operations and Maintenance Costs
  - Field Exploration Costs

- Financial Data
  - Base Year
  - Power On-Line Year (beginning of Stage 2)
  - Project Life
  - Loan Life
  - Working Capital
  - Electricity Price
  - Geothermal Fluid Price
  - Capacity Factor of Power Plant
  - Equity Fractions
  - Equity Rate of Return
  - Debt Interest Rate
  - General Inflation Rate
  - Escalation Rate for a Variety of Capital Accounts
  - Escalation Rate for Electricity Price
  - Escalation Rate for Fluid Price
  - Escalation Rate for O&M Costs
  - Discount Rate (used in levelized breakeven price and PDV calculations)
  - Various Tax Rates

The relevant outputs of the GCFM, for the purposes of this analysis are (a) net cashflows for each year of operation (Stages 2 and 3), (b) the PDV of each project with the base year being 1981, (c) the IRR of each project based on the present value of cashflows in 1981 dollars, and (d) a levelized breakeven price for the geothermal steam or fluid in 1981 dollars.

Sample Analysis

In this subsection the analysis for project Type D is discussed in detail as an illustrative example of the analysis performed for all project types. In the following subsection the results for all project types are summarized.

Eight alternative cases or scenarios were compared to the basecase cashflows. These differed (a) in terms of whether annual insurance premiums were added as additional operating expenses or expected losses were added, and (b) in terms of different combinations of loss categories. Annual premiums as calculated for Stages 1, 2, and 3 (shown in Exhibit V-18) were considered for each year of a 36-year project life (Stage 1, years 1-5; Stage 2, year 6; Stage 3, years 7-36). In addition, premiums were calculated on an annual basis to cover risks in Stages 1 and 2 combined, in order to try to spread the high insurance costs in the sixth year (Stage 2) over-time. For example, in project Type D, annual insurance premiums for developer's direct loss were estimated to be $4.4 million throughout Stage 1, $14.5 million for Stage 2, and $.4 million throughout Stage 3. Estimated annual premiums for a policy that would cover risks through Stages 1 and 2, however, would be $6.0 million thereby reducing the burden of a very large premium in the sixth year.

The eight scenarios compared to the basecase cashflows for Type D are:

A. Annual insurance premiums added to expenses
   - A-1 Direct and indirect loss for Stages 1, 2, and 3 separately
   - A-2 Direct and indirect loss for Stage 3, with Stages 1 and 2 combined
   - A-3 Direct loss for Stages 1, 2, and 3 separately
   - A-4 Direct loss for Stage 3, with Stages 1 and 2 combined

B. Annualized expected losses added to expenses

  - B-1 Direct and indirect loss for Stages 1, 2, and 3 separately
  - B-2 Direct and indirect loss for Stage 3, with Stages 1 and 2 combined.
  - B-3 Direct loss for Stages 1, 2, and 3 separately
  - B-4 Direct loss for Stage 3, with Stages 1 and 2 combined

The results of the analysis using the GCFM for the eight scenarios for Type D along with the basecase for Type D are presented in Exhibit VI-3. Sample computer model outputs are provided in Exhibit VI-4 that compare (a) the basecase IRR with (b) the IRR for the scenario where annual insurance premiums for developer's direct loss are added to expenses (considering Stages 1 and 2 combined).

Predictably the IRR and PDV in each of the eight scenarios was lower than the IRR and PDV for the basecase. Similarly the levelized breakeven price was greater than the basecase. Furthermore, project economics are not as severely affected when annual insurance premiums are calculated to cover Stages 1 and 2 combined. Project economics are most severely affected when both direct and indirect losses are covered for Stages 1, 2, and 3 separately.

Of particular significance is the fact that the IRR and PDV in all cases for this alternative were positive. This indicates that even in the case of the most extreme insurance costs the project has a positive return over the project life and a positive current value. This analysis indicates that the estimated insurance costs are not prohibitive to the project.

Although in some cases the reduction in IRR or PDV from the basecase appears significant, the reductions in IRR and PDV from buying insurance as opposed to paying out the expected losses of the risks

Exhibit VI-3

FINANCIAL IMPACT ANALYSIS FOR TYPE D

Scenario*	IRR (%)	PDV (millions-$1981)	Levelized Breakeven Price (mills/kw-hr)
Basecase	11.3**	72.7	60.8
Insurance Premiums:			
A-1	1.3	11.6	82.9
A-2	2.9	22.2	79.8
A-3	6.1	53.5	69.5
A-4	8.0***	59.3	66.3
Expected Losses:			
B-1	3.8	30.9	76.7
B-2	4.8	36.7	74.5
B-3	7.7	61.2	66.7
B-4	8.8	62.9	64.5

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* Alternative scenarios defined in text.

** See Exhibit VI-4, Page 1 of 2.

*** See Exhibit VI-4, Page 2 of 2.

EXHIBIT VI-4
Page 1 2

TYPE D BASECASE INTERNAL RATE OF RETURN

YEAR	AFTER TAX INCOME/LOSS	+ CASH * SOURCES	+ TAX LOSS FORWARD	- DEBT RETIREMENT	= GROSS CASH FLOW	- SINK. FUND DEPOSIT	- OTHER CAP.** INVESTMENTS	= NET CASH FLOW
6 - 1986	1976.6	6154.7	1976.6	340.8	9767.1	.0	1989.8	7777.2
7 - 1987	2977.7	6207.7	2977.7	340.8	11822.2	.0	2129.1	9693.1
8 - 1988	3769.3	6218.1	3769.3	340.8	13416.0	.0	2278.2	11137.8
9 - 1989	4611.1	6231.3	4611.1	340.8	15112.7	.0	2437.6	12675.1
10 - 1990	5506.4	6247.6	5506.4	340.8	16919.6	.0	2608.3	14311.3
11 - 1991	5442.7	6267.2	2280.0	340.8	13649.0	.0	2790.8	10858.2
12 - 1992	5645.7	6290.2	.0	340.8	11595.0	.0	2986.2	8608.8
13 - 1993	5229.8	6626.4	.0	340.8	11515.3	.0	3195.2	8320.1
14 - 1994	4678.7	6990.2	.0	340.8	11328.1	.0	3418.9	7909.2
15 - 1995	5124.1	7383.7	.0	340.8	12167.0	.0	3658.2	8508.7
16 - 1996	5596.9	7808.9	.0	340.8	13065.0	.0	3914.3	9150.7
17 - 1997	6099.1	8267.9	.0	340.8	14026.3	.0	4188.3	9838.0
18 - 1998	6632.8	8763.3	.0	340.8	15055.2	.0	4481.5	10573.7
19 - 1999	7188.2	9320.7	.0	340.8	16168.1	.0	4795.2	11372.9
20 - 2000	7779.5	9919.7	.0	340.8	17358.4	.0	5130.8	12227.5
21 - 2001	6409.4	10563.1	.0	340.8	16631.7	.0	5490.0	13141.6
22 - 2002	9080.4	11254.0	.0	340.8	19993.6	.0	5874.3	14119.3
23 - 2003	9795.5	11995.9	.0	340.8	21450.5	.0	6285.5	15165.0
24 - 2004	10557.7	12792.2	.0	340.8	23009.0	.0	6725.5	16283.5
25 - 2005	11370.3	13646.7	.0	340.8	24676.2	.0	7196.3	17479.9
26 - 2006	14116.1	10927.5	.0	340.8	24702.7	.0	2851.9	21850.9
27 - 2007	15240.7	11346.1	.0	340.8	26246.0	.0	3051.5	23194.5
28 - 2008	16533.3	11851.7	.0	340.8	28044.2	.0	3265.1	24779.1
29 - 2009	17884.3	12450.5	.0	340.8	29994.0	.0	3493.6	26500.4
30 - 2010	19298.0	13148.9	.0	340.8	32106.0	.0	3738.2	28367.8
31 - 2011	20778.5	13953.9	.0	340.8	34391.6	.0	3999.9	30391.7
32 - 2012	22330.7	14872.9	.0	340.8	36862.9	.0	4279.9	32583.0
33 - 2013	23959.6	15914.0	.0	340.8	39532.8	.0	4579.5	34953.4
34 - 2014	25699.8	17028.0	.0	340.8	42367.0	.0	4900.0	37466.9
35 - 2015	27559.1	18219.9	.0	340.8	45438.2	.0	5243.0	40195.2
36 - 2016	29545.8	19495.3	.0	340.8	48700.3	.0	5610.0	43090.3

DISCOUNTED CASH FLOW RATE OF RETURN = 24.5 % (BASED ON NOMINAL CASH FLOWS)

= 11.3 % (BASED ON PRESENT VALUE OF CASH FLOWS IN 1981 DOLLARS)

* - CASH SOURCES INCLUDES ALL TAX DEPRECIATION, DEPLETION ALLOWANCES, INTANGIBLE DRILLING COSTS, AND DRY HOLE EXPENSES.

** - OTHER CAPITAL INVESTMENTS INCLUDE ANNUAL REPLACEMENT WELL INVESTMENTS, MAKE-UP WELL INVESTMENTS, AND FUNDS REQUIRED TO COVER ANY SINKING FUND SHORTFALLS.

EXHIBIT VI-4
Page 2 2

TYPE D WITH ANNUAL INSURANCE PREMIUMS INTERNAL RATE OF RETURN

YEAR	AFTER TAX INCOME/LOSS	+ CASH * SOURCES	+ TAX LOSS FORWARD	- DEBT RETIREMENT	= GROSS CASH FLOW	- SINK. FUND DEPOSIT	- OTHER CAP.** INVESTMENTS	= NET CASH FLOW
6 - 1986	-7348.8	4346.2	.0	340.8	-3343.3	.0	1989.8	-5333.2
7 - 1987	2256.1	6207.7	2256.1	340.8	10379.1	.0	2129.1	8250.0
8 - 1988	2997.3	6218.1	2997.3	340.8	11871.9	.0	2278.2	9593.7
9 - 1989	3785.0	6231.3	3785.0	340.8	13460.5	.0	2437.6	11022.9
10 - 1990	4622.5	6247.6	4622.5	340.8	15151.8	.0	2608.3	12543.5
11 - 1991	5513.2	6267.2	5513.2	340.8	16952.8	.0	2790.8	14162.0
12 - 1992	5896.1	6290.2	4115.5	340.8	15960.9	.0	2986.2	12974.7
13 - 1993	5410.0	6626.4	.0	340.8	11695.5	.0	3195.2	8500.3
14 - 1994	4521.0	6990.2	.0	340.8	11170.5	.0	3418.9	7751.6
15 - 1995	4494.8	7383.7	.0	340.8	11537.7	.0	3658.2	7879.5
16 - 1996	4923.6	7808.9	.0	340.8	12391.6	.0	3914.3	8477.4
17 - 1997	5378.7	8267.9	.0	340.8	13305.8	.0	4188.3	9117.5
18 - 1998	5861.8	8763.3	.0	340.8	14284.3	.0	4481.5	9802.8
19 - 1999	6363.3	9320.7	.0	340.8	15343.2	.0	4795.2	10548.0
20 - 2000	6896.9	9919.7	.0	340.8	16475.8	.0	5130.8	11344.9
21 - 2001	7465.0	10563.1	.0	340.8	17687.3	.0	5490.0	12197.3
22 - 2002	8069.9	11254.0	.0	340.8	18983.1	.0	5874.3	13108.8
23 - 2003	8714.2	11995.9	.0	340.8	20369.3	.0	6285.5	14083.8
24 - 2004	9400.7	12792.2	.0	340.8	21852.1	.0	6725.5	15126.6
25 - 2005	10132.4	13646.7	.0	340.8	23438.3	.0	7196.3	16242.0
26 - 2006	12791.5	10927.5	.0	340.8	23378.2	.0	2851.9	20526.3
27 - 2007	13823.4	11346.1	.0	340.8	24828.7	.0	3051.5	21777.2
28 - 2008	15016.8	11851.7	.0	340.8	26527.7	.0	3265.1	23262.6
29 - 2009	16261.7	12450.5	.0	340.8	28371.4	.0	3493.6	24877.7
30 - 2010	17561.7	13148.9	.0	340.8	30369.8	.0	3738.2	26631.6
31 - 2011	18920.8	13953.9	.0	340.8	32533.8	.0	3999.9	28533.9
32 - 2012	20342.9	14872.9	.0	340.8	34875.1	.0	4279.9	30595.2
33 - 2013	21832.7	15914.0	.0	340.8	37405.9	.0	4579.5	32826.4
34 - 2014	23423.9	17028.0	.0	340.8	40111.1	.0	4900.0	35211.1
35 - 2015	25123.9	18219.9	.0	340.8	43003.1	.0	5243.0	37760.0
36 - 2016	26940.2	19495.3	.0	340.8	46094.7	.0	5610.0	40484.7

DISCOUNTED CASH FLOW RATE OF RETURN = 19.4 % (BASED ON NOMINAL CASH FLOWS)
= 8.0 % (BASED ON PRESENT VALUE OF CASH FLOWS IN 1981 DOLLARS)

* - CASH SOURCES INCLUDES ALL TAX DEPRECIATION, DEPLETION ALLOWANCES, INTANGIBLE DRILLING COSTS, AND DRY HOLE EXPENSES.

** - OTHER CAPITAL INVESTMENTS INCLUDE ANNUAL REPLACEMENT WELL INVESTMENTS, MAKE-UP WELL INVESTMENTS, AND FUNDS REQUIRED TO COVER ANY SINKING FUND SHORTFALLS.

is only marginal. These differentials are of primary importance in considering the decision to buy insurance because they represent how much it is necessary to pay to avoid risk.

For example, the PDV of project Type D, if insurance is purchased to avoid the risk of direct loss (considering Stages 1 and 2 combined), is $59.3 million ($1981). If insurance is not purchased the expected direct loss is such that the expected PDV of the project is $62.9 million ($1981). This results in insurance lowering the expected PDV of the project by $3.6 million ($1981) or approximately 5% of the basecase PDV. Therefore, in theory, the insurance will be purchased if the developer places at least a $3.6 million ($1981) present value on avoiding the risk of actual direct loss (which could be in excess of the expected loss) over the life of the project.

Results

Exhibit VI-5 presents the results of the financial analysis for the remaining project types (Types A, B, E, F, and G). Only in the one case of the most extreme insurance costs for Type F do the IRR or PDV for any project become negative as a result of paying insurance premiums. Furthermore, as with Type D, the differential between the IRR and PDV from paying insurance to avoid risk as compared to paying the expected losses of the risks appears marginal. On the basis of this analysis, even with the high cost of initial premiums and no deductible provisions, the financial burden imposed by the estimated insurance costs does not appear to be prohibitive to project economics.

Exhibit VI-5
Page 1 of 5

FINANCIAL IMPACT ANALYSIS FOR TYPE A

Scenario*	IRR (%)	PDV (millions-$1981)	Levelized Breakeven Price (mills/kw-hr)
Basecase	37.7	$252.2	15.9
Insurance Premiums:			
A-1	24.2	198.4	20.7
A-2	27.9	202.7	20.7
A-3	29.5	241.7	16.7
A-4	33.5	245.7	16.4
Expected Losses:			
B-1	27.7	214.2	19.3
B-2	30.7	216.9	19.1
B-3	31.4	244.5	16.5
B-4	34.5	247.2	16.3

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* Alternative scenarios defined in text.

Exhibit VI-5
Page 2 of 5

FINANCIAL IMPACT ANALYSIS FOR TYPE B

Scenario*	IRR (%)	PDV (millions-$1981)	Levelized Breakeven Price (mills/kw-hr)
Basecase	11.9	$125.4	40.1
Insurance Premiums:			
A-1	2.3	32.7	53.7
A-2	3.5	43.1	52.4
A-3	8.6	109.9	43.3
A-4	9.5	112.3	42.0
Expected Losses:			
B-1	5.0	62.8	49.7
B-2	5.7	67.0	48.9
B-3	9.7	113.7	42.3
B-4	10.1	115.0	39.7

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* Alternative scenarios defined in text.

Exhibit VI-5
Page 3 of 5

FINANCIAL IMPACT ANALYSIS FOR TYPE E

Scenario*	IRR (%)	PDV (millions-$1981)	Levelized Breakeven Price (mills/kw-hr)
Basecase	11.1	$61.4	40.6
Insurance Premiums:			
A-1	4.7	31.1	49.8
A-2	5.4	33.9	49.0
A-3	9.1	57.8	42.2
A-4	9.7	58.5	41.4
Expected Losses:			
B-1	6.3	39.8	47.2
B-2	6.6	40.4	46.7
B-3	9.5	58.3	41.7
B-4	9.8	58.7	41.2

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* Alternative scenarios defined in text.

Exhibit VI-5
Page 4 of 5

FINANCIAL IMPACT ANALYSIS FOR TYPE F

Scenario*	IRR (%)	PDV (millions-$1981)	Levelized Breakeven Price (mills/kw-hr)
Basecase	14.2	$193.7	75.4
Insurance Premiums:			
A-1	-0.7	-11.3	97.8
A-2	0.2	3.7	96.1
A-3	9.7	162.3	79.7
A-4	11.3	167.9	78.0
Expected Losses:			
B-1	4.2	66.7	90.2
B-2	4.8	70.6	89.0
B-3	10.5	169.2	78.1
B-4	12.0	175.8	77.2

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* Alternative scenarios defined in text.

Exhibit VI-5
Page 5 of 5

FINANCIAL IMPACT ANALYSIS FOR TYPE G

Scenario*	IRR (%)	PDV (millions-$1981)	Levelized Breakeven Price (mills/kw-hr)
Basecase	15.5	$98.7	35.0
Insurance Premiums:			
A-1	3.3	32.1	44.4
A-2	4.8	40.1	43.5
A-3	10.2	84.2	37.4
A-4	12.0	86.6	36.5
Expected Losses:			
B-1	6.0	52.0	41.9
B-2	7.0	56.0	41.2
B-3	11.1	87.0	36.8
B-4	12.9	89.8	36.1

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* Alternative scenarios defined in text.

Estimated Cost to Government

The cost to government of a federally sponsored insurance program is based on the potential liability and administrative costs. The geothermal reservoir insurance alternatives call for varying levels of government provided insurance or reinsurance and, consequently, they will have different cost implications for government.

The cost to government will depend on numerous factors that are difficult to determine prior to the exact specification of a detailed program. For the purposes of comparing the cost implications of each of the program alternatives, this section provides analysis and discussion in terms of the relative estimated cost implications of each alternative. In Section VII of the report, where a specific program recommendation is discussed, the cost implications of that program are quantitatively estimated.

The cost of any government program clearly is an important consideration. Public programs depend on the congressional appropriations process and, as a result, a large part of the debate over any new program will focus on its cost. Cost considerations are also important for comparison with projected benefits to determine overall program economics.

To fully assess the possible cost consequences to government of the geothermal reservoir insurance alternatives, several cost dimensions must be considered. These are:

- Expected loss
- Expected revenue
- Probable maximum government loss cost
- Variability of actual losses relative to revenues
- Administrative costs

The expected loss and the expected revenue provide an estimate of the most likely amount of federal liability associated with an alternative. The expected loss is the expected level of insurance payments to policyholders. It serves as the benchmark for the planning of funding and premium requirements. The expected revenue is the total premium income estimated to be generated by the program. Unless a program is anticipated to be heavily subsidized, the expected revenue should at least cover the expected losses and administrative costs.

Two other important liability considerations are (a) the variability of actual losses relative to revenues, and (b) the probable maximum government loss cost. The possibility of actual losses exceeding revenues gives some idea of the variability of the actual losses versus estimated losses. The probable maximum government loss cost is an estimate of the largest amount the government would have to pay out to cover claims under very extreme (and unlikely) circumstances.

Finally, in addition to liability, each alternative should be considered in terms of administrative costs. Administrative costs provide insight into the overall efficiency and simplicity of a program's operation.

The geothermal reservoir insurance program alternatives are discussed below in terms of each of these cost dimensions. The discussion is limited to Alternatives 2 through 5 because Alternative 1 proposes no government involvement in geothermal reservoir insurance and consequently would result in no cost to the government.

Expected loss

The expected loss is the best estimate of the value of insurance claims that will need to be paid by the provider of insurance. It is a function of (a) the probability of loss, and (b) the projected average cost, or severity, of a loss limited by the conditions of the insurance policy.

Alternatives 2, 3 and 5 can be ranked relative to one another in terms of the government's expected loss because these programs involve a common defined set of "insurable" risks for geothermal projects. The program envisioned in Alternative 4 would provide coverage for certain risks that fall outside this definition of "insurable" risks and, therefore, it will be discussed separately.

Under Alternatives 2, 3 and 5, the government would provide some proportion of the total insurance/reinsurance coverage for the same set of risks. These alternatives thus constitute a comparable risk situation and the level of the government's expected loss will depend on the proportion of insurance/reinsurance coverage provided by the government. Alternative 5 has the highest government expected loss because it envisions the government providing all coverage for the "insurable" risks of the geothermal reservoir. Alternative 3 has a lower government expected loss because the government would provide only reinsurance, thus resulting in a sharing of the total insurance burden with the private sector. The expected government loss under Alternative 2 is lower still because the government share of reinsurance provided is smaller than that provided under Alternative 3.

It was noted that Alternative 4 is designed to cover certain risks that fall outside the definition of "insurable" risks for geothermal projects. As a result, this alternative cannot be compared relative to the other alternatives in terms of the government expected loss. The expected loss could be either very high or very low depending on the nature of the risks covered under this program relative to the risks insured under the other three alternative programs.

Expected revenue

The expected revenue, as previously mentioned, is the total premium income expected to be generated by an insurance program. It is derived by summing the premiums expected to be charged to individual policy holders. As discussed above, when the expected revenue covers the expected loss, plus administrative expenses and a risk loading, the premium is considered to be adequate.

Alternatives 2, 4 and 5 call for an adequate premium to be assessed. Thus, the revenues of any of these alternative programs are expected to cover program costs and are not expected to require government subsidization. Alternative 3, however, assumes that premiums (expected revenues) are set exclusive of administrative expenses and risk loadings. Therefore, the revenues of Alternative 3 may not necessarily cover total program costs.

Probable maximum government loss cost

The probable maximum loss is an estimate of the maximum foreseeable amount of insurable loss, regardless of whether the full amount is insured. This would be the expenditure required under extreme and unlikely circumstances and the probability of having to cover losses of this magnitude is remote. However, it should be noted that no matter how the probable maximum loss is calculated, it is not an absolute maximum.

The probable maximum government loss cost is a function of the probability distributions relating to the frequency and size of losses and the amounts of insurance coverage provided against loss. As the alternatives have been defined, the ranking of them in terms of the government's share of the probable maximum loss, is the same as the ranking in terms of expected loss. Alternatives 2, 3, and 5 can be ranked relative to one another because they provide different amounts of insurance coverage against the same set of risks. Alternative 5 would have the highest probable maximum goverment cost because it envisions the government providing all coverage for the "insurable" risks of the geothermal reservoir. Alternative 2 calls for the government to provide the smallest proportion of the total level of insurance and consequently, it has the lowest probable maximum government cost. Alternative 3 calls for the government to provide a level of coverage between the levels of coverage provided by Alternatives 2 and 5 and, therefore, its probable maximum cost to government falls between Alternatives 2 and 5. Alternative 4 cannot be ranked relative to the others because it provides coverage for a different set of risks. The probable maximum government cost of this program would be very high by the very definition of the nature of the risks covered.

Variability of actual losses relative to revenues

For any insurance program, there is the possibility that actual losses will exceed the amount assumed in the premium calculation. The risk loading in the insurance premium reduces but does not eliminate the possibility that actual losses will exceed revenues.

There are two principal causes of actual losses exceeding the provision for losses contained in revenue:

- The actual value of loss for the risks insured is greater than the provision for losses based on the estimated expected value of losses for the risks insured. This may be due to adverse selection or to inadequacy in the original rate determination, such as an unforeseen increase in the frequency or average amount of losses.
- While the actual value of losses for the risks insured is not greater than the provision for expected losses, the randomness of loss occurance causes higher than expected numbers of claims or size of claims or both.

These two concepts relate respectively to (a) the mean or expected value, and (b) the variance of the statistical distribution of losses under a given insurance program.

Over a sufficient period of time the actual losses under a program will tend to approximate the true expected loss for the distribution. However, the actual occurance of losses during a short period of time may vary considerably. This variation is described by comparing the variance of the distribution to its mean. For example, an excess catastrophe cover will almost always incur no loss; in the rare year when loss occurs, it will be enormous compared to premiums for that year.

It is possible to compare several loss distributions if the insurance provided under the alternatives is designed to provide coverage for the same set of risks. Alternatives 2, 3 and 5 meet this condition and can, therefore, be ranked relative to one another. Again, because Alternative 4 would cover a different set of risks its loss distribution cannot be compared to the others. The loss distribution will depend on the specific risks covered under Alternative 4.

Of Alternatives 2, 3 and 5, Alternative 2 has the largest variance relative to the overall mean and thus, has the highest possibility of actual losses exceeding expected losses. Alternative 5 has the smallest variance relative to the overall mean, and as a result, it has the lowest possibility of actual losses exceeding expected losses. Alternative 3 has a medium possibility of actual losses exceeding expected losses relative to Alternatives 2 and 5 because its variance relative to the overall mean is between that of Alternatives 2 and 5.

It is useful to balance the possibility of losses exceeding revenues against the probable maximum government cost. For example, in the case of Alternative 2, there is a relatively high possibility of actual losses exceeding expected losses, but the probable maximum government cost is relatively low. This implies that although there is a good chance of losses exceeding revenues, the magnitude of any excess would most likely be rather small compared to the total revenues of the insurance program. Conversely, Alternative 5 has the opposite condition with the highest probable maximum government cost among insurance alternatives but a comparatively low variability of actual losses relative to expected losses and therefore revenues.

The above discussion is based on the assumption of fixed premiums. It is possible, and preferable, to allow adjustments to be made to the premium. These adjustments would be based on the emergence of experience with the program. Therefore, while the possibility exists for any insurance program to run at a deficit, adjustments to premiums for new insureds, and to some extent mid-term policyholders, will help to minimize this possibility.

Administrative costs

Administrative costs are costs incurred in drawing up policies, processing claims and providing other services to the insured. These costs increase with increases in the number of policies written, the level of service provided, requirements for specialized client services such as site inspections, the number and complexity of claims to be processed, safety engineering services and claim-related legal costs.

Primary insurance programs are nearly always more expensive to administer than reinsurance programs. A primary insurer is responsible for analyzing individual projects, assessing risk and establishing premiums -- processess that tend to be especially time consuming and specialized for projects of the uncertain nature and magnitude of geothermal developments. Further, primary insurers deal with many policyholders and they must maintain an acceptable level of accessibility and responsiveness to client needs. Reinsurers generally accept the assessment of risk provided by the primary insurer, eliminating any need for the reinsurer to perform this function. Moreover, reinsurers tend to deal with fewer entities than primary insurers because they service insurance companies rather than individual policyholders.

Within each of the alternative geothermal reservoir insurance programs, the administrative functions are assumed to be performed by a third party under contract to the federal government, and therefore each involves a relatively low level of administrative burden to the government. Moreover, administrative costs, except in the case of Alternative 3, are assumed to be factored into the insurance premium.

Because Alternatives 4 and 5 call for the government to provide primary insurance and Alternatives 2 and 3 envision the government providing reinsurance, Alternatives 4 and 5 would each have higher administrative costs than either of Alternatives 2 and 3. Of Alternatives 4 and 5, the latter would most likely have higher administrative costs because it calls for the government to provide primary coverage for the full range of "insurable" risks. Under Alternative 4, the government would only serve as the primary insurer for a designated group of risks falling outside the definition of "insurable" risks. Of Alternatives 2 and 3, Alternative 3 would have higher administrative costs because the government would assume a larger proportion of the total coverage under this program than under Alternative 2.

Summary comparison

Exhibit VI-6 summarizes the relative comparison of the four insurance alternatives in terms of each dimension of estimated cost to government.

EXHIBIT VI-6

RELATIVE COMPARISON OF ALTERNATIVES
IN TERMS OF ESTIMATED COST TO GOVERNMENT*

	Government Liability				
	Expected Loss	Expected Revenue**	Probable Maximum Government Loss Cost	Variability of Losses Relative to Revenues	Administrative Costs
Alternative 2	low	full	low	high	low
Alternative 3	medium	partial	medium	medium	low-medium
Alternative 4	non-comparable	full	non-comparable	non-comparable	high-medium
Alternative 5	high	full	high	low	high

* Comparison does not include Alternative 1 which calls for no government involvement in geothermal reservoir insurance and consequently has no cost to government.

**The designation "full" indicates that revenues are anticipated to cover expected losses, administrative costs and a contingency for the possibility of losses exceeding revenues. The designation "partial" indicates that revenues are anticipated to cover only expected losses.

Phase-Out Considerations

It was assumed in the definition of alternatives that all the alternatives would have some provision for orderly phase-out. This is based on an indications, substantiated by research, that long-term dependency on the government should be avoided. A government sponsored geothermal reservoir insurance program should therefore be regarded as temporary, and its planning should be performed with the goal of eventual phase-out. The following discussion provides a comparison of the geothermal insurance alternatives in terms of phase-out considerations. The discussion will be confined to Alternatives 2 through 5 because Alternative 1 proposes no government involvement in geothermal reservoir insurance and, therefore, presents no phase-out considerations.

If a government insurance program is to be terminated, it should be done in a manner that would be least disruptive to the program's constituency. This depends on preparedness and willingness on the part of the private sector to assume responsibility for the program's functions. A major contributor to this is the structure of the government program and how it is designed to interact with the private sector. If a government insurance program is designed to operate independently of the private sector, it would be difficult for the private sector to develop the capability to take the place of the government. Conversely, if the government program is designed to complement or support private sector activity, the private sector would be better prepared to respond to a phase-out of the government presence.

Alternative 2 calls for the government to provide a low level of support in the form of excess catastrophe reinsurance. The private market would have responsibility for the underwriting functions and would provide most of the insurance coverage. It would be relatively easy to phase-out the government program under this alternative because the level of government support would be low and directed toward insurance companies. The government would be able to gradually reduce its proportion of the total insurance coverage provided with minimal disruption. This will be possible because increased experience with geothermal projects will most likely have either diminished the need for catastrophe reinsurance or created a willingness in the private sector to expand its role to include this type of coverage.

Alternative 3, like Alternative 2, calls for a government reinsurance program that would support the private sector. Phase-out of this program could thus be accomplished relatively easily by gradually scaling back the proportion of reinsurance coverage provided by the government (assuming a willingness by the private sector to assume the additional risks.) Because the proportion of insurance provided by the government under this alternative would be larger than under Alternative 2, the phase-out process might be prolonged. There is a potential for increases in premium charges with the termination of the government program because the government program calls for cost support through removal of the risk loading factor and administrative charges in the premium. The risk loading and administrative charges would be added back in under a private program and would affect the ultimate cost of insurance in the future.

Alternatives 4 and 5 call for the government to provide insurance at the primary level. The federal program envisioned under either of these alternatives would be an insurance program largely separate from the private sector. Phase-out of the government presence under either of these alternatives, therefore, can be potentially disruptive. Rather than expanding an existing service, the private market would be called on to develop a new service to replace the federal program.

Alternatives 4 would be less disruptive than Alternative 5 because under this alternative the private market would be providing some level of geothermal reservoir insurance for "insurable" risks. The phase-out of the geothermal program would present the private sector with a choice of whether or not to provide coverage for certain risks deemed "uninsurable". The choice made by the private sector and the importance that experience has placed on providing coverage for these risks will determine the level of disruption. In any case, individual policyholders will be forced to either do without a type of insurance coverage they previously had, or seek it elsewhere.

Alternative 5 would have the most disruptive phase-out of the government role because it involves no private participation in providing insurance for risks of the geothermal reservoir. Consequently, the private market would have to develop an entirely new service capability to fill the void left by termination of the federal program. The government program, while in existence, would have provided the private insurers no previous incentive to develop this capability. Phase-out of the government program would thus be likely to result in a difficult and disruptive transition period.

Interaction with Other Government Programs

The federal government can play a role in the development of a domestic energy industry through a variety of incentive programs. In implementing a new government program, it is important for government to keep its approach in balance with other existing programs. The incentives selected must fit the conditions inherent in the geothermal industry as well as the technical and economic risks of geothermal production.

This section discusses a number of existing government incentives that should be considered in analyzing a new program to stimulate geothermal energy production.

Loan guaranties

The Geothermal Loan Guaranty Program (GLGP) is the government program that is likely to have the most direct impact on the alternatives. It is designed to reduce certain risks of geothermal projects and serves as a valuable incentive for the development of geothermal energy. In the loan guaranty program, the federal government can enter into commitments to guaranty lenders against the loss of principal or interest payments on loans made to geothermal developers and users.

The primary feature of the GLGP is its ability to reduce the risk of financial loss on project failure. The loan guaranty enables developers and users to secure up to 90% of the project costs through a federally guarantied loan with the government guarantying up to 100% of the amount borrowed. In the event of default by the developer, the government must repay the balance remaining on the loan up to the maximum amount guarantied. The government would have access to only those assets of the defaulting firm that were directly involved in the project.

The program permits the borrower to use project financing techniques whereby loan repayment comes only from the project's income and is not dependent on other corporate income. This serves to reduce the risk of the project. As a consequence of the reduced risk, relatively low-interest debt would be available to an investment project. A possible drawback of this type of program, however, is the cost to government in the event of default when failure to meet principal and interest payment occurs.

Risk reduction can also be achieved by using insurance as a means of eliminating short term financial uncertainty. In this situation, the insurer accepts the financial risks of an inadequate energy supply, for example, in return for a premium from the insured. Part of the uncertainty associated with geothermal development is the lack of knowledge about potential losses stemming from the productivity of a reservoir over a long period of time, which is the result of a lack of operating experience. Thus, the actual operating experience in the early stages of development will alter expectations about future failure rates. It is during the early years of a project, wherein experience with the geothermal development is not sufficient to sustain a more fully developed insurance market, that a loan guaranty program can provide a valuable and complementary service.

Price incentives

Government price supports or price guarantees are designed to assure the profitability of the end product. Its success depends on whether the price support is high enough to encourage investment, given the risk perceived by the investor. If the price offered assures significant profit over and above risk, investment is likely to occur.

Price support can be used in combination with risk reduction programs to promote production. If used in combination with a loan guaranty or insurance program, it may not be necessary for the price supports to assure sufficient profit to compensate for risk. That factor may be reduced by the loan guaranty or insurance protection. In this way the costs of a price support program could be reduced by shifting part of the cost to a possibly less costly arrangement. Thus, geothermal production can be encouraged by a combination of policy mechanisms. However, the combination of programs should allow sufficient profit to encourage taking the risks associated with geothermal development.

Tax incentives

Tax incentives are similar to price supports in that they enhance the profitability of the project and reduce risk, except they do so in a more indirect manner.

These incentives can take a variety of forms including accelerated depreciation, special expensing provisions and preferential taxation of the profits from specified investment and tax credits. The National Energy Act of 1978 provided incentives encouraging the development of geothermal resources, including investment tax credits, expensing of intangible drilling costs and a percentage depletion allowance. These incentives should facilitate the financial involvement of industry in the exploration for the confirmation of high-temperature geothermal reservoirs.

The benefits of tax incentives vary with the incentive, type of company, the period covered and project. Although there is no government outlay, there is still a cost to government in the form of unrealized reserve.

Regulatory actions

Claims that regulatory barriers exist to geothermal development are frequently made. Environmental regulations can interact with development in various ways. Many delays and expenses are involved in meeting the requirements of various government agencies. The agencies have been slow to review and approve applications, resulting in more time lost and a potential increase in costs to the project. Equipment and labor must be scheduled to conduct the work, making the streamlining of permitting requirements vital to development.

Public utility commissions also have indirect regulatory impacts because they are in a position to direct incentive programs and can thus facilitate the development of specific energy resources. The public utility commission can offer three incentives that cover risks of development.

First, through its authority to determine what investments constitute the base on which a utility earns an approved rate of return, the public utility commission can enable utilities to recover plant costs through the rate structure thereby minimizing concern over the reservoir's life. When coupled with some arrangement for steady power, this is similar to a form of reservoir insurance for the utility.

Second, through its authority to determine allowable expenditures for the purchase of fuel or electricity, the public utility commission can allow a utility to cover expenses of purchasing electricity from a geothermal power plant at a cost that could be higher than other sources. This measure can cover the utility in those situations when it was not the actual builder of the power plant but was the plant operator or the purchaser of the electricity from the plant. When combined with a loan guaranty to a company other than the utility constructing the plant, this measure can effectively bring the utilities within the scope of the existing GLGP without putting them in the position of having to default on a loan to activate the coverage of their risk.

Third, through its authority to determine allowable expenditures, the public utility commission can allow the utility to expense as research and development those building and operating expenses of geothermal power plants that are above what it have to pay for electricity from other sources. This measure combines aspects of one and two above by applying to either capital or operating costs, or both, depending on the situation and the determination of what costs are above the normal and should, therefore, be attributed to the research and development activities.

Regulatory incentives are of a more general nature in that they affect the geothermal industry whether or not there exists a geothermal reservoir insurance program.

Advantages and Disadvantages

This subsection discusses the advantages and disadvantages for each of the five geothermal insurance alternatives. Because of the overlapping features for some of the alternatives, several of the same advantages/disadvantages may apply to more than one alternative.

Alternative 1 - A private market insurance program for "insurable" geothermal reservoir risks in a competitive insurance environment.

Advantages

- Maximizes the role of the private sector.
- Places the burden of providing protection with private insurers who have the most expertise in managing risk.

- Encourages tailoring of protection to meet the specific needs of the insured.
- Encourages competition and innovation among insurers.
- Has no cost to the government.
- Motivates the geothermal industry to use the best technical and managerial skills to reduce ultimate costs.
- Has a positive impact on the private sector's development of geothermal insurance programs.

Disadvantages

- May not fully benefit any projects except those having the highest likelihood of success.
- May not make adequate coverage available at a reasonable rate.
- The program may not be adequately developed.

This alternative reflects the absence of government involvement and assumes the viability and availability of private insurance protection. Competition between insurers should lead to a greater variety of policies available as well as the adoption of provisions that make coverage more attractive. By reducing risks to the insured, it will create incentives for geothermal development.

Alternative 2 - A private market insurance program for "insurable" risks underwritten by insurers/reinsurers in an open competitive environment supplemented by the federal government providing excess catastrophe reinsurance.

Advantages

- Encourages the industry to provide adequate coverage by mitigating the risk of exposure to losses beyond the desired capacity of insurance companies to cover.

- Offers considerable flexibility by enabling the insurance industry to provide the amount of coverage needed by insurers and to retain as much of the business as possible.

- Has positive impact on the private insurance sector's development of geothermal insurance programs.

- Requires a low level of government involvement by providing the smallest proportion of the total level of insurance of those alternatives allowing for government insurance.

- Has the lowest probable maximum goverment loss cost.

Disadvantages

- Raises doubts about the private insurance industry involvement.

- Has the highest variability of actual losses relative to revenues.

This alternative identifies a supportive role for the federal government to assist private insurers/reinsurers in providing coverage during that time when historical data on reservoir performance, necessary to accurately assess loss potential, are unavailable. As the private sector becomes more confident in predicting reservoir performance, it may assume a greater share of the risk.

Alternative 3 - A private market insurance program for "insurable" risks underwritten by insurers/reinsurers with the federal government making available limited excess reinsurance at a cost to insurers that is less than what the private market will provide.

Advantages

- Places the primary burden of providing protection with private insurers who have the most expertise in managing risks.

- Permits each private insurer to select its level of participation, if any, in the government reinsurance program.
- Encourages competition and innovation among insurers.
- Provides cost support by removing risk loading and administrative costs from the federal reinsurance premium calculation, thereby reducing cost to the insurer and potentially to the insured and providing an incentive for early participation.
- Minimizes the federal government role and provides for an orderly phase-out as adequate performance data on geothermal risks are obtained.
- Encourages tailoring of protection to meet the specific needs of the insured.
- Has a positive impact on the private sector's development of geothermal insurance programs.
- Motivates the geothermal industry to utilize the best technology and management skills to reduce ultimate costs.

Disadvantages

- Has the highest potential for the government to experience losses due to the absence of a risk loading factor in the premium calculation.
- Calls for the government to cover administrative expenses thereby creating a government subsidy.
- Does not encourage private market participation in providing reinsurance in the short-term because few reinsurers will be able to compete with the government program's reduced rate premium.

This alternative encourages participation of private insurers in providing primary coverage by making low cost reinsurance available to them. The government's support of the program will be gradually reduced during the period of participation. With the administration of the program being contracted to a third party having reinsurance expertise, the need for the government to staff and administer the program is eliminated.

Alternative 4 - A private market insurance program for "insurable" risks underwritten by private insurers/reinsurers with the federal government providing primary insurance protection for risks not insured by the private sector.

Advantages

- Permits private insurers/reinsurers to participate in meeting the insurance needs of those involved in geothermal development.
- Encourages private insurers/reinsurers to actively provide protection for insurable geothermal reservoir risks.

Disadvantages

- Requires administration and management of a new government program.
- Raises concerns about whether two primary insurance markets would provide adequate coverage.
- Provides the potential for an increasing role for government.
- Requires the establishment of detailed specifications for a government primary insurance program.
- Provides coverage for a set of risks, potentially unknown and different from the risks covered under the other alternatives.

- Encourages placement of bad risks with the government (adverse selection).

This program assumes that the private insurance market is unwilling to insure certain risks on a direct basis. The risks are considered too sensitive or too large to be handled by the private sector. Government involvement would be required where the project would otherwise not be able to obtain private sector insurance. Of concern would be government's absorbing those bad risks private insurance was unwilling to cover.

Alternative 5 - A primary insurance program covering "insurable" risks of the geothermal reservoir sponsored by the federal government.

Advantages

- Satisfies a need of the geothermal industry if the private insurance industry cannot or does not offer such insurance.
- Provides a centralized vehicle for data generation and dissemination of information about geothermal development risks.
- Has a low variability of losses relative to revenue.

Disadvantages

- Competes with the private insurance industry for providing coverage and does not encourage private sector participation.
- Minimizes the role of the private sector.
- Has the highest expected loss and probable maximum government loss cost.
- Has high administrative costs because it calls for the government to provide primary coverage for the full range of insurable risks.
- Requires developing a new government program to administer and manage.

This program would compete with the private insurance sector rather than complement or support it. By extending beyond a supportive or complementary role, the government's role and involvement would have a negative impact on the development of a viable private market insurance program.

VII. RECOMMENDATION

RECOMMENDATION

DETAILED TABLE OF CONTENTS

RECOMMENDATION

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RECOMMENDATION

The recommended geothermal reservoir insurance alternative was determined on the basis of its responsiveness to the perceived need for geothermal reservoir insurance and its effectiveness in stimulating development of geothermal resources. This section describes the need for and feasibility of a geothermal reservoir insurance program and provides a discussion of the characteristics and implications of the recommended program.

NEED FOR AND FEASIBILITY OF A GEOTHERMAL RESERVOIR INSURANCE PROGRAM

The study began with the fundamental assumption that it is advantageous to develop geothermal resources in the United States. As evidenced by Section V, there clearly are risks inherent in geothermal resource development. The study has detailed and analyzed these risks and found them to be significant. Reducing the financial uncertainty that stems from these risks can provide a strong incentive for the development of geothermal resources.

Although current means exist to reduce certain aspects of the financial uncertainty of loss to geothermal developers and users (e.g. Geothermal Loan Guaranty Program, tax incentives, etc.), there is room for complementing these programs. This study has shown that insurance would provide a means of protecting against the financial uncertainties of geothermal development. The study has also shown that insurance would most likely be a cost effective means of dealing with geothermal project financial uncertainties. Even with a likelihood of high initial premiums and the possibility of no cost-support, analysis has indicated that the burden of an insurance premium need not be prohibitive to project economics.

Interviews with members of the geothermal constituency showed that although there is some difference of opinion on the appropriateness of a federally supported reservoir insurance program, there is a widespread belief that such a program, if properly structured, would enhance the development of geothermal resources. Those interviewed also believed that geothermal insurance would be most efficiently provided by the private insurance industry.

The need for insurance in geothermal development and the terms of coverage required will vary depending on the particular project and the specific insured. The factors which will influence need and affect the coverages actually made available include:

- The nature of the development project and the specific risks associated with it.
- The financial capacity of the developer and his ability to absorb the financial impact of loss uncertainty from his own resources.
- The available financial capacity of the insurance sector and its willingness to commit a portion of that capacity to insuring geothermal development.

This study indicates that certain risks associated with each of the major project types are insurable. At present, the geothermal developer is bearing the financial uncertainty of loss due to those risks completely from his own resources, subject to overall project support from the government under the GLGP program and other incentives.

The willingness of the private insurance sector to commit a portion of their financial capacity to insuring geothermal development on a basis that is not prohibitive to project economics has been limited. This lack of broad participation has been due to unfamiliarity with the nature of the risks of geothermal projects and the limited number of projects that have been presented to the private insurance sector for consideration.

This study has served as a first step in identifying and classifying the risks associated with geothermal projects and has prompted discussion of the insurability of those risks by developers, users, lenders, and potential insurers. Information and intelligence have been gathered on probabilities of loss occurrence and estimates have been made of potential overall costs of loss. This information of itself will encourage further discussion and analysis within the private insurance sector. In addition, the number of projects of each type is projected to increase substantially over the next several years which will focus the attention of the private insurance sector on geothermal projects as a market for coverage.

Under these circumstances, it was determined that there is a viable role for the government to help accelerate the emergence of geothermal insurance supplied through the private sector. Given that:

- it is desirable to provide incentives for the development of geothermal energy as an alternative energy source,
- there are significant risks associated with geothermal development,
- insurance provides incentives for geothermal development by reducing the financial uncertainty of geothermal risks to the insured,
- the geothermal constituency believes that a properly structured insurance program would speed the development of geothermal resources, and
- the private insurance sector currently lacks broad participation in insuring geothermal development, this implies

there is a need for a temporary government role in a geothermal reservoir insurance program until such time as private insurers are actively providing adequate coverage on a broad basis. In addition, because (a) the significant risks associated with geothermal development can be insured, and (b) there is a historical precedence for the government playing a role in insuring highly technical or emerging industries, it is feasible for the government to have a role in a geothermal reservoir insurance program.

Based on the above summarization of, and the detailed findings reported in, Sections III, IV, V and VI of this report, it has been concluded that there is both the need for and the feasibility of a federally supported, and properly structured, geothermal reservoir insurance program.

RECOMMENDED ALTERNATIVE

Recommendation

Because of the previously established need for and feasibility of a federally supported geothermal reservoir insurance program and based on (a) the analysis of the perceptions of the major geothermal market sectors in Section III, (b) the analysis of the perceptions of the private insurance sector and existing geothermal reservoir insurance programs in Section IV, (c) a thorough analysis of geothermal risks in Section V, and (d) a detailed analysis of alternative government roles in Section VI, the recommended program is:

> A private market insurance program for insurable risks underwritten by private insurers should be encouraged. The federal government should support this effort by making available limited excess reinsurance at a specified level decreasing over time. Additionally, through cost support, the price to insurers should be substantially less than what the private reinsurance market might provide.

The recommendation, which is an elaboration of Alternative 3 discussed in Section VI, includes several provisions which were determined by the study to support the rationale behind the selection of this recommendation. These provisions include:

- The federal government will encourage broader participation by private insurers through facilitating communication between the geothermal industry and the private insurance sector.

- The specific details of the reinsurance program will be developed by the federal government in cooperation with the private insurance sector. This includes determination of the appropriate attachment point for federal involvement.
- The federal government reinsurance program will be structured to phase out in a specific period of time wherein adequate performance data can be obtained such that the insurance industry is able to make a determination of its commitment to underwrite the full program.
- The federal government's support of the program will be gradually reduced during the participation period.
- The administration of the government reinsurance program will be contracted to a third party having reinsurance expertise, thereby eliminating the need for the federal government to staff and administer the program.

In particular, this alternative was selected because it demonstrated the most desirable characteristics. This program is preferable because it:

- Addresses the primary constraints inhibiting the private insurance sectors' broad participation in geothermal projects, including the concern about the potential for unusually large loss.
- Places the primary burden of providing protection with private insurers who have the most expertise in managing risk.
- Permits each private insurer to select its level of participation, if any, in the geothermal reinsurance program.
- Encourages open competition and innovation between insurers.

- Provides cost support by removing risk loading and administrative costs from the federal reinsurance premium calculation, thereby reducing costs to the insurer and potentially to the insured and providing an incentive for early participation.

- Minimizes the federal government role and provides for an orderly phase-out as adequate performance data on geothermal risks are obtained.

- Encourages tailoring of protection to meet the specific needs of the insured.

- Has a positive impact on the private sector's development of geothermal insurance programs.

- Motivates the geothermal industry to utilize the best technology and management skills to reduce ultimate costs.

It is important to recognize that, as is the case with any alternative involving the federal government as an insurer or reinsurer, there is the potential for adverse selection within the recommended reinsurance program. The primary insurer may tend to purchase the excess reinsurance from the government for those insureds that the insurer believes are more likely to have a poor loss experience. Further, insurers may tend to retain more exposure on the preferred insureds because they present the greater profit potential. The results of this adverse selection could be that a federal reinsurance program collects premiums computed to be adequate for average exposures, but insures only risks that have worse than average loss potential.

The technique most often used to deal with adverse selection is a flexible rating program with premiums adjusted to reflect the loss propensity of the individual insured. If such an approach can be developed in a geothermal reservoir insurance program, the effect of adverse selection will be minimized.

Cost to Government

The cost to government for any reinsurance program will depend on numerous factors that are difficult to determine prior to the exact specification of a detailed program. For example, the ultimate cost to government depends on such factors as (1) the number of insured geothermal projects, (2) the scope of the government's coverage, (3) the amount of reinsurance ceded to the government by insurers, (4) the actual loss experience of the developers and users, and (5) the duration of the program. Absent this type of detailed information for the recommended program, the estimated cost to government necessarily relies on many assumptions, some of which have significant impacts on the final estimate. Therefore, the estimates presented in this subsection should only be considered as approximations.

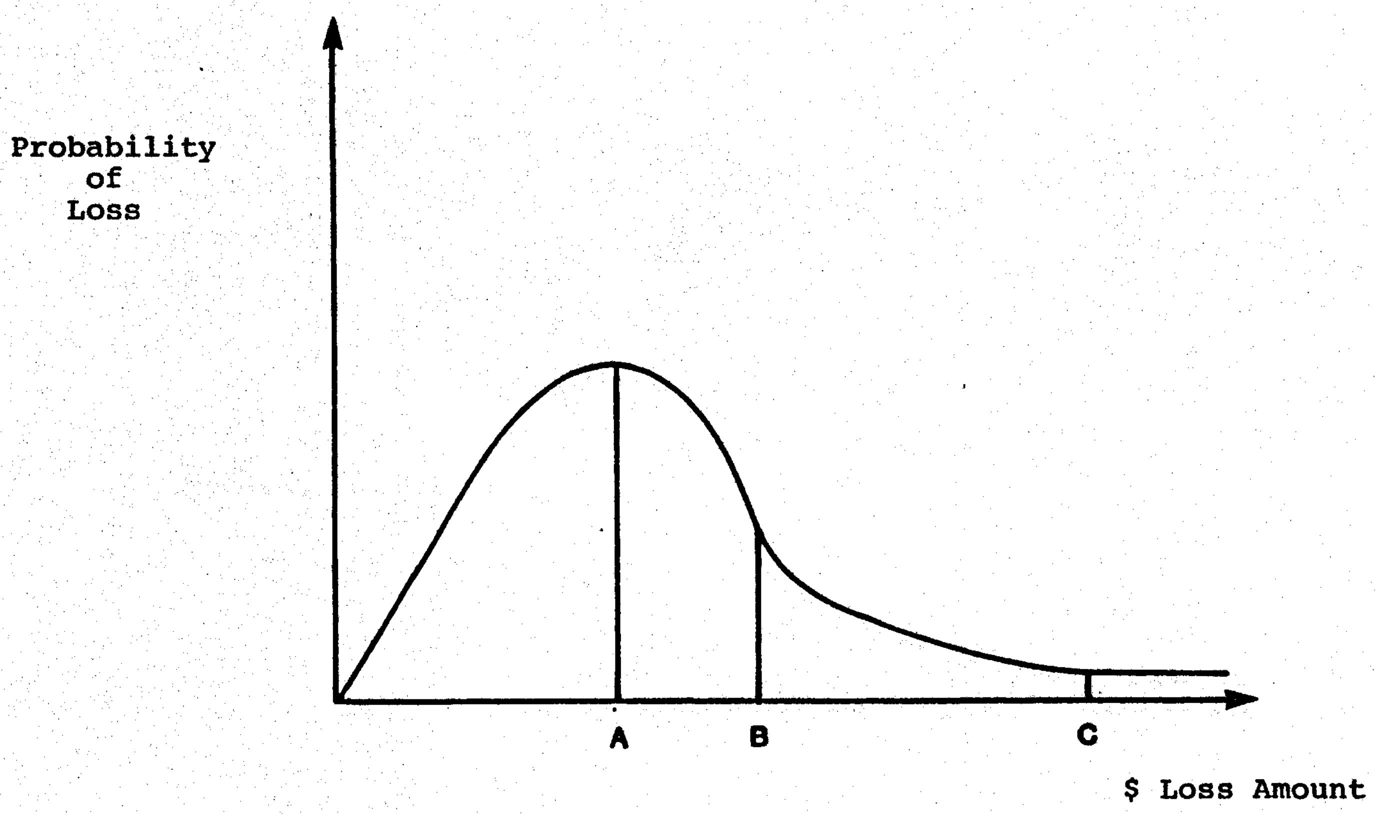
As discussed in Section VI, there are several dimensions of cost for any government reinsurance program. It is important to consider (a) the probable maximum government loss cost, (b) the expected loss from claims, (c) the expected premium income to balance these losses, and (d) the overall administrative costs of the program. However, before describing the assumptions made to estimate these costs for the recommended program, it is instructive to first consider Exhibit VII-1 which helps to define these costs.

Exhibit VII-1 depicts a hypothetical example of a loss distribution for a particular geothermal project over some specified period of time. It is an aggregate distribution in the sense that the potential losses from all insurable risks are considered. The total expected loss for all risks for this hypothetical project is represented by point A on the horizontal axis. This is that point which is the best single approximation, in a statistical sense, of the losses this project can expect under normal circumstances with good management and an active safety engineering program.

The probable maximum loss is represented by point C. This is an extreme loss, which is an estimate of the most this project would be expected to lose in the event of a major event affecting the project. Conceivably, losses could exceed this point, but the

EXHIBIT VII-1

EXAMPLE LOSS DISTRIBUTION
FOR A PARTICULAR PROJECT



A: Total Expected Loss

B: Attachment Point

C: Probable Maximum Loss

probability of this happening is so remote that it is appropriate to assume that C represents a maximum loss.

Point B on the horizontal axis represents a proposed attachment point for government reinsurance. This is the amount of potential loss above which the government will make available reinsurance in the example.

For the hypothetical example discussed above, the probable maximum government loss cost, if it provides the maximum amount of reinsurance for this project, is the difference between point C and point B (C minus B). The government will not have to pay any claims until losses exceed B, and therefore will never have to pay more than [C minus B] in claims. The government's claims payout would in all likelihood range from 0 to [C minus B], with different probabilities for each amount in between. This then defines the loss distribution that the government, or any reinsurer for this project, providing excess coverage, would face. If the details of this distribution were known the expected value could be calculated, which would represent the best single approximation of how much the government could expect to pay out in claims. If the program is designed with the private insurance sector such that the government's attachment point is moved closer to point C, then the anticipated level of cost to the government would decrease.

Assumptions and approximations

To estimate the cost to government for the recommended program several significant assumptions and approximations were made. The most important assumption is that the government excess reinsurance program will cover all insurable risks presented in Section V and will provide reinsurance on a per project basis. In this sense, it is necessary to consider the loss distribution for each project (or a typical project) to estimate potential claims. However, if the structure of the primary insurance developed by the private insurance sector takes the form of an association or pool of insurers who develop a joint program and thereby seek reinsurance for aggregated risks across all projects, then the loss distribution could be significantly different, implying much different costs.

Once given the major assumption that the program structure will be such that the government will provide the maximum level of excess reinsurance under the program for all insurable risks on a per project basis, then the following approximations and assumptions were made to estimate specific cost parameters:

- From the analysis of reservoir risks (Section V) an average per project expected loss and variance for each coverage category was determined for the six independent electric generation project types considered.
- The probable maximum loss per project for each coverage category was defined to be the average per project expected loss plus three standard deviations. This implies that there is much less than a .01 chance of such a loss ever occurring.
- The total probable maximum loss per project for all risks was derived as the sum of the probable maximum losses for each coverage category.
- The program was assumed to be established January 1, 1982 and entirely phased out December 31, 1991 with the phase-out period beginning January 1, 1990.
- The attachment point for government reinsurance was assumed to equal the average expected loss per project plus five percent of the probable maximum loss per project during the first year of the program. The attachment point increases by the same five percent margin of the probable maximum loss in each successive year through 1989.*

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*An alternative method of expressing the attachment point may be necessary if reinsurance is obtained on a treaty basis (terms negotiated for all policies to be reinsured in advance of those policies being issued) rather than obtained for each individual policy when written. While the attachment point can be determined for each individual policy on the basis of variance, the use of a reinsurance treaty requires that the amount of coverage (and, therefore, the attachment point) be known prior to issuing a single policy. Therefore, the attachment point is expressed as a ratio to the expected losses for all policies to be reinsured through the treaty. Because expected loss is generally assumed to be a percentage of premium, the attachment point for this type of treaty reinsurance would also be expressed as a percentage of the total premium reinsured under the treaty.

- Premiums charged by the government are equal to expected government losses with no provisions for loading administrative expenses and risk charges.

- The number of geothermal electric generation projects in existence in 1990 is estimated to approximate 100, which would generate approximately 5,000 megawatts of electrical capacity. This estimate includes the 16 projects (812 megawatts) that are currently operating and an annual addition of between 5 and 13 plants coming on line from 1982-1990.*

- Fifty percent of all geothermal electric generation projects were assumed to buy insurance leading to government reinsurance.

The estimated cost to government in 1981 dollars is based on the assumptions stated above. In reviewing the cost to government, it is important to recognize that the amount paid out for claims (losses) would be offset by funds received from premiums. The expected amount of losses paid by the government would aggregate approximately $400 million with annual expected losses ranging from $20 million to $55 million.** As stated, premiums charged by the government are then assumed to equal the expected government losses. The government's total probable maximum loss, which by definition is significantly unlikely to be attained, would aggregate approximately $1 billion during the period of the program. Because reinsurance premium income of $400 million would offset the total maximum loss, the net probable maximum loss exposure to the government would be $600 million. Administrative costs are estimated at ten percent of premium income during the period of the program.

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*Based on estimates provided in Geothermal Progress Monitor: Progress Report, September 1980, DOE/RA-0051/4, P.1-7. The assumed number of geothermal electric generation projects approximates the mid-point between the operating and planned plants and the Interagency Geothermal Coordinating Council goal for cumulative geothermal electric power on line in 1990.

**The expected losses increase annually by an average of $5 million from approximately $20 million in 1982 to $55 million in 1989 and then decrease to zero by 1992 as the program is phased out.

The aggregate expected amount of losses of approximately $400 million (exclusive of premium income) paid by the government during the duration of the program represents approximately $100 million to cover direct loss (repair and/or replacement) and approximately $300 million to cover indirect loss (lost potential revenue). The $100 million expected government loss to cover direct loss is less than one percent of the estimated initial capital investment for all geothermal electric generation projects assumed to be in existence in 1990, and less than two percent of the initial capital investment for those projects assumed to participate in the geothermal reservoir insurance program.* Because the program would cover direct loss for total capital investment and not just the initial capital investment, the $100 million expected government loss for direct loss actually represents much less than two percent of the total capital investment for projects in the program.

An additional cost that should be given consideration could possibly result from the structured program phase-out process. The government may have to accept a net loss when it phases out its reinsurance program. Ideally, the government would want to be reinsured through the private sector at a cost equal to the unearned premiums and future renewal premiums on policies reinsured by the government. However, a net loss could occur if private sector reinsurers perceive the government reinsurance premium as inadequate for the potential exposures and outstanding liabilities to be assumed. This may be due to adverse selection or it may occur due to unforeseen poor loss experience in the government program or inadequacy of the loss provision in the premium. Under any of these conditions, the government reinsurance portfolio might not be attractive to private sector reinsurers at the prior premium level, hence the reinsurers would likely request extra funds from the government as a condition of accepting the portfolio. The probability and amount of such a loss cannot be estimated because it requires information as to utilization and both historical and prospective loss estimates, which will be available only after the program is underway.

**The total initial capital investment for all projects in existence in 1990 is estimated to be approximately $12.8 billion. This is based on the number of geothermal electric generation projects assumed to exist in 1990 and an assumed average initial capital investment of $60-65 million for well field and surface facility development and $66 million for plant and transmission lines.

Interaction with Other Government Programs

There are a variety of government programs that provide incentives for geothermal development. It is assumed that the recommended program would work in concert with and complement such programs as the Geothermal Loan Guaranty Program and tax incentives discussed in Section VI.

The Geothermal Loan Guaranty Program (GLGP) is the most similar of these government programs to a reservoir insurance program in that GLGP also serves to mitigate risks in certain situations. The loan guaranty and reservoir insurance programs are different strategies that serve to encourage geothermal resource development.

Though a close relationship between the two programs exists, the Geothermal Loan Guaranty Program is not an equivalent substitute for the recommended insurance program and vice versa. The primary feature of the GLGP is its ability to reduce the risk of financial loss of project failure. Similarly, the recommended insurance program would reduce the financial uncertainty to the insured due to project failure, but also insures against potential financial losses that are significant enough to impede development but do not cause project failure. The existence of the GLGP would likely decrease the demand for insurance for a limited number of potential insureds. In most instances, however, the recommended program is assumed to complement the GLGP.

The following example illustrates a situation where reservoir insurance provides the essential coverage of risk and, therefore, provides a critically needed impetus to encourage geothermal development. In this example, a major landslide occurs severely damaging and forcing the abandonment of three production wells. This constitutes a direct loss of $5.4 million and an indeterminate indirect loss that might have a significant financial impact on the project but does not force either a temporary or permanent default on the developer's loan. (The developer is able, and continues, to make all principal and interest payments). While the GLGP would provide no relief in this situation, the reservoir insurance program would provide coverage for the loss of the physical property and possibly coverage for loss of revenue to both the developer and user due to the lower production during the period of redrilling and returning to capacity flow. In this case the loan guaranty would not assume this risk while reservoir insurance would provide the needed coverage.

Discussion of Recommended Program Elements

Certain general program elements which are appropriate for the recommended program are identified in this subsection. These elements would be necessary for structuring the program:

- Legislative authority
- Program management
- Project qualifications
- Nature of losses qualifying for coverage
- Scope of coverage
- Evaluation parameters
- Premium structure
- Method of paying claims

Development of the final program elements would be carried out in cooperation with the private insurance industry and would reflect the extent of the private sector's primary insurance programs. This may result in some modification of the program presented herein though an attempt has been made to keep these guidelines sufficiently flexible to support the private sector's efforts.

Legislative authority

Adequate authority should exist for the recommended program. The Energy Security Act of 1980, Title VI, Subtitle B, Section 622, Paragraph (k), specifically authorizes the Secretary of Energy to enter into reinsurance agreements with the private insurance sector for any risk associated with insurance for the development and utilization of a geothermal resource or associated reservoir. This section authorizes the establishment of a reservoir insurance program if the Secretary of Energy concurs with the findings and recommendation of this study and if Congress by law, after reviewing the Secretary's recommendation, specifically authorizes the establishment of the program. The Secretary shall have six months from the date of enactment of such legislation to establish and implement a geothermal reservoir insurance program. This period of time will be used to develop the specific program details in cooperation with the private insurance sector. It is important that the authority establishing and implementing this recommended program be exercised in such a manner as to encourage the efforts of the private insurance sector to fulfill the primary role in protecting against the geothermal resource.

Program management

The program recommended herein lends itself to being managed without significant resources provided by the federal government. A reinsurance program usually requires significantly fewer resources than would a primary insurance program. The current geothermal division of the Department of Energy might have sufficient resources to administer the recommended program within the structure proposed. This includes the supposition that the day-to-day administration of the government reinsurance program would be contracted to a third party who has demonstrated reinsurance expertise. Individuals with the necessary background and experience to administer a reinsurance program within the federal government are likely to be difficult to recruit and retain. Contracting the program administration to a third party eliminates the need for the government to staff the program. The added benefits of using a third party administrator is the ability to utilize this expertise during development of the program specifications and should allow for more rapid program start-up.

Project qualifications

For the insurance industry, eligibility to receive reinsurance protection as a participant in this program would be based on the insurance industry providing primary reservoir insurance to geothermal energy developers or users for a project in which the insured has at least a $1 million (1981 base) investment. This investment specifically excludes the exploration and testing phases of a geothermal project. However, the minimum investment level should remain somewhat flexible so as not to exclude sizeable direct-use commercial projects having a demonstrated need for insurance.

Nature of losses qualifying for coverage

The nature of losses qualifying for coverage under this reinsurance program should include both direct and indirect losses incurred by the insured party from specific risk events resulting from or affecting the geothermal resource or reservoir. Both total and partial losses should be included in the program. Included in the kinds of losses that should be within the structure of the program, though not necessarily in the same primary policy, are the loss of capital and the loss of present or future revenues, subject to the agreed primary policy limits. The cost differential of alternative energy resources to users of geothermal energy and the cost of conversion to that alternative may also be appropriate in some cases. The reinsurance afforded under this program will need to be specifically negotiated by the program administrator in light of the provisions of the primary policy. It is also possible that the program administrator will deal with provisions in the primary policies which may have significantly different coverage implications. It appears unlikely that a standard policy form would be developed and used by those primary insurers writing this coverage, though a standard approach could evolve over the life of this reinsurance program.

Scope of coverage

The scope of coverage available through private insurers and this program should be sufficient to allow geothermal energy developers and users to protect their full amount of the financial interest in the project. The coverage available would be subject to any self-insured retention provisions desired by the insured party or deductible provisions required by the primary insurer. Both of these mechanisms serve to eliminate smaller claims from the scope of coverage, allowing the insured to assume claims below the specified level in return for lower premiums for the coverage on losses where there is short-term financial hardship to the insured. These mechanisms also cause the insured party to share in the risk of financial loss and provide an incentive to the insured to properly manage the project based on sound managerial and technical principles.

In the recommendation no limit has been assumed in the coverage that can be provided to the insured under this program, except for the limit of the insured's insurable interest and/or the coverage limits provided by the primary insurer. Section 622(e) limits coverage to the lesser of 90 percent of, or $50,000,000 of, the loss of investment subject to the risk. Because this is a reinsurance program, the percent limit may not be applicable and the dollar limit may not be appropriate for the level of reinsurance recommended. These limits appear to be artificial barriers which may restrict rather than encourage participation in geothermal reservoir insurance.

Evaluation parameters

Evaluation of specific projects for the acceptability of the project for coverage under this recommended program will depend heavily on the data obtained by the primary insurers. It will also be consistent with generally accepted industry underwriting practices. All data used by the primary insurer and other reinsurers to evaluate the risks of a particular project should be made available to the program administrator such that an informed decision can be made on the particular level of reinsurance provided by the federal government. Among the project information that should be obtained are:

- Project financial projections and estimated time spans.
- Copies of pertinent contracts.
- Technical reports evaluating the reservoir, wells and other facilities including test results of the field.

Premium structure

The premium received by the federal government for this reinsurance will be proportional to the level of participation by the federal government. This means the premiums will reflect the potential exposure of the federal government, including probabilities of loss, as compared to the total amount at risk and the probabilities of expected losses. The specific amounts of premiums cannot be determined until the exact specifications of the reinsurance program are developed. However, using the most reliable data available, the federal government and their third party administrator should use sound actuarial principles and methods to determine the premium to be charged for this reinsurance.

Because it is desirable for the federal government to provide an incentive for the private insurance sector, the method selected is a form of cost support arrived at by removing administrative and risk loading from the premium calculation. This should encourage the private insurance sector to participate in providing basic coverage.

Method of paying claims

As with other forms of insurance/reinsurance, the recommendation presumes that the existence of this federal excess reinsurance program will be transparent to the policyholder. All claims under the policy issued by the primary insurer will be handled by that primary insurer in line with the terms and conditions of the policy. The primary insurer should identify, on a regular basis, all new claims received, for reported and incurred reserves, but not reported losses and claims closed which are subject to the government's resinurance participation, during the reporting period. This statement should also include the amount due from the reinsurer. The reinsurer, in this case the federal government or program administrator, should regularly review open claim files which are subject to reinsurance.

VIII. APPENDIX

APPENDIX

DETAILED TABLE OF CONTENTS

APPENDIX

TABLE OF EXHIBITS

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LEGISLATION

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PUBLIC LAW 96-294 [S. 932]; June 30, 1980

ENERGY SECURITY ACT

TITLE VI - GEOTHERMAL ENERGY

SUBTITLE B

RESERVOIR INSURANCE PROGRAM STUDY

Sec. 621. The Secretary shall conduct a detailed study of the need for and feasibility of establishing a reservoir insurance and reinsurance program incorporating the terms, conditions, and provisions set forth in Section 622, and shall submit to the Congress within one year after the date of the enactment of this Act a report on the results of such study including his findings and recommendations with respect thereto.

ESTABLISHMENT OF PROGRAM

Sec. 622. (a) If the report of the Secretary submitted pursuant to Section 621 affirmatively recommends the establishment of the program and the Congress by law (after review of such recommendation) specifically authorizes the establishment of the program, the Secretary shall establish and implement within six months after the date of the enactment of such authorization a program, in cooperation with the insurance and reinsurance industry, to provide reservoir insurance to qualified eligible applicants in accordance with this section.

(b) For the purpose of this section--

(1) the term "investment" means the expenditure of, and any irrevocable legal obligation to expend, funds (together with the reasonable interest costs thereof) for the purchase or construction of machinery, equipment, and facilities manufactured, or for services contracted to be furnished, for the development and utilization of a geothermal resource in the United States to provide energy in the form of heat for direct use or for generation of electricity.

(2) the term "geothermal resource" means a resource in the United States including (A) all products of geothermal processes embracing indigenous steam, hot water, and hot brines; (B) steam and other gases, hot water and hot brines resulting from water, gas or

other fluids artificially introduced into geothermal formations; (C) heat or other associated energy found in geothermal formations; and (D) any byproducts derived from them, where "byproduct" means any mineral or minerals (exclusive of oil, hydrocarbon gas, and helium) which are found in solution or in association with other geothermal resources and which have a value of less than 75 per centum of the value of the geothermal steam or are not, because of quantity, quality, or technical difficulties in extraction and production, of sufficient value to warrant extraction and production by themselves;

(3) the term "risk" means the hazard that a reservoir of geothermal resources will cease to provide sufficient quantities of geothermal resources at minimum conditions required to maintain an economically or technically viable operation for utilization of the geothermal resource;

(4) the term "reasonable premiums" means premium amounts determined by the Secretary to be reasonable in light of the amount of investment subject to the risk and premiums charged in similar or analogous situations by private insurers where private insurance is concerned and by insurers or guarantors, both public and private, where public insurance is concerned.

(5) the term "other insurance" means any combination of private or public insurance other than investment insurance provided by the Secretary under this section;

(6) the term "reservoir" means the physical subsurface geologic structure which forms the natural repository for the undisturbed geothermal resource; and

(7) the term "person" means any public or private agency, institution, association, partnership, corporation, political subdivision, or other legal entity which is a United States citizen as determined by application of the test for United States citizenship contained in section 2(a)-(c) of the Shipping Act, 1916 (46 U.S.C. 802), or in the first sentence of section 27A of the Merchant Marine Act, 1920 (46 U.S.C. 883-1(a)-(e)).

(c) Any person with a total direct investment of not less than $1,000,000 in the development and use, not including exploration and testing, of a geothermal resource associated with a reservoir, and unable to obtain other insurance at reasonable premiums for the amount of the investment subject to risk, as determined by the Secretary under this section, shall be eligible for investment insurance.

(d) Any eligible person seeking investment insurance under this section shall file an application with the Secretary setting forth (1) the total amount of the contemplated investment in a geothermal resource and associated reservoir; (2) the views of the applicant concerning the nature and extent of the risk, including a geologic, engineering, and financial assessment based on site specific results of exploration and testing of the geothermal resource and the reservoir, stated with as much specificity as is possible; (3) the status of all required Federal, State, and local approvals, permits, and leases for the proposed development and utilization operations at the site; (4) the extent to which the applicant has been able to obtain other insurance against the risk; and (5) such other information as the Secretary may require.

(e) Unless the Secretary determines the risk proposed by the applicant is unreasonable, the Secretary, within ninety days after receipt of a satisfactory application, shall determine in writing and submit to the applicant (1) the risk which may cause loss of investment for the applicant (2) the total investment subject to the risk; (3) the amount of the other insurance which is available at reasonable premiums for the purpose of indemnifying the applicant against the risk; (4) the amount of investment insurance available pursuant to this section, which shall be the difference between the total investment subject to the risk and the total other insurance determined to be available at reasonable premiums, but not in excess of the lesser of 90 per centum of, or $50,000,000 of, the loss of investment subject to the risk; and (5) any reasonable terms and conditions necessary for the prudent administration of the program, including reasonable premiums for the insurance pursuant to this section (which shall be deposited in the Geothermal Resources Development Fund).

(f) The Secretary, within ninety days after making and submitting the determinations under subsection (e), and upon agreement of the applicant to such determinations, shall issue a certificate of insurance containing such terms and conditions as the Secretary shall specify, which shall not be transferrable without the express approval of the Secretary for good cause shown, and shall execute a contract with the applicant setting forth the terms and conditions of the investment insurance and such other provisions as may be necessary to protect the interests of the United States, including provisions with respect to the ownership, use, and disposition of any currency, credits, assets, or investments on account of which payment under such insurance is to be made and any right, title, claim, or course of action existing in relation thereto.

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(g) Any holder of a certificate of insurance pursuant to subsection (f) who claims a loss of value of his investment by reason of the specified risk shall receive compensation, to the extent the Secretary determines that the holder is eligible to receive compensation pursuant to the certificate and the contract, in the amount of the loss incurred by the holder which is subject to insurance and for which the holder has not received and will not receive compensation from other insurance.

(h) Any compensation received by the holder shall be withdrawn from the Geothermal Resources Development Fund. The full faith and credit of the United States is hereby pledged to the payment of any compensation under this section.

(i) A person shall not be denied insurance pursuant to this section solely because such person is the recipient of other Federal assistance under this or any other Act.

(j) There may be appropriated to the Geothermal Resources Development Fund (established pursuant to Section 204 of the Geothermal Energy Research, Development and Demonstration Act of 1974 (30 U.S.C. 1144)), for purposes of this section, such amounts as are authorized for such purposes in the law referred to in subsection (a) or in other legislation hereafter enacted.

(k) The Secretary may enter into agreements to reinsure any private insurer for any risk associated with insurance for the development and utilization of a geothermal resource and associated reservoir, using the procedures set forth in subsections (c) through (i), to the extent that he deems it appropriate in order to provide an incentive for the participation of the private insurance industry in geothermal development; and he may also use any other available authority to obtain such participation. The Secretary shall submit a report to the Congress, within one year after the enactment of the law referred to in subsection (a), on the need for any additional authority to obtain such participation.

RESULTS OF RISK ANALYSIS FOR ALL TYPES

EXHIBIT VIII-2
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WELL RISKS
DRILLING AND COMPLETION PROBLEMS
TYPE A - STAGE 1
EVENT 1

Description: Drilling and/or completion problems in Stage 1 cause loss of one or more producer wells requiring an equivalent number of holes to be drilled. (Injector wells are not considered for Type A only, because no drilling of injector wells needed - unsuccessful producers should be available to act as injector wells.)

Cost Consequences:

Developer: Capital cost of replacement producer wells.

User: None.

Input Data:

Cost Per Well: $1.8 (millions - $1981)

	Loss Distribution
Probabilities	Well Replacement Cost (millions-$1981)
p(X=0) = .12	$ 0.0
p(X=1) = .27	1.8
p(X=2) = .29	3.6
p(X=3) = .19	5.4
p(X=4) = .09	7.2
p(X=5) = .03	9.0
p(X=6) = .01	10.8
Expected Loss:	3.6

X = number of producer wells requiring replacement

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WELL RISKS
DRILLING AND COMPLETION PROBLEMS
TYPE B - STAGE 1
EVENT 1

Description: Drilling and/or completion problems in Stage 1 cause loss of one or more producer wells requring an equivalent number of holes to be drilled.

Cost Consequences:

Developer: Capital cost of replacement producer wells.

User: None.

Input Data:

Cost Per Well: $1.5 (millions - $1981)

Probabilities	Loss Distribution Well Replacement Cost (millions-$1981)
$p(X=0) = .12$	$0.0
$p(X=1) = .27$	1.5
$p(X=2) = .29$	3.0
$p(X=3) = .19$	4.5
$p(X=4) = .09$	6.0
$p(X=5) = .03$	7.5
$p(X=6) = .01$	9.0
Expected Loss:	3.0

X = number of producer wells requiring replacement

EXHIBIT VIII-2
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WELL RISKS
DRILLING AND COMPLETION PROBLEMS
TYPE B - STAGE 1
EVENT 2

Description: Drilling and/or completion problems in Stage 1 cause loss of one or more injector wells requring an equivalent number of holes to be drilled.

Cost Consequences:

Developer: Capital cost of replacement injector wells.

User: None.

Input Data:

Cost Per Well: $1.4 (millions - $1981)

Probabilities	Loss Distribution Well Replacement Cost (millions-$1981)
p(X=0) = .35	$0.0
p(X=1) = .39	1.4
p(X=2) = .19	2.8
p(X=3) = .06	4.2
p(X=4) = .01	5.6
Expected Loss:	1.4

X = number of injector wells requiring replacement

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WELL RISKS
DRILLING AND COMPLETION PROBLEMS
TYPE C - STAGE 1
EVENT 1

Description: Drilling and/or completion problems in Stage 1 cause loss of one or more producer wells requring an equivalent number of holes to be drilled.

Cost Consequences:

Developer: Capital cost of replacement producer wells.

User: None.

Input Data:

Cost Per Well: $0.07 (millions - $1981)

Probabilities	Loss Distribution Well Replacement Cost (millions-$1981)
p(X=0) = .66	$0.00
p(X=1) = .29	0.07
p(X=2) = .05	0.14
Expected Loss:	0.03

X = number of producer wells requiring replacement

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WELL RISKS
DRILLING AND COMPLETION PROBLEMS
TYPE C - STAGE 1
EVENT 2

Description:	Drilling and/or completion problems in Stage 1 cause loss of one or more injector wells requring an equivalent number of holes to be drilled.

Cost Consequences:

Developer:	Capital cost of replacement injector wells.
User:	None.

Input Data:

Cost Per Well: $0.06 (millions - $1981)

Probabilities	Loss Distribution Well Replacement Cost (millions-$1981)
p(X=0) = .66	$0.00
p(X=1) = .29	0.06
p(X=2) = .05	0.12
Expected Loss:	0.02

X = number of injector wells requiring replacement

WELL RISKS
DRILLING AND COMPLETION PROBLEMS
TYPE D - STAGE 1
EVENT 1

Description: Drilling and/or completion problems in Stage 1 cause loss of one or more producer wells requiring an equivalent number of holes to be drilled.

Cost Consequences:

Developer: Capital cost of replacement producer wells.

User: None.

Input Data:

Cost Per Well: $1.8 (millions - $1981)

Probabilities	Loss Distribution Well Replacement Cost (millions-$1981)
p(X=0) = .31	$0.0
p(X=1) = .39	1.8
p(X=2) = .21	3.6
p(X=3) = .07	5.4
p(X=4) = .02	7.2
Expected Loss:	2.0

X = number of producer wells requiring replacement

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WELL RISKS
DRILLING AND COMPLETION PROBLEMS
TYPE D - STAGE 1
EVENT 2

Description:	Drilling and/or completion problems in Stage 1 cause loss of one or more injector wells requiring an equivalent number of holes to be drilled.

Cost Consequences:

Developer:	Capital cost of replacement injector wells.
User:	None.

Input Data:

Cost Per Well: $1.7 (millions - $1981)

Probabilities	Loss Distribution Well Replacement Cost (millions-$1981)
p(X=0) = .53	$0.0
p(X=1) = .36	1.7
p(X=2) = .09	3.4
p(X=3) = .02	5.1
Expected Loss:	1.0

X = number of injector wells requiring replacement

EXHIBIT VIII-2

WELL RISKS
DRILLING AND COMPLETION PROBLEMS
TYPE E - STAGE 1
EVENT 1

Description: Drilling and/or completion problems in Stage 1 cause loss of one or more producer wells requiring an equivalent number of holes to be drilled.

Cost Consequences:

Developer: Capital cost of replacement producer wells.

User: None.

Input Data:

Cost Per Well: $1.9 (millions - $1981)

Probabilities	Loss Distribution Well Replacement Cost (millions-$1981)
p(X=0) = .13	$0.0
p(X=1) = .31	1.9
p(X=2) = .30	3.8
p(X=3) = .17	5.7
p(X=4) = .07	7.6
p(X=5) = .02	9.5
Expected Loss:	3.4

X = number of producer wells requiring replacement

EXHIBIT VIII-2

WELL RISKS
DRILLING AND COMPLETION PROBLEMS
TYPE E - STAGE 1
EVENT 2

Description: Drilling and/or completion problems in Stage 1 cause loss of one or more injector wells requiring an equivalent number of holes to be drilled.

Cost Consequences:

Developer: Capital cost of replacement injector wells.

User: None.

Input Data:

Cost Per Well: $1.3 (millions - $1981)

Probabilities	Loss Distribution Well Replacement Cost (millions-$1981)
$p(X=0) = .77$	$0.0
$p(X=1) = .21$	1.3
$p(X=2) = .02$	2.6
Expected Loss:	3.3

X = number of injector wells requiring replacement

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WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE A - STAGE 3 (YEARS 1-25)
EVENT 1

Description: Mechanical damage causes loss of one or more producer wells in excess of original expectations during years 1-25. Well is replaced. Injector wells not considered because of the insignificant risk for this type.

Cost Consequences:

Developer: (a) Capital cost of replacement producer wells.

(b) Revenue loss while well is replaced. (Assumes that reserve wells are occupied while dealing with expected replacement).

User: Cost differential of replacement power.

Input Data:

Cost Per Well: $1.8 (millions - $1981)

Time Delay: 5 months

Revenue Loss Per Well Per Month: $.066 (millions - $1981)

Excess Cost of Replacement Power Per Well Per Month: $.066 (millions - $1981)

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WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE A - STAGE 3 (YEARS 1-25)
EVENT 1

	Loss Distribution		
Probabilities	Well Replacement Cost (millions-$1981)	Revenue Loss (millions-$1981)	Cost of Replacement Power (millions-$1981)
p(X=0) = .21	$ 0.00	$0.00	$0.00
p(X=1) = .33	1.80	0.33	0.33
p(X=2) = .25	3.60	0.66	0.66
p(X=3) = .12	5.40	0.99	0.99
p(X=4) = .05	7.20	1.32	1.32
p(X=5) = .03	9.00	1.65	1.65
p(X=6) = .01	10.80	1.98	1.98
Expected Loss:	2.88	0.53	0.53

X = number of producer wells requiring replacement

EXHIBIT VIII-3
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WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE A - STAGE 3 (YEARS 26-30)
EVENT 1

Description:	Mechanical damage causes loss of one or more producer wells in excess of original expectations during years 26-30. Lost well(s) is abandoned.

Cost Consequences:

Developer:	Loss of revenue per producer well over the remainder of project life.
User:	(a) Cost differential of replacement power. (b) Unamortized value of plant from loss of wells.

Input Data:

Developers Revenue Loss Per Well:
Range: $0 - 1.9 (millions - $1981)
Expected Value: $0.95 (millions - $1981)

Users Excess Cost of Replacement Power Per Well:
Range: $0 - 1.9 (millions - $1981)
Expected Value: $0.95 (millions - $1981)

Expected Unamortized Value of Plant Due to the Loss of One Well: $0.16 (millions - $1981)

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE A - STAGE 3 (YEARS 26-30)
EVENT 1

	Loss Distribution		
Probabilities	Revenue Loss (millions-$1981)	Cost of Replacement Power (millions-$1981)	Unamortized Value of Plant (millions-$1981)
p(X=0) = .03	$0.00	$0.00	$0.00
p(X=1) = .08	0.95	0.95	0.16
p(X=2) = .15	1.90	1.90	0.32
p(X=3) = .19	2.85	2.85	0.48
p(X=4) = .23	3.80	3.80	0.64
p(X=5) = .17	4.75	4.75	0.80
p(X=6) = .10	5.70	5.70	0.96
p(X=7) = .14	6.65	6.65	1.12
p(X=8) = .01	7.60	7.60	1.28
Expected Loss:	3.50	3.50	0.59

X = number of producer wells abandoned in excess of expectations

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE B - STAGE 1
EVENT 1

Description: Mechanical damage causes loss of one or more producer wells (before field is in production). Well is replaced.

Cost Consequences:

Developer: Capital cost of replacement producer wells.

User: None.

Input Data:

Cost Per Well: $1.5 (millions - $1981)

Probabilities	Loss Distribution Well Replacement Cost (millions-$1981)
p(X=0) = .36	$0.0
p(X=1) = .38	1.5
p(X=2) = .18	3.0
p(X=3) = .06	4.5
p(X=4) = .02	6.0
Expected Loss:	1.5

X = number of producer wells requiring replacement

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE B - STAGE 2
EVENT 1

Description:	Mechanical damage causes loss of one or more producer wells. Well is replaced.
Cost Consequences:	
Developer:	(a) Capital cost of replacement producer wells. (b) Revenue loss while each producer well (beyond reserve capacity) is replaced.
User:	None.

Input Data:

Delay Time: 5 months

Well Replacement Cost: $1.5 (millions - $1981)

Revenue Loss Per Well Per Month: $0.063 (millions - $1981)

Number of Reserve Wells: 2

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE B - STAGE 2
EVENT 1

Probabilities	Loss Distribution	
	Well Replacement Cost (millions-$1981)	Revenue Loss (millions-$1981)
p(X=0) = .12	$0.00	$0.00
p(X=1) = .27	1.50	0.00
p(X=2) = .29	3.00	0.00
p(X=3) = .19	4.50	0.32
p(x=4) = .09	6.00	0.63
p(X=5) = .03	7.50	0.95
p(X=6) = .01	9.00	1.27
p(X=7) = .00		
Expected Loss:	2.29	0.16

X = number of producer wells
requiring replacement

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE B - STAGE 2
EVENT 2

Description: Mechanical damage or well-face plugging causes loss of one or more injector wells. For each injector well (beyond reserve capacity) that is shut down, 2 producer wells must be taken off-line. Injector well is replaced.

Cost Consequences:

Developer: (a) Capital cost of replacement injector wells.

(b) Revenue loss while each injector well is replaced.

User: None.

Input Data:

Delay Time: 5 months

Revenue Loss Per Injector Well Per Month: $0.126 (millions - $1981)

Well Replacement Cost: $1.4 (millions - $1981)

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WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE B - STAGE 2
EVENT 2

	Loss Distribution	
Probabilities	Well Replacement Cost (millions-$1981)	Revenue Loss (millions-$1981)
p(X=0) = .50	$0.00	$0.00
p(X=1) = .25	1.40	0.00
p(X=2) = .15	2.80	0.63
p(X=3) = .05	4.20	1.26
p(X=4) = .03	5.60	1.89
p(X=5) = .02	7.00	2.52
Expected Loss:	1.29	0.26

X = number of injector wells requiring replacement

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE B - STAGE 3 (YEARS 1-25)
EVENT 1

Description:	Mechanical damage, scaling, corrosion or well-face plugging cause loss of one or more producer wells beyond original expectations. Well is replaced.

Cost Consequences:

Developer:	(a) Capital cost of replacement producer wells.
	(b) Revenue loss while well is replaced. (Assumes that reserve wells are occupied while dealing with expected replacement).
User:	None.

Input Data:

Delay Time: 5 months

Well Replacement Cost: $1.5 (millions - $1981)

Revenue Loss Per Producer Well Per Month: $.0556
(millions - $1981)

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE B - STAGE 3 (YEARS 1-25)
EVENT 1

Probabilities	Loss Distribution Well Replacement Cost (millions-$1981)	Revenue Loss (millions-$1981)
p(X=0) = .25	$ 0.00	$0.00
p(X=1) = .25	1.50	0.28
p(X=2) = .15	3.00	0.56
p(X=3) = .10	4.50	0.84
p(X=4) = .07	6.00	1.12
p(X=5) = .05	7.50	1.40
p(X=6) = .04	9.00	1.68
p(X=7) = .03	10.50	1.96
p(X=8) = .03	12.00	2.24
p(X=9) = .02	13.50	2.52
p(X=10)= .01	15.00	2.80
Expected Loss:	3.53	0.66

X = number of producer wells requiring replacement

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE B - STAGE 3 (YEARS 26-30)
EVENT 1

Description:	Mechanical damage, scaling, corrosion or well-face plugging cause loss of one or more producer wells in excess of original expectations during years 26-30. Lost well(s) is abandoned.

Cost Consequences:

Developer:	Loss of revenue per producer well over the remainder of project life.
User:	Unamortized value of plant from loss of wells.

Input Data:

Developer's Revenue Loss Per Well:

Range:	\$0.0 - \$2.0 (millions - \$1981)
Expected Value:	\$1.0 (millions - \$1981)

Expected Unamortized Value of Plant Due to Loss of One Well:
\$0.15 (millions - \$1981)

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE B - STAGE 3 (YEARS 26-30)
EVENT 1

Probabilities	Loss Distribution Revenue Loss (millions-$1981)	Unamortized Value of Plant (millions-$1981)
p(X=0) = .25	$0.00	$0.00
p(X=1) = .25	1.00	0.15
p(X=2) = .15	2.00	0.30
p(X=3) = .10	3.00	0.45
p(X=6) = .25	6.00	0.90
Expected Loss:	2.35	0.35

X = number of producer wells abandoned in excess of expectations

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE B - STAGE 3 (YEARS 1-30)
EVENT 2

Description: Mechanical damage, scaling, corrosion or well-face plugging cause the loss of one or more injector wells requiring replacement. For every such injector well that is replaced two producer wells must be taken off-line temporarily.

Cost Consequences:

Developer: (a) Capital cost of replacement injector wells.

(b) Revenue loss while each injector well is replaced and two producer wells are taken off-line.

User: None.

Input Data:

Delay Time: 5 months

Well Replacement Cost: $1.4 (millions - $1981)

Revenue Loss Per Injector Well Per Month: $0.111 (millions - $1981)

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE B - STAGE 3 (YEARS 1-30)
EVENT 2

Probabilities	Loss Distribution: Well Replacement Cost (millions-$1981)	Loss Distribution: Revenue Loss (millions-$1981)
p(X=0) = .50	$ 0.00	$0.00
p(X=1) = .25	1.40	0.56
p(X=2) = .06	2.80	1.12
p(X=3) = .05	4.20	1.68
p(X=4) = .04	3.60	2.24
p(X=5) = .03	7.00	2.80
p(X=6) = .02	8.40	3.36
p(X=7) = .02	9.80	3.92
p(X=8) = .01	11.20	4.48
p(X=9) = .01	12.60	5.04
p(X=10)= .01	14.00	5.60
Expected Loss:	1.90	0.76

X = number of injector wells
requiring replacement

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE D - STAGE 1
EVENT 1

Description: Mechanical damage, scaling or corrosion cause loss of one or more producer wells (before field is in production). Well is replaced.

Cost Consequences:

Developer: Capital cost of replacement producer wells.

User: None.

Input Data:

Cost Per Well: $1.8 (millions - $1981)

	Loss Distribution
Probabilities	Well Replacement Cost (millions-$1981)
p(X=0) = .25	$0.00
p(X=1) = .25	1.80
p(X=2) = .15	3.60
p(X=3) = .10	5.40
p(X=4) = .07	7.20
p(X=5) = .05	9.00
p(X=6) = .04	10.80
p(X=7) = .03	12.60
p(X=8) = .03	14.40
p(X=9) = .02	16.20
p(X=10)= .01	18.00
Expected Loss:	4.23

X = number of producer wells requiring replacement

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE D - STAGE 2
EVENT 1

Description:	Mechanical damage, scaling or corrosion cause loss of one or more producer wells. Well is replaced.
Cost Consequences:	
Developer:	(a) Capital cost of replacement producer wells.
	(b) Revenue loss while each producer well (beyond reserve capacity) is replaced.
User:	None.

Input Data:

Delay Time: 5 months.

Well Replacement Cost: $1.8 (millions - $1981)

Number of Wells: 10 producers/1 reserve

Revenue Loss Per Producer Well Per Month: $0.069 (millions - $1981)

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE D - STAGE 2
EVENT 1

	Loss Distribution	
Probabilities	Well Replacement Cost (millions-$1981)	Revenue Loss (millions-$1981)
p(x=0) = .25	$ 0.00	$0.00
p(x=1) = .25	1.80	0.00
p(x=2) = .15	3.60	0.35
p(x=3) = .10	5.40	0.69
p(x=4) = .07	7.20	1.05
p(x=5) = .05	9.00	1.38
p(x=6) = .04	10.90	1.75
p(x=7) = .03	12.60	2.07
p(x=8) = .03	14.40	2.45
p(x=9) = .02	16.20	2.76
p(x=10)= .01	18.00	3.15
Expected Loss:	4.23	0.56

X = number of producer wells requiring replacement

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WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE D - STAGE 2
EVENT 2

Description: Mechanical damage, scaling, corrosion or well-face plugging cause loss of one or more injector wells. For each injector well (beyond reserve capacity) that is shut down two producer wells must be taken off-line. Injector well is replaced.

Cost Consequences:

Developer: (a) Capital cost of replacement injector wells.

(b) Revenue loss while each injector well beyond reserve capacity is replaced.

User: None.

Input Data:

Delay Time: 5 months.

Well Replacement Cost: $1.7 (millions - $1981)

Revenue Loss Per Injector Well Per Month: $0.138 (millions - $1981)

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE D - STAGE 2
EVENT 2

	Loss Distribution	
Probabilities	Well Replacement Cost (millions-$1981)	Revenue Loss (millions-$1981)
p(X=0) = .25	$0.00	$0.00
p(X=1) = .50	1.70	0.00
p(X=2) = .10	3.40	0.69
p(X=3) = .07	5.10	1.38
p(X=4) = .05	6.80	2.07
p(X=5) = .03	8.50	2.76
Expected Loss:	2.18	0.35

X = number of injector wells requiring replacement

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE D - STAGE 3 (YEARS 1-25)
EVENT 1

Description: Mechanical damage, scaling, corrosion or well-face plugging cause loss of one or more producer wells beyond original expectations. Well is replaced.

Cost Consequences:

Developer:

(a) Capital cost of replacement producer wells.

(b) Revenue loss while well is replaced. Assumes that reserve wells are occupied while dealing with expected replacement.

User: None.

Input Data:

Delay Time: 5 months.

Well Replacement Cost: $1.8 (millions - $1981)

Revenue Loss Per Producer Well Per Month: $0.0602 (millions - $1981)

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE D - STAGE 3 (YEARS 1-25)
EVENT 1

	Loss Distribution	
Probabilities	Well Replacement Cost (millions-$1981)	Revenue Loss (millions-$1981)
p(X=0) = .25	$ 0.00	$0.00
p(X=1) = .25	1.80	0.30
p(X=2) = .15	3.60	0.60
p(X=3) = .10	5.40	0.90
p(X=7) = .25*	12.50	2.10
Expected Loss:	4.68	0.78

X = number of producer wells requiring replacement

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*For computational reasons, the tail of the distribution $p(4 \leq X \leq 16) = .25$ was truncated and approximated by X=7 wells.

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE D - STAGE 3 (YEARS 26-30)
EVENT 1

Description: Mechanical damage, scaling, corrosion or well-face plugging cause loss of one or more producer wells in excess of original expectations during years 26-30. Lost well(s) is abandoned.

Cost Consequences:

Developer: Loss of revenue per producer well over the remainder of project life.

User: Unamortized value of plant from loss of wells.

Input Data:

Developer's Revenue Loss Per Well:
Range: $0 - $2.1 (millions - $1981)
Expected Value: $1.05 (millions - $1981)

Expected Unamoritzed Value of Plant
Due to Loss of One Well: $0.16 (millions - $1981)

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE D - STAGE 3 (YEARS 26-30)
EVENT 1

Probabilities	Loss Distribution Revenue Loss (millions-$1981)	Unamortized Value of Plant (millions-$1981)
p(X=0) = .25	$ 0.00	$0.00
p(X=1) = .25	1.05	0.16
p(X=2) = .15	2.10	0.32
p(X=3) = .10	3.15	0.48
p(X=4) = .07	4.20	0.64
p(X=5) = .05	5.25	0.80
p(X=6) = .04	6.30	0.96
p(X=7) = .03	7.35	1.12
p(X=8) = .03	8.40	1.28
p(X=9) = .02	9.45	1.44
p(X=10)= .01	10.50	1.60
Expected Loss:	2.47	0.47

X = number of producer wells abandoned in excess of expectations

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE D - STAGE 3 (YEARS 1-30)
EVENT 1

Description:	Mechanical damage, scaling, corrosion or well-face plugging cause loss of one or more injector wells requiring replacement. For every such injector well that is replaced two producer wells must be taken off-line temporarily.

Cost Consequences:

Developer:	(a) Capital cost of replacement injector wells. (b) Revenue loss while each injector well is replaced and two producer wells are off-line.
User:	None.

Input Data:

Delay Time: 5 months.

Well Replacement Cost: $1.7 (millions - $1981)

Revenue Loss Per Injector Well Per Month: $0.120 (millions - $1981)

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE D - STAGE 3 (YEARS 1-30)
EVENT 2

	Loss Distribution	
Probabilities	Well Replacement Cost (millions-$1981)	Revenue Loss (millions-$1981)
p(X=0) = .25	$ 0.00	$0.00
p(X=1) = .50	1.70	0.60
p(X=2) = .10	3.40	1.20
p(X=3) = .05	5.10	1.80
p(X=4) = .04	6.80	2.40
p(X=5) = .02	8.50	3.00
p(X=6) = .02	10.20	3.60
p(X=7) = .02	11.90	4.20
Expected Loss:	2.33	0.82

X = number of injector wells requiring replacement

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE F - STAGE 1
EVENT 1

Description: Mechanical damage, scaling or corrosion causes loss of one or more producer wells (before field is in production). Well is replaced.

Cost Consequences:

Developer: Capital cost of replacement producer wells.

User: None.

Input Data:

Well Replacement Cost: $1.1 (millions - $1981)

Probabilities	Loss Distribution Well Replacement Cost (millions-$1981)
p(X=0) = .13	$ 0.00
p(X=1) = .11	1.10
p(X=2) = .10	2.20
p(X=3) = .09	3.30
p(X=4) = .07	4.40
p(X=5) = .07	5.50
p(X=6) = .06	6.60
p(X=7) = .06	7.70
p(X=8) = .06	8.80
p(X=9) = .05	9.90
p(X=10)= .05	11.00
p(X=11)= .05	12.10
p(X=12)= .05	13.20
p(X=13)= .05	14.30
Expected Loss:	5.74

X = number of producer wells requiring replacement

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE F - STAGE 2
EVENT 1

Description: Mechanical damage, scaling, or corrosion cause loss of one or more producer wells. Well is replaced.

Cost Consequences:

Developer: (a) Capital cost of replacement producer wells.

(b) Revenue loss while each producer well beyond reserve capacity is replaced.

User: None.

Input Data:

Delay Time: 5 months

Well Replacement Cost: $1.1 (millions - $1981)

Revenue Loss Per Producer Well Per Month: $0.053 (millions - $1981)

Number of Reserve Producer Wells: 4

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE F - STAGE 2
EVENT 1

Probabilities	Loss Distribution Well Replacement Cost (millions-$1981)	Revenue Loss (millions-$1981)
p(X=0) = .1250	$ 0.00	$0.00
p(X=1) = .0625	1.10	0.00
p(X=2) = .0625	2.20	0.00
p(X=3) = .0625	3.30	0.00
p(X=4) = .0625	4.40	0.00
p(X=5) = .0625	5.50	0.27
p(X=6) = .0625	6.60	0.53
p(X=7) = .0625	7.70	0.80
p(X=8) = .0625	8.80	1.06
p(X=9) = .0625	9.90	1.33
p(X=10)= .0625	11.00	1.59
p(X=13)= .2500*	14.30	2.38
Expected Loss:	7.36	0.94

X = number of producer wells requiring replacement

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*For computational reasons, the tail of the distribution $p(11 \leq X \leq 20) = .25$ was truncated and approximated by X=13 wells.

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE F - STAGE 2
EVENT 2

Description: Mechanical damage, scaling, corrosion or well-face plugging cause loss of one or more injector wells. For each injector well beyond reserve capacity that is shut down, two producer wells must be taken off-line.

Cost Consequences:

Developer: (a) Capital cost of replacement injector wells.

(b) Revenue loss while each injector well beyond reserve capacity is replaced.

User: None.

Input Data:

Delay Time: 5 months

Well Replacement Cost: $0.8 (millions - $1981)

Revenue Loss Per Injector Well Per Month: $0.106 (millions - $1981)

Number of Reserve Injector Wells: 2

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WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE F - STAGE 2
EVENT 2

	Loss Distribution	
Probabilities	Well Replacement Cost (millions-$1981)	Revenue Loss (millions-$1981)
p(X=0) = .125	$0.0	$0.00
p(X=1) = .125	0.8	0.00
p(X=2) = .125	1.6	0.00
p(X=3) = .125	2.4	0.53
p(X=4) = .125	3.2	1.06
p(X=5) = .125	4.0	1.59
p(X=6) = .125	4.8	2.12
p(X=7) = .125	5.6	2.65
Expected Loss:	2.8	0.99

X = number of injector wells
requiring replacement

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE F - STAGE 3 (YEARS 1-25)
EVENT 1

Description: Mechanical damage, scaling, corrosion or well-face plugging cause loss of one or more producer wells beyond original expectations. Well is replaced.

Cost Consequences:

Developer: (a) Capital cost of replacement producer wells.

(b) Revenue loss while well is replaced. (Assumes that reserve wells are occupied while dealing with expected replacement.)

User: None.

Input Data:

Delay Time: 5 months

Well Replacement Cost: $1.1 (millions - $1981)

Revenue Loss Per Producer Well Per Month: $0.0503 (millions - $1981)

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE F - STAGE 3 (YEARS 1-25)
EVENT 1

	Loss Distribution	
Probabilities	Well Replacement Cost (millions-$1981)	Revenue Loss (millions-$1981)
p(X=0) = .0625	$ 0.00	$0.00
p(X=1) = .0625	1.10	0.25
p(X=2) = .0625	2.20	0.50
p(X=3) = .0625	3.30	0.75
p(X=4) = .0625	4.40	1.00
p(X=5) = .0625	5.50	1.25
p(X=6) = .0625	6.60	1.50
p(X=7) = .0625	7.70	1.75
p(X=8) = .0625	8.80	2.00
p(X=9) = .0625	9.90	2.25
p(X=10)= .0625	11.00	2.50
p(X=11)= .0625	12.10	2.75
p(X=14)= .0625*	15.40	3.50
Expected Loss:	8.39	1.90

X = number of producer wells requiring replacement

---

*For computational reasons, the tail of the distribution $p(12\leq X\leq 20)=.25$ was truncated and approximated by X=14 wells.

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE F - STAGE 3 (YEARS 26-30)
EVENT 1

Description:	Mechanical damage, scaling, corrosion or well-face plugging cause loss of one or more producer wells in excess of original expectations during years 26-30. Lost wells are abandoned.

Cost Consequences:

Developer:	Loss of revenue per producer well over the remainder of project life.
User:	Unamortized value of plant.

Input Data:

Developer's Revenue Loss Per Well:

Range:	\$0 - \$2.1 (millions - \$1981)
Expected Value:	\$1.05 (millions - \$1981)

Expected Unamortized Value of Plant Due to Loss of One Well:
\$0.12 (millions - \$1981)

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE F - STAGE 3 (YEARS 26-30)
EVENT 1

Probabilities	Loss Distribution Revenue Loss (millions-$1981)	Unamortized Value of Plant (millions-$1981)
p(X=0) = .0625	$ 0.00	$0.00
p(X=1) = .0625	1.05	0.12
p(X=2) = .0625	2.10	0.24
p(X=3) = .0625	3.15	0.36
p(X=4) = .0625	4.20	0.48
p(X=5) = .0625	5.25	0.60
p(X=6) = .0625	6.30	0.72
p(X=7) = .0625	7.35	0.84
p(X=8) = .0625	8.40	0.96
p(X=9) = .0625	9.45	1.08
p(X=10)= .0625	10.50	1.20
p(X=11)= .0625	11.55	1.32
p(X=14)= .2500*	14.70	1.68
Expected Loss:	8.00	0.86

X = number of producer wells abandoned in excess of expectations

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*For computational reasons, the tail of the distribution $p(12 \leq X \leq 20) = .25$ was truncated and approximated by X=14 wells.

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE F - STAGE 3 (YEARS 1-30)
EVENT 1

Description:	Mechanical damage, scaling, corrosion or well-face plugging cause loss of one or more injector wells requiring replacement. For every such injector well that is replaced, two producer wells must be taken off-line temporarily.

Cost Consequences:

Developer:	(a) Capital cost of replacement injector wells. (b) Revenue loss while injector well is replaced and two producer wells are off-line.
User:	None.

Input Data:

Delay Time: 5 months

Well Replacement Cost: $0.8 (millions - $1981)

Revenue Loss Per Injector Well Per Month: $0.101 (millions - $1981)

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE F - STAGE 3 (YEARS 1-30)
EVENT 1

Probabilities	Loss Distribution: Well Replacement Cost (millions-$1981)	Loss Distribution: Revenue Loss (millions-$1981)
p(X=0) = .100	$0.0	$0.0
p(X=1) = .150	0.8	0.5
p(X=2) = .125	1.6	1.0
p(X=3) = .125	2.4	1.5
p(X=4) = .100	3.2	2.0
p(X=5) = .080	4.0	2.5
p(X=6) = .080	4.8	3.0
p(X=7) = .080	5.6	3.5
p(X=8) = .080	6.4	4.0
p(X=9) = .080	7.2	4.5
Expected Loss:	3.2	2.0

X = number of injector wells requiring replacement

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE G - STAGE 1
EVENT 1

Description: Mechanical damage, scaling or corrosion cause loss of one or more producer wells (before field is in production). Well is replaced.

Cost Consequences:

Developer: Capital cost of replacement producer wells.

User: None.

Input Data:

Well Replacement Cost: $0.8 (millions - $1981)

	Loss Distribution
Probabilities	Well Replacement Cost (millions-$1981)
p(X=0) = .250	$0.00
p(X=1) = .125	0.80
p(X=2) = .125	1.60
p(X=3) = .125	2.40
p(X=4) = .125	3.20
p(X=5) = .070	4.00
p(X=6) = .060	4.80
p(X=7) = .050	5.60
p(X=8) = .040	6.40
p(X=9) = .030	7.20
Expected Loss:	2.32

X = number of producer wells requiring replacement

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE G - STAGE 2
EVENT 1

Description: Mechanical damage, scaling or corrosion cause loss of one or more producer wells. Well is replaced.

Cost Consequences:

Developer: (a) Capital cost of replacement producer wells.

(b) Revenue loss while each producer well beyond reserve capacity is replaced.

User: None.

Input Data:

Delay Time: 5 months

Well Replacement Cost: $0.8 (millions - $1981)

Revenue Loss Per Injector Well Per Month: $0.065 (millions - $1981)

Number of Reserve Producer Wells: 2

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE G - STAGE 2
EVENT 1

	Loss Distribution	
Probabilities	Well Replacement Cost (millions-$1981)	Revenue Loss (millions-$1981)
p(X=0) = .170	$0.00	$0.00
p(X=1) = .083	0.80	0.00
p(X=2) = .083	1.60	0.00
p(X=3) = .083	2.40	0.33
p(X=4) = .083	3.20	0.65
p(X=5) = .083	4.00	0.97
p(X=6) = .083	4.80	1.30
p(X=7) = .083	5.60	1.63
p(X=8) = .083	6.70	1.95
p(X=9) = .083	7.20	2.27
p(X=10)= .083	8.00	2.60
Expected Loss:	3.65	0.99

X = number of producer wells requiring replacement

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE G - STAGE 2
EVENT 2

Description: Mechanical damage, scaling, corrosion or well-face plugging cause loss of one or more injector wells. For each each injector well that is shut down, two producer wells must be taken off-line.

Cost Consequences:

Developer: (a) Capital cost of replacement injector wells.

(b) Revenue loss while each injector well beyond reserve capacity is replaced.

User: None.

Input Data:

Delay Time: 5 months

Well Replacement Cost: $0.7 (millions - $1981)

Revenue Loss Per Injector Well Per Month: $0.13 (millions - $1981)

Number of Reserve Injector Wells: 1

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE G - STAGE 2
EVENT 2

Probabilities	Loss Distribution: Well Replacement Cost (millions-$1981)	Loss Distribution: Revenue Loss (millions-$1981)
p(X=0) = .25	$0.00	$0.00
p(X=1) = .25	0.70	0.00
p(X=2) = .15	1.40	0.65
p(X=3) = .10	2.10	1.30
p(X=4) = .09	2.80	1.95
p(X=5) = .09	3.50	2.60
p(X=6) = .07	4.20	3.30
Expected Loss:	1.46	0.87

X = number of injector wells requiring replacement

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE G - STAGE 3 (YEARS 1-25)
EVENT 1

Description: Mechanical damage, scaling, corrosion or well-face plugging cause loss of one or more producer wells beyond original expectations. Well is replaced.

Cost Consequences:

Developer: (a) Capital cost of replacement producer wells.

(b) Revenue loss while each well is replaced. (Assumes that reserve wells are occupied while dealing with expected replacement.)

User: None.

Input Data:

Delay Time: 5 months

Well Replacement Cost: $0.8 (millions - $1981)

Revenue Loss Per Producer Well Per Month: $0.059 (millions - $1981)

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE G - STAGE 3 (YEARS 1-25)
EVENT 1

	Loss Distribution	
Probabilities	Well Replacement Cost (millions-$1981)	Revenue Loss (millions-$1981)
p(X=0) = .170	$0.00	$0.00
p(X=1) = .083	0.80	0.30
p(X=2) = .083	1.60	0.60
p(X=3) = .083	2.40	0.90
p(X=4) = .083	3.20	1.20
p(X=5) = .083	4.00	1.50
p(X=6) = .083	4.80	1.80
p(X=7) = .083	5.60	2.10
p(X=9) = .250*	7.20	2.70
Expected Loss:	3.66	1.37

X = number of producer wells requiring replacement

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*For computational reasons, the tail of the distribution $p(8 \leq X \leq 14) = .25$ was truncated and approximated by X=9 wells.

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE G - STAGE 3 (YEARS 26-30)
EVENT 1

Description:	Mechanical damage, scaling, corrosion or well-face plugging cause loss of one or more producer wells in excess of original expectations during years 26-30. Lost wells are abandoned.

Cost Consequences:

Developer:	Loss of revenue per producer well over the remainder of the project life.
User:	Unamortized value of plant.

Input Data:

Developer's Revenue Loss Per Well:
Range: $0 - $2.3 (millions - $1981)
Expected Value: $1.15 (millions - $1981)

Expected Unamortized Value of Plant Due to Loss of One Well:
$0.23 (millions - $1981)

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE G - STAGE 3 (YEARS 26-30)
EVENT 1

Probabilities	Loss Distribution	
	Revenue Loss (millions-$1981)	Unamortized Value of Plant (millions-$1981)
$p(X=0) = .170$	$ 0.00	$0.00
$p(X=1) = .083$	1.15	0.23
$p(X=2) = .083$	2.30	0.46
$p(X=3) = .083$	3.45	0.69
$p(X=4) = .083$	4.60	0.92
$p(X=5) = .083$	5.75	1.15
$p(X=6) = .083$	6.90	1.38
$p(X=7) = .083$	8.05	1.61
$p(X=9) = .250$*	10.35	2.07
Expected Loss:	5.26	1.05

X = number of producer wells requiring replacement

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*For computational reasons, the tail of the distribution $p(8 \leq X \leq 14)=.25$ was truncated and approximated by X=9 wells.

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE G - STAGE 3 (YEARS 1-30)
EVENT 1

Description:	Mechanical damage, scaling, corrosion or well-face plugging cause loss of one or more producer wells requiring replacement. For each injector well that is shut down, two producer wells must be taken off-line temporarily.

Cost Consequences:

Developer:	(a) Capital cost of replacement injector wells. (b) Revenue loss while each injector well is replaced and two producer wells are off-line.
User:	None.

Input Data:

Delay Time: 5 months

Well Replacement Cost: $0.7 (millions - $1981)

Revenue Loss Per Injector Well Per Month: $0.118 (millions - $1981)

WELL RISKS
EVENTS LEADING TO REDUCTION IN USEFUL WELL LIFE
TYPE G - STAGE 3 (YEARS 1-30)
EVENT 1

Probabilities	Loss Distribution: Well Replacement Cost (millions-$1981)	Loss Distribution: Revenue Loss (millions-$1981)
p(X=0) = .250	$0.00	$0.00
p(X=1) = .125	0.70	0.59
p(X=2) = .125	1.40	1.18
p(X=3) = .125	2.10	1.77
p(X=4) = .125	2.80	2.36
p(X=5) = .125	3.50	2.95
p(X=6) = .125	4.20	3.54
Expected Loss:	1.84	1.55

X = number of injector wells requiring replacement

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WELL RISKS
SUCCESS RATIO LESS THAN EXPECTED
TYPE D - STAGE 1
EVENT 1

Description:	Inadequate knowledge of geological and/or hydrological model leads to worse than expected success ratio during Stage 1 drilling; additional producer wells must be drilled.
Cost Consequences:	
Developer:	Capital cost of replacement producer wells.
User:	None.
Input Data:	
Cost Per Well:	$1.8 (millions - $1981)

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WELL RISKS
SUCCESS RATIO LESS THAN EXPECTED
TYPE D - STAGE 1
EVENT 1

	Loss Distribution
Probabilities	Well Replacement Cost (millions-$1981)
$p(X=0) = .25$	$ 0.00
$p(X=1) = .25$	1.80
$p(X=2) = .15$	3.60
$p(X=3) = .10$	5.40
$p(X=4) = .07$	7.20
$p(X=5) = .05$	9.00
$p(X=6) = .04$	10.80
$p(X=7) = .03$	12.60
$p(X=8) = .03$	14.40
$p(X=9) = .02$	16.20
$p(X=10) = .01$	18.00
Expected Loss:	4.23

X = number of additional producer wells required

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RESERVOIR PERFORMANCE RISKS
INTERFERENCE OF OTHER WELLS (ADJACENT DEVELOPMENT)
TYPE A - STAGE 1
EVENT 1

Description: Wells in an adjacent development commence full production, causing declines in pressure and/or productivity of wells within project. Reservoir engineering calculations indicate that additional wells must be drilled in order to supply full design steam flow to plant, and sufficient excess project area and/or reservoir volume is present within the project to make this feasible.

Cost Consequences:

Developer: Capital cost of additional producer wells. (Additional injector wells not considered because adequate injection capacity is assumed always present for this type of project).

User: None.

Input Data:

Cost of Additional Producer Well: $1.8 (millions - $1981)

EXHIBIT VIII-5
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RESERVOIR PERFORMANCE RISKS
INTERFERENCE OF OTHER WELLS (ADJACENT DEVELOPMENT)

TYPE A - STAGE 1
EVENT 1

Probabilities	Loss Distribution Cost of Additional Wells (millions - $1981)
p(X=0) = .50	$0.00
p(X=1) = .20	1.80
p(X=2) = .11	3.60
p(X=3) = .09	5.40
p(X=4) = .07	7.20
p(X=5) = .03	9.00
Expected Loss:	2.02

X = number of additional producer wells required

RESERVOIR PERFORMANCE RISKS
INTERFERENCE OF OTHER WELLS (ADJACENT DEVELOPMENT)
TYPE A - STAGE 2
EVENT 1

cription:	Wells in an adjacent development commence full production, causing declines in pressure and/or productivity of wells within project. Reservoir engineering calculations indicate that additional wells must be drilled in order to supply full design steam flow to plant, and sufficient excess project area and/or reservoir volume is present within the project to make this feasible.

Cost Consequences:

Developer:	(a) Capital cost of additional producer wells. (b) Diminished revenue until new wells (in excess of reserve capacity) come on-line.
User:	Cost differential of replacement power until new wells come on-line.

Input Data:

Delay Time in Adding a Well: 5 months

Cost of Additional Producer Well: $1.80 (millions - $1981)

Revenue Loss Per Producer Well Per Month: $0.084 (millions - $1981)

Excess Cost of Replacement Power Per Producer Well Per Month: $0.084 (millions - $1981)

Number of Wells: 18 producers/2 reserves

RESERVOIR PERFORMANCE RISKS
INTERFERENCE OF OTHER WELLS (ADJACENT DEVELOPMENT)
TYPE A - STAGE 2
EVENT 1

	Loss Distribution		
	Cost of Additional Wells (millions-$1981)	Revenue Loss (millions-$1981)	Cost of Replacement Power (millions-$1981)
p(X=0) = .50	$0.00	$0.000	$0.000
p(X=1) = .20	1.80	0.000	0.000
p(X=2) = .11	3.60	0.000	0.000
p(X=3) = .09	5.40	0.420	0.420
p(X=4) = .07	7.20	0.840	0.840
p(X=5) = .03	9.00	1.260	1.260
Expected Loss:	2.02	0.134	0.134

X = number of additional producer wells required

RESERVOIR PERFORMANCE RISKS
INTERFERENCE OF OTHER WELLS (ADJACENT DEVELOPMENT)
TYPE A - STAGE 3
EVENT 1

Description:	Wells within project show declines in pressure and/or productivity; reservoir engineering calculations show that interference by wells in adjacent development has caused the declines. Because the project's reservoir already is fully developed during this stage, producing from additional wells within the project would only cause intensified reservoir decline. The diminished productivity will persist throughout the remainder of the project life.

Cost Consequences:

Developer:	Revenue loss from reduced design flow of project over the remainder of the project life.
User:	(a) Cost differential of replacement power over the remainder of project life. (b) Unamortized value of plant.

Input Data:

Field Revenue - Stage 3: $572.0 (millions - $1981)

Plant Cost: $67.8 (millions - $1981)

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RESERVOIR PERFORMANCE RISKS
INTERFERENCE OF OTHER WELLS (ADJACENT DEVELOPMENT)
TYPE A - STAGE 3
EVENT 1

	Loss Distribution		
Probabilities	Loss of Revenue (millions-$1981)	Unamortized Value of Plant (millions-$1981)	Excess Cost of Replacement Power (millions-$1981)
.700	$ 0.00	$0.00	$ 0.00
.066	4.70	0.56	4.70
.068	14.30	1.70	14.30
.066	23.90	2.84	23.90
.023	9.40	1.12	9.40
.024	28.60	3.40	28.60
.023	47.80	5.70	47.80
.009	14.10	1.68	14.10
.010	42.90	5.08	42.90
.009	71.70	8.52	71.70
Expected Loss:	6.15	0.73	6.15

RESERVOIR PERFORMANCE RISKS
RESERVOIR CHARACTERISTICS WORSE THAN ORIGINALLY EXPECTED
TYPE A - STAGE 1
EVENT 1

Description:	Temperature, pressure, enthalpy or permeability are found to be lower than expected, such that additional producer wells must be drilled in order to supply design flow of project, and sufficient project area and/or reservoir volume is available during this stage.

Cost Consequences:

Developer:	Capital cost of additional producer wells. Additional injector wells are not considerd because adequate injection capacity is assumed always present for this type.
User:	None.

Input Data:

Cost of Additional Producer Well: $1.8 (millions - $1981)

	Loss Distribution
Probabilities	Cost of Additional Wells (millions-$1981)
p(X=0) = .50	$0.00
p(X=1) = .25	1.80
p(X=2) = .10	3.60
p(X=3) = .07	5.40
p(X=4) = .05	7.20
p(X=5) = .03	9.00
Expected Loss:	1.82

X = number of additional
producer wells required

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RESERVOIR PERFORMANCE RISKS
RESERVOIR CHARACTERISTICS WORSE THAN ORIGINALLY EXPECTED
TYPE A - STAGE 2
EVENT 1

Description: Temperature, pressure, enthalpy or permeability are found to be lower than expected, such that additional producer wells must be drilled in order to supply design flow of project, and sufficient project area and/or reservoir volume is available during this stage.

Cost Consequences:

Developer: (a) Capital cost of additional producer wells. Additional injector wells are not considerd because adequate injection capacity is assumed always present for this type.

(b) Diminished revenue until new wells (in excess of reserve capacity) come on-line.

User: Cost differential of replacement power.

Input Data:

Delay Time in Adding a Well: 5 months

Cost of Additional Producer Well: $1.8 (millions - $1981)

Revenue Loss Per Well Per Month: $0.084 (millions - $1981)

Excess Cost of Replacement Power Per Well Per Month: $0.084 (millions - $1981)

Number of Reserve Producer Wells: 2

RESERVOIR PERFORMANCE RISKS
RESERVOIR CHARACTERISTICS WORSE THAN ORIGINALLY EXPECTED
TYPE A - STAGE 2
EVENT 1

	Loss Distribution		
Probabilities	Cost of Additional Producer Wells (millions-$1981)	Revenue Loss in Excess of Reserves (millions-$1981)	Excess Cost of Replacement Power (millions-$1981)
p(X=0) = .40	$ 0.00	$0.00	$0.00
p(X=1) = .20	1.80	0.00	0.00
p(X=2) = .15	3.60	0.00	0.00
p(X=3) = .15	5.40	0.42	0.42
p(X=4) = .05	7.20	0.84	0.84
p(X=5) = .03	9.00	1.26	1.26
p(X=6) = .02	10.80	1.68	1.68
Expected Loss:	2.56	0.18	0.18

X = number of additional producer wells required

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RESERVOIR PERFORMANCE RISKS
RESERVOIR CHARACTERISTICS WORSE THAN ORIGINALLY EXPECTED
TYPE B - STAGE 1
EVENT 1

Description:	Temperature, chemistry, enthalpy, pressure or permeability are found to be lower than expected, such that additional producer wells must be drilled in order to supply design flow of project, and sufficient project area and/or reservoir volume is available during this stage.

Cost Consequences:

Developer:	Capital cost of additional producer and injector wells. One additional injector is needed for each two additional producer wells.
User:	None.

Input Data:

Cost of Additional Producer Well:	$1.5 (millions - $1981)
Cost of Additional Injector Well:	$1.4 (millions - $1981)

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RESERVOIR PERFORMANCE RISKS
RESERVOIR CHARACTERISTICS WORSE THAN ORIGINALLY EXPECTED
TYPE B - STAGE 1
EVENT 1

	Loss Distribution
Probabilities	Cost of Additional Producer and Injector Wells (millions-$1981)
p(X=0) = .500	$ 0.00
p(X=1) = .100	1.50
p(X=2) = .075	4.40
p(X=3) = .075	5.90
p(X=4) = .075	8.80
p(X=5) = .075	10.30
p(X=6) = .050	13.20
p(X=7) = .030	14.70
p(X=8) = .020	17.80
Expected Loss:	3.81

X = number of additional
producer wells required

RESERVOIR PERFORMANCE RISKS
RESERVOIR CHARACTERISTICS WORSE THAN ORIGINALLY EXPECTED
TYPE B - STAGE 2
EVENT 1

Description: Temperature, chemistry, enthalpy, pressure or permeability are found to be lower than expected, such that additional producer wells must be drilled in order to supply design flow of project, and sufficient project area and/or reservoir volume is available during this stage.

Cost Consequences:

Developer: (a) Capital cost of additional producer and injector wells. One additional injector is needed for each two additional producer wells.

(b) Diminished revenue until new wells (in excess of reserve capacity) come on-line.

User: None.

Input Data:

Delay Time in Adding a Well: 5 months

Cost of Additional Producer Well: $1.5 (millions - $1981)

Cost of Additional Injector Well: $1.4 (millions - $1981)

Revenue Loss Per Producer Well Per Month: $0.063 (millions - $1981)

Number of Producer Wells: 18 producers - 2 reserves

RESERVOIR PERFORMANCE RISKS
RESERVOIR CHARACTERISTICS WORSE THAN ORIGINALLY EXPECTED
TYPE B - STAGE 2
EVENT 1

	Loss Distribution	
Probabilities	Cost of Additional Producer and Injector Wells (millions-$1981)	Revenue Loss in Excess of Reserves (millions-$1981)
p(X=0) = .40	$ 0.00	$0.000
p(X=1) = .15	1.50	0.000
p(X=2) = .12	4.40	0.000
p(X=3) = .08	5.90	0.315
p(X=4) = .07	8.80	0.630
p(X=5) = .06	10.30	0.945
p(X=6) = .04	13.20	1.260
p(X=7) = .03	14.70	1.575
p(X=8) = .02	17.60	1.890
p(X=9) = .02	19.10	2.205
p(X=10)= .01	22.00	2.520
Expected Loss:	4.38	0.330

X = number of additional producer wells required

RESERVOIR PERFORMANCE RISKS
RESERVOIR CHARACTERISTICS WORSE THAN ORIGINALLY EXPECTED
TYPE C - STAGE 1
EVENT 1

Description:	Temperature, chemistry, enthalpy, pressure or permeability are found to be lower than expected, such that additional producer wells must be drilled in order to supply design flow of project, and sufficient project area and/or reservoir volume is available during this stage.

Cost Consequences:

Developer:	Capital cost of additional producer and injector wells. One additional injector is needed for each additional producer well.
User:	None.

Input Data:

Cost of Additional Producer Well: $0.07 (millions - $1981)

Cost of Additional Injector Well: $0.06 (millions - $1981)

	Loss Distribution
Probabilities	Cost of Additional Producer and Injector Wells (millions-$1981)
p(X=0) = .50	$0.000
p(X=1) = .25	0.130
p(X=2) = .12	0.260
p(X=3) = .08	0.390
p(X=4) = .05	0.520
Expected Loss:	0.121

X = number of additional producer wells required

RESERVOIR PERFORMANCE RISKS
RESERVOIR CHARACTERISTICS WORSE THAN ORIGINALLY EXPECTED
TYPE C - STAGE 2
EVENT 1

Description: Temperature, chemistry, enthalpy, pressure or permeability are found to be lower than expected, such that additional producer wells must be drilled in order to supply design flow of project, and sufficient project area and/or reservoir volume is available during this stage.

Cost Consequences:

Developer: (a) Capital cost of additional producer and injector wells. One additional injector well is needed for each additional producer well.

(b) Revenue loss until new wells come on-line.

User: Cost differential of replacement power.

Input Data:

Delay Time in Adding a Well: 5 months

Cost of Additional Producer Well: $0.07 (millions - $1981)

Cost of Additional Injector Well: $0.06 (millions - $1981)

Revenue Loss Per Producer Well Per Month: Insufficient data to estimate

Excess Cost of Replacement Power: Insufficient data to estimate

Number of Wells: 4 producers - 0 reserves

RESERVOIR PERFORMANCE RISKS
RESERVOIR CHARACTERISTICS WORSE THAN ORIGINALLY EXPECTED
TYPE C - STAGE 2
EVENT 1

	Loss Distribution		
Probabilities	Cost of Additional Producer and Injector Wells (millions-$1981)	Revenue Loss* (millions-$1981)	Cost of Replacement Power* (millions-$1981)
p(X=0) = .40	$0.000	$-	$-
p(X=1) = .35	0.130	-	-
p(X=2) = .12	0.260	-	-
p(X=3) = .08	0.390	-	-
p(X=4) = .05	0.520	-	-
Expected Loss:	0.133	-	-

X = number of additional producer wells required

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*Insufficient data exists to estimate cost consequences.

RESERVOIR PERFORMANCE RISKS
RESERVOIR CHARACTERISTICS WORSE THAN ORIGINALLY EXPECTED
TYPE D - STAGE 1
EVENT 1

Description: Temperature, chemistry, enthalpy, pressure or permeability are found to be lower than expected, such that additional producer wells must be drilled in order to supply design flow of project, and sufficient project area and/or reservoir volume is available during this stage.

Cost Consequences:

Developer: Capital cost of additional producer and injector wells. One additional injector well is needed for each two additional producer wells.

User: None.

Input Data:

Cost of Additional Producer Well: $1.8 (millions - $1981)

Cost of Additional Injector Well: $1.7 (millions - $1981)

RESERVOIR PERFORMANCE RISKS
RESERVOIR CHARACTERISTICS WORSE THAN ORIGINALLY EXPECTED
TYPE D - STAGE 1
EVENT 1

	Loss Distribution
Probabilities	Cost of Additional Producer and Injector Wells (millions-$1981)
p(X=0) = .40	$ 0.00
p(X=1) = .25	1.80
p(X=2) = .15	5.30
p(X=3) = .08	7.10
p(X=4) = .05	10.60
p(X=5) = .04	12.40
p(X=6) = .03	15.90
Expected Loss:	3.32

X = number of additional producer wells required

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RESERVOIR PERFORMANCE RISKS
RESERVOIR CHARACTERISTICS WORSE THAN ORIGINALLY EXPECTED
TYPE D - STAGE 2
EVENT 1

Description: Temperature, chemistry, enthalpy, pressure or permeability are found to be lower than expected, such that additional producer wells must be drilled in order to supply design flow of project, and sufficient project area and/or reservoir volume is available during this stage.

Cost Consequences:

Developer:

(a) Capital cost of additional producer and injector wells. One additional injector needed for each two additional producer wells.

(b) Diminished revenue until new wells (in excess of reserve capacity) come on-line.

User: None.

Input Data:

Delay Time in Adding a Well: 5 months

Cost of Additional Producer Well: $1.8 (millions - $1981)

Cost of Additional Injector Well: $1.7 (millions - $1981)

Revenue Loss Per Producer Well Per Month: $0.069 (millions - $1981)

Number of Producer Wells: 10 producers - 1 reserve

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RESERVOIR PERFORMANCE RISKS
RESERVOIR CHARACTERISTICS WORSE THAN ORIGINALLY EXPECTED
TYPE D - STAGE 2
EVENT 1

	Loss Distribution	
Probabilities	Cost of Additional Producer and Injector Wells (millions-$1981)	Loss of Revenue (millions-$1981)
p(X=0) = .30	$ 0.0	$0.000
p(X=1) = .35	1.8	0.000
p(X=2) = .15	5.3	0.345
p(X=3) = .08	7.1	0.690
p(X=4) = .05	10.6	1.035
p(X=5) = .04	12.4	1.380
p(X=6) = .03	15.9	1.725
Expected Loss:	3.5	0.270

X = number of additional producer wells required

RESERVOIR PERFORMANCE RISKS
RESERVOIR CHARACTERISTICS WORSE THAN ORIGINALLY EXPECTED
TYPE E - STAGE 1
EVENT 1

Description: Temperature, chemistry, enthalpy, pressure or permeability are found to be lower than expected, such that additional producer wells must be drilled in order to supply design flow of project, and sufficient project area and/or reservoir volume is available during this stage.

Cost Consequences:

Developer: Capital cost of additional producer and injector wells. One additional injector well needed for each two additional producer wells.

User: None.

Input Data:

Cost of Additional Producer Well: $1.9 (millions - $1981)

Cost of Additional Injector Well: $1.3 (millions - $1981)

	Loss Distribution
Probabilities	Cost of Additional Producer and Injector Wells (millions-$1981)
p(X=0) = 0.40	$ 0.00
p(X=1) = 0.25	1.90
p(X=2) = 0.15	5.10
p(X=3) = 0.08	7.00
p(X=4) = 0.05	10.20
p(X=5) = 0.04	12.10
p(X=6) = 0.03	15.30
Expected Loss:	3.25

X = number of additional producer wells required

RESERVOIR PERFORMANCE RISKS
RESERVOIR CHARACTERISTICS WORSE THAN ORIGINALLY EXPECTED
TYPE E - STAGE 2
EVENT 1

Description: Temperature, chemistry, enthalpy, pressure or permeability are found to be lower than expected, such that additional producer wells must be drilled in order to supply design flow of project, and sufficient project area and/or reservoir volume is available during this stage.

Cost Consequences:

Developer:
(a) Capital cost of additional producer and injector wells. One additional injector well needed for each two additional producer wells.

(b) Diminished revenue until new wells (in excess of reserve capacity) come on-line.

User: None.

Input Data:

Delay Time in Adding a Well: 5 months

Cost of Producer Well: $1.90 (millions - $1981)

Cost of Injector Well: $1.30 (millions - $1981)

Revenue Loss Per Well Per Month: $0.072 (millions - $1981)

Number of Wells: 8 producers - 1 reserve

RESERVOIR PERFORMANCE RISKS
RESERVOIR CHARACTERISTICS WORSE THAN ORIGINALLY EXPECTED

TYPE E - STAGE 2
EVENT 1

	Loss Distribution	
Probabilities	Cost of Additional Producer and Injector Wells (millions-$1981)	Revenue Loss in Excess of Reserves (millions-$1981)
p(X=0) = .30	$ 0.00	$0.00
p(X=1) = .35	1.90	0.00
p(X=2) = .15	5.10	0.36
p(X=3) = .08	7.00	0.72
p(X=4) = .05	10.20	1.08
p(X=5) = .04	12.10	1.44
p(X=6) = .03	15.30	1.80
Expected Loss:	3.44	0.28

X = number of additional producer wells required

RESERVOIR PERFORMANCE RISKS
RESERVOIR CHARACTERISTICS WORSE THAN ORIGINALLY EXPECTED
TYPE F - STAGE 1
EVENT 1

Description: Temperature, chemistry, enthalpy, pressure or permeability are found to be lower than expected, such that additional producer wells must be drilled in order to supply design flow of project, and sufficient project area and/or reservoir volume is available during this stage.

Cost Consequences:

Developer:	Capital cost of additional producer and injector wells. One additional injector is needed for each additional producer well.
User:	None.

Input Data:

Cost of Producer Well: $1.1 (millions - $1981)

Cost of Injector Well: $0.8 (millions - $1981)

RESERVOIR PERFORMANCE RISKS
RESERVOIR CHARACTERISTICS WORSE THAN ORIGINALLY EXPECTED

TYPE F - STAGE 1
EVENT 1

Probabilities	Loss Distribution Cost of Additional Producer and Injector Wells (millions-$1981)
p(X=0) = .500	$ 0.00
p(X=1) = .200	1.10
p(X=2) = .060	3.00
p(X=3) = .040	4.10
p(X=4) = .040	6.00
p(X=5) = .035	7.10
p(X=6) = .025	9.00
p(X=7) = .025	10.10
p(X=8) = .025	12.00
p(X=9) = .025	13.10
p(X=10)= .025	15.00
Expected Loss:	2.53

X = number of additional producer wells required

RESERVOIR PERFORMANCE RISKS
RESERVOIR CHARACTERISTICS WORSE THAN ORIGINALLY EXPECTED
TYPE F - STAGE 2
EVENT 1

Description: Temperature, chemistry, enthalpy, pressure or permeability are found to be lower than expected, such that additional producer wells must be drilled in order to supply design flow of project, and sufficient project area and/or reservoir volume is available during this stage.

Cost Consequences:

Developer:
(a) Capital cost of additional producer and injector wells. One additional injector needed for each two additional producer wells.
(b) Diminished revenue until new wells (in excess of reserve capacity) come on-line.

User: None.

Input Data:

Delay Time in Adding a Well: 5 months

Cost of Additional Producer Well: $1.1 (millions - $1981)

Cost of Additional Injector Well: $0.8 (millions - $1981)

Revenue Loss Per Producer Well Per Month: $0.053 (millions - $1981)

Number of Wells: 38 producers - 4 reserves

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RESERVOIR PERFORMANCE RISKS
RESERVOIR CHARACTERISTICS WORSE THAN ORIGINALLY EXPECTED
TYPE F - STAGE 2
EVENT 1

	Loss Distribution	
Probabilities	Cost of Additional Producer and Injector Wells (millions-$1981)	Revenue Loss in Excess of Reserves (millions-$1981)
p(X=0) = .400	$ 0.00	$0.000
p(X=1) = .300	1.10	0.000
p(X=2) = .060	3.00	0.000
p(X=3) = .040	4.10	0.000
p(X=4) = .040	6.00	0.000
p(X=5) = .035	7.10	0.265
p(X=6) = .025	9.00	0.530
p(X=7) = .025	10.10	0.795
p(X=8) = .025	12.00	1.060
p(X=9) = .025	13.10	1.325
p(X=10)= .025	15.00	1.590
Expected Loss:	2.64	0.140

X = number of additional
producer wells required

RESERVOIR PERFORMANCE RISKS
RESERVOIR CHARACTERISTICS WORSE THAN ORIGINALLY EXPECTED
TYPE G - STAGE 1
EVENT 1

Description: Temperature, chemistry, enthalpy, pressure or permeability are found to be lower than expected, such that additional producer wells must be drilled in order to supply design flow of project, and sufficient project area and/or reservoir volume is available during this stage.

Cost Consequences:

Developer: Capital cost of additional producer and injector wells. One additional injector needed for each two additional producer wells.

User: None.

Input Data:

Cost of Producer Well: $0.8 (millions - $1981)

Cost of Injector Well: $0.7 (millions - $1981)

Probabilities	Loss Distribution Cost of Additional Producer and Injector Wells (millions-$1981)
p(X=0) = .50	$0.00
p(X=1) = .25	0.80
p(X=2) = .09	2.30
p(X=3) = .06	3.10
p(X=4) = .05	4.60
p(X=5) = .03	5.40
p(X=6) = .02	6.90
Expected Loss:	1.12

X = number of additional producer wells required

RESERVOIR PERFORMANCE RISKS
RESERVOIR CHARACTERISTICS WORSE THAN ORIGINALLY EXPECTED

TYPE G - STAGE 2
EVENT 1

Description: Temperature, chemistry, enthalpy, pressure or permeability are found to be lower than expected, such that additional producer wells must be drilled in order to supply design flow of project, and sufficient project area and/or reservoir volume is available during this stage.

Cost Consequences:

Developer:

(a) Capital cost of additional producer and injector wells. One additional injector needed for each two additional producer wells.

(b) Diminished revenue until new wells (in excess of reserve capacity) come on-line.

User: None.

Input Data:

Delay Time in Adding a Well: 5 months

Cost of Additional Producer Well: $0.8 (millions - $1981)

Cost of Additional Injector Well: $0.7 (millions - $1981)

Revenue Per Producer Well Per Month: $0.065 (millions - $1981)

Number of Wells: 14 producers - 2 reserves

RESERVOIR PERFORMANCE RISKS
RESERVOIR CHARACTERISTICS WORSE THAN ORIGINALLY EXPECTED
TYPE G - STAGE 2
EVENT 1

	Loss Distribution	
Probabilities	Cost of Additional Producer and Injector Wells (millions-$1981)	Revenue Loss in Excess of Reserves (millions-$1981)
p(X=0) = .40	$0.00	$0.000
p(X=1) = .35	0.80	0.000
p(X=2) = .09	2.30	0.000
p(X=3) = .06	3.10	3.250
p(X=4) = .05	4.60	0.650
p(X=5) = .03	5.40	0.975
p(X=6) = .02	6.90	1.625
Expected Loss:	1.20	0.110

X = number of additional
producer wells required

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RESERVOIR PERFORMANCE RISKS
ADVERSE CHANGES FROM EXPECTATIONS IN RESERVOIR MODEL
TYPE A - STAGES 1-3
EVENT 1

Description:

Stages 1-2:	Reservoir size is smaller than expected, leading to lower than expected productivity. Reservoir must be operated at lower than design flow throughout project life.
Stage 3:	Change in reservoir characteristics from expectations leads to a reduction from design flow and overall lower productivity. Because additional project area and/or reservoir volume is not available during this stage, lowered productivity will persist throughout the remainder of the project life.

Cost Consequences:

Developer:	Loss of revenue from lowered productivity during Stages 2 and 3.
User:	(a) Unamortized value of plant. (b) Cost of differential of replacement power.

Input Data:

Field Revenue - Stage 2: $18.0 (millions - $1981)

Field Revenue - Stage 3: $572.0 (millions - $1981)

Plant Cost: $67.8 (millions - $1981)

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RESERVOIR PERFORMANCE RISKS
ADVERSE CHANGES FROM EXPECTATIONS IN RESERVOIR MODEL
TYPE A - STAGES 1-3
EVENT 1

	Loss Distribution		
Probabilities	Revenue Loss (millions-$1981)	Unamortized Value of Plant (millions-$1981)	Excess Cost of Replacement Power (millions-$1981)
.14	$ 0.0	$0.0	$ 0.0
.06	14.3	1.7	14.3
.27	46.5	5.4	46.5
.03	59.7	7.0	59.7
.27	55.4	4.1	55.4
.03	48.8	5.7	48.8
.18	62.3	7.5	62.3
.02	75.1	9.0	75.1
Expected Loss:	38.9	4.6	38.9

RESERVOIR PERFORMANCE RISKS
ADVERSE CHANGES FROM EXPECTATIONS IN RESERVOIR MODEL
TYPE B - STAGES 1-3
EVENT 1

Description:

Stages 1-2:	Reservoir size is smaller than expected, leading to lower than expected productivity. Reservoir must be operated at lower than design flow throughout project life.
Stage 3:	Change in reservoir characteristics from expectations leads to a reduction from design flow and overall lower productivity. Because additional project area and/or reservoir volume is not available during this stage, lowered productivity will persist throughout the remainder of the project life.

Cost Consequences:

Developer:	Loss of revenue from lowered productivity during Stages 2 and 3.
User:	Unamortized value of plant.

Input Data:

Field Revenue - Stage 2: $13.7 (millions - $1981)

Field Revenue - Stage 3: $434.0 (millions - $1981)

Plant Cost: $44.8 (millions - $1981)

RESERVOIR PERFORMANCE RISKS
ADVERSE CHANGES FROM EXPECTATIONS IN RESERVOIR MODEL

TYPE B - STAGES 1-3
EVENT 1

Probabilities	Loss Distribution Revenue Loss (millions-$1981)	 Unamortized Value of Plant (millions-$1981)
.12	$ 0.00	$0.00
.08	21.70	2.24
.27	66.13	6.72
.03	75.40	7.67
.27	56.00	5.60
.03	65.50	6.60
.18	94.60	10.08
.02	103.00	10.95
Expected Loss:	58.00	5.97

RESERVOIR PERFORMANCE RISKS
ADVERSE CHANGES FROM EXPECTATIONS IN RESERVOIR MODEL
TYPE C - STAGES 1-3
EVENT 1

Description:

Stages 1-2: Reservoir size is smaller than expected, leading to lower than expected productivity. Reservoir must be operated at lower than design flow throughout project life.

Stage 3: Change in reservoir characteristics from expectations leads to a reduction from design flow and overall lower productivity. Because additional project area and/or reservoir volume is not available during this stage, lowered productivity will persist throughout the remainder of the project life.

Cost Consequences:

Developer: Loss of revenue from lowered productivity during Stages 2 and 3.

User: Unamortized value of plant.

Input Data:

Field Revenue - Stage 2: Insufficient data to estimate

Field Revenue - Stage 3: Insufficient data to estimate

Plant Cost: Insufficient data to estimate

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RESERVOIR PERFORMANCE RISKS
ADVERSE CHANGES FROM EXPECTATIONS IN RESERVOIR MODEL
TYPE D - STAGES 1-3
EVENT 1

Description:

Stages 1-2:	Reservoir size is smaller than expected, leading to lower than expected productivity. Reservoir must be operated at lower than design flow throughout project life.
Stage 3:	Change in reservoir characteristics from expectations leads to a reduction from design flow and overall lower productivity. Because additional project area and/or reservoir volume is not available during this stage, lowered productivity will persist throughout the remainder of the project life.

Cost Consequences:

Developer:	Loss of revenue from lowered productivity during Stages 2 and 3.
User:	Unamortized value of plant.

Input Data:

Field Revenue - Stage 2: $8.4 (millions - $1981)

Field Revenue - Stage 3: $264.0 (millions - $1981)

Plant Cost: $28.6 (millions - $1981)

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RESERVOIR PERFORMANCE RISKS
ADVERSE CHANGES FROM EXPECTATIONS IN RESERVOIR MODEL

TYPE D - STAGES 1-3
EVENT 1

	Loss Distribution	
Probabilities	Revenue Loss (millions-$1981)	Unamortized Value of Plant (millions-$1981)
.12	$ 0.0	$0.00
.08	13.2	1.43
.27	26.8	2.86
.03	32.7	3.50
.27	27.2	2.86
.03	33.1	3.50
.18	51.3	5.72
.02	56.6	6.29
Expected Loss:	28.0	3.02

RESERVOIR PERFORMANCE RISKS
ADVERSE CHANGES FROM EXPECTATIONS IN RESERVOIR MODEL
TYPE E - STAGES 1-3
EVENT 1

Description:

Stages 1-2:	Reservoir size is smaller than expected, leading to lower than expected productivity. Reservoir must be operated at lower than design flow throughout project life.
Stage 3:	Change in reservoir characteristics from expectations leads to a reduction from design flow and overall lower productivity. Because additional project area and/or reservoir volume is not available during this stage, lowered productivity will persist throughout the remainder of the project life.

Cost Consequences:

Developer:	Loss of revenue from lowered productivity during Stages 2 and 3.
User:	Unamortized value of plant.

Input Data:

Field Revenue - Stage 2: $6.9 (millions - $1981)

Field Revenue - Stage 3: $218.0 (millions - $1981)

Plant Cost: $33.6 (millions - $1981)

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RESERVOIR PERFORMANCE RISKS
ADVERSE CHANGES FROM EXPECTATIONS IN RESERVOIR MODEL
TYPE E - STAGES 1-3
EVENT 1

	Loss Distribution	
Probabilities	Revenue Loss (millions-$1981)	Unamortized Value of Plant (millions-$1981)
.12	$ 0.00	$0.00
.08	10.90	1.68
.27	22.10	3.36
.03	27.00	4.12
.27	22.50	3.36
.03	27.41	4.12
.18	42.40	6.72
.02	76.80	7.39
Expected Loss:	23.10	3.55

RESERVOIR PERFORMANCE RISKS
ADVERSE CHANGES FROM EXPECTATIONS IN RESERVOIR MODEL
TYPE F - STAGES 1-3
EVENT 1

Description:

Stages 1-2:	Reservoir size is smaller than expected, leading to lower than expected productivity. Reservoir must be operated at lower than design flow throughout project life.
Stage 3:	Change in reservoir characteristics from expectations leads to a reduction from design flow and overall lower productivity. Because additional project area and/or reservoir volume is not available during this stage, lowered productivity will persist throughout the remainder of the project life.

Cost Consequences:

Developer:	Loss of revenue from lowered productivity during Stages 2 and 3.
User:	Unamortized value of plant.

Input Data:

Field Revenue - Stage 2: $24.3 (millions - $1981)

Field Revenue - Stage 3: $768.0 (millions - $1981)

Plant Cost: $63.0 (millions - $1981)

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RESERVOIR PERFORMANCE RISKS
ADVERSE CHANGES FROM EXPECTATIONS IN RESERVOIR MODEL

TYPE F - STAGES 1-3
EVENT 1

	Loss Distribution	
Probabilities	Revenue Loss (millions-$1981)	Unamortized Value of Plant (millions-$1981)
.12	$ 0.0	$ 0.00
.08	38.4	3.15
.27	117.0	9.45
.03	133.3	10.79
.27	99.0	7.87
.03	115.8	9.25
.18	167.3	14.17
.02	182.4	15.39
Expected Loss:	102.6	8.39

RESERVOIR PERFORMANCE RISKS
ADVERSE CHANGES FROM EXPECTATIONS IN RESERVOIR MODEL
TYPE G - STAGES 1-3
EVENT 1

Description:

Stages 1-2:	Reservoir size is smaller than expected, leading to lower than expected productivity. Reservoir must be operated at lower than design flow throughout project life.
Stage 3:	Change in reservoir characteristics from expectations leads to a reduction from design flow and overall lower productivity. Because additional project area and/or reservoir volume is not available during this stage, lowered productivity will persist throughout the remainder of the project life.

Cost Consequences:

Developer:	Loss of revenue from lowered productivity during Stages 2 and 3.
User:	Unamortized value of plant.

Input Data:

Field Revenue - Stage 2: $10.9 (millions - $1981)

Field Revenue - Stage 3: $342.0 (millions - $1981)

Plant Cost: $49.9 (millions - $1981)

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RESERVOIR PERFORMANCE RISKS
ADVERSE CHANGES FROM EXPECTATIONS IN RESERVOIR MODEL
TYPE G - STAGES 1-3
EVENT 1

	Loss Distribution	
Probabilities	Revenue Loss (millions-$1981)	Unamortized Value of Plant (millions-$1981)
.180	$ 0.0	$0.00
.120	17.1	2.50
.270	34.7	4.99
.030	42.4	6.11
.216	35.3	4.99
.024	43.0	6.11
.144	66.6	9.98
.016	73.5	10.98
Expected Loss:	32.1	4.67

EXHIBIT VIII-8
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PLANT RISKS
POWER PLANT PERFORMANCE
TYPE A - STAGE 3
EVENT 1

Description: Reblading -- Mechanical damage to turbine requires reblading and consequent shutdown.

Cost Consequences:

Developer: Loss of steam revenue while plant is down.

User:
(a) Cost of reblading.
(b) Cost of replacement power while plant is down.

Input Data:

Cost of Reblading: $1.5 (millions - $1981)

Downtime: 1 month

Revenue Loss Per Month: $1.59 (millions - $1981)

Excess Cost of Replacement Power Per Month: $1.59 (millions - $1981)

	Loss Distribution		
Probabilities	Cost of Reblading (millions-$1981)	Revenue Loss (millions-$1981)	Cost of Replacement Power (millions-$1981)
p(0 reblades) = 0.80	$0.000	$0.000	$0.000
p(1 reblade) = 0.15	1.500	1.590	1.590
p(2 reblades) = 0.05	3.000	3.180	3.180
Expected Loss:	0.375	0.397	0.397

EXHIBIT VIII-8
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PLANT RISKS
POWER PLANT PERFORMANCE
TYPE B - STAGE 3
EVENT 1

Description: Reblading -- Mechanical damage to turbine requires reblading and consequent shutdown.

Cost Consequences:

Developer: Loss of steam revenue while plant is down.

User: Cost of reblading.

Input Data:

Cost of Reblading: $1.5 (millions - $1981)

Downtime: 1 month

Revenue Loss Per Month: $1.21 (millions - $1981)

Probabilities	Loss Distribution	
	Cost of Reblading (millions-$1981)	Revenue Loss (millions-$1981)
p(0 reblades) = 0.80	$0.000	$0.000
p(1 reblade) = 0.15	1.500	1.210
p(2 reblades) = 0.05	3.000	2.420
Expected Loss:	0.375	0.303

EXHIBIT VIII-8
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PLANT RISKS
POWER PLANT PERFORMANCE
TYPE D - STAGE 3
EVENT 1

Description: Reblading -- Mechanical damage to turbine requires reblading and consequent shutdown.

Cost Consequences:

Developer: Loss of steam revenue while plant is down.

User: Cost of reblading.

Input Data:

Cost of Reblading: $0.75 (millions - $1981)

Downtime: 1 month

Revenue Loss Per Month: $0.74 (millions - $1981)

	Loss Distribution	
	Cost of Reblading (millions-$1981)	Revenue Loss (millions-$1981)
p(0 reblades) = .80	$0.00	$0.00
p(1 reblade) = .15	0.75	0.74
p(2 reblades) = .05	1.50	1.48
Expected Loss:	0.19	0.18

EXHIBIT VIII-9
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SURFACE FACILITY RISKS
FAILURE OF ADVANCED DESIGN EQUIPMENT
TYPE D - STAGE 3
EVENT 1

Description: Greater than expected failure of downhole pumps requiring replacement.

Cost Consequences:

Developer: (a) Replacement cost of pumps.

(b) Loss of steam revenue during downtime for well associated with the faculty pump.

User: None.

Input Data:

Cost of Pump: $0.17 (millions - $1981)

Downtime: 1.5 months

Revenue Loss Per Pump Per Month: $0.06 (millions - $1981)

	Loss Distribution	
Probabilities	Replacement Cost (millions-$1981)	Revenue Loss (millions-$1981)
p(X=0) = .50	$0.00	$0.00
p(X=1) = .12	0.17	0.09
p(X=2) = .10	0.34	0.18
p(X=3) = .08	0.51	0.27
p(X=4) = .07	0.85	0.36
p(X=5) = .06	1.02	0.45
p(X=6) = .04	1.19	0.54
p(X=7) = .03	1.36	0.63
Expected Loss:	0.30	0.14

X = number of downhole pumps requiring replacement greater than expected

EXHIBIT VIII-9
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SURFACE FACILITY RISKS
FAILURE OF ADVANCED DESIGN EQUIPMENT
TYPE F - STAGE 1
EVENT 1

Description: Greater than expected failure of downhole pumps requiring replacement.

Cost Consequences:

Developer: Cost of replacement pumps.

User: None.

Input Data:

Cost of Pump: $0.17 (millions - $1981)

	Loss Distribution
Probabilities	Replacement Cost (millions-$1981)
$p(X=0) = 0.25$	$0.00
$p(X=1) = 0.25$	0.17
$p(X=2) = 0.15$	0.34
$p(X=3) = 0.10$	0.51
$p(X=4) = 0.08$	0.68
$p(X=5) = 0.07$	0.85
$p(X=6) = 0.05$	1.02
$p(X=7) = 0.03$	1.19
$p(X=8) = 0.02$	1.36
Expected Loss:	0.37

X = number of downhole pumps requiring replacement greater than expected

SURFACE FACILITY RISKS
FAILURE OF ADVANCED DESIGN EQUIPMENT
TYPE F - STAGE 2
EVENT 1

Description: Greater than expected failure of downhole pumps requiring replacement.

Cost Consequences:

Developer: (a) Replacement cost of pumps.

(b) Revenue loss during downtime for well (in excess of reserve capacity) associated with faulty pump.

User: None.

Input Data:

Cost of Pump: $0.17 (millions - $1981)

Revenue Loss Per Pump Per Month: $0.053 (millions - $1981)

Downtime: 1.5 months

Number of Reserve Wells: 4

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SURFACE FACILITY RISKS
FAILURE OF ADVANCED DESIGN EQUIPMENT
TYPE F - STAGE 2
EVENT 1

	Loss Distribution	
	Replacement Cost (millions-$1981)	Revenue Loss (millions-$1981)
p(X=0) = 0.50	$0.00	$0.00
p(X=1) = 0.12	0.17	0.00
p(X=2) = 0.10	0.34	0.00
p(X=3) = 0.08	0.51	0.00
p(X=4) = 0.05	0.68	0.00
p(X=5) = 0.05	0.85	0.08
p(X=6) = 0.05	1.02	0.16
p(X=7) = 0.03	1.19	0.24
p(X=8) = 0.02	1.36	0.32
Expected Loss:	0.29	0.03

X = number of downhole pumps requiring replacement greater than expected

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SURFACE FACILITY RISKS
FAILURE OF ADVANCED DESIGN EQUIPMENT
TYPE G - STAGE 1
EVENT 1

Description: Greater than expected failure of separators requiring replacement.

Cost Consequences:

Developer: Cost of replacing separators.

User: None.

Input Data:

Cost of Replacing Each Separator: $0.1 (millions - $1981)

	Loss Distribution
Probabilities	Replacement Cost (millions-$1981)
p(X=0) = 0.50	$0.0
p(X=1) = 0.25	0.1
p(X=2) = 0.10	0.2
p(X=3) = 0.08	0.3
p(X=4) = 0.07	0.4
Expected Loss:	0.1

X = number of separators
requiring replacement

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SURFACE FACILITY RISKS
FAILURE OF ADVANCED DESIGN EQUIPMENT
TYPE G - STAGE 2
EVENT 1

Description: Greater than expected failure of separators requiring replacement.

Cost Consequences:

Developer: (a) Replacement cost of separators.

(b) Revenue loss while one or more separators are down

User: None.

Input Data:

Cost of Separators: $0.1 (millions - $1981)

Downtime: 1.5 months

Revenue Loss Per Separator Per Month: $0.18 (millions - $1981)

	Loss Distribution	
Probabilities	Replacement Cost (millions-$1981)	Revenue Loss (millions-$1981)
p(X=0) = .30	$0.00	$0.00
p(X=1) = .30	0.10	0.27
p(X=2) = .18	0.20	0.54
p(X=3) = .12	0.30	0.81
p(X=4) = .06	0.40	1.08
p(X=5) = .04	0.50	1.35
Expected Loss:	0.30	0.39

X = number of separators requiring replacement

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SURFACE FACILITY RISKS
SCALING AND CORROSION
TYPE B - STAGE 3
EVENT 1

Description:	Scaling and corrosion greater than expected leading to the replacement of portions of the pipeline system.

Cost Consequences:

Developer:	Capital cost of replacing portions of the pipeline system. Revenue loss is considered zero because adequate redundancy is likely to exist to maintain full flow to the power plant.
User:	None.

Input Data:

Cost of Piping System: $9.0 (millions - $1981)

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SURFACE FACILITY RISKS
SCALING AND CORROSION
TYPE B - STAGE 3
EVENT 1

Probabilities	Loss Distribution Replacement Cost of Portions of the Piping System (millions-$1981)
.500	$0.000
.132	0.225
.011	0.450
.011	1.125
.011	2.745
.136	0.900
.011	1.125
.011	1.800
.011	3.420
.132	2.520
.011	2.745
.011	3.420
.011	5.040
Expected Loss:	0.730

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Page 3 of 6

SURFACE FACILITY RISKS
SCALING AND CORROSION
TYPE F - STAGE 3
EVENT 1

Description:	Scaling and corrosion greater than expected leading to the replacement of portions of the pipeline system.
Cost Consequences:	
Developer:	Capital cost of replacing portions of the pipeline system. Revenue loss is considered zero because adequate redundancy is likely to exist to maintain full flow to the power plant.
User:	None.

Input Data:

Cost of Piping System: $22 (millions - $1981)

EXHIBIT VIII-10
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SURFACE FACILITY RISKS
SCALING AND CORROSION
TYPE F - STAGE 3
EVENT 1

Probabilities	Loss Distribution Replacement Cost of Portions of the Piping system (millions-$1981)
.500	$0.00
.132	0.55
.011	1.10
.011	2.75
.011	6.71
.136	2.20
.011	2.75
.011	4.40
.011	8.36
.132	6.16
.011	6.71
.011	8.36
.011	12.32
Expected Loss:	1.77

EXHIBIT VIII-10
Page 5 of 6

SURFACE FACILITY RISKS
SCALING AND CORROSION
TYPE G - STAGE 3
EVENT 1

Description:	Scaling and corrosion greater than expected leading to the replacement of portions of the pipeline system.

Cost Consequences:

Developer:	Capital cost of replacing portions of the pipeline system. Revenue loss is considered zero because adequate redundancy is likely to exist to maintain full flow to the power plant.
User:	None.

Input Data:

Cost of Piping System: $10.5 (millions - $1981)

EXHIBIT VIII-10
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SURFACE FACILITY RISKS
SCALING AND CORROSION
TYPE G - STAGE 3
EVENT 1

	Loss Distribution
Probabilities	Replacement Cost of Portions of the Piping system (millions-$1981)
.40	$0.00
.11	0.42
.03	0.84
.03	1.68
.03	3.78
.11	1.26
.03	1.68
.03	2.52
.03	4.62
.11	3.36
.03	3.78
.03	4.62
.03	6.72
Expected Loss:	1.46

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Page 1 of 6

ACTS OF GOD
VOLCANIC HAZARDS
TYPE E - STAGE 3
EVENT 1

Description:	Lava flow from a volcanic eruption damages one or more wells (either producers or injectors) leading to, for each well damaged, either: (a) slight damage or burial of well-head resulting in basically clean-up costs; or (b) heavy damage resulting in clean-up and significant repair to well. (Note: Very severe damage to wells causing replacement and/or blowouts not considered as having significant probability in this case).

Cost Consequences:

Developer:	(a) Clean-up expense. (b) Repair cost of wells. (c) Revenue loss while each well is down for repairs.
User:	None.

Input Data:

Clean-up Expenses in the Event of Slight Damage: $0.1 (millions - $1981); 1-month delay

Repair Costs in the Event of Heavy Damage: $1.0 (millions - $1981); 3-months delay

Revenue Loss Per Well Per Month: $0.06 (millions - $1981)

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ACTS OF GOD
VOLCANIC HAZARDS
TYPE E - STAGE 3
EVENT 1

	Loss Distribution	
Probabilities	Repair Cost (millions-$1981)	Revenue Loss (millions-$1981)
0.900	$0.00	$0.00
0.050	0.55	0.12
0.025	1.10	0.24
0.015	1.65	0.36
0.007	2.20	0.48
0.003	2.75	0.60
Expected Loss:	0.10	0.02

EXHIBIT VIII-11
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ACTS OF GOD
VOLCANIC HAZARDS
TYPE E - STAGE 3
EVENT 2

Description:	Lava flow from a volcanic eruption causes significant damage to the power plant (as measured by a percentage of replacement cost required to repair plant), severe enough to cause shut-down while repairs take place.

Cost Consequences:

Developer:	Loss of revenue while plant is shut-down.
User:	Cost of repairing power plant measured as a percentage of total replacement cost. 100% of replacement cost corresponds to total destruction of the plant. Total destruction considered extremely unlikely (<.0001) and therefore only repair costs were considered.

Input Data:

Cost of Power Plant: $33.63 (millions - $1981)

Revenue Loss Per Month While Plant is Shut-Down: $0.61 (millions - $1981)

EXHIBIT VIII-11
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ACTS OF GOD
VOLCANIC HAZARDS
TYPE E - STAGE 3
EVENT 2

	Loss Distribution	
Probabilities	Repair Cost (millions-$1981)	Revenue Loss (millions-$1981)
.900	$ 0.00	$0.00
.033	2.00	0.61
.034	6.70	3.66
.033	14.80	7.32
Expected Loss:	0.78	0.37

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ACTS OF GOD
VOLCANIC HAZARDS
TYPE E - STAGE 3
EVENT 3

Description: Lava flow from a volanic eruption causes significant damage to surface facilities, severe enough to cause temporary shut-down of project and replacement of a percentage of the piping system.

Cost Consequences:

Developer:

(a) Cost of replacing a portion of piping system (measured as a percentage of the replacement cost of the system).

(b) Revenue loss while replacement is taking place and the project is shut-down.

User: None.

Input Data:

Cost of Surface Piping System: $4.0 (millions - $1981)

Revenue Loss Per Month while Project Is Down: $0.61 (millions - $1981)

EXHIBIT VIII-11
Page 6 of 6

ACTS OF GOD
VOLCANIC HAZARDS
TYPE E - STAGE 3
EVENT 3

Probabilities	Loss Distribution Replacement Cost (millions-$1981)	Revenue Loss (millions-$1981)
.900	$0.00	$0.00
.033	0.10	0.61
.034	0.40	2.44
.033	1.12	3.66
Expected Loss:	0.05	0.22

EXHIBIT VIII-12
Page 1 of 6

ACTS OF GOD
LANDSLIDES
TYPE A - STAGE 3
EVENT 1

Description: Landslide damages one or more wells leading to (for each well affected) either (a) slight damage or burial of well-head resulting in basically clean-up costs, (b) heavy damage resulting in clean-up and replacement of well, or (c) very severe damage causing blow-out, which results in remedial work (usually a remedial well), clean-up, and a replacement well.

Cost Consequences:

Developer:

(a) Clean-up expense.

(b) Capital cost for replacement wells.

(c) Capital cost for remedial wells and/or other measures needed to control blow-outs.

(d) Revenue loss while each well is replaced (assumed all reserve wells are occupied with expected replacement).

User: Cost of replacement power.

Input Data:

Cost of Well Replacement: $1.8 (millions - $1981)

Cost of Remedial Work Due to Blowout (usually a remedial well): $1.8 (millions - $1981)

Downtime for Replacement or Remedial Work: 5 months

Revenue Loss Per Well Per Month: $0.060 (millions - $1981)

Excess Cost of Replacement Power Per Well Per Month: $0.60 (millions - $1981)

Clean-up Costs Per Well: $0.10 (millions - $1981)

EXHIBIT VIII-12
Page 2 of 6

ACTS OF GOD
LANDSLIDES
TYPE A - STAGE 3
EVENT 1

	Loss Distribution	
Probabilities	Developer's Cost (millions-$1981)	Excess Cost of Replacement Power (millions-$1981)
0.800000	$0.00	$0.00
0.105000	1.10	0.12
0.024500	2.20	0.24
0.005250	3.30	0.36
0.003500	4.40	0.48
0.001050	5.50	0.60
0.000700	6.60	0.72
0.022500	2.20	0.24
0.005250	3.30	0.36
0.001125	4.40	0.48
0.000750	5.50	0.60
0.000225	6.60	0.72
0.000150	7.70	0.84
0.015000	3.30	0.36
0.003500	4.40	0.48
0.000750	5.50	0.60
0.000500	6.60	0.72
0.000150	7.70	0.84
0.000100	8.80	0.96
0.004500	4.40	0.48
0.001050	5.50	0.60
0.000225	6.60	0.72
0.000150	7.70	0.84
0.000045	8.80	0.96
0.000030	9.90	1.08
0.003000	5.50	0.60
0.000700	6.60	0.72
0.000150	7.70	0.84
0.000100	8.80	0.96
0.000300	9.90	1.08
0.000020	11.00	1.20
Expected Loss:	0.42	0.05

EXHIBIT VIII-12
Page 3 of 6

ACTS OF GOD
LANDSLIDES
TYPE A - STAGE 3
EVENT 2

Description:	Landslide causes significant damage to the power plant (as measured by a percentage of replacement cost required to repair the plant), severe enough to cause shut-down while repairs take place.

Cost Consequences:

Developer:	Loss of revenue while plant is shut-down.
User:	(a) Cost of repairing power plant measured as a percentage of the total replacement cost.
	(b) Excess Cost of replacement power.

Input Data:

Cost of Power Plant: $67.8 (millions - $1981)

Revenue Loss Per Month While Plant is Down (to Developer): $1.59 (millions - $1981)

Excess Cost of Replacement Power Per Month While Plant is Down (to User): $1.59 (millions - $1981)

ACTS OF GOD
LANDSLIDES
TYPE A - STAGE 3
EVENT 2

Probabilities	Loss Distribution Repair Costs (millions-$1981)	Revenue Loss (millions-$1981)	Excess Cost of Replacement Power (millions-$1981)
.900	$0.00	$0.00	$0.00
.033	8.10	1.59	1.59
.034	27.10	14.30	14.30
.033	47.50	28.62	28.62
Expected Loss:	2.76	1.48	1.48

ACTS OF GOD
LANDSLIDES
TYPE A - STAGE 3
EVENT 3

Description:	Landslide causes significant damage to surface facilities, severe enough to cause temporary shut-down of project and replacement of a percentage of the piping system.

Cost Consequences:

Developer:	(a)	Cost of replacing a portion of piping system (measured as a percentage of the replacement cost of the surface piping system).
	(b)	Revenue loss while replacement is taking place and the project is shut-down.
User:		Excess Cost of replacement power.

Input Data:

Cost of Surface Piping System: $5.0 (millions - $1981)

Revenue Loss Per Month While Project is Down: $1.59 (millions - $1981)

Excess Cost of Replacement Power While Project is Down: $1.59 (millions - $1981)

EXHIBIT VIII-12
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ACTS OF GOD
LANDSLIDES
TYPE A - STAGE 3
EVENT 3

	Loss Distribution		
Probabilities	Replacement Cost of Piping System (millions-$1981)	Revenue Loss (millions-$1981)	Cost of Replacement Power (millions-$1981)
.8000	$0.000	$0.00	$0.00
.0495	0.125	1.59	1.59
.0055	0.250	3.18	3.18
.0056	0.625	7.95	7.95
.0054	1.525	11.13	11.13
.0510	0.500	6.36	6.36
.0056	0.625	3.18	3.18
.0058	1.000	12.72	12.72
.0056	1.900	15.90	15.90
.0495	1.400	9.54	9.54
.0054	1.525	11.13	11.13
.0056	1.900	15.90	15.90
.0055	2.800	19.08	19.08
Expected Loss:	0.170	1.43	1.43

BASE INPUT DATA

Revenue Input Data

EXHIBIT VIII-13

CONVERSION FACTORS TO DETERMINE WELL AND FIELD REVENUE

Project Type	Steam Sales Price (mills/kw-hr.) ($1981)*	Plant Size	Total Mass Flow Needed to Operate Plant at Maximum Rated Capacity (millions lb./hr.)
A	27.8**	110 MW	2.20
B	44.7	50 MW	3.42
C***	-	-	-
D	68.1	20 MW	3.57
E	45.1	25 MW	1.25
F	79.2	50 MW	19.00
G	35.5	50 MW	4.60

---

* Based on breakeven analysis utilizing DOE Geothermal Loan Guaranty Cash Flow Model described in in Section VI.

** Based on current operations.

*** Insufficient data available to estimate revenue for direct-use type of project. Mention of Type C revenue data excluded from remainder of Appendix.

EXHIBIT VIII-14

REVENUE LOSS
STAGE 2
(millions - $1981)

Project Type*	Well Loss		Total Field	
	Per Month	Per Year	Per Month	Per Year
A	$.084	$1.01	$1.5	$18.1
B	.063	0.76	1.1	13.7
D	.069	0.83	0.7	8.4
E	.072	0.86	0.6	6.9
F	.053	0.67	2.0	24.3
G	.065	0.78	0.9	10.9

---

* Electric generation projects only

EXHIBIT VIII-15

REVENUE LOSS PER WELL PER MONTH
STAGE 3
(millions - $1981)

Project Type*	Range**	Expected Value***
A	$.037 - .096	$.066
B	.039 - .073	.056
D	.041 - .079	.060
E	.043 - .082	.062
F	.040 - .061	.050
G	.044 - .079	.059

---

* Electric generation projects only.

** High value corresponds to loss of well during early years of Stage 3. Low value corresponds to loss of well in year 25. Difference is due to assumed natural decline rate in reservoir productivity.

*** Mid-point of range; assumes that loss of well is equally likely throughout years 1-25 of Stage 3.

EXHIBIT VIII-16

REVENUE LOSS PER ABANDONED WELL
STAGE 3 (YEARS 26-30)
(millions - $1981)

Project Type*	Range**	Expected Value***
A	$0 - 1.9	$0.95
B	0 - 2.0	1.00
D	0 - 2.1	1.05
E	0 - 2.2	1.10
F	0 - 2.1	1.05
G	0.- 2.3	1.15

---

* Electric generation projects only.

** High value corresponds to abandonment of well during the first day of year 26. Low value corresponds to abandonment of well on last day of project.

*** Mid-point of range; assumes that abandonment of well is equally likely throughout years 26-30 of Stage 3.

EXHIBIT VIII-17

REVENUE LOSS DUE TO TOTAL FIELD ABANDONMENT DURING STAGE 3 (YEARS 1-30)(a)

(millions - $1981)

Project Type(b)	Range(c)	Expected Value(d)	Low Value (p=.33)(e)	Medium Value (p=.34)(e)	High Value (p=.33)(e)
A	$0 - 572	$286	$94	$286	$478
B	0 - 434	217	72	217	362
D	0 - 264	132	44	132	220
E	0 - 218	109	36	109	182
F	0 - 768	384	127	384	641
G	0 - 342	171	56	171	286

(a) Used to estimate revenue loss due to percentage reduction in field productivity.

(b) Electric generation projects only.

(c) High value corresponds to loss of field at the beginning of Stage 3. Low value corresponds to loss of field at the end of Stage 3.

(d) Mid-point of range; assumes field productivity loss is equally likely throughout Stage 3.

(e) Discrete approximation of the uniform loss distribution at three points: (1) 33 percent chance of loss occuring at the 5-year point, (2) 34 percent chance of loss occuring at the 15-year point, and (3) 33 percent chance of loss occuring at the 25-year point of Stage 3.

Well Input Data

EXHIBIT VIII-18

NUMBER OF WELLS*

Project Type	Type of Well	Stage 1	Stage 2	Stage 3 (Beginning)	Stage 3 (End)
A	Producers (reserves)	18(2)	18(2)	18(2)	18(4)
B	Producers (reserves)	18(2)	18(2)	18(2)	26(2)
	Injectors (reserves)	9(1)	9(1)	9(1)	13(1)
C	Producers	4	4	4	4
	Injectors	4	4	4	4
D	Producers (reserves)	10(1)	10(1)	10(1)	15(1)
	Injectors (reserves)	5(1)	5(1)	5(1)	7(1)
E	Producers (reserves)	8(1)	8(1)	8(1)	12(1)
	Injectors (reserves)	4(1)	4(1)	4(1)	6(1)
F	Producers (reserves)	38(4)	38(4)	38(4)	45(2)
	Injectors (reserves)	19(2)	19(2)	19(2)	23(2)
G	Producers (reserves)	14(2)	14(2)	14(2)	18(1)
	Injectors (reserves)	7(1)	7(1)	7(1)	9(1)

---

* Based on DOE estimates

EXHIBIT VIII-19
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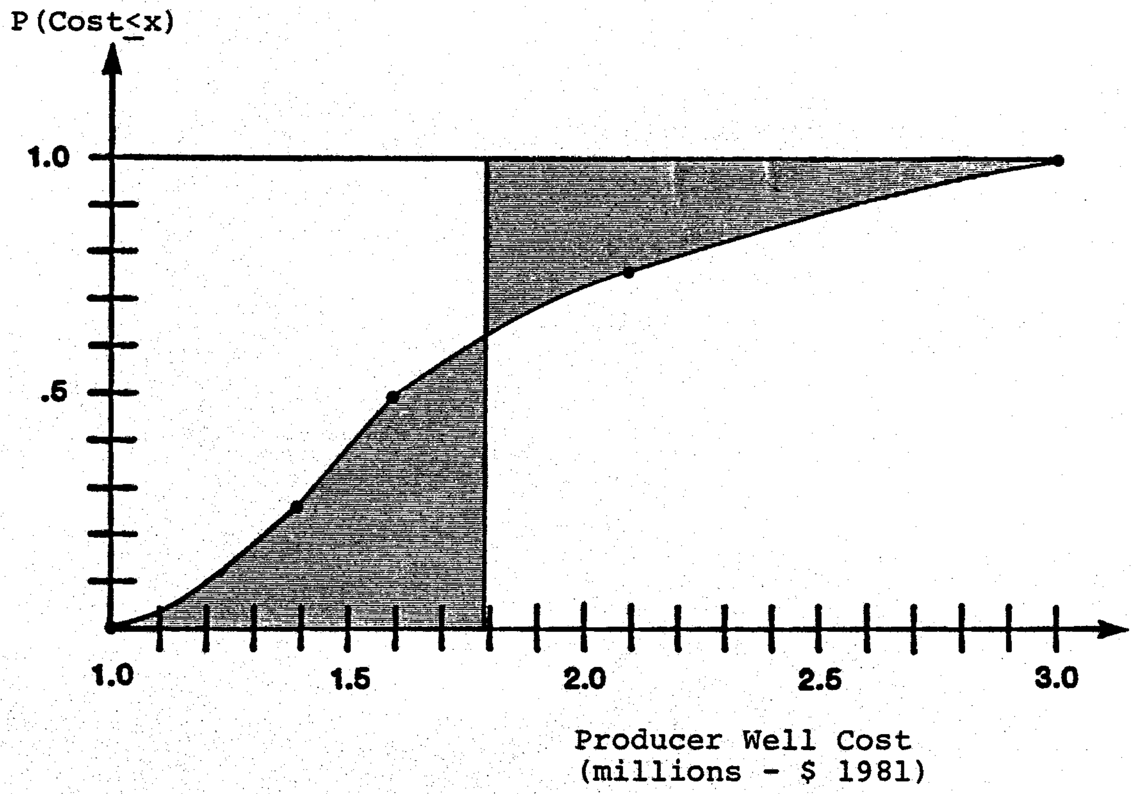
WELL COSTS*

PROJECT TYPE A

Producer Well Cost: (millions - $ 1981)	$1.00	$1.40	$1.60	$2.10	$3.00
P(Cost≤x):	.01	.25	.50	.75	.99



Expected Value**: $1.8 (millions - $ 1981)

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*Probability estimates from DOE sources for all project types derived using direct interval method.

**Expected values of all well cost distributions graphically estimated at the point where area above the curve approximates the area below the curve.

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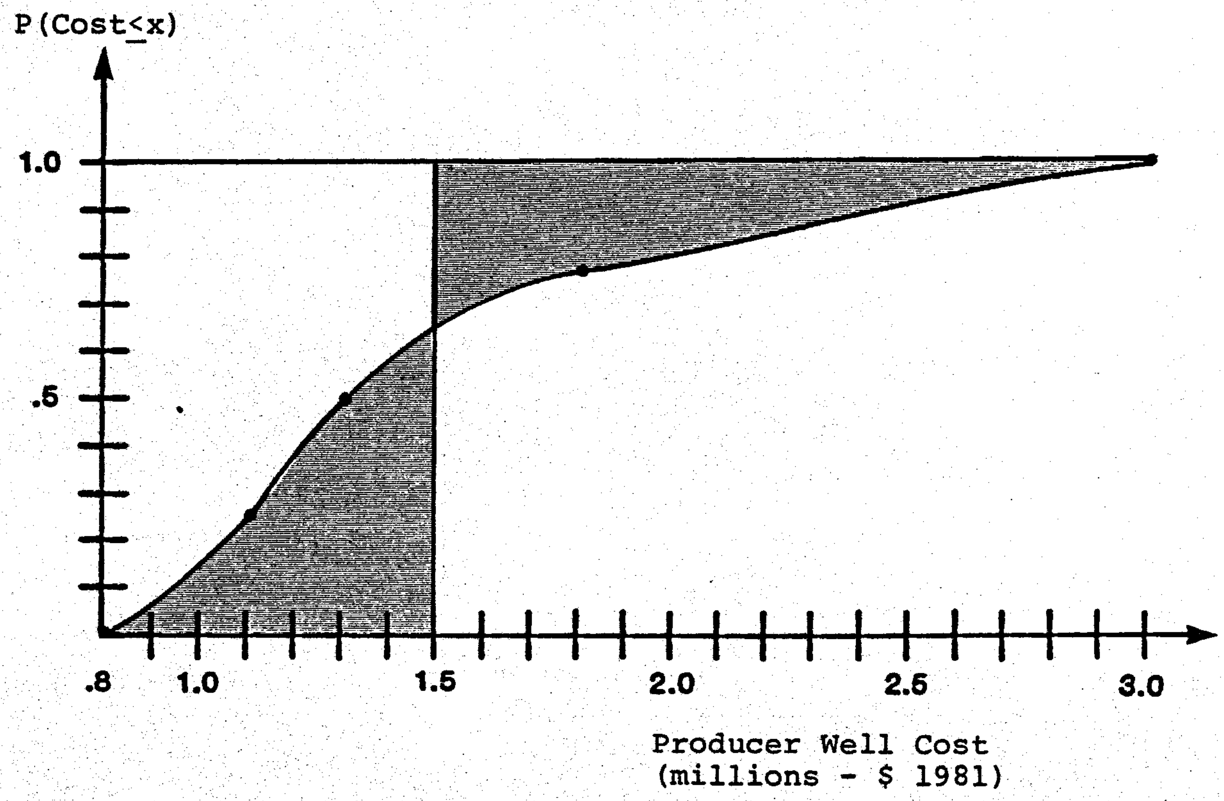
WELL COSTS

PROJECT TYPE B

Producer Well Cost: (millions - $ 1981)	$ .80	$1.10	$1.30	$1.80	$3.00
P(Cost≤x):	.01	.25	.50	.75	.99



Expected Value:

Producer Wells - $1.5 (millions - $ 1981)

Injector Wells* - $1.4 (millions - $ 1981)

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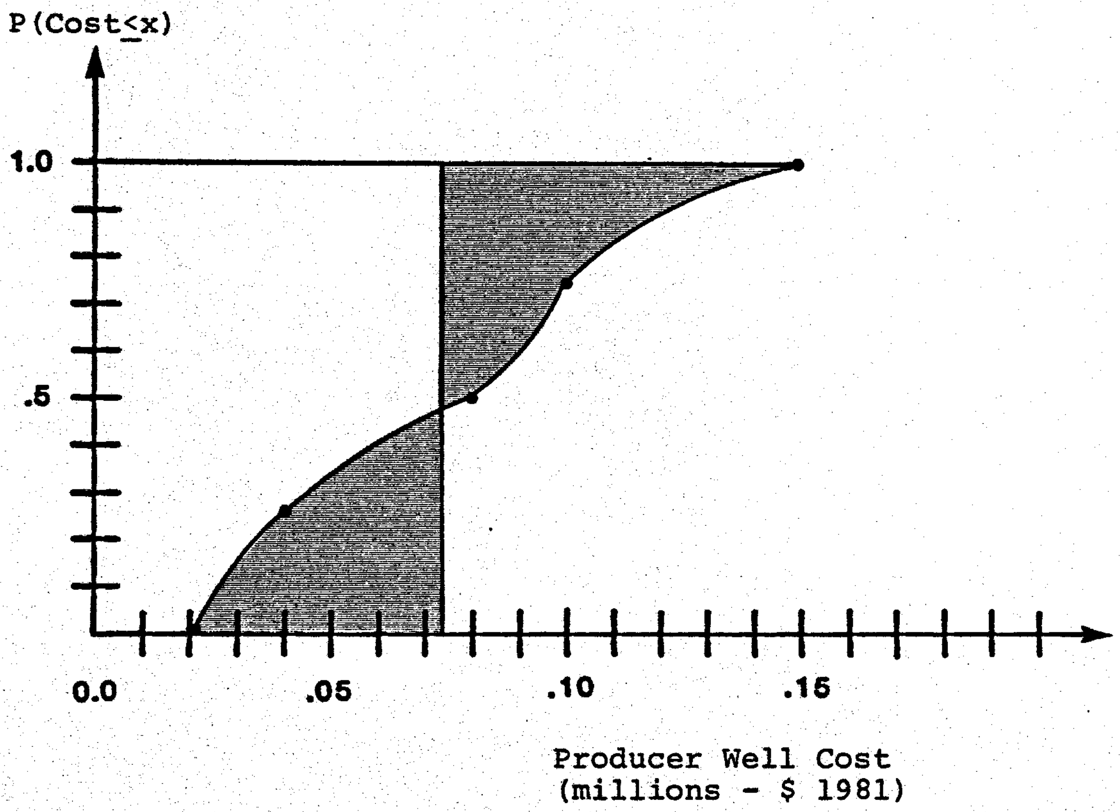
*Injector well costs for all project types estimated to be $100,000 less than the cost of producer wells unless otherwise noted.

WELL COSTS

PROJECT TYPE C

Producer Well Cost: (millions - $ 1981)	$ .02	$ .04	$ .08	$ .10	$ .15
P(Cost≤x):	.01	.25	.50	.75	.99



Expected Value:

Producer Wells - $ .07 (millions - $ 1981)

Injector Wells - $ .06 (millions - $ 1981)

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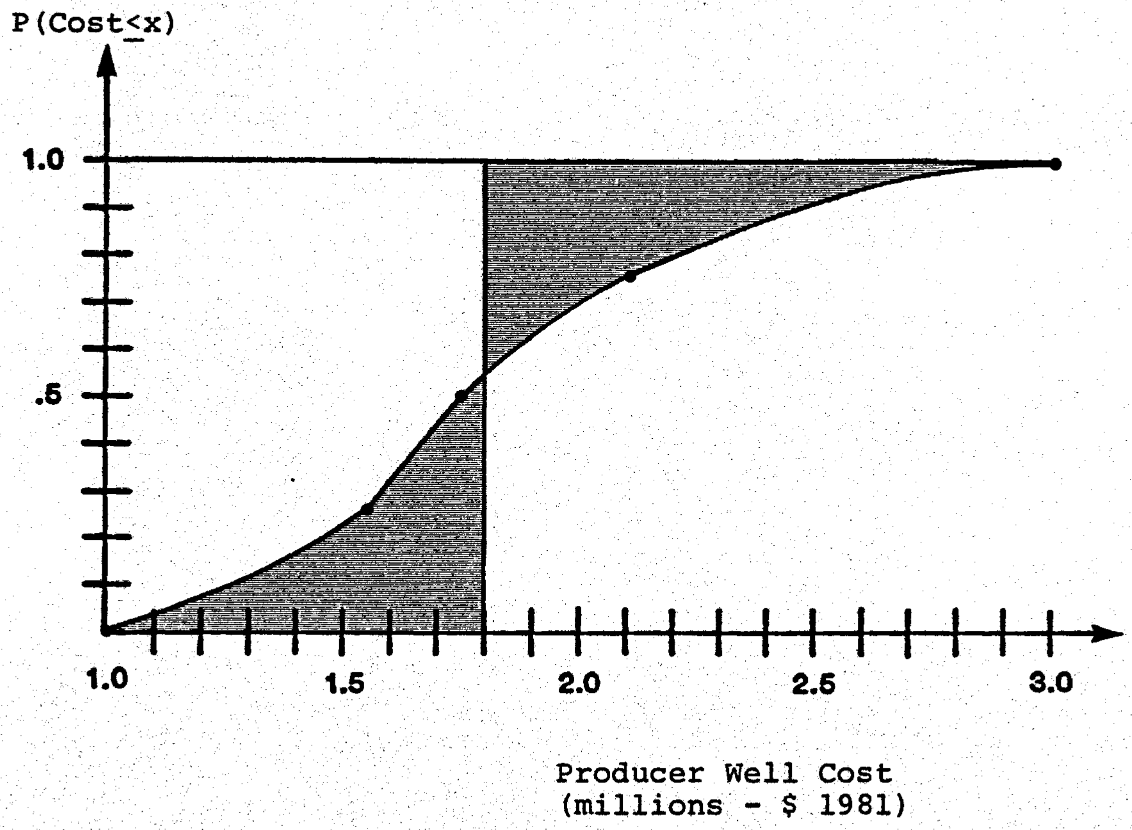
WELL COSTS

PROJECT TYPE D

Producer Well Cost: (millions - $ 1981)	$1.00	$1.55	$1.75	$2.10	$3.00
P(Cost≤x):	.01	.25	.50	.75	.99



Expected Value:

Producer Wells - $1.8 (millions - $ 1981)

Injector Wells - $1.7 (millions - $ 1981)

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WELL COSTS

PROJECT TYPE E

Producer Wells

Well Cost: (millions - $ 1981)	$1.00	$1.70	$1.85	$2.20	$3.00
P(Cost≤x):	.01	.25	.50	.75	.99
Expected Value:	$1.9 (millions - $ 1981)				

Injector Wells

Well Cost: (millions - $ 1981)	$ .80	$1.00	$1.20	$1.50	$3.00
P(Cost≤x):	.01	.25	.50	.75	.99
Expected Value:	$1.3 (millions - $ 1981)				

EXHIBIT VIII-19
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WELL COSTS

PROJECT TYPE F

Producer Wells

Well Cost: (millions - $ 1981)	$ .50	$ .85	$1.00	$1.30	$2.00
P(Cost≤x):	.01	.25	.50	.75	.99

Expected Value: $1.10 (millions - $ 1981)

Injector Wells

Well Cost: (millions - $ 1981)	$ .50	$ .60	$ .70	$ .85	$2.00
P(Cost≤x):	.01	.25	.50	.75	.99

Expected Value: $ .80 (millions - $ 1981)

EXHIBIT VIII-19
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WELL COSTS

PROJECT TYPE G

Producer Wells

Well Cost: (millions - $ 1981)	$ .40	$ .60	$ .70	$ .85	$2.00
P(Cost≤x):	.01	.25	.50	.75	.99
Expected Value:	$ .80 (millions - $ 1981)				

Injector Wells

Well Cost: (millions - $ 1981)	$ .40	$ .55	$ .60	$ .75	$2.00
P(Cost≤x):	.01	.25	.50	.75	.99
Expected Value:	$ .70 (millions - $ 1981)				

Other Input Data

EXHIBIT VIII-20

PLANT AND FIELD CAPITAL COSTS*
(millions - $1981)

	Plant		Field		
Project Type**	Power Plant	Reblading	Piping System	Downhole Pumps	Steam Separators
A	$67.80	$1.50	$5.0	N/A	N/A
B	44.77	1.50	9.0	N/A	N/A
D	28.57	0.75	6.6	$0.17	N/A
E	33.63	0.75	4.0	N/A	N/A
F	63.00	1.50	22.0	0.17	N/A
G	49.89	1.50	10.5	N/A	$0.10

---

* Estimates based on DOE data sources

** Electric generation projects only

EXHIBIT VIII-21

DELAY TIMES FOR REPLACEMENT OF WELLS OR EQUIPMENT

Event	Expected Delay Time*
Replacement or addition of well	5 months
Reblading of turbine	1 month
Replacement of downhole pump	1.5 months
Replacement of steam separators	1.5 months

---

*Expected values based on subjectively assessed probability distributions for delay time.

EXHIBIT VIII-22

CHEMICAL DATA BY PROJECT TYPE

	Reservoir Designations						
Species	A[4]	B	C	D	E[6]	F[7]	G
pH	5.7	7.3	6.5	8.0	4.8	N.A.	N.A.
alkalinity	-	-	-	-	36[5]	-	-
$CO_3^=$	N.A.[2]	24[2]	0[2]	44[2]	-	N.A.	N.A
HCO_3^-	46[2]	150[2]	37[2]	143[2]	-	511	N.A
$SO_4^=$	7[2]	88[2]	301[2]	165[2]	N.A.	160	N.A
Ca^{++}	<0.1[1]	13[2]	34[2]	4[2]	15[2]	6	25,000
SiO_2	4[2]	610[2]	N.A	400[2]	280[2]	178	500
H_2S	35[2]	230[3]	0	N.A.	N.A.	0	N.A
$S^=$	N.A.	2[2]	N.A.	N.A.	232[2]	-	N.A.
Ba	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
Pb	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
Fe	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
Sr	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.

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[1] N.A. - no data available.

[2] mg/l measured in liquid phase.

[3] ppm by weight in non-condensible gas.

[4] Analysis of steam condensate.

[5] Flow line temperature 400°D. pH-temperature relations need to be considered in determining most likely species present in fluid.

[6] Analysis is of total flow, not post-flash liquid fraction (obtained from flow line before separator, then cooled and condensed to liquid phase. Non-condensible gases dissolved or entrained in sample.)

[7] Represents pre-flash flow.