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Énergie, Mines et Ressources Canada

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Geothermal Service of Canada
Service géothermique du Canada

REGULATORY AND COMMERCIAL ASPECTS OF GEOTHERMAL ENERGY DEVELOPMENT

Acres Consulting Services Limited
8th Floor - 800 West Pender Street
Vancouver, B.C.
V6C 2V6

Earth Physics Branch Open File Number 84-12
Dossier public de la Direction de la Physique du Globe No. 84-12

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ABSTRACT

A survey has been carried out of regulatory and commercial aspects of geothermal energy development, for use by federal government program leaders, geothermal energy developers, provincial legislators, and other parties interested in development. Reference is made to geothermal experience in other countries, particularly the United States and France.

Canadian laws that potentially apply to geothermal energy are examined, including the Geothermal Resources Act of B.C., natural resource and groundwater laws, and environmental protection legislation.

Financial factors such as provincial assistance programs, tax treatments and consumer incentives are discussed. In many areas; the oil and gas industry provides a basis for comparison with the geothermal industry.

RESUME

Une enquête a été menée sur les aspects réglementaires et commerciaux du développement de l'énergie géothermique. Cette étude a été preparée à l'intention des directeurs de programmes fédéraux, des développeurs en géothermie, des législateurs provinciaux et des groupes intéresses par le développement. On y fait référence à l'expérience géothermique d'autres pays, notamment des Etats-Unis et de la France.

Les lois canadiennes qui pourraient s'appliquer a l'énergie géothermique sont examinées, y compris la Loi sur les ressources géothermiques de la Colombie-Britannique, les lois sur les ressources naturelles et les eaux souterraines, et la législation sur la protection de l'environnement.

Les facteurs financiers tels que les programmes d'aide provinciale, les traitements fiscales et les mesures d'encouragement à la consommation sont discutés. Dans plusieurs cas l'industrie pétrolière sert de base de comparaison avec l'industrie géothermique.

REGULATORY AND COMMERCIAL ASPECTS OF GEOTHERMAL ENERGY DEVELOPMENT

EXECUTIVE SUMMARY

Prepared for:

Government of Canada

DSS Contract 0SQ83-00288
Project Scientist: Dr. B. Larkin

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March 1984
P7055.00

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1.0 INTRODUCTION

Geothermal energy is heat generated by natural processes which occur within the earth. The temperature increases with depth. The temperature gradient varies from place to place according to geological conditions, but is generally on the order of 25°C/km. Human utilization is possible only in regions where geothermal heat is concentrated in exploitable form (e.g. hot water or steam), in sufficient quantity, and at a depth within economic reach of the surface.

In Canada, geothermal energy development is in its infancy. It is currently at the investigation stage of limited exploration, resource testing, and the examination of potential applications.

If geothermal energy is to be developed and compete with other energy supply options, many regulatory, jurisdictional and commercial issues must first be identified and resolved. The purpose of this survey was therefore to evaluate the regulatory status and commercial climate in Canada and to examine the issues and practices which have developed in selected geothermal user countries. The intent is that this information will provide a basic reference framework useful for guiding the future direction of geothermal development in Canada.

Canadian regulatory controls and financial inducements directed to geothermal energy development are extremely limited at present. This report reviews legislation for the petroleum, mining and forest industries, as well as for other energy technologies, which is potentially applicable to geothermal developments. Attention is drawn to selected features which could be applied to a geothermal-based energy industry.

Many of the issues have already been faced by other countries during the development of their geothermal energy sources. In planning the future of geothermal development in Canada, it is therefore useful to examine the experience of other countries.

It should be noted that the practices reviewed in this report do not necessarily represent desirable models to be followed. In fact, some of the examples presented are clearly to be avoided. In considering the adoption of foreign practices in Canada, the differing social, economic and political realities must be taken into account. To assist in highlighting these considerations, the report has included comparative assessments, interpretations and analyses of implications in terms of Canadian applicability. The comprehensive discussion of the United States provides valuable lessons on the difficulties encountered by the different levels of government, and the solutions which have evolved.

This report is intended as a reference work for the use of geothermal program leaders within the federal government, for potential geothermal developers and for legislators across Canada.

2.0 STATUS OF GEOTHERMAL DEVELOPMENT IN CANADA

Since 1982 the federal agency responsible for geothermal research has been the Gravity Geothermics and Geodynamics Division of the Earth Physics Branch, Department of Energy, Mines and Resources.

A map of known or potential geothermal resources in Canada is shown in Figure 1.

The only applications of geothermal energy in Canada to date are the heating of about a dozen recreational swimming pools in the west, and the warming of some community water systems in the north.

2.1 British Columbia

British Columbia has sparked more interest than other areas because of the promise of near-surface high temperature fluids, which could potentially be used in electrical generation. Comparatively little effort has been directed toward investigations of lower temperature resources such as might be used for space heating, although there is evidence that exploitable resources are present.

The B.C. Geothermal Resources Acts of 1973 and 1982 defined geothermal resources, reserved all rights to them to the Crown in the right of the Province, provided for the disposition of geothermal rights, and addressed various aspects of resource management.

In 1974 the Geological Survey of Canada drilled two diamond drill holes near Meager Creek in southwestern B.C. Both encountered hot artesian water. The area was

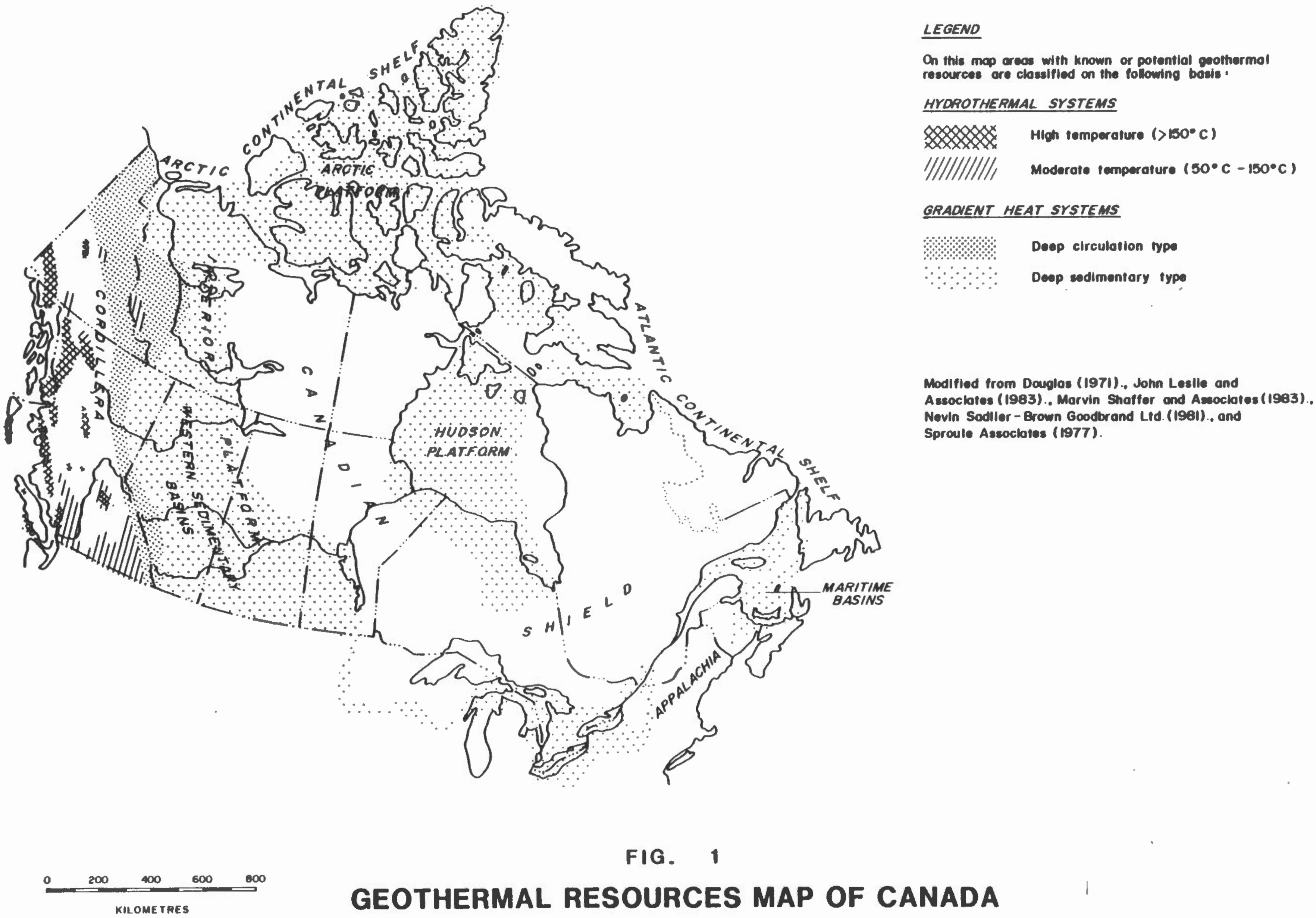

FIG. 1

GEOTHERMAL RESOURCES MAP OF CANADA

selected for detailed geothermal exploration by B.C. Hydro. A program of geological mapping, geophysical and geochemical surveys, and drilling was initiated. In 1981 and 1982, three deep production-scale holes were drilled. Attempts at sustained steam production on a commercial scale have so far been frustrated, but the first geothermally- generated electricity in Canada was scheduled for production in 1984 (Stauder, 1984).

In the first public auction of geothermal leases in British Columbia, O'Brien Energy Ltd. acquired exploration rights to a tract of land near Squamish in 1983. The company has committed itself to a five-year work program that will require expenditures up to $4.25 million.

2.2 Prairie Provinces

Geothermal resources of the Prairie provinces are of the deep basin type occurring within the Western Canadian Sedimentary Basin. Various studies directed at regional delineation, characterization and assessment of prospective geothermal resources on the Prairies have been on-going since 1975. The leading site-specific work has been performed at the University of Regina, Saskatchewan, where the campus has been tested by drilling, and related studies have been conducted. The project is currently on hold, pending funding for a fluid disposal well which would allow for long-term testing of the reservoir.

No specific regulations govern the development of geothermal resources. The Regina demonstration well was permitted under existing oil and gas regulations. It is probable that such existing regulations are sufficient.

2.3 Northern Canada

In the Yukon and Northwest Territories, geothermal resource potential is greatest in the western regions, the Yukon and the District of Mackenzie. Both low and high grade resources may be expected to occur in the displaced western component of the Yukon Cordillera.

No legislation has been passed by the territorial or federal governments to regulate geothermal development in these areas. Existing developments are regulated by other legislation, particularly land and water acts.

Use of geothermal resources in the north is limited. At Mayo, Yukon, water warmed by gradient heat in a deep well is used to prevent freezing in the public water supply system (except under severe conditions). In addition, an area just west of Whitehorse might have economically exploitable geothermal resources of the system-electric type.

2.4 Ontario and Quebec

No geothermal resources have been identified or exploited in Ontario and Quebec, and it appears likely that none will be, in the foreseeable future. The geology indicates that temperature gradients would be too low to warrant commercial application in the near future.

There is no legislation which would directly regulate geothermal development in these two provinces.

2.5 Maritime Provinces

The Maritimes have the potential for two types of geothermal resource, neither of which is likely to have high temperatures: gradient heat in deep sedimentary basins, and hot dry rock in Paleozoic granitic intrusions. No geothermal resources have been exploited apart from demonstration projects using heat pumps or shallow water wells. However, the Earth Physics Branch has been conducting assessment studies since 1980.

No specific geothermal legislation exists in the Maritimes and none is anticipated. Each province has laws controlling groundwater use, environmental protection, and exploration for oil, gas and minerals. In the interim, these would probably apply to geothermal development.

3.0 REGULATORY AND COMMERCIAL ASPECTS IN SELECTED FOREIGN COUNTRIES

3.1 United States

The regulatory and commercial aspects of geothermal development have been addressed in varying degrees by the United States Congress and by the legislatures of various states. Often the conclusions reached, and the directions given, by these differing bodies have been significantly different. The study outlines existing U.S. legislation and comments on its effectiveness, and discusses a number of important but controversial issues.

One critical issue is the definition and characterization of geothermal resources. Strict definition is required for legal and jurisdictional purposes, to describe the physical properties which distinguish geothermal resources from other natural resources. The resource must also be characterized in relation to groundwater, subsurface minerals and other established resources, in order to avoid conflicts with owners of other resources. In several U.S. court decisions, geothermal resources have been determined to be mineral. The implication is that, unlike groundwater, mineral ownership may be "severed" from property rights to the overlying surface.

Resource access can be provided through exploration or prospecting permits, and/or non-competitive leases for lands of unknown potential. However, competitive bidding may be conducted for particularly valuable resource areas. Another approach is to allow for exploration and prospecting permits, but to require all leasing to be by competitive bid.

The U.S. federal government and most states have set limitations on the size of leases, and limitations upon holdings in any one state. The setting of limits on minimum lease size has drawn criticism from small developers. On the other hand, developers object that the limit on individual holdings in a given state prevents a successful operator from conducting additional exploration and forces companies to give up attractive prospects.

Annual rentals are normally assessed for the opportunity to explore on public lands. Rentals may provide the lessor with a tool for ensuring diligent exploration in that required expenditures on exploration must equal a set amount or increased rentals will be assessed. Without diligence requirements, public lands can be held for long periods by speculators. The U.S. Congress requires that a plan of operation for exploration be filed within a fixed period after the issuance of a lease, and that drilling commence within another specified period.

As illustrated in the report, the manner in which royalties are calculated may penalize the developer engaged in the direct utilization of geothermal resources in comparison to the developers of electrical generation projects.

Geothermal energy must be used on site, and often involves substantial outlays for utilization facilities and pipe lines, and/or electrical transmission lines which require amortization periods of 20 to 30 years. Therefore the effective lease life, adjustments of lease provisions, and lease renewals are of great importance to developers. The report draws special reference to leasing provisions which have resulted in the greatest amount of controversy or which may deter exploration and development.

Most states have recognized that groundwater is an integral part of any geothermal resource (except hot dry rock). Some states exclude low temperature regimes (e.g. below 120°C) from the definition of geothermal resources. Thus the lower temperature resource is subjected to groundwater law and development provisions, rather than to geothermal leasing and development regulations.

Federal and state governments have adopted environmental statutes which require that all major proposed activities review environmental impacts. The structuring of the environmental review process can have a profound impact upon timely and successful completion of a project.

The report outlines the prescribed processes and conditions for exploration, drilling and production permits, energy facility siting, and utility easements.

In order to promote the use of geothermal energy, the federal government and many state governments have established programs aimed at reducing the financial risks of exploration and development, and demonstrating the viability of geothermal energy utilization for both electrical generation and direct application projects. These programs have utilized grants, loans, guaranteed loans, or cost sharing provisions. Other programs have served to ease financial risks of project development by providing tax incentives or reservoir insurance. Information on such programs is presented in the report.

3.2 France

Geothermal energy development in France has involved mainly low temperature resources. By the beginning of 1984, a financial and legal infrastructure was firmly in place and the commercialization of geothermal energy is underway.

Introduction of specific legislation for geothermal energy began in 1977. The geothermal resource is defined as a mineral. It is thus subject to mining legislation with specific applications to the geothermal resource defined in subsequent acts. The official agency having final jurisdictional authority over geothermal energy is the AFME (Agence Francaise pour la Maitrise d'Energie), created by congress in 1982 with authority for development and implementation of national energy policy.

The definition of a geothermal resource effectively includes a minimum temperature of 20°C. Drill holes exceeding 100 m must first be authorized.

A developer of a geothermal resource must obtain an exploration permit, an operating permit and a concession (exclusive right to exploit mineral deposits). These permits require information on the project such as financing, environmental impacts, scheduling and use of the energy. A public inquiry is included in the permitting process.

In 1983, the SPG (Service Publique Geothermie) was created to centralize all information relating to geothermal energy. A national company, Geochaleur, was formed to act as a consultant to prospective developers and be able to set up all the financial, administrative and technical aspects of the operation.

Up to the present, the most important users of geothermal energy have been large housing projects. The use of heat pumps greatly expands the use of shallower, lower temperature resources for geothermal heating. With lower investment costs, geothermal energy has become accessible to small communities.

The financial support structure of the French geothermal industry includes government subsidies, low interest loans with special repayment schedules and conditions, and short and long term risk insurance. It is evident that these strong government incentives have been an important factor in the commercialization of geothermal energy. The report documents a number of case histories of specific geothermal projects in France.

3.3 Other Countries

Brief information is provided on geothermal development, particularly the regulatory aspects, for the Commission of the European Communities (CEC), the United Kingdom, New Zealand, Iceland and Japan.

4.0 SURVEY OF LEGISLATION AFFECTING GEOTHERMAL DEVELOPMENT IN CANADA

The B.C. Geothermal Resources Act (1982) vests the right, title, and interest in all geothermal resources in the provincial government. The Act also defines permitting, leasing, operation, authorization and licensing requirements, and makes provision for royalties. The Act and regulations closely follow the Petroleum and Natural Gas Act and its regulations, particularly with respect to leasing and authorization procedures, drilling practice, sampling and reporting.

Most geothermal exploration and drilling in B.C. has preceded the Geothermal Resources Act and therefore little experience has been acquired in applying the Act. Similarly, the relationship to the B.C. Hydro and Power Authority Act has not yet been clarified.

No geothermal legislation exists in the other provinces and territories, and none is anticipated in the near future. Potential geothermal development would be most directly affected by existing laws for natural resources, groundwater and petroleum.

Some provinces appear to have adequate regulatory experience to cope with geothermal development under existing legislation; while in other provinces, developers would face either a lack of experience on the part of government authorities, or serious ambiguities in existing laws as they might apply to geothermal development.

5.0 FINANCIAL FACTORS AFFECTING GEOTHERMAL DEVELOPMENT IN CANADA

Provincial and federal assistance programs for geothermal research, development, and demonstration studies increase the available geothermal data pool. This type of assistance is crucial in early stages of development, when the technology has yet to be demonstrated to potential developers. As knowledge increases, other incentives are required to encourage commercial adoption. Rates of return to private developers may be increased by incentives such as capital assistance for investment, favourable tax write-offs and tax credits. Finally, consumer incentives intended to create an awareness and demand among users may be beneficial.

Since geothermal energy is still in its infancy in Canada, most assistance is directed towards research and demonstration projects at the present. To assess the potential capital, tax, and consumer incentives which may one day be applied to the geothermal industry, a survey was conducted of similar incentives to the oil and gas, mining and alternative energy industries in Canada. The report identifies the impacts of these incentives, should they be extended to include geothermal energy applications.

6.0 COMMERCIAL FACTORS AFFECTING GEOTHERMAL DEVELOPMENT IN CANADA

Worldwide interest in geothermal energy has historically focused on high temperature systems for electric power production. However, direct-use non-electric applications using low temperature resources now predominate the geothermal industry.

The two critical aspects determining the successful commercialization of geothermal energy are co-location of suitable resources and appropriate development opportunities, and economic competitiveness with other energy supply options.

Some key areas where governments can remove some of the development uncertainties involve assistance with geotechnical information and clear regulatory and land tenure institutionalization.

The significant constraints on geothermal electric projects are more likely to be resource and technology related rather than commercial in nature. The key factor is whether a particular geothermal project will provide power more economically than a conventional power plant.

The commercial aspects of direct use systems are far more complex and inter-related. Compared to high temperature resources, low temperature resources are more abundant and accessible, offer higher conversion efficiency, require shorter development schedules, and have less expensive exploration and development requirements. However, successful market penetration of low temperature geothermal energy requires that favourable market opportunities be close to the resource.

For the predominantly low temperature resources in Canada, the principal use of geothermal energy is likely to be space and domestic hot water heating. Geothermal systems are capital intensive, with drilling costs and distribution system installation costs typically being the most significant items.

For successful commercialization of low temperature geothermal energy, one or several users are required with a large and constant total base load. Such systems can either take the form of a single well supplying a large building complex or formation of a geothermal heating district where geothermal fluids are distributed. A discussion of geothermal system costs and economic considerations is given in the report.

In order to compete in the energy market, geothermal developments require certain favourable circumstances. Key factors which influence market conditions include transportability and "grade" of energy, economic uses, the price of alternative energy, and market acceptance.

It is clear that geothermal systems can be exploited for a variety of applications, that other societies have found geothermal energy to be economic, and that Canada has geothermal resources of varying quality which can be developed. Nevertheless, to date there has been almost no commercial interest in geothermal development in Canada.
A well-managed, concerted plan for implementation is required for effective development of the industry.

ACRES

March 30, 1984

Acres File P7055.00
DSS File 07SX.31945-3-0025

National Research Council
Division of Mechanical Engineering
Building M-10, Montreal Road
Ottawa, Ontario
K1A 0R6

ATTENTION: Dr. Brian Larkin

Gentlemen:

Re: DSS Contract 0SQ83-00288 -
Survey of Regulatory and Commercial Aspects
of Geothermal Energy Development in Canada

We are pleased to submit 48 copies and one original set of our final report entitled "Regulatory and Commercial Aspects of Geothermal Energy Development". We have also forwarded one copy of the report to the Science Contracting Officer, at the Department of Supply and Services.

Acres Consulting Services Limited carried out the work with Nevin Sadlier-Brown Goodbrand Limited. We also wish to acknowledge with thanks the contributions made to this report by R. Gordon Bloomquist (Section 3.1) and Ronald E. Openshaw, (Section 3.2).

We believe that this assignment may open many new geothermal development avenues, and that the report offers a basis for future geothermal planning. Should you have any further questions, please do not hesitate to contact us.

Yours very truly,

T.M. Wardle, P.Eng.
Vice President

TMW/cbr
Enclosures

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REGULATORY AND COMMERCIAL ASPECTS OF GEOTHERMAL ENERGY DEVELOPMENT

Prepared for:

Government of Canada

DSS Contract 0SQ83-00288
Project Scientist: Dr. B. Larkin

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March 1984
P7055.00

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ABSTRACT

A survey was carried out of regulatory and commercial aspects of geothermal energy development. The study is intended for use by federal government program leaders, geothermal energy developers, provincial legislators, and other parties interested in development. Reference is made to geothermal experience in other countries, particularly the United States and France.

Canadian laws which potentially apply to geothermal energy are examined, including the Geothermal Resources Act of B.C., natural resource and groundwater laws, and environmental protection legislation.

Financial factors such as provincial assistance programs, tax treatments and consumer incentives are discussed. In many areas, the oil and gas industry provides a basis for comparison with the geothermal industry.

Finally, the report outlines the complex factors which affect the commercial climate for geothermal development in Canada. These include resource assessment and development concerns, system-electric development potential, direct-use commercialization costs and economic considerations, and a discussion of the competitive environment.

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1.0 INTRODUCTION

1.1 Report Objectives and Organization

In Canada, geothermal energy development is in its infancy. It is currently at the investigation stage of limited exploration, resource testing, and the examination of potential applications. It is evident that if geothermal energy is to be developed and compete with other energy supply options such as conventional oil and gas, solar, biomass, wind and hydro, a multitude of regulatory, jurisdictional and commercial issues need to be identified and resolved. The objective of this report is to outline these key factors and the implications arising from them, based on precedents in Canada and elsewhere.

Issues and practices that have developed in selected geothermal user countries are surveyed, and the status of the regulatory and commercial climate in Canada is evaluated.

It should be noted that the practices reported herein do not all necessarily represent exemplary models to be followed. In fact, some of the examples presented are clearly to be avoided. In considering the adoption of foreign practices in Canada, the differing social, economic and political realities must be taken into account. To assist in highlighting these differing considerations, the report has included comparative assessments, interpretations and analyses of implications in terms of Canadian applicability, so as to provide a perspective for the reader.

This report is intended for the use of geothermal program leaders within the federal government, for potential geothermal developers, and for legislators across Canada. In accordance with the study terms of reference, it is designed to function as a reference work for any person interested in geothermal energy in the country. The information will provide a basic framework useful for guiding the future direction of Canada's geothermal development.

The major sections of the report are essentially "stand-alone" discussions of the topics named, and thus the reader can go directly to sections of interest, omitting others in whcih he is not interested, without losing continuity.

In view of the diverse readership familiarity and expertise, the report commences with a very brief overview of technical aspects and applications in Section 1.0.

Section 2.0 reviews geothermal resources in Canada and the status of investigations in each province.

Section 3.0 examines selected experiences abroad. In particular, the comprehensive discussion of the United States presents rationales for different approaches to regulation of its geothermal industry. Details of financial incentive programs are provided.

Section 4.0 is a province-by-province survey of legislation affecting geothermal development in Canada. In most cases this legislation has not been specifically directed to the geothermal industry. Rather it is legislation such as natural resource laws (oil and gas, groundwater, minerals, etc.) which is potentially applicable to geothermal exploration and development.

Section 5.0 identifies financial factors which may encourage geothermal development in Canada. They include provincial programs, tax treatments, and consumer incentive programs.

Finally, Section 6.0 addresses the broad topic of commercial factors affecting geothermal development in Canada. These include resource assessment and development concerns, system-electric potential, direct-use potential, commercialization costs and economic considerations, and the competitive environment.

1.2 Definition and Characteristics of the Resource

"Geothermal energy" is heat generated by natural processes which occur within the earth. This heat is present everywhere beneath the surface of the earth. Its intensity increases with depth and varies from place to place according to geological conditions. In some areas, unusually high temperatures may be manifested at the surface in such features as hot springs, fumaroles and volcanoes. In other areas they are present only at great depths and can only be detected through temperature measurements in drill holes. The increase in temperature with depth has been observed worldwide and is known as the "geothermal gradient". As with other natural phenomena, the geothermal gradient varies from one locality to another, but in general the temperature increase is to the order of 25°C per kilometre.

A "geothermal system" is formed by the presence of anomalous heat in the earth's crust and is generally associated with high geothermal gradients.

Of the vast quantity of heat stored within the earth, the proportion which can presently be used for practical applications is very small. Human utilization is possible only in regions where geothermal heat is concentrated in exploitable form (presently as either hot water or steam), in sufficient quantity, and at a depth within economic reach of the surface. These conditions may be produced by an active geothermal system conveying the heat to a near-surface environment or by the presence of a reservoir of fluid deep enough to be hot under normal gradient conditions. Either of these sets of circumstances may constitute a "geothermal resource".

Geothermal resources may be classified according to common characteristics. These include temperature; host medium (water, steam, dry rock); host rock; and reservoir type; size and depth. The five most widely accepted basic categories are:

- Hydrothermal Systems
  - Vapour dominated
  - High temperature, liquid dominated (>150°C)
  - Moderate temperature, liquid dominated (50°C-150°C)

- Gradient Heat Systems
  - Deep circulation and deep sedimentary basin types
  - Hot dry rock

Reservoir characteristics are functions of the means of heat concentration in the near-surface environment. Regardless of how they are classified, the ultimate origin of the heat that drives the system is the same: it is the product of the radioactive decay of unstable elements which are dispersed throughout the earth.

1.3 Recovery Methods and Applications

Geothermal energy is economically recovered from naturally heated steam or hot water. This is used to drive steam turbines for electrical generation and to provide heat for a variety of applications. For some applications, sufficient heat may be obtained from natural springs. However, for large scale industrial use, geothermal reservoirs must be tapped at depth by drilling.

Geothermal drilling uses equipment similar to rigs used in the oil and gas industry. Modifications to compensate for high temperatures and corrosive fluids may be necessary, and differences between geothermal and petroleum reservoir characteristics may dictate different drilling practices.

Geothermal production holes must be connected to a gathering system which directs the fluid from the well(s) to the point of utilization. Electrical generation is the preferred application for vapour-dominated and high temperature liquid-dominated fluids. In the case of the vapour-dominated system, dry steam may be piped directly to turbines for electrical generation. If the fluid is high temperature water it may be directed to a separator vessel at reservoir pressure, then flashed to produce a steam and water component. The steam fraction may then flow to turbines and the hot water may be flashed again at a lower pressure, used for another purpose, or discarded.

Heat from low temperature geothermal waters may be converted to electricity utilizing binary-cycle turbines, or applied directly for space heating, process heating (e.g. material drying, cooking, chemical production), agricultural and aquacultural heating, and recreational uses such as swimming pools and spas.

2.0 STATUS OF GEOTHERMAL DEVELOPMENT IN CANADA

2.1 Historical Outline

Geothermal resources have yet to become a factor in the Canadian national energy equation, in part because readily accessible hydro and fossil fuel resources have been a disincentive to geothermal research. In addition, the absence of spectacular geothermal manifestations such as active volcanoes, geysers and fumarole fields, has contributed to the perception that Canada is geothermally benign. Recent work in British Columbia has shown that this is not accurate, but to date the only applications of geothermal energy in Canada are the heating of approximately a dozen recreational swimming pools in the west, and the warming of some community water systems in the north.

Prior to the early 1960's there was very little scientific interest in geothermal resources in Canada. Geological mappers in industry and government routinely ignored such features as hot springs and tufa deposits - both evidence of the possible presence of geothermal energy.

In 1962, the federal government, as an adjunct to the Upper Mantle Project then being undertaken by the Department of Mines and Technical Surveys, organized a geothermal study group within the Seismology Division (later the Division of Seismic and Geothermal Studies) of the Dominion Observatory. This group initiated heat flow research as part of an on-going geothermic study of Canada. Its objectives were scientific rather than utilitarian and it was not specifically intended as geothermal resource research. It nevertheless led in this direction when, in cooperation with the Cordilleran Volcanic Project of the Geological Survey of Canada (GSC), work was conducted in areas of recent volcanism in British Columbia.

In 1966 the Department of Mines and Technical Surveys was renamed the Department of Energy, Mines and Resources, and geophysical research (including geothermic studies) was assigned to the Earth Physics Branch. In a reorganization of this branch in 1982 the Gravity Geothermics and Geodynamics Division was established, and this is now the federal agency responsible for geothermal research.

Provincial and territorial government interest in geothermal resources has traditionally been limited. Only British Columbia has enacted specific geothermal legislation or contributed to geothermal research and development.

Exploration and development by corporate and private interests has been carried out only in B.C. with the provincial utility, B.C. Hydro, being the most important contributor. Their participation, which began in 1973, resulted in the discovery of geothermal steam at Meager Creek in southwestern B.C. In addition B.C. Hydro evaluated a number of other areas in the province during the 1970's. Meager Creek, however, remains the most ambitious Canadian geothermal project.

The exploration activity being carried out by B.C. Hydro led to increased interest in the geothermal potential of western Canada by a number of private corporations during the 1970's. Most of these companies were engaged in developments in the western United States. One of them, O'Brien Energy Ltd., later acquired exploration rights to a tract of land near Squamish, B.C., in the first public auction of geothermal land held by the province.

Geothermal development in any area is primarily a function of geological compatibility, but commercial, political, and logistical considerations are also important. For this reason Sections 2.2 through 2.6 discuss the level of effort into applied geothermal investigations, and the present development status across Canada. The discussion is organized by five geopolitical regions, namely: British Columbia, the Prairie Provinces, Northern Canada, Central Canada, and the Atlantic Provinces.

Figure 2-1 shows areas in Canada with known or potential geothermal resources.

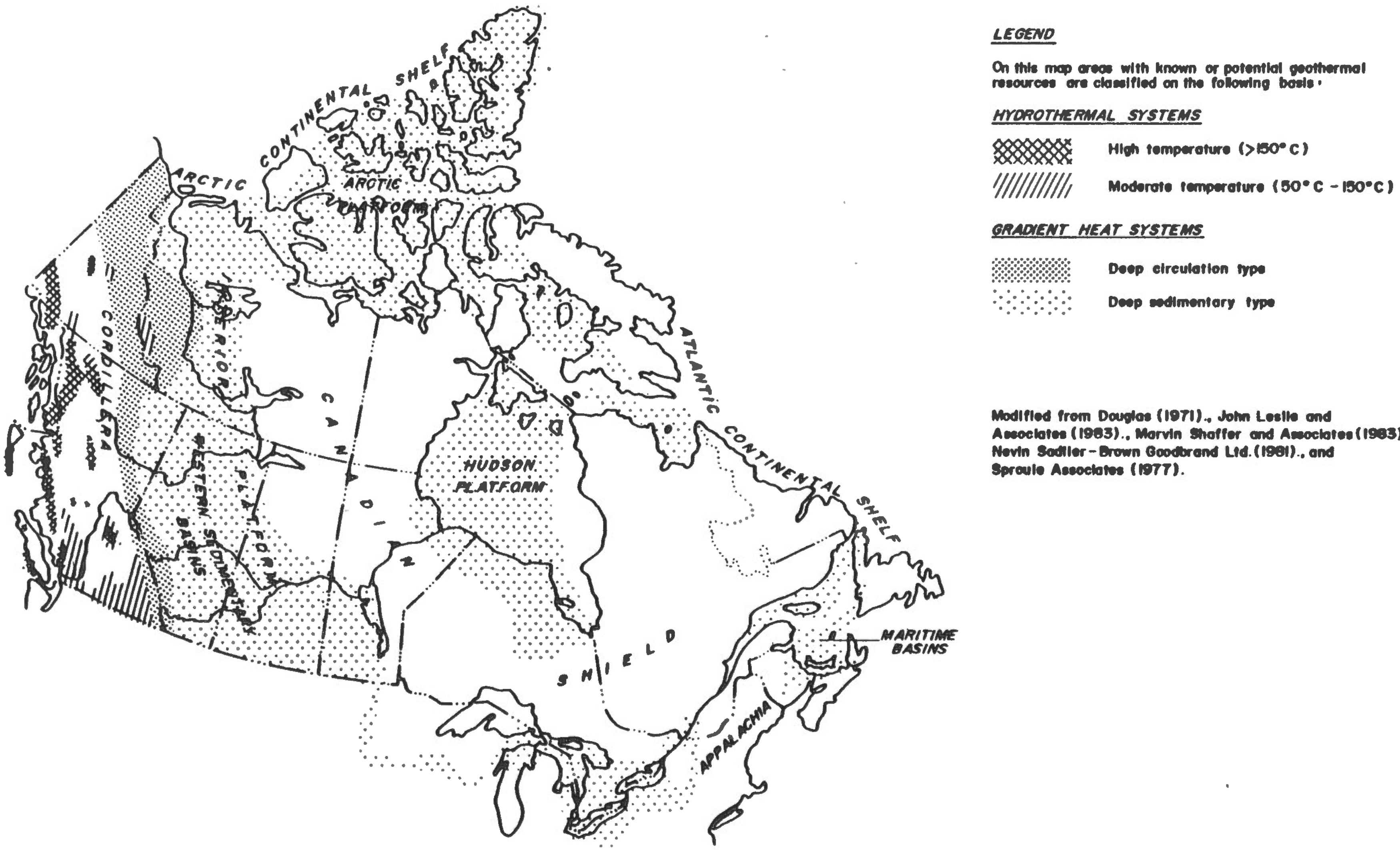


FIG.2-1

GEOTHERMAL RESOURCES MAP OF CANADA

2.2 British Columbia

Geological Setting

Of the five regional geothermal study areas referred to in Section 2.1, British Columbia has unquestionably experienced the greatest expenditure of research, exploration and development effort. Work in B.C. has been funded by the federal government through the Ministry of Energy, Mines and Resources (EMR), the provincial government, B.C. Hydro, and private developers.

The principal attraction of B.C. over the other regions has been the promise of near-surface high-temperature fluids which could be used in electrical generation. The province is host to about 25 young volcanic centres in three regional belts, and at least 60 hot springs, all evidence of contemporaneous geothermal activity.

Comparatively little effort has been spent in B.C. on investigations of lower temperature resources such as might be utilized for space heating. There is, nevertheless, considerable evidence that such resources are present in potentially exploitable quantities in several localities in the province (Souther, 1976; 1981).

Legislation and Regulation

Early recognition (Nevin and Sadlier-Brown, 1972) of B.C.'s potential geothermal resources led the provincial government to adopt the Geothermal Resources Act (on November 7, 1973). This legislation defined geothermal resources and reserved all rights to them to the Crown in the right of the Province. On June 7, 1982, this Act was repealed and replaced by a new Act which provides for disposition of geothermal rights and addresses all aspects of management of the resource.

Federal Government Participation in B.C.

In 1966 the Geological Survey and the Dominion Observatory Branches of the federal Department of Mines and Technical Surveys jointly carried out the Stikine Geothermal Drilling Project. This consisted of heat flow and geological studies of the Mt. Edziza area in northern British Columbia. Prior heat flow investigations differed from the work conducted here, as they were principally directed towards acquisition of geothermic data on a national scale and not necessarily in areas where anomalous heat flows might be expected. As one of B.C.'s largest and youngest volcanoes, Mt. Edziza, is a first order geothermal prospect, and the 1966 investigation may be considered the first true geothermal study carried out in Canada.

Since the Stikine project, the Department of Mines and Technical Surveys and its successor EMR have continued geothermic studies throughout British Columbia. In addition, through the work of the Geological Survey, it has carried out investigations of a number of Quaternary volcanic centres and thermal spring areas which might be related to geothermal resources.

In March 1974 the Geological Survey drilled two diamond drill holes in the vicinity of the Meager Creek Hot Springs in southwestern British Columbia (Lewis and

Souther, 1978). Both encountered hot artesian water which indicated that a larger geothermal system than previously envisioned was present. The area was subsequently selected for detailed geothermal exploration by B.C. Hydro, and a program of geological mapping, geophysical and geochemical surveys, and drilling was initiated (Nevin and Stauder, 1975). While the bulk of the work was funded by B.C. Hydro, EMR contributed substantially by carrying out detailed geological mapping, geophysical and geochemical studies, and by funding certain aspects of the gradient drilling program.

Other EMR projects in British Columbia which relate to geothermal research include geological and geophysical studies at Mt. Cayley in southwestern B.C., in the Lakelse area near Terrace, within the Anaheim Volcanic Belt in Central B.C., the Wells Gray/North Thompson River area, at Mt. Silverthrone, and in the Okanagan Valley (Souther, 1981).

EMR is the leading source of public information on geothermal research in British Columbia. Both the Earth Physics Branch, with offices at Patricia Bay near Victoria, and the Geological Survey Branch with offices in Vancouver, contribute to this research directly. In addition they regularly supervise projects performed under contract by private firms and educational institutions. Funding for federal government geothermal research is presently included in a budget provided under the National Energy Program.

Provincial Government Involvement

In addition to legislative recognition of geothermal resources, the B.C. Government has contributed to development through participation in several geothermal studies funded through the Ministry of Energy Mines and Petroleum Resources.

In 1979 the Ministry commissioned a comprehensive study of the geothermal potential of B.C. The study (Nevin Sadlier-Brown Goodbrand Ltd., 1981) addressed all aspects of geothermal development including technical, legal and commercial considerations.

Aspects of the geothermal potential of northeastern B.C. have been evaluated by two studies performed under contract to the Ministry. One of these, (Reid, Crowther and Partners, 1980) reviewed direct use geothermal resource potential near three northern communities: Dawson Creek, Fort St. John, and Fort Nelson. The other (Johnstone, 1982) evaluated the potential for use, in a binary electrical generating plant, of the hot water encountered in wells in the Clarke Lake gas field, near Fort Nelson.

In partnership with the federal government under the terms of the Conservation and Renewable Energy Development Agreement (CREDA), the B.C. government contributed financially to the research drilling carried out on B.C. Hydro's Meager Creek Project during 1979. Ministry of Energy, Mines and Petroleum Resources personnel also participated as advisors on the project.

B.C. Hydro and Power Authority Developments

As noted earlier, of the various groups which have participated in geothermal research exploration and development in British Columbia, B.C. Hydro have been the leading contributor. Their studies began with a survey of thermal springs associated with the Lillooet Valley fracture system and the Pemberton and Garibaldi Volcanic Belts of southwestern B.C. in 1973 and 1974. In addition they subsequently carried out evaluations of the geothermal potential of Vancouver Island and other areas in southwestern, west-central and northern B.C.

In 1974 B.C. Hydro initiated what was to become the most ambitious geothermal exploration program in Canada at Meager Creek, some 150 km north of Vancouver. During the course of this project 25 temperature gradient holes were drilled in two target areas on the southwest and northeast flanks of the Meager Creek Volcanic Complex, a Quaternary volcanic centre (Fairbank et al, 1981; Reader and Fairbank, 1983).

In 1981 and 1982 three deep production-scale holes were drilled (Stauder et al, 1983). Two of these had bottom hole temperatures in excess of 260°C and one produced geothermal steam. Due to drill-related problems, attempts at sustained steam production on a commercial scale have so far been frustrated. In February 1984, a 20 kW wellhead turbine generator was connected to hole MC1 as part of a limited flow test. The first geothermally generated electricity in Canada was scheduled for production March 21, 1984 (Stauder, 1984).

Private Development

The first offering of geothermal rights under the B.C. Geothermal Resources Act was made by public tender dated June 15, 1983. The rights consisted of a permit to explore and develop Crown geothermal resources on six parcels of land located near Mt. Cayley, a Quaternary volcano near the town of Squamish in southwestern B.C. One permit covering 8286 hectares was issued to O'Brien Energy, a Canadian company active in geothermal exploration in the United States (B.C. Government news release, June 30, 1983). O'Brien drilled one short, temperature-gradient hole in the summer of 1983. O'Brien has committed itself to a five-year work program that will require expenditures up to a maximum of $4.25 million.

The only present geothermal utilization in B.C. is in heating bathing pools at seven developed resorts and at a dozen or so undeveloped hot springs scattered throughout the province.

2.3 Prairie Provinces (Alberta, Saskatchewan, Manitoba)

Geothermal resources of the Prairie provinces are of the deep basin type occurring within the Western Canadian Sedimentary Basin underlying virtually all of Alberta, the southern half of Saskatchewan and southwestern Manitoba. The temperature of formation water or brine, contained within permeable reef complexes and stratigraphic aquifers, is determined by the geothermal gradient and the depth to host formations at any given locality. Representative temperature gradients within the basin average 25-30°C/km, but vary between 20°C/km in recharge areas along the southwestern margin of the basin to regional highs of 50°C/km. Drilling depths to potentially exploitable resources are between 1000 m and 3000 m.

Representative resource temperatures are therefore between 50°C and 125°C, suitable for direct use applications, with the higher temperatures attainable only in the deeper parts of the basin. Shallow groundwater resources at temperatures less than 50°C may be utilized in conjunction with heat pumps or for very low grade heat applications. In general, the basin is deepest (and potential resource temperatures greatest), along its southwestern margin in Alberta and northeastern B.C., and becomes progressively shallower towards its northeastern margin where it thins out completely. It extends into the Yukon and Northwest Territories to the north, and the U.S.A. to the south.

Various studies directed at regional delineation, characterization and assessment of prospective geothermal resources on the prairies have been on-going since 1975.

Virtually all of this work has been based upon a vast amount of drill hole data available through many years of oil, gas and mineral (potash) exploration and development. The raw data include fundamental information on formation porosity, permeability, temperature and fluid chemistry. Inconsistencies in measurement techniques and reporting of information critical to geothermal assessments are common since water production potential and accurate temperature measurements have not been a primary concern of the developers. In addition, data are incomplete on potentially productive geothermal aquifers or regions as these do not necessarily coincide with productive oil and gas horizons and explored areas.

The majority of the geothermal research done to date has been sponsored under the federal government's Energy Research and Development Program. The lead agency for geotechnical assessment work has been the Earth Physics Branch of the Department of Energy, Mines and Resources (Jessop, 1975). Initial studies of a basin-wide nature and on specific regions of interest have delineated and characterized geothermal resources on a regional scale (Sproule Associates, 1976, 1977; Jones et al, 1982). Reservoir mapping techniques and associated problems in using existing well data are outlined in a report by Sproule Associates (1984). More recently, federal studies sponsored by Energy, Mines and Resources and the National Research Council (NRC) have focused on extraction technology and the identification of potential applications for deep-basin geothermal resources (Sproule and Angus Butler, 1981; SNC Group, 1982; Acres, 1983; Acres and Nevin Sadlier-Brown Goodbrand Ltd., in preparation).

The leading geothermal work of a site-specific nature has been performed at the University of Regina, Saskatchewan (Vigrass et al, 1978). To date, the University of Regina campus is the only potential geothermal site that has been tested by drilling (Vigrass, 1979). Related studies have included water chemistry and corrosion testing (Postlethwaite et al, 1980a, 1980b) and economic evaluations (Bens et al, 1982). The project is currently on hold, pending funding for a fluid disposal well which would allow for long-term testing of the reservoir.

Other important contributions to geothermal research on temperature distribution within the basin include that by the University of Alberta in Edmonton (Lam et al, 1982; Jones et al, 1982), the American Association of Petroleum Geologists (AAPG, 1976), and various researchers studying regional heat flow (Anglin and Beck, 1965; Garland and Lennox, 1962; Majorowitcz and Jessop, 1981).

At present, no specific regulations are in place to govern the development of geothermal resources. The one demonstration well drilled to date at Regina was permitted under the existing oil and gas regulations for the Province of Saskatchewan. Many operations involved in deep-basin geothermal exploration and development (for example: exploration and production well drilling, well testing, fluid disposal by injection, environmental and safety requirements) are commonplace in oil and gas development and there are regulations governing that industry. It is probable that existing regulations are sufficient, or else can be adapted to control geothermal development. Additional regulations covering above-ground geothermal installations may be required in the future.

A wealth of subsurface data, useful in assessing the geothermal potential of various regions, has been gathered by oil and gas developers and is made publicly available through established reporting procedures. Temperature measurements are often collected in conjunction with other geophysical well logs; however, this data is of limited use for geothermal because, as a general rule, there is insufficient supporting information on the well status. Standards for the reporting format of temperature measurements and supporting data, particularly the elapsed time since last drilling fluid circulation, would be invaluable to geothermal reservoir mapping and would be a minimal imposition for the oil and gas industry.

2.4 Northern Canada

Geological Setting

The two jurisdictions which, for purposes of this discussion, make up Northern Canada are the Yukon and Northwest Territories (including the Districts of Mackenzie, Franklin, and Keewatin). Geothermal resource potential is greatest in the western regions, the Yukon and the District of Mackenzie, where over 40 hot springs and several young volcanic terranes are known (Crandall and Sadlier-Brown, 1976). Both low and high grade resources may be expected to occur in the displaced western component of the Yukon Cordillera. In the District of Mackenzie, low grade gradient heat may be expected in the northern part of the Western Canadian Sedimentary Basin including the Mackenzie Fold Belt which comprises the eastern component of the Cordillera. In addition the Arctic Sedimentary Basin which underlies the greater part of the District of Franklin, the most northerly jurisdiction, is also geologically compatible with the existence of low grade geothermal resources.

Legislation and Regulation

No legislation has been passed by the Government of the Yukon or the Northwest Territories or by the Federal Government to regulate geothermal development in these jurisdictions. Existing developments are regulated by other legislation, particularly land and water acts.

Development Status

Geothermal investigations in Northern Canada have been carried out by the federal Department of Energy, Mines and Resources and by one private company, Canada Tungsten Mines Ltd. (Crandall and Sadlier-Brown, 1976). Two Yukon communities have explored the possibilities of using warm water from deep wells in community water systems to prevent freezing in the winter, and there are two hot springs, one in the Yukon and one in the Northwest Territories, where development for recreation has taken place.

As part of an on-going study of terrestrial heat flow in Canada, EMR is continually compiling gradient and heatflow data in the north. Although this work is not considered to be geothermal resource exploration, when coordinated with geological studies in areas with geothermal potential it provides a useful data base, as experience in B.C. has shown.

In 1976 the Department of Energy, Mines and Resources sponsored a study intended to assess the geothermal resources of the Cordilleran Yukon and Northwest Territories (Crandall and Sadlier-Brown, 1976). During the course of the study 42 thermal or suspected thermal springs and three areas of recent volcanism were evaluated.

In 1977 the Canada Tungsten Mining Company funded a geothermal evaluation of the vicinity of the CanTung Mine in the Flat River area Northwest Territories. The objective of the project was discovery of an exploitable geothermal resource. The work was suspended, however, after early results proved inconclusive.

Utilization of geothermal resources in the north is presently quite limited. Water from hot springs is used to heat a public swimming pool at Takhini near Whitehorse, Yukon and a bathing pool near the community of CanTung, Northwest Territories.

At Mayo, Yukon, water warmed by gradient heat in a deep well is used in the public water supply system. This well water at 15.5°C is mixed with cooler well water at ambient temperature. The resulting increase in temperature, though marginal, is sufficient to prevent freezing in the system except under severe conditions. This problem which is prevalent in northern communities is normally offset by heating with oil.

The Engineering Department of the City of Whitehorse, Yukon, has evaluated proposals to augment that community's water system with water from warm wells.

Like other areas of Canada, the north has benefited from hydroelectric resources sufficiently abundant to provide most of its needs. A significant component of the electrical load in the region is nevertheless dependent upon diesel generation. This is attributed to the sparse population often in small isolated centres which could not justify the capital cost of long hydro lines or conventional hydroelectric developments. In addition, small hydro which is gaining acceptance elsewhere, might be subject to freezing problems in winter.

Northern Canada Power Commission (NCPC), the federally-owned utility which serves the north, has contemplated alternative energy resources including geothermal. For the present, however, the unique challenge of providing power to this vast area is adequately met using the hydro-diesel mix.

On the basis of geological considerations, there are two areas of the Yukon which might be compatible with geothermal resources of the system-electric type (Crandall and Sadlier-Brown, 1976; Shaffer and Associates, 1983). One, the Wrangel Volcanic belt, is located in the extreme western Yukon adjacent to the Alaska border and remote from any population centres. The other lies immediately west of Whitehorse, almost certainly close enough to be economically exploited if found to host a geothermal resource.

2.5 Central Canada (Ontario and Quebec)

No geothermal resources have been identified or exploited in Ontario and Quebec, and it appears likely that none will be for the foreseeable future. The reasons for this are geological, regulatory, and commercial. (A project is underway in northern Toronto to study the storage of heated water in shallow aquifers as a way to reduce building heating costs, but this has no bearing on geothermal resource use.)

Ontario and Quebec are mostly underlain by the Canadian Shield which contains parts of the oldest continental crust in the world. The Shield consists of Precambrian (greater than 600 million years old) igneous, metamorphic, and sedimentary rocks that are overlain by younger, Paleozoic sedimentary rocks in southern Ontario and Quebec, and Paleozoic to Mesozoic sedimentary rocks along the western shores of James and Hudson Bays. The most recent intrusive rocks are located in the Monteregian Hills near Montreal. Radiometric dating indicates these igneous rocks are about 100 million years old.

The geology of Ontario and Quebec precludes any high temperature heat sources and most low temperature sources as well. Because of their great age, igneous rocks of the Shield have lost some of their ability to generate heat through radioactive decay, and have long since lost any of their original, magmatic heat. Geothermal gradients in the Shield are low, around 10°C/km. Fracture permeability that would permit deep circulation of fluids is also apparently low as there are no reported surface manifestations such as warm or hot springs. The most likely source for low temperature fluids would lie, not in the Shield itself, but in the overlying Paleozoic sedimentary rocks that have been explored for petroleum and groundwater resources. These sedimentary sequences are as much as 600 m thick and contain aquifers capable of producing the volume of water needed. Geothermal gradients, measured in petroleum exploration drill holes, vary unsystematically from less than 1°C/km at London, to 20°C/km at Hamilton, to 35°C/km near Montreal (American Assoc. of Petroleum Geologists and USGS, 1976). Anticipated geothermal resources in these rocks would be comparable to resources found in the shallow strata underlying the Prairies. The resource would have low temperatures (less than 40°C), variable amounts of dissolved solids, and insufficient hydraulic head to sustain artesian flow. The resource could be used for some agricultural purposes (such as soil heating; aquaculture; fermentation) or space heating if used with heat pumps.

Given the low temperatures anticipated, even from the deepest aquifers in Ontario and Quebec, it is not surprising that no geothermal resources have been identified or exploited. No legislation exists that would directly regulate geothermal development. Instead, resource exploration and exploitation would be affected by parts of acts pertaining to other natural resources such as minerals, brines, petroleum, and groundwater, although application of these acts to geothermal development might strain their intent.

2.6 Atlantic Provinces (New Brunswick, Nova Scotia, Prince Edward Island, Newfoundland)

The geologic setting of the Atlantic Provinces is the product of a very long period of mainly sedimentary deposition, extending from the late Precambrian to the Cenozoic, punctuated by two major mountain building cycles (including deformation, igneous intrusion, uplift, and erosion) in Ordovician and Devonian time. Deformation since the Devonian has been mainly faulting and folding. Deformed Carboniferous rocks were overlain by Mesozoic terrestrial sedimentary and volcanic rocks deposited in fault troughs. Post-Devonian deformation has created a series of structural basins which are as much as 8,000 m thick. Parts of the Maritimes are underlain by granitic plutons, of Paleozoic age, that were intruded into the sedimentary sequences. These are magmatic or volcanic rocks younger than Mesozoic age in the area.

The Atlantic Provinces have the potential for two types of geothermal resource, although neither is likely to have high temperatures. These are: gradient heat type resources in deep sedimentary basins; and hot, dry rock type in Paleozoic granitic intrusions. Heat in the granitic rocks would come from the radioactive decay of unstable elements that might be concentrated there.

No geothermal resources have been exploited in the Atlantic Provinces apart from demonstration projects using heat pumps or shallow water wells. Since 1980, under the direction of the Earth Physics Branch several studies have been conducted aimed at a broad assessment of geothermal resource potential in the area. These have entailed the compilation of existing data on drill hole temperatures, thermal properties of rocks, heat generation, age of granites, and hydrological data such as formation pressures and water chemistry (Leslie and Associates, 1981; 1983a). In addition, the Earth Physics Branch has drilled temperature gradient holes in New Brunswick and P.E.I. (Leslie and Associates, 1983b). Other studies of heat production of granitic rocks have been conducted in New Brunswick and in Newfoundland (Wright et al, 1980). Apart from publicly funded studies, only one private company (Noval Corp. of Halifax) is known to be collecting temperature data from their oil and gas drill holes with a view to potential geothermal applications.

No geothermal legislation exists in the Atlantic Provinces and none is anticipated. Every province has various laws controlling groundwater resource use, oil, gas and mineral exploration as well as for the protection of the environment. Geothermal exploration and development would likely proceed under the terms of existing resource legislation which is differently treated in each province. Provincial interest in alternative energy sources is variable. Due to long term economic conditions in the Atlantic Provinces it appears that government assistance for geothermal projects will come primarily from federal rather than provincial sources.

3.0 REGULATORY AND COMMERCIAL ASPECTS IN SELECTED FOREIGN COUNTRIES

3.1 United States

3.1.1 Introduction

To a large extent, the regulatory and commercial aspects of geothermal development have been addressed, in varying degrees, by the United States Congress and by the legislatures of each of the states known to possess geothermal resources. Often the conclusion reached, and the direction given by these differing bodies, have been significantly different. Often, as well, the legislation has left as many questions unanswered as answered, or created as many new problems as it resolved. In some cases, the legislation has, in fact, proven to be more of an obstacle to development than an aid.

3.1.2 Leasing

Providing access and a secure right to the resource for exploration and development is provided for through leasing.

The development of statutes for the regulation of geothermal leasing in the United States began with the passage of the California Geothermal Resources Act of 1967, and the Federal Geothermal Steam Act of 1970. A majority of the states possessing geothermal resources followed suit during the 1970's, and often modeled their statutes after either the California or federal Acts. However, a number of state leasing statutes differ considerably from the California and federal models, and this divergence can be attributed to the complexity of dealing with this "new" resource, or to historical differences in how the states dealt with the disposition and protection of its natural resources.

The major differences in the statutes can be traced to how geothermal resources are defined and characterized.

3.1.3 Resource Definition

Geothermal resources are related to water, gas, and minerals, to both the surface and subsurface estates, and to both water rights and mineral titles. How geothermal resources are defined will effect all of the others.

There are, therefore, two basic tasks in defining geothermal resources. The first is to describe the physical properties which distinguish geothermal resources from other natural resources and thus clearly establish what is subject to geothermal leasing, taxation, and development regulations. And second, a definition must relate geothermal resources to groundwater, subsurface minerals, and other established resources. An ideal resource definition should, therefore, be both anticipative and retrospective. It must look forward to future leases, exploration, and development activities while, at the same time, looking backward in order to place geothermal resources into the framework of leases, reservations, and property titles inherited from the past (Sacarto, 1976).

How well legislation accomplishes these two tasks will have a profound influence upon the reduction of future conflicts of ownership.

The California Geothermal Resources Act of 1967 made the first attempt at defining geothermal resources and reads as follows:

> 'Geothermal resources' shall mean the natural heat of the earth, the energy, in whatever form, below the surface of the earth present in, resulting from, or created by, or which may be extracted from, such natural heat, and all minerals in solution or other products obtained from naturally heated fluids, brines, associated gases, and steam, in whatever form, found below the surface of the earth, but excluding oil, hydrocarbon gas, or other hydrocarbon substances.

The Federal Geothermal Steam Act of 1970 (Public Law 91-581) defined geothermal resources thusly:

> 'Geothermal steam and associated geothermal resources' means (i) all products of geothermal processes, embracing indigenous steam, hot water, and hot brines; (ii) steam and other gases, hot water, and hot brines resulting from water, gas, or other fluids artificially

> introduced into geothermal formations; (iii) heat or other associated energy found in geothermal formations; and (iv) any by products derived from them.

The federal definition defined byproduct so as to exclude oil, hydrocarbon gas, and helium.

Both the California and the federal definition provide a detailed discription of the physical properties which distinguish geothermal resources from other natural resources, but fail to relate geothermal to such things as groundwater and minerals.

Washington took a somewhat different approach to defining geothermal resources:

> 'Geothermal resource' means only that natural heat energy of the earth from which it is **technologically practical to produce electricity commercially** and the medium by which such heat energy is extracted from the earth, including liquids or gases, as well as any minerals contained in any natural or injected fluids, brines, and associated gas, but excluding oil, hydrocarbon gas, and other hydrocarbon substances (RCW 79.76.). (Bold type added for emphasis.)

The principal difference in the Washington definition is that it restricts geothermal resources to those **"from which it is technologically practical to**

produce electricity commercially." Geothermal resources were so defined in Washington State to provide for a clear division of responsibilities for purposes of regulation. The Department of Natural Resources, which normally regulates oil and gas drilling, was, by this mechanism, given the responsibility for the regulation of the high temperature and pressure resources, while the Department of Ecology, which normally regulates groundwater, was given the responsibility for low temperature pressure resources. Unfortunately, because no cut off temperature was set, but instead let to float, the Department of Natural Resources must now regulate resources with temperatures down to approximately 100°C because advances in technology have made the generation of electricity possible at temperatures much below that which was anticipated at the time the Act was passed into law.

Alaska also desired to separate the regulation of its resources, but, unlike Washington, adopted a definite temperature cut off (Basescu, et al., 1980). The Alaska definition reads as follows:

> "'Geothermal resources' means the natural heat of the earth at temperatures greater than 120 degrees Celsius, measured at the point where the highest temperature resources encountered enter or contact a well shaft or other resource extraction device, and include.

> The definite temperature cut off tends to take the guess work out of where an applicant should

> apply for a resource or drilling permit and allows for a district separation of agency responsibilities. This also clarifies whether or not the fluids are available through appriation as groundwater or lease as geothermal."

By excluding resources of less than 120°C from the definition of geothermal, the Alaska legislature has facilitated their use, since regulation meant for large-scale commercial use of high temperature resources need not be observed for most direct use applications (Basescu, et al., 1980). Although this was also the objective of the Washington Legislators at the time the Geothermal Resources Act of 1974 was passed, they could not anticipate that rapid developments in technology would, in time, so completely change the definition and possibly place an undue burden upon both the developer of direct use projects, as well as the developer of moderate temperature resources for electrical generation where neither high temperatures or pressure present the degree of risk associated with the development of high temperature resources.

The Oregon definition, which, for the most part, is based on the federal model, provides additional restrictions based upon temperature and depth. Hot water from wells deeper than 600 m (2,000 feet) must be developed according to geothermal statutes. Hot water from shallower wells with bottom-hole temperatures less than 120°C (250°F), must be developed according to state water law. It is not necessary, however, under Oregon law to know bottom-hole temperature of wells before they drilled as all geothermal wells prospecting is regula under the geothermal statutes. However, if a wat well should, in the course of development, encounte temperatures approaching 120°C (250°F), a geothermal permit must be obtained (Justus, et al., 1980).

In all of the above examples, the definition accomplishes the task of describing the physical properties which distinguish geothermal resources from other natural resources, but generally fail to characterize geothermal resources in relation to groundwater, subsurface minerals, and other established resources. It is only through such characterization that ownership of the resource can be established, conflicts with owners of other resources avoided, and a sound leasing program established.

3.1.4 <u>Resource Characterization</u>

Geothermal resources are similar in some respects to water, minerals, and gas. As a result, considerable disagreement--including litigation--has arisen over the essential nature of the resource and corresponding ownership rights. Such a climate of uncertainty has, and will certainly continue to, impede geothermal development, and makes resource characterization a major issue which must be dealt with in any statutes which deal with the leasing of geothermal resources for exploration and development.

The federal government, in passage of the Geothermal Steam Act of 1970, avoided the question as to how geothermal resources should be characterized. In fact, the Steam Act chose instead to direct the Justice Department to bring suit to quit title and decide whether or not geothermal resources had been reserved to the federal government as part of the mineral estate. The action brought by the Justice Department (United States of America vs Union Oil Company of California) began in 1971, and a verdict in favor of the United States was not reached until October 1977 under the title Ottobonie vs the United States of America. This delay resulted in a moratorium on leasing until the case was decided and a lack of considerable revenue to the United States. As the primary area in question was at the Geysers in Northern California (the richest geothermmal area in the world), the loss of revenue to the federal government, and the negative effect which this case had upon development in the Geyser area, could have been avoided if the legislation had simply characterized the resource as mineral and a part of the mineral estate.

California, in the passage of the California Geothermal Resources Act of 1967, also avoided this very important question, and again it was left up to the courts to characterize the resource. It wasn't until the case of Pariani vs California was decided in 1981 (California Court of Appeal, 1981) that geothermal was declared to be a mineral resource for purposes of ownership and leasing of California lands.

Unlike California and the federal government, a number of states have chosen to characterize geothermal resources. However, not all of these have done so in a manner which resulted in clear understanding of ownership or leasing rights.

In Idaho, the state declared that geothermal resources are...*sui generis*, being neither a mineral resource nor a water resource, but they are...closely related to, and possibly affecting and affected by, water and mineral resources in many instances (Renwick and Lewis, 1976).

In Washington, the legislature declared that "Notwithstanding any other provision of law, geothermal resources are found and hereby determined to be *sui generis*, being neither a mineral resource nor a water resource" (Bloomquist, et al., 1980).

The *sui generis* characterization of geothermal resources serves only to cloud the ownership issue and is, for all practical purposes, meaningless.

The states of Wyoming, Utah, and Montana have characterized geothermal resources as water, while the state of Hawaii has chosen to characterize geothermal resources as minerals.

In many other states it is very unclear exactly how geothermal is characterized. For example, in New Mexico it is stated that geothermal is not water (Renwick and Lewis, 1976), but it is unclear as to whether or not the legislature intended that geothermal be considered to be a mineral. In Alaska, geothermal is characterized as being similar to oil, gas, coal, ores, and minerals, but no clear assignment is made (Basescu, et al., 1980).

Whether geothermal resources are characterized as water or mineral, it would be preferable to have such a solution explicitly legislated so that ownership can be clearly determined. Due to the fact that in three court decisions, geothermal resources have been determined to be mineral and a part of the mineral reservation (usually in keeping with the usage of geothermal resources as an energy fuel), it seems appropriate and desirable, in view of the court decisions, that future legislation characterize geothermal as a mineral resource.

It can thus be clearly seen that the characterization of the resource serves as the second task in defining the resource in that it relates geothermal resources to groundwater, subsurface minerals, and other established resources, and by doing so allows for the placement of geothermal resources into the framework of existing leasing, reservation, and property titles.

3.1.5 Ownership

By clearly defining geothermal resources to be either water or mineral, the problems associated with the establishment of ownership will be greatly reduced.

Mineral ownership derives from an estate in land, which may be 'severed' from property rights to the overlying surface. Groundwater, at least in the west, is generally held in the public domain while being an aspect of surface ownership in most eastern states. In the case where the resource has been determined to be sui generis, the state may assign the resource to the owner of the surface estates or the mineral estate, or may, in fact, claim the ownership of all geothermal resources in the state regardless of ownership of the surface or mineral estate, and separate from existing water rights.

The federal government claims geothermal ownership wherever it holds the mineral estate, either jointly with the surface estate or as a mineral reservation where the estates have been severed. This claim was upheld in the Ottobonie vs U.S. case which was mentioned earlier. Whether federal ownership extends to groundwater useful for thermal purposes where the estates are severed is unclear. Absent, implied, or explicit reservation of water pursuant to the establishment of a federal enclave, the states have primary control over water resources.

The states have taken a number of approaches to the assignment of ownership and reflect how the resource was characterized as to water, mineral, or sui generis.

In Alaska, the state claims ownership of all geothermal resources, including those under private lands, and is in line with the state's claim to all subsurface resources in the state. The state of Alaska does, however, give the surface owner a preferential right to a prospecting permit or lease. It must be remembered that by definition, geothermal resources in Alaska are limited to those above 120°C, while ownership of 'geothermal resources' below that temperature would fall under water law statute, and ownership would be assigned accordingly (Basescu, et al., 1980).

In Utah, Wyoming, and Montana, geothermal resources are also in the public domain due to their characterization as water.

A majority of the other states, except for Oregon and Washington, which have declared geothermal resources to be the property of the surface owner, either by statute or practice, appear to recognize mineral ownership. In Hawaii, geothermal ownership is assigned to the mineral estate, and all minerals are the property of the state until severed (Renwick and Ried, 1976).

Washington has declared geothermal resources to be the property of the surface owner (Bloomquist, et al., 1980), but it is presently unclear, because of the impractical way which the state has defined geothermal, what is truly included in such an assignment and what remains available for appropriation as groundwater. It is also likely that the assignment of geothermal to the surface owner in Washington will result in a number of court challenges by those who have maintained an interest in the mineral estate, but where the surface estate had been severed.

It is thus extremely important that geothermal resources be defined so as to be easily distinguished from other natural resource characteristics in order that a clear assignment to an estate can be accomplished and ownership determined. It is only after the completion of these tasks that access to the resources can be made available to developers through leasing.

3.1.6 Resource Access

Providing prompt access and secure rights to public lands for geothermal exploration and development is crucial if geothermal resources are to become an important additional energy resource available to regional and national energy planners.

There are a number of ways through which access can be made available through the transfer of public resource rights to private developers. Resources may be simply conveyed without charge, such as in the case of federal mining claims and non-competitive oil and gas leases, or made available through bidding procedures (Sacarto, 1976).

Bidding may take the form of cash bonuses, annual rentals, production royalties, profit shares, or work commitments. Regardless of whether the resource is transferred by competitive or non-competitive means, developers may be required to pay annual rentals, production royalties, and diligently explore for and develop the resource.

Access can be provided through two or three procedures which can include exploration or prospecting permits and/or non-competitive leases for lands of unknown potential while requiring competitive bidding for particularly valuable resource areas. Another approach would be to allow for exploration and prospecting permits, but require all leasing to be by competitive bid.

The federal government has adopted a three tier approach. Prospecting permits are available to developers and allow for geological, geochemical, and geophysical surveys, as well as the drilling of holes to a depth of 900 m (3,000 feet). The permits are non-exclusive and are not convertible to leases. Non-competitive leases are available to the first qualified applicant on lands of unknown potential. Competitive leases are available to the highest qualified bidder in Known Geothermal Resource Areas, or KGRAs. A non-competitive lease application can, however, be rejected at anytime up to when the lease is issued if the area becomes a KGRA. (KGRA is defined as "an area in which the geology, nearby discoveries, competitive interest, or other indications would, in the opinion of the Secretary (of the Interior) engender a belief in men who are experienced in the subject matter that the prospects for extracting of geothermal steam or associated geothermal resources are good enough to warrant expenditures of money for that purpose") (United States Geological Survey, 1979).

Competitive bidding for KGRA lands is by cash bonus bidding only. However, legislation now pending before Congress (Senate Bill S 558) (United States Senate, 1983) would call for a percentage of all KGRA lands to be offered on other than a cash bonus basis--namely royalty bidding.

A majority of the states have also adopted the two or three tiered access system. Oregon, California, and Alaska all have provisions for the issuance of exploration or prospecting permits in addition to having both competitive and non-competitive leases available. Oregon, in addition to competitive cash bonus bidding, provides for simultaneous filing of applications, with the successful qualified applicant selected by random public drawing (Oregon Revised Statutes Chapter 522).

Washington and Montana lease all lands through a competitive bidding process (Sacarto, 1976). In Montana, however, if only one person bids for the tract, the applicant may negotiate a lease with the Department of Natural Resources and Conservation. The Department may, however, choose to reject all bids and applications (Perlmutter and Birkby, 1980).

Careful consideration must be given to several factors in the adoption of the mechanism for the transfer of public resources and the form or forms of distribution which will be employed.

The system should provide for multiple forms of access. Exclusive or non-exclusive exploration or prospecting permits can attract developers to wildcat areas. Such permits can be extremely effective in encouraging exploration if developers are given preference in converting the permit to a non-competitive lease or the right to match the highest bid if the leases are awarded through competitive bidding. Non-competitive leases provide a mechanism by which developers can secure rights to a resource with little cash outlay, and are extremely important in attracting developers to unproven areas. The filing of a non-competitive lease application should provide protection for the applicant against reclassification of the area as a KGRA before the lease is granted. Such protection can guarantee that the applicant will be granted a lease on a non-competitive basis if work performed by the applicant resulted in the reclassification and/or the applicant can be given the right to match the highest bid if the reclassification was the result of work performed by another applicant. Senate Bills S 558 and S 883, which are presently under consideration by Congress (United States Senate, 1983), would provide these forms of protection to federal lease applicants.

Competitive leasing can result in the greatest initial monetary benefit to the public, but it can also serve to discourage or prevent certain developers from gaining access to public lands. This is probably most true and detrimental where leases are only offered on a competitive basis. For example, the lower economic value of low to moderate temperature resources can seldom warrant large outlays of money, and may result in many areas receiving no bids severely inhibiting exploration and development. Competitive leasing can also provide extreme difficulties for public bodies which cannot expend large sums of money on high risk ventures. There is also a problem for such public entities in that they must obtain approval of expenditures in a public forum, thus providing other bidders with knowledge of the bids which will be submitted.

Several possible solutions to such problems are worth consideration. First, competitive areas should be limited to those areas where a significant high temperature discovery has been made in order that the value of the resource can be accurately determined by both the lessor and the potential lessees. Legislation now under consideration by the U.S. Congress would limit KGRAs to areas where there is physical evidence of the existence of geothermal resources capable of generating electricity (Senate Bill S 558, Sec. 3) (United States Senate, 1983). It is extremely important that such areas be limited to only those possessing high temperature resources capable of being utilized to generate electricity as the economic value of resources for direct applications cannot justify the additional expenditures and risk required by competitive bidding.

As an example of the problems which can be created by the creation of KGRAs in low temperature areas, a well was drilled near Boise, Idaho, in the late

1970's, on federal Bureau of Land Management property. The well encountered approximately 71°C (170°F) geothermal resources, and the area was immediately reclassified as a KGRA requiring competitive bidding. However, the low temperature of the resource would not justify a cash bonus bid. The well was also in an area of considerable interest to the city of Boise, Idaho, which desired to construct a geothermal district heating system using water from the area which was now a KGRA. In order for this area to be made available to the city, an act of Congress was necessary which transferred this area to the city in exchange for other properties (McClain, 1984).

Second, the use of non-cash bonus bidding, i.e. royalties or profit sharing, allows for maximum return to the public without tying up needed exploration dollars for cash bonuses. This also allows for full participation by public entities.

Third, work commitments can speed development, but will not provide for maximum return to the public from the exploitation of public resources if it is not tied to royalties or profit sharing.

Fourth, it is possible to use cash bonus bidding and still allow for the participation of the public sector if sealed bids are submitted by private developers well in advance of the submission of bids by the public entities. This allows the public bodies a period of time for gaining approval of the expenditure of funds through the public process.

This, however, is based upon the assumption that there is no other prohibition against the expenditure of such funds by the public entities involved.

Fifth, a mechanism should be provided for reclassifying KGRA lands which have been offered but which have received no bid (Senate Bill S 558, Sec. 4) (United States Senate, 1983).

3.1.7 Acreage Limitations

The federal government, as well as most states, has set limitations on the size of leases and limitations upon holdings in any one state. At the federal level, the Geothermal Steam Act of 1970 limited lease size to a maximum of 1,036 hectares (2,560 acres) with a minimum of 260 hectares (640 acres). In addition, the Steam Act limits individual holdings to 8,290 hectares (20,480 acres) per state (United States, 1970).

Size limitations have also been adopted by many states. In most cases, the minimum size has been set at 16 hectares (40 acres), while maximums ranges from 260 to 1,036 hectares (640 to 2,560 acres) and above. Alaska and California have both set maximum state acreage limitations of 20,700 hectares (51,200 acres) and 10,360 hectares (25,600 acres) respectively. Idaho has taken another approach by limiting the holding of leases to a maximum 50 townships (Sacarto, 1976).

The setting of limitations on minimum lease size has drawn severe criticism from small developers of low temperature resources for direct applications. This is because a minimum of 260 hectares (640 acres) requires tying up a great deal of acreage with accompanying rentals for applications which can be successfully undertaken on 16 hectares (40 acres) or less.

The maximum lease size, which generally ranges from 260 to 1,036 hectares (640 to 2,560 acres), appears to be of very little consequence, although if a sizeable application fee is required per application, the 260 hectare (640 acre) maximum could result in a financial burden to the developer because of the total number of applications which would have to be filed.

On the other hand, a limitation upon individual holdings in a given state has been singled out by developers as the single most serious impediment to geothermal development in the United States. Developers contend that the 8,230 hectare (20,480 acre) limitation severely handicaps the successful operator since two discoveries in a state effectively eliminates a company from additional exploration. Because of this, once a skilled group of technical personnel are trained, there are insufficient resources to allow them to continue an orderly progression of exploration and development. The limitation has, in addition, forced many companies to give up attractive prospects because they were at or near the acreage limitation.

At present, the U.S. Congress is considering legislation (Senate Bills S 558 and S 883) which would raise the acreage limitation to 20,700 hectare (51,200 acres) per state, and exempt from this limitation any leases under development (United States Senate, 1983). The exemption of acreage under development from the limitation appears to provide for industry's desire to have an even greater acreage allowance without having a problem of too much acreage being tied up which is not under development.

3.1.8 Rentals and Royalties

Annual rentals are normally assessed for the opportunity to explore on public lands and serve primarily to cover the cost of regulation and administration. Rentals may also provide the lessor with a tool for ensuring diligent exploration in that required expenditures on exploration must equal a set amount or increased rentals will be assessed.

Rentals on federal and state lands usually begin at $1.00 per acre per year. The rental on federal KGRA lands is $2.00 per acre per year.

On federal lands, the rental increases to three dollars per acre, beginning with the sixth year, but with the provision that expenditures on exploration may be deducted from the increased amount. Exploration expenditures in order to qualify must equal $4.00 per acre in year six, $6.00 per acre in year seven, and $8.00 per acre in year eight, $10.00 per acre in year nine, and $12.00 per acre in years 10 through 15.

The states of Oregon and Idaho have also adopted increasing rentals as a means of encouraging diligent exploration.

Other states, such as Arizona and Colorado, have no set rental fee, but instead, the rental is negotiated along with other lease terms (Sacarto, 1976).

Royalties are assessed on production and ensure that some portion of the value of the public resource is returned to the public treasury.

Royalties, unlike cash bonuses and rentals, involve no risk for the developer and, therefore, appear to treat equitably both large and small developers as well as public and private entities. However, the manner in which royalties are calculated may significantly penalize the developer engaged in the direct utilization of geothermal resources in comparison to the developers of electrical generation projects. Although royalties on both electrical and direct use products range from 10-15 percent for state as well as federal leases, the way in which the royalty is calculated can and does make a significant difference in the amount different developers will pay. In the case of electrical generation, the royalty is based upon the selling price of the steam or electricity. On direct use projects, the royalty is based upon the value of the heat energy available, unless the project involves the sale of that energy, in which case the royalty is based on gross sales.

The following clearly illustrates how differences in how the royalty is calculated can seriously affect the economic viability of direct use projects. If developer A leases and develops a geothermal resource on federal lands and sells the energy to User B, the 10 percent federal royalty is assessed against gross sales. If, on the other hand, the Developer and the User are the same entity, and no sale takes place, then the royalty is based on the equivalent cost of the cheapest conventional fuel in the area. The royalty is then inflated at the same inflation rate as that of the conventional fuel. If the lessee happens to be a corporation in a 48 percent effective federal income tax bracket, the royalty would be subtracted from sales and reduce the company's tax liability by 48 percent of the royalty. The net effect would be a 5.2 percent royalty. If the royalty is assessed against a non-taxable entity such as a public utility or a municipal heating district, it can become one of the major annual costs of the geothermal project. For example, the Klamath Falls, Oregon, Business Core Heating District is projected to pay itself back in seven years. If it were necessary to drill the production wells on federal lands and pay a 10 percent royalty on the energy consumed, this same project would suffer a $3,600 per year loss for the first 10 years in terms of annual equivalent costs. If the annual cost of operating the Klamath Falls system included a federal royalty of 10 percent, the breakdown of the annual costs for the first year of operation would be as follows: (Higbee, 1979)

	Percent
Electrical pumping costs	24.8
Maintenance costs	19.7
Federal royalty payments	55.5

The problems which the inequity that royalties have placed upon developers of direct use geothermal energy has resulted in legislation being introduced into the U.S. Congress which would lower the royalty on such projects from the present 10 to 15 percent to a more reasonable 5 to 10 percent (Senate Bills S 558 and S 883). The same bills allow the Secretary of the Interior to "defer royalty payments for non-electric geothermal developments when it is deemed to be in the public interest, for municipal, cooperative, or other political subdivisions lessees where legal limitations on front-end financing otherwise would prohibit or significantly deter development" (United States Senate, 1983).

However, the deferring of royalty payments and reductions in the percentage do not solve the problems associated with the way in which the royalty is calculated. A possible solution to this problem is, however, under consideration by the Washington State Department of Natural Resources (see Table 3-1) (Washington Department of Natural Resources, 1982). The method of calculation encourages full utilization of the resource by rewarding the developer who utilizes more Btus per unit of resource with a lower royalty per Btu. The system will also result in a greater return to the state treasury

TABLE 3-1

PRICING OF DIRECT USE LOW TEMPERATURE GEOTHERMAL ENERGY

($ per 1,000 U.S. gallons)

DISCHARGE TEMPERATURE - DEGREES FARENHEIT

*ΔT	270°	260°	250°	240°	230°	220°	210°	200°	190°	180°	170°	160°	150°	140°	130°	120°	110°	100°	90°	80°	70°	*ΔT	** Base Price $/1,000 Gal.
10	$.073	$.068	$.065	$.061	$.058	$.055	$.053	$.050	$.048	$.046	$.044	$.042	$.040	$.039	$.037	$.035	$.034	$.033	$.031	$.030	$.029	10	0.458
20	.146	.137	.129	.122	.116	.110	.105	.100	.096	.092	.088	.084	.080	.077	.074	.071	.068	.065	.063	.060	.058	20	0.917
30		.205	.194	.183	.174	.166	.158	.151	.144	.137	.132	.126	.121	.116	.111	.106	.102	.098	.094	.090	.086	30	1.375
40			.258	.245	.232	.221	.210	.201	.192	.183	.175	.168	.161	.154	.148	.142	.136	.130	.125	.120	.115	40	1.833
50				.306	.290	.276	.263	.251	.240	.229	.219	.210	.201	.193	.185	.177	.170	.163	.156	.150	.144	50	2.292
60					.348	.331	.316	.301	.288	.275	.263	.252	.241	.231	.222	.213	.204	.196	.188	.180	.173	60	2.750
70						.386	.368	.351	.336	.321	.307	.294	.282	.270	.259	.248	.238	.228	.219	.210	.201	70	3.208
80							.421	.401	.383	.367	.351	.336	.322	.308	.296	.284	.272	.261	.250	.240	.230	80	3.667
90								.452	.431	.412	.395	.378	.362	.347	.333	.319	.306	.294	.282	.270	.259	90	4.125
100									.479	.458	.439	.420	.402	.386	.370	.355	.340	.326	.313	.300	.288	100	4.583
110										.504	.482	.462	.443	.424	.407	.390	.374	.359	.344	.330	.317	110	5.042
120											.526	.504	.483	.463	.444	.425	.408	.391	.375	.360	.345	120	5.500
130												.546	.523	.501	.481	.461	.442	.424	.407	.390	.374	130	5.958
140													.563	.540	.518	.496	.476	.457	.438	.420	.403	140	6.417
150														.578	.555	.532	.510	.489	.469	.450	.432	150	6.875
160															.592	.567	.544	.522	.501	.480	.460	160	7.333
170																.603	.578	.555	.532	.510	.489	170	7.792
180																	.612	.587	.563	.540	.518	180	8.250
190																		.620	.594	.570	.547	190	8.708
200																			.626	.600	.576	200	9.167
210																				.630	.604	210	9.625
220																					.633	220	10.08
%	15.88	14.93	14.09	13.34	12.66	12.05	11.48	10.95	10.46	10.00	9.569	9.163	8.778	8.413	8.066	7.736	7.420	7.117	6.827	6.548	6.280	Royalty Rate	

Example: Lessee uses 100,000 gallons of fluid during one month @ an input temperature of 200°F and a discharge temperature of 100°F. The monthly production royalty due is $.326/1,000 gal., or $32.60.

*ΔT = °Farenheit extracted by geothermal energy conversion process

** Base price - $5.50 per million Btu

because even at the lower royalty, the full utilization of the available Btu's will result in a higher total payment (see Appendix C).

Washington is also considering providing incentives to developers of electric generation projects by offering a 1 percent reduction in the royalty if the resource is cascaded for use in direct use projects. An additional 1 percent reduction in the royalties is allowed if the fluids are reinjected (Washington Department of Natural Resources, 1982).

Royalties are also assessed on the extracted value of by-products. On federal leases, the royalty is up to 5 percent of the value of the by-products, and the state leases royalties on by-products range from 2 percent to over 12.5 percent (Sacarto, 1976).

3.1.9 Lease Terms, Adjustments, and Renewals

Because geothermal energy is unique in that it must be used on site, and often involves substantial outlays for utilization facilities and pipe lines and/or electrical transmission lines which require amortization periods of 20-30 years, the effective lease life, adjustments of lease provisions during the life of the lease, and lease renewals are of paramount importance to developers. Equally important, however, is the prevention of land speculation on the part of the lessor, the ability to make adjustments in lease provisions so as to ensure compliance with state regulations, and to ensure that a reasonable portion of the revenue generated from public lands is returned to the public treasury.

The use of exploration or prospecting permits which require work commitments, and which are granted for periods of 1-3 years, is an excellent way to prevent speculation but may discourage exploration if such permits are not convertible to leases or provide the holder of the permit with a preference to a lease.

Noncompetitive and competitive leases are normally issued for periods of 5 to 20 years (Sacarto, 1976). The longer the primary lease term, the more important it is that the lease carry reasonable diligence requirements to minimize having public lands locked up by land speculators. It is also extremely important that the lease term be of sufficient length to ensure that the developer has a reasonable opportunity to fully evaluate the leased area.

Most leases carry clauses which ensure an extension of the primary lease term if the developer is actively engaged in exploration and/or drilling, and all state and federal leases provide for the extension of the lease once production of geothermal resources in commercial quantities begins. Such an extension is usually limited to 40 to 50 years. California allows for a lease term of up to a maximum of 99 years so long as production continues (California, 1970), and several states, including Montana, Wyoming, and New Mexico, allow for the continuation of the lease so long as geothermal resources are produced or are capable of being produced (Sacarto, 1976).

One very important consideration which has surfaced since the enactment of most state and federal leasing statutes is a need to provide for an extension of the primary lease term where, for no fault of the developer, commercial production cannot begin although resources capable of being developed have been discovered. Legislation now pending before the U.S. Congress (Senate Bills S 558 and S 883) would allow for such an extension and Section 7 of S 558 reads as follows: "...However, in the event construction of the (utilization) facility or facilities has not been possible due to administrative delays beyond the control of the lessee or due to the demonstrated marginal economics of such a (utilization) facility or facilities, and substantial investment in development of the lease has been made, the Secretary (of the Interior) will consider an additional extension of the extended primary lease term of up to 10 years: <u>Provided</u>, that the lessee be required to submit annual reports detailing bona fide efforts to resolve the administrative delays or to bring the (utilization) facility or facilities into economic production" (United States Senate, 1983)

Readjustment of terms during the period of the lease is extremely important, and must take into consideration what effect that frequent renegotiations will have upon compounding the risks already inherent to geothermal development in deterring investment.

The Federal Geothermal Steam Act of 1970 provides for a readjustment of lease terms and conditions at not less than 10 year intervals after the date the geothermal steam is produced. However, readjustment of rentals and royalties is restricted to not less than 20 year intervals beginning 35 years after the date geothermal steam is produced (United States, 1970).

Alaska provides for a renegotiation of rentals and royalties due on geothermal leases 20 years after the initiation of commercial production and at 10 year intervals thereafter (Basescu, et al., 1980). A number of other states, including California, Montana, and New Mexico, provide for 10 year renegotiation of rentals and royalties beginning 20 years after the lease date (Sacarto, 1976).

Frequent readjustments in rentals and royalties is likely to deter investments in geothermal development, and appears to be unnecessary in that if royalties are based upon the price for which the energy is sold, revenues will increase at a rate proportional to the rate at which the value of the energy is inflating. The pricing formula being considered by the state of Washington (Table 3-1) would, however, require frequent adjustments in the base price upon which royalties are calculated.

Frequent adjustments in terms other than rentals and royalties has also drawn criticism, and has resulted in a reluctance on the part of utilities to utilize geothermal resources for power plant operation (United States Department of Energy, 1979). However, as a result of the Report of the Interagency Geothermal Coordinating Council on Geothermal Streamlining Recommendations, legislation has been introduced to modify the readjustment provisions of the Geothermal Steam Act of 1970. At present, Senate Bills S 558 and S 883 contain language which would revise the adjustment period clause. Section 8 of S 558 reads as follows. "The Secretary (of the Interior) may adjust the terms and conditions,...,of any geothermal lease issued under this Act at not less than 20 year intervals beginning 20 years after the date production is commenced, as determined by the Secretary..." This would make a 20 year readjustment period as opposed to the present 10 year period (United States Senate, 1983).

Leases should also provide preferences to lease holders in the event that leases are to be renewed. Most renewal clauses, however, carry provisions for the renegotiation of lease terms (Sacarto, 1976).

3.1.10 Diligence Requirements

One of the most controversial provisions of most leasing statutes involves diligent exploration requirements; however, without such requirements public lands can be held for long periods of time by speculators who have no intention of exploring or developing geothermal resources, but who are hoping that a nearby discovery will substantially increase the value of their property so that it will be purchased by a legitimate developer.

The use of escalating rentals, as a means of encouraging diligent operations, has already been discussed in the section on rentals and royalties. However, a number of other approaches are also available to lessors, and should be given serious consideration.

At present, Section 13 of Senate Bill S 558, which is being considered by the U.S. Congress, would require that a plan of operation for exploration be filed within three years of the issuance of a lease, and that drilling shall commence no later than two years after approval of such plan, or two years after a drilling permit has been approved, whichever is later (United States Senate, 1983). This provision has been the target of a great deal of criticism by industry which claims that drilling within five years of the issuance of the lease may cause premature drilling and unnecessarily increase the cost and risk of developing geothermal resources. Section 13 of Senate Bill S 883 would require that a plan of operation be submitted within five years, and drilling begin not later than four years after the approval of the plan and the granting of the drilling permit. Since the primary lease term is ten years, the diligence provision of S 883 would have very little impact on encouraging more rapid development (United States Senate, 1983). A more reasonable approach and perhaps an acceptable compromise would appear to require that a plan of operation be submitted within four or five years of the issuance of a lease, with drilling beginning no later than two years after the approval of the plan and the granting of the drilling permit.

Washington has proposed in its draft Rules and Regulations for Geothermal Resource Leasing that during the first five years of the lease, the operator would be required to spend on approved exploration and development, a minimum of $20 per acre during the first two years; during the third year, not less than $15 per acre; during the fourth year, not less than $20 per acre; and during the fifth year, not less than $25 per acre. The draft would provide for the lessee to pay the state the scheduled amount in lieu of the performance of development work or improvements (see Appendix C). Beginning the sixth year of the lease, the lessee shall be producing geothermal resources in paying qualities or:

- the lessee shall be engaged in drilling of production and/or reinjection wells with no more than 90 days elapsed time between the completion of one well and the spudding of the next, or
- the lessee shall be engaged in deepening, repairing, or redrilling of any wells without 90 day cessation of operations, or

- the lessee shall be diligently constructing facilities for the processing, conversion, or use of geothermal resources, or
- the lessee shall be diligently attempting to obtain necessary permits and environmental approvals for commercial operation.

Although Washington's proposed diligence requirements should be given serious consideration as a way to guarantee performance by a lessee, they would require a great deal more administration than the proposed federal requirements.

A more comprehensive analysis of U.S. leasing statutes and regulations is beyond the scope of the present study. This study has instead attempted to concentrate on those provisions which have resulted in the greatest amount of controversy or which have been determined to have deterred exploration and development.

The recommendations which have been presented represent the views of the author, and do not necessarily represent a consensus of opinion of developers and regulators. The importance of leasing statutes and regulations to the success of any state or national geothermal program cannot be over emphasized. Geothermal development in most areas cannot occur without access to public lands, and access is provided through leasing.

A comprehensive leasing program is, however, not sufficient by itself to ensure a successful geothermal program. A number of other considerations must be addressed in order to ensure that the legal and institutional framework necessary for geothermal development is provided. Groundwater law, environmental reviews, exploration and development permits, as well as utility and facility siting requirements, must be addressed through statute.

3.1.11 Groundwater Law

Groundwater is an integral part of any geothermal resource (except hot dry rock) being the medium by which the heat energy of the earth is conveyed to the surface. Most states have recognized the importance of groundwater in their definitions or characterizations of geothermal resources. In some states, such as Montana and Wyoming, geothermal has been declared to be a groundwater resource (Sacarto, 1976). In other states, such as Washington, Oregon, and Alaska, geothermal resources are divided into high and low temperature regime(s) for purposes of regulation with high temperature resources being considered geothermal and the low temperature (below 120°C in Alaska and below 120°C (250°F) in Oregon) geothermal resources being considered to be groundwater (Basescu, et al., 1980) (Justus, et al., 1980). By making such a distinction based on temperature, the lower temperature resources have become subject to groundwater law and development regulations and not geothermal leasing and development regulations.

Groundwater is treated as a public resource in most western states. The exceptions are Arizona, California, and Hawaii, in which, like most eastern states, groundwater is attached to the surface unless critical groundwater areas have been designated requiring water rights to be adjudicated (Sacarto, 1976).

Because historical uses of groundwater included domestic, agricultural, and industrial purposes, but not geothermal, conflicts between existing uses and geothermal needs were almost ensured as geothermal development became more widespread.

Montana attempted to minimize conflicts through its claim that geothermal resources are water and must be regulated accordingly. A permit for appropriation is required for any use of water over 0.38 m^3 (100 gallons) per minute, and must be issued when the following criteria are met: (Montana Water Use Act 85-2-101 et. seg. M.C.A.) (Perlmutter and Birkby, 1980)

1. unappropriated water in the supply source is available, in the amounts and at the time of year required by the applicant;

2. the rights of prior appropriation will not be affected adversely;

3. the proposed means of diversion or construction are adequate;

4. the proposed use of the water is a "beneficial use;"

5. the proposed use will not interfere unreasonably with other planned uses or developments for which a permit has been issued or for which water has been reserved.

(Montana considered heat extraction as a beneficial use.)

Idaho and California have attempted to minimize conflicts between geothermal and groundwater usage by differentiating between waters which have a beneficial use (groundwater that must be appropriated) and those which cannot be used for purposes other than for their energy content.

In Oregon, such conflict has been addressed in Chapter 522.255 of the Oregon Revised Statute. The Statute reads as follows: (Oregon, 1983)

> "Resolution of conflicts between geothermal and water uses. If interference between an existing geothermal well permitted under this chapter and/or existing water appropriation permitted under ORS Chapter 537 is found to be either the State Geologist as the Water Resources Director, the State Geologist and the Water Resources Director shall work cooperatively to resolve the conflict and

develop a cooperative management program for the area. In determining what action should be taken, they shall consider the following goals:

1. Achieving the most beneficial use of the water and heat resources;
2. Allowing all existing users of the resource to continue to use those resources to the greatest extent possible; and
3. Ensuring that the public interest in efficient use of water and heat resources is protected."

However, despite all attempts to minimize conflicts resulting from competing use, and to ensure that geothermal resources could be developed, conflicts have arisen and often with devastating results. Perhaps the best example can be found in the experience of Klamath Falls, Oregon.

The city of Klamath Falls, Oregon, began evaluating the feasibility of constructing a downtown geothermal district heating system in 1977, and by late that year received notification from the U.S. Department of Energy that it would receive demonstration funds under a federal USDOE grant program. The city began by drilling two highly successful production wells, and once the resource had been proven, the construction of the system began in earnest. However, Klamath Falls is an area where geothermal energy has been utilized by a number of homeowners and commercial establishments since early in the 1900's, and these users began to worry that the city system would, in spite of reinjection of the fluids into the reservoir, adversely affect their own geothermal energy supplies. Because of these fears, a citizen's initiative, organized by the Citizens for Responsible Geothermal Development (CRGD) was successful in filing over 1,500 signatures with the city, and when the initiative measure was voted on in 1981, the future of the city's geothermal system received a serious setback. The initiative, which was passed 788 to 567, forbid "persons, cooperatives, organizations, municipal corporations, or any political subdivision of the state of Oregon from withdrawing geothermal water 'from a well unless it is returned' undiminished in volume to the <u>same well</u>." (Emphasis added) The effectiveness of the initiative was to prevent the city from using either of the two wells (even though the entire system was completed and ready to begin operation in 1982), and forced the city to consider alternative heat sources (United States Conference of Mayors, 1982). The future of the system was still in limbo as of March 1984. However, long term reservoir tests were completed in 1983 which indicated that existing wells would not be effected by the operation of the city's district heating system, and the initiative was repealed in part by the City Council in early March 1984, allowing for the system to be put into operation (Allen, 1984). What legal action, if any, that the CRGD will take is at this time unclear.

The Klamath Falls example, as well as the problems experienced by the city of Pagosa Springs, Colorado, only serve to emphasize the importance of groundwater to geothermal development (Eliot Allen, 1984).

3.1.12 Environmental Reviews

Providing adequate protection for the environment is a major responsibility of any government, but how that protection is structured can have a profound impact upon a developer's ability to successfully complete a project in a timely fashion.

The federal government, as well as the state governments, have adopted environmental statutes which require that all major activities proposed be subjected to review of the environmental impact that such action will involve.

The Geothermal Steam Act of 1970 was the first major piece of legislation to be enacted after the passage of the National Environmental Protection Act, and managers of federal lands, as well as developers, were presented with an uncharted course to follow. The result has often been confusion and serious time delays.

The most serious delays (at present over ten years) have been in the processing of lease applications and the offering of KGRA lands for lease. The primary cause of these delays was that, in the view of the U.S. Forest Service and Bureau of Land Management, all pre-lease environmental reviews must consider the environmental risks associated with all exploration and development activities--in other words, the pre-lease environmental review must be based upon a worst case scenario before a lease could be issued. However, close review and analysis of the leasing statutes and implementing rules and regulations clearly indicate that the issuance of a lease provides the lessee with nothing more than the right to explore for and develop geothermal resources if such exploration and development activities can be accomplished in an environmentally acceptable manner (United States Geological Survey, 1979).

In order that this interpretation become a matter of law, the Report to the Interagency Geothermal Coordinating Council, from the Streamlining Task Force on Streamlining the Federal Leasing and Environmental Review Procedure, recommended that in order to expedite geothermal exploration and development, the "use of generalized, area wide environmental assessments through the Land Management Planning process in pre-lease review, and detailed site-specific studies only for post-lease activities" (United States Department of Energy, 1979).

Thus, pre-lease environmental reviews should be limited to determining which areas are totally unacceptable to development activities, and detailed environmental reviews should be undertaken only in response to specifically proposed activities. In this way, the environmental review can be restricted to the evaluation of each proposed activity in relationship to the exact area where the activity will be undertaken. For example, since very little environmental degradation is likely to occur from surface geological exploration, geophysical, and geochemical surveys, an extensively detailed environmental reviews should not be required.

However, as the drilling of deep exploratory wells is planned and sited, an environmental review of much greater detail would be required, but such a review would be restricted to the immediate area where the drilling was to take place. Finally, if a geothermal resource is encountered and a permit application for facility construction is filed, the detailed environmental review can be based upon the qualities of the resource, knowledge of any environmentally hazardous substances present in the fluids, the proposed conversion and disposal technologies, and the exact proposed site for facility construction.

The ability to utilize a phased environmental review process as opposed to the worst case scenario approach will result in much lower costs to the surface management agency, more timely processing of both lease and post-lease permit applications, and ultimately better protection for the environment since the review will be based upon facts instead of suppositions.

3.1.13 Exploration, Drilling, and Production Permits

Permits for exploration, drilling, and production on federal lands are issued by the Department of the Interior, Bureau of Land Management (BLM), pursuant to the Geothermal Resource Operational Orders (United States Geological Survey, 1979).

Permits to conduct surface exploration and to drill temperature gradient holes to a depth of 150 m (500 feet) are issued to the applicant after a finding of no significant environmental impact by the BLM. Application for such permits, entitled a "Notice of Intent and Permit to Conduct Exploration Operations," can be filed by developers on all federally managed lands, including lands in KGRAs and land which is under lease application by another developer. Federal permits may also be issued to a non-lease holder to drill exploration holes to a depth of 900 m (3,000 feet) upon the approval of a Plan of Operation filed by the applicant. All post-lease exploration activities are carried out under a Plan of Operation approved by the BLM. Permit applications for all such post-lease exploration activities require the completion of an environmental review by the surface management agency before permit issuance (Fujimoto, 1984).

Resource production on federal lands is regulated by an approved Plan of Production from the BLM. Before such a Plan of Production can be approved, the applicant must gather environmental baseline data describing the existing environmental setting for a one year period. No Plan of Production can be approved by the BLM until after the completion of an environmental review. A finding of significant environmental impact during the review process will require the preparation of an environmental impact statement pursuant to the National Environmental Protection Act before the plan may be approved.

States have the authority to issue exploration, drilling, and production permits on state lands, and, in some instances, on private and federal lands as well.

The states of Oregon and Alaska regulate and issue permits for well drilling regardless of land ownership, while the state of Washington regulates drilling on all state and private lands, but claims no authority to issue permits related to exploration, drilling, or production on federal lands. The state of Montana issues permits for drilling and seismic exploration on all lands (Perlmutter and Birkby, 1980).

Production permits are issued by states for all lands where the state claims ownership of geothermal resources, and may require unit operation of lands of mixed ownership if necessary for the conservation of natural resources which underlays in common state, private, and federal lands.

3.1.14 Energy Facility Siting

The securing of permits and licenses related to the siting of energy conversion facilities and transmission lines is an extremely important step in the development of geothermal resources, and the complexity of the process involved in obtaining such permits can have a serious consequence upon the timeliness and cost effectiveness of development.

The construction of energy conversion facilities and transmission lines is regulated on federal lands by the BLM under the provisions of the Geothermal Resource Operational Orders. On state lands this responsibility is often within the State Energy Facility Siting Council Department or Division. Such state energy facility siting authority over state lands may extend to the siting of energy facilities on federal lands, as is the case in Oregon. Oregon has one of the most comprehensive Energy Facility Siting Acts, and will be examined here in detail.

The State of Oregon Energy Facility Siting Council (EFSC), established under provisions of the Energy Facility Siting Act, has jurisdiction over certain energy facilities on all lands, private, state, or federally owned. Site certifications are required by the EFSC for any geothermal power plant with a nominal electrical generating capacity of more than 25 megawatts (ORS 469.300(10)(a)); pipelines transporting geothermal fluids which are six inches or greater in diameter and five miles or longer in length (ORS 469.300 (e)(A)); and high voltage transmission lines of more than ten miles in length with a capacity in excess of 230,000 volts (Justus, et al., 1980).

The Oregon EFSC has adopted general standards which apply to all energy facilities and require the following mandatory findings: need for the proposed facility based on energy demand and economic prudence, protection of public health and safety, environmental protection, beneficial use of wastes and byproducts, conformance with statewide planning goals and comprehensive land-use plans, protection of historical and archaeological sites, no infringement on existing water rights, necessary expertise to operate, construction and retire the facility, reasonable assurance of obtaining the necessary funds, and identification of foreseeable socioeconomic impacts in the vicinity of the proposed facility (OAR 345-74-025) (Justus, et al., 1980).

The Oregon EFSC also has the power to conduct investigations into all aspects of site selection, designate areas within the state as suitable or unsuitable for geothermal power plants, and to establish standards and promulgate rules which must be satisfied in order to obtain a site certification.

The power of the EFSC to designate areas as unsuitable for geothermal power plant siting resulted in a decision by the Council in the mid 1970s that geothermal power plants greater than 25 MWe could not be constructed in Newberry Caldera. This area has, since that decision, been determined to be one of the highest potential geothermal areas in the Northwest, and possibly the entire U.S. Such rulings tend to seriously deter exploration in what may be extremely high potential areas, and appear to be premature since the decision is based on a lack of information concerning the nature of the resource and the energy conversion technology which would be employed.

A very important element of energy facility siting statutes, and a critical role of the implementing authority, is to provide for the coordination of permit and license application processing through all state and local agencies affected by such an application, and ensure that the coordination with other agencies makes siting of all energy facilities a one step process for applicants, saving both time and money, as well as ensuring that all applications are handled and evaluated in a consistent manner. Once a siting certification for a transmission or energy conversion facility is granted, all state and local agency permits and licenses must be granted as a matter of course. Each permitting agency, however, retains the authority to enforce all requirements of the permit or license issued. Examples of some of the permits required include: conditional land use permits, construction permits, drilling permits, a permit for the disposition of liquid wastes, and permits for air emissions.

Unlike Oregon, other states such as Montana and Washington have given the energy facility siting authority only limited powers over state and private lands. For example, in Washington, the Energy Facility Siting Evaluation Council (EFSEC) maintains siting jurisdiction over all lands, private and state owned, but only in the case where on-site improvements exceed $250,000, and the generating plant has a capacity of 250 MWe or more (Bloomquist, et al., 1980). Thus, geothermal development would only rarely fall under the jurisdiction of the EFSEC. The exemption of most geothermal developments in Washington from EFSC regulations may, as some developers contend, simplify the siting process, but, on the other hand, the ability of the EFSEC to coordinate the processing of an application through all state and local agencies should result in substantial savings in both time and money, and be much preferable.

3.1.15 Utility Easements

The culmination of any successful geothermal exploration and development project is the delivery of the energy to the user. However, the ability to deliver the energy to the market, either in the form of hot water or electricity, is highly dependent upon the developer's ability to obtain easements across federal, state, local, and/or private lands for the construction of pipelines or electric power transmission lines.

The ability to obtain easements to cross both public and private lands is simplified if such easements are for "public use." The public use requirement is satisfied by most definitions of a "public utility," and, therefore, a closer examination of utility law as it pertains to geothermal appears to be in order to determine the utility status of electrical and direct use projects.

Public utilities are entities (individuals, corporations, associations, etc.) that supply services considered indispensable to the public, and are thus "affected with a public interest" (Nimmons, et al., 1979). Although "services" is defined differently from state to state, suppliers of heat, water, electricity, and natural gas are commonly considered to be subject to public utility statutes.

California's Public Utilities Code defines public utility to include "every common carrier, toll bridge corporation, pipeline corporation, gas corporation, **electrical corporation, water corporation,** sewer system corporation, wharfinger, warehouseman, and **heat corporation**, where the service is performed for, or the commodity delivered to, the public or any portion thereof."

In Colorado's statute "the term public utility...includes every common carrier, **pipeline corporation**, gas corporation, **electric corporation**, telephone corporation, telegraph corporation, **water corporation**, person or municipality operating for the purpose of supplying the public for domestic, mechanical or public uses and every corporation, or person declared by law to be affected with a public interest and each of the preceding is hereby declared to be a public utility and subject to the jurisdiction, control and regulation of the commission..." (Nimmons, et al., 1979).

Thus, under most utility statutes, both electrical generating and direct use projects would be considered to be public utilities entitled to apply for easements across state and federal lands for the construction of needed pipelines and electric transmission lines.

Applications for such easements are made through the appropriate local, district, or area office of the appropriate land management agency. Applications require the preparation of environmental reviews and, if there is a finding of significant environmental impact, an environmental impact statement will be required and prepared under provisions of the appropriate state or national environmental protection act. If the easement is granted, the applicant will be required to pay annually the fair market value of the interest in the land being acquired.

Easements may also be required across city or county properties, and may be granted as a public use by the city or town councils, boards, or county commissioners.

If pipelines, transmission lines, or other facilities for developing or using a geothermal resource must cross privately owned lands, the geothermal developer must either negotiate with the landowner(s) for the necessary easements, or, if that fails, seek to acquire such an easement through the right of "eminent domain." Eminent domain is the right of the state or other entities operating in the public interest to take private property for "public use" (Perlmutter and Birkby, 1980).

In order to use eminent domain, the developer must file a complaint in district court describing the proposed public use, the source of the right to such use, the property interest sought, and the present ownership(s). The court must determine whether the proposed use is an authorized public use, and establish the amount of property to be taken. The court may also determine the appropriate compensation to be paid by the petitioner.

It is thus clear that the inclusion of both direct application and electrical generating geothermal projects in utility law, and a determination that such projects are for "public use," are vital in ensuring that markets are accessible to developers of geothermal resources.

The statutory provisions which the author has described above have been developed by federal and state governments in an attempt to provide developers with the legal and institutional framework necessary to ensure that geothermal resources are accessible and developable in a timely manner, and that rights necessary to such exploration and development activities are secure.

The establishment of a sound legal and institutional framework, however, may not be sufficient in itself to promote widespread geothermal resource development, and if such development is determined to be desirable or necessary, a number of financial, and commercial initiatives, and programs should be given full consideration.

3.1.16 United States Financial Incentive Programs

The financing of geothermal resource exploration and development projects has, and continues to be, a difficult task for developers. The expense of drilling deep exploration and/or development holes, and the risk of encountering fluids which are unusable in terms of either temperature or flow to meet the energy needs of the proposed project, have served to severely limit the availability of conventional financing to conduct exploration and development activities. Even after developers have successfully discovered geothermal fluids in usable quantities and of usable quality, financial institutions have been unwilling to provide financing because of their lack of familiarity with geothermal projects and how the risks of project success can be adequately evaluated. Venture capitalists have also been reluctant to provide necessary financing because of the high risks, and because of the marginal economics of nearly all except high temperature electrical generation projects.

In order to promote the use of geothermal energy, the federal government, as well as many state governments, have established programs aimed at eliminating or substantially reducing the financial risks of exploration and development, and demonstrating the viability of geothermal energy utilization for both electrical generation and direct application projects. These programs have been in the form of grants, loans, guaranteed loans, or cost sharing. Other programs served to ease financial risks of project development by providing tax incentives or reservoir insurance.

The success of these programs in providing needed financing, reducing project risk, and improving economics has been highly variable. A thorough evaluation of how program structure has related to success in meeting the needs of various geothermal developments is necessary before the adoption of any such programs should be considered or proposed.

Several grant programs have been offered by the federal government, as well as state governments, to encourage commercial geothermal development. Because of the tremendous demand for funding under these programs, and the limited budgets of most state and federal agencies, grant awards have typically been made on a competitive basis. Programs administered by various state and federal agencies have provided financing for exploration, technical and economic feasibility studies, and the construction of demonstration projects. And, although most grant programs have been available to developers of direct application geothermal resources, a limited number of grants have also been available for exploration and drilling in areas where the generation of electricity was the primary objective.

The author has selected a limited number of federal and state grant programs which should provide the reader with a better understanding of how such programs can be structured to meet the needs of various aspects of geothermal development.

3.1.17 Technical Assistance Grants

One of the most successful of all state and federal geothermal grant programs has been the U.S. Department of Energy's Technical Assistance Grant Program which has been available through John Hopkins University, the University of Utah Research Institute, E G and G Idaho, and the Oregon Institute of Technology Geo-Heat Utilization Center.

The program's intent is to provide assistance to potential developers of geothermal energy, who have little or no experience in the geothermal field, in order to promote the rapid development of direct application resources. Assistance is available to all public and private entities, and is offered on a non-competitive first-come, first-served basis (Bloomquist, et al., 1980). Entities wishing assistance can apply to the technical assistance center which serves the area, and receive assistance in resource assessment and/or the preparation of technical and economic feasibility studies. Technical Assistance Grants are normally limited to 100 hours of assistance provided directly by the technical center or by a consultant selected by the center.

The limited assistance provided under the provisions of the program is usually adequate to provide the potential developer with enough information so that a decision as to whether or not the project is worth pursuing can be made. In some cases, the assistance is adequate to allow project initiation and development without the need for further engineering and/or economic analysis.

The Technical Assistance Grant Program has resulted in numerous projects throughout the United States being brought on line over the past several years. The demand for the program has remained strong, and has actually increased as energy consumers became more and more aware of the geothermal energy potential of their area and its potential for meeting their energy needs.

Although the Technical Assistance Grant Program has been extremely successful, it has drawn a certain amount of criticism, primarily in three areas. First, in spite of the assistance provided in the geological, technical, and economic areas, there remained a definite need to provide legal assistance which was never met. Second, a greater proportion of the assistance should have been provided through established consulting firms, under the direction of the technical centers, in order to encourage the development of a greater degree of expertise relating to geothermal development in the private sector. And third, because the assistance was provided on a first-come, first-served basis, a great deal of the grant monies were expended providing assistance to nearly identical projects. However, in defense of the program, the simplicity of the application process, and the lack of need for a complicated competitive evaluation process, ensured that assistance was available in a timely manner to as many applicants as possible.

3.1.18 Program Research and Development Announcement

The Program Research and Development Announcement (PRDA) was initiated to provide an opportunity for potential developers to propose engineering and economic feasibility studies of direct applications of geothermal resources. PRDA solicitations were part of the United States Department of Energy's national geothermal energy program plan which placed primary emphasis on the near-term commercialization of geothermal resources for direct application by the private sector (Hammer, et al., 1979).

The PRDA program was designed to provide funding for much more detailed feasibility studies than were possible under the Technical Assistance Grant Program. Individuals, corporations, companies, educational institutions, non-profit and not-for-profit organizations were encouraged to participate and submit proposals under the guidelines of the PRDA program.

In order to be considered for funding under this program, proposers were required to demonstrate their ability to carry the project through to completion, and it was vital that the proposer was familiar with the economic, energy utilization technology, and institutional requirements of the direct application of geothermal resources.

Most announcements released by DOE requested proposals for site-specific studies of the use of a specific geothermal reservoir to meet the needs of a single application or multi-use application, and the proposer was required to either own or to have rights to the utilization of the resource.

PRDAs usually targeted particular applications which USDOE had a special interest in promoting. The following is a partial list of applications at which announcements were aimed:

- Industrial - Process steam and moderate to low temperature heat for industrial plants.

- Agricultural - Space, water, and soil heating for greenhouses, grain drying, irrigation pumping, and extraction of chemicals for agricultural products (starches, acetic acid, acetone/butanol, and ethanol).

- Space/Water Heating and Cooling - Space heating and cooling, water heating (especially district heating and/or cooling systems) for commercial-sized buildings or business complexes and residential developments.

- Mineral Extraction - Process steam and moderate to low temperature heat for ore concentrating, leaching, and flotation processes.

All proposals were subjected to a comprehensive two staged review. The preliminary review was conducted to determine, among other things, whether the proposal:

1. Contained sufficient cost, technical, managerial, and other information to permit a full evaluation;

2. Provided a proposed site which could be available for commercial exploitation; and

3. Clearly addressed the purpose of the PRDA.

Proposals which passed the preliminary review were then evaluated on the following basis:

1. Quality of the technical plan, including a discussion of the study objectives, background, study plan for producing the information required as the final product of the effort, statement of work, and implementation plan;

2. Adequacy of the proposed organizational structure and project management plan, including provisions for financial control; and

3. The capabilities, related experience, and facilities which the proposer offers, and which are considered to be integral factors for achieving the objectives of the proposal,

> including the qualifications, capabilities, and experience of the project manager and other key personnel (Hammer, et al., 1979).

Announcements were typically issued once or twice per year. Grant awards were limited to $100,000 to $125,000, and from 6 to 12 awards were usually made per announcement.

The PRDA program was very successful in providing funding for the completion of detailed engineering and economic feasibility studies aimed at a broad array of potential geothermal applications. However, the success of the program in terms of the number of projects which were carried through to completion could have been significantly improved if more significance had been placed upon geologic, geophysical, and resource data as evaluation criteria, or if grants had provided monies for resource assessment as an integral part of the program.

The PRDA program was closely tied to another U.S. Department of Energy program entitled "Program Opportunity Notice."

3.1.19 Program Opportunity Notice

The purpose of the Program Opportunity Notice (PON) was to provide an opportunity for interested parties to propose direct utilization or combined electrical/direct application projects which would demonstrate single or multiple uses of geothermal energy through field experiments in space/water heating and cooling for residential and commercial buildings, agricultural, and aquacultural uses and industrial processing.

Entities eligible to submit proposals under the PON program included individuals, corporations, educational and other institutions, and state and local governments.

All grants under the PON program were made on a competitive basis, and required a cost share by the proposer. However, no set percentage of cost share was ever established, and the cost share could be in actual dollar expenditures or "in-kind" match (Hammer, et al., 1979).

The evaluation process for applications under the PON program was much the same as that for PRDA applications, with the main evaluation criteria being:

1. Overall feasibility of the proposed project, including quality and adequacy of the technical and cost data submitted, and <u>reasonable evidence of the existence of suitable geothermal resources</u> and availability of facilities, site, equipment, and other project-related needs for the duration of the field experiment;

2. Suitability of match-up between prospective geothermal energy user(s) and the proposed applications, including potential for

alternative energy savings and degree of transferability of the project results to other potential users of geothermal energy; and

3. Evidence that the proposed application is likely to promote new or expanded use of geothermal resources (Hammer, et al., 1979).

Under the PON program, much more emphasis was placed upon the need to provide strong evidence of suitable geothermal resources than was the case with the PRDA program, and this made a significant difference in the overall success of the program.

Another important difference was the emphasis placed upon cost sharing, and the greater financial commitment required of the proposer helped ensure that the project would be carried through to completion.

The PON program has resulted in a number of successful demonstrations of the use of geothermal energy. Three of the most well known projects which were made possible through the PON program are the district heating systems in Klamath Falls, Oregon; Boise, Idaho; and Susanville, California. Although these three projects cannot all be placed in the success column at this time, the problems which they encountered have been unrelated to the PON program.

The PON program, despite its successes, has also had its share of unsuccessful projects, most of which appear to have been the result of a lack of geothermal resource development expertise on the part of the grant recipients. This lack of expertise has resulted in a number of unsuccessful wells--wells that were either poorly constructed or sited. The problems could most likely have been avoided if DOE had chosen to play a larger role and more closely monitored the activities of the grant recipients.

Although the PON program is usually considered to have been directed primarily toward the development of direct applications of geothermal resources, a Program Opportunity Notice issued in 1977 solicited offers from private industry to participate in a geothermal demonstration power plant project (Province, et al, 1980). The successful proposers under this PON announcement were Union Geothermal Company of New Mexico (Union), and Public Service Company of New Mexico (PNM), who proposed to develop a liquid-dominated fracture volcanic reservoir by employing the flash steam process at Valles Caldra, New Mexico. A Cooperative Agreement between the U.S. Department of Energy, Union, and PNM, entitled the Baca Cooperative Agreement, was executed in 1979. Under the terms of the agreement, DOE's share of the overall project cost was 49 percent, and in a like manner under the revenue share provisions of the agreement, DOE was entitled to recover up to 50 percent of its "aggregate project cost."

The project was divided into three major elements as follows: 1) wells and steam production; 2) power plant and power production; and 3) data gathering evaluation and dissemination (Province, et al, 1980).

The project proceeded through the completion of several wells, but failure to locate fluids in sufficient quantities to support a power plant caused cancellation of the agreement in 1982.

3.1.20 Industry Coupled Program

The Industry Coupled Program was another program designed to be a cooperative effort between USDOE and industrial organizations engaged in geothermal exploration for electrical power generation. The program was designed to foster development by providing for: 1) cost sharing with industry for exploration, reservoir assessment, and reservoir confirmation; and 2) the release to the public of geoscience data which would increase the understanding of geothermal resources.

Under the guidelines of the program, a contract between DOE and a particular industry would specify: 1) an exploration and/or reservoir confirmation program which industry would undertake and manage; 2) a data package which industry would agree to make public; and 3) a certain percentage of the total project cost (generally 20 to 50 percent) which DOE would contribute toward the works (Hammer, et al, 1979).

The Industry Coupled Program was never well publicized, and when it was employed, it was never particularly successful in meeting its objective. The main problem was that in most instances, the participating industrial organization controlled the resource either through ownership or lease, and the release of what would otherwise have been priority information had little effect as it was impossible for other developers to establish a land position where they would be significantly benefited by the released information.

If government is to become involved in cost sharing with industry in order to reduce the financial risk to industry, consideration should be given to the benefits which can be returned to the public. Two primary avenues to this end appear to be available. The first would be to require revenue sharing with the government agency which provided the cost share, thus, in effect, creating a revolving fund; and second, require that in exchange for the cost share, the industrial participant provide energy at a reduced cost to consumers.

3.1.21 Other Federal Grant Programs

In addition to the above mentioned grant programs which were all aimed directly at encouraging the development of electrical generating and/or direct application geothermal projects, a number of other federal programs have been available to developers of geothermal resources through a number of federal agencies. Some of these programs are identified below.

(a) United States Department of Energy

- Institutional Building Grants Program

The program provides funding on a cost shared basis for schools, hospitals, local government, and public care facilities for technical assistance studies. Schools and hospitals are also eligible to receive funds for implementation of capital improvements identified through the technical assistance studies (Bloomquist, et al., 1980).

(b) Farmers Home Administration

- Business and Industrial Development Grants

The program provides assistance to organizations or individuals in rural areas to improve, develop, or finance businesses, industry, and employment in order to improve the economic and environmental climate through project grants (Bloomquist, et al., 1980).

(c) Economic Development Administration

- Public Works and Development Facilities

Assistance is provided to public and non-profit groups through grants to promote growth and expansion of private sector industry through public works and development facilities grants in EDA-designated areas to alleviate unemployment.

3.1.22 Department of Housing and Urban Development

- Community Development Block Grants

Grants are available to large and small cities to help alleviate physical and economic distress through stimulation of private investment and community revitalization in areas with populations of migrants or a declining tax bases. Funds may be applied to projects, such as housing and neighborhood conservation, local development corporations, and financing commercial or industrial building construction. Small cities with populations of less than 50,000, that are not in urban counties, can apply for funds for construction and improvement of public works facilities (Bloomquist, et al., 1980).

- Urban Development Action Grants

Cities and urban counties in HUD-designated areas can qualify for project grants to enhance economic revitalization. Project grants aim to stimulate new development and investment in distressed areas through public and private sector financial partnerships (Bloomquist, et al., 1980).

The importance of these peripheral programs to the successful development of a great many geothermal projects cannot be overemphasized.

In Klamath Falls, Oregon, funding from the HUD Community Development Block Grant Program and the HUD Housing Rehabilitation Program were both vital to the successful completion of the city's district heating system. In Susanville, California, the success of the district heating system can, to a large extent, be attributed to funding made available by the HUD Innovative Community Energy Conservation Program, a Farmers Home Administration Grant, and the USDOE Institutional Building Grant Program (U.S. Conference of Mayors, 1982). In Ephrata, Washington, funding from the HUD Innovative Community Energy Conservation Program resulted in the successful completion of the nation's first geothermal heat pump district heating systems.

A number of grant programs have also been established by states which directly or indirectly support geothermal development.

3.1.23 State Grant Programs - Idaho

- Technical Assistance Grants

The Economic Development Administration provided technical assistance grants for pilot or demonstration projects. Entities eligible for such monies must show projected employment gains to the community. The grants require a minimum 25 percent cost share, and are available in amounts varying from $25,000 to $80,000. (Hammer, et al., 1979)

- Public Works Grants

Funds for geothermal development under this Economic Development Administration program are designated to be used for public services and/or facilities. The applicants may be public or private non-profit organizations, and must have the approval and support of the local government entities. The extend of funds available is generally limited to 60 percent of the total project cost. (Hammer, et al., 1979)

3.1.24 State Grant Programs - Montana

- Alternative Renewable Energy Sources Program

This program, which has been in existence since 1975, was authorized by the state legislature to assist the state lessen its reliance on conventional energy sources. Funding for the program comes from a 5 percent state coal severance tax.

Grants are awarded to projects that research, develop, or demonstrate renewable energy sources such as geothermal. The Department of Natural Resources and Conservation may solicit specific proposals at any time in order to initiate projects needed to meet program objectives. In addition, unsolicited proposals are accepted during specific time periods. (Perlmutter and Birkby, 1980)

3.1.25 State Grant Programs - California

- Local Governments

The overall goal of the grant program is to provide local communities with assistance in planning for and developing their geothermal resources in a manner consistent with local economic, environmental, and social values (Coughanour, 1981). Funding for the program comes from the state's share of federal lease revenues, and the grant program is administered by the California Energy Commission.

Projects which are eligible for funding under this program include, but are not limited to:

1. Resource assessment and exploration.

2. Local and regional planning and policy development.

3. Identification of feasible measures that will mitigate the adverse impacts of the development of geothermal resources and the adoption of ordinances, regulation, and guidelines to implement such measures.

4. Monitoring and inspecting geothermal facilities and related activities to assure compliance with applicable laws, regulations, and ordinances.

5. Undertaking projects demonstrating the technical and economic feasibility of geothermal direct heat and electrical generation applications.

Proposed projects are evaluated on the basis of innovation, transferability of information or technology, potential savings of conventional fuels, likelihood of success, financial need, and the degree to which the project will mitigate negative impacts caused by geothermal development and/or generate positive social, economic, or environmental benefits. Projects which meet these criteria are then evaluated on criteria specific to the type of project proposed (Coughanour, 1981).

- <u>Technical Assistance Grant Program</u>

Since 1982, the California Energy Commission has offered technical assistance for geothermal direct use and small-scale electric projects (under 6 MW). Under this program, the Oregon Institute of Technology Geo-Heat Center provides potential developers with on-site investigations, consultations, and preliminary assessment of a project's engineering and economic feasibility.

Technical Assistance Grants are made available to qualified individuals and organizations, and do not require a cost share on the part of the proposer. (The Geyser, 1982)

Grant programs have proven to be very effective in promoting the development of geothermal resources by removing a substantial portion of the financial risk associated with both exploration and project construction.

Grant programs, however, can be extremely costly and, unless they involve some form of revenue sharing, do not return money to the public treasury. Loan programs, on the other hand, will return money to be used on a revolving basis, and nevertheless provide a comparable degree of risk reduction if they are forgivable. An alternative method of reducing the financial risk of geothermal development is the guaranteed loan.

A careful review of how such programs can be structured will provide the reader with the basis for determining whether grants, loans, or a combination of grants and loans can best meet the needs of their particular geothermal programs.

3.1.26 Loan Programs

A number of loan programs have been instituted by federal and state government to assist developers of geothermal resources who were unable to obtain commercial loans because of the high risk nature of geothermal developments in the perception of most conventional lending institutions. These loan programs have been aimed at all aspects of geothermal development from the preparation of feasibility studies to exploration, drilling, reservoir confirmation, and finally, system construction. There has also been a very conscience attempt to structure the loan programs so as to meet the needs of the small developer engaged in the development of low temperature geothermal resources for direct application as well as the needs of major developers whose only interest is electrical generation. Because of the high risk involved in geothermal energy development, a number of the programs have provided federally guaranteed loans.

A brief review of the major provisions of a number of the loan programs will provide the reader with a better understanding of what should be considered in the establishment of a comprehensive geothermal loan program.

3.1.27 Geothermal Loan Guaranty Program

The Geothermal Loan Guarantee Program (GLGP) is perhaps the best known of all state and federal geothermal loan programs. The GLGP became effective on June 25, 1976, under Title II of the Geothermal Research, Development and Demonstration Act of 1974 (Nasr, 1978).

The GLGP was designed to accomplish the following objectives:

a. To encourage and assist the private and public sectors to accelerate development of geothermal resources in an environmentally acceptable manner by minimizing a lenders financial risk;

b. To develop normal borrower-lender relationships in order that financing be made available without guarantees at some future time; and

c. To enhance competition and encourage new entrants into the geothermal market.

Under the terms of the Act, loan guaranties can be granted for up to 75 percent of project costs with the federal government guaranteeing up to 100 percent of the amount borrowed. The applicant must contribute a minimum of 25 percent of the total project cost. The Act was, however, amended in 1980 by Title VI of the "Energy Security Act" (Public Law 96-299) so as to allow for the granting of a loan for up to 90 percent of the total aggregate project cost providing that the applicant is an electric, housing, or other cooperative, or a municipality.

Loans may not exceed $100 million per project, and no qualified borrower may receive more than $200 million in loans.

The program provides for the Secretary of Energy to approve agreements to guaranty and commit to guaranty lenders against the loss of principal and accrued interest on loans made by such lenders to qualified borrowers.

In the granting of loans, the Secretary must give first priority consideration to those applicants for projects having a plan of operation which shows substantial promise of the prompt development and utilization of energy from undeveloped geothermal resource areas. Second priority must be given to projects designed to demonstrate or utilize new technological advances, and finally, lowest priority is given to projects that propose only geological and geophysical exploration, only the acquisition of land or leases, only research and development, or to projects that will be located at a geothermal resource area where utilization, technology, and economics have been proven (Nasr, 1978).

The Geothermal Loan Guaranty Program has been successful in furthering geothermal developments at a number of locations and successful in terms of bringing both electrical and direct use projects on line.

The program has, however, not been free from criticism. The problems which have been considered to be most serious include:

1. The program was not structured so as to meet the needs of small developers (projects under \$3-\$5 million);

2. Loan guaranty approval often took from several months to several years;

3. The loan guaranty requirements often served to limit the use of the program to those who could qualify for a conventional loan without the guaranty; and

4. Utilities were unwilling to use the loan guaranty program because default on a loan, even if guaranteed by the federal government, would seriously affect their credit rating.

Such criticism resulted in the development by several additional programs of the U.S. Department of Energy. A number of these programs were initiated through provisions of Title VI of the Energy Security Act which was passed by Congress in 1980 (United States Senate, 1980).

3.1.28 User Coupled Confirmation Drilling Program

The User Coupled Confirmation Drilling Program was initiated by the U.S. Department of Energy in 1980 to help meet the needs of developers of direct application geothermal projects by substantially reducing risk by cost-sharing with industry the confirmation of hydrothermal reservoirs. The program was designed to cost-share expenses for exploration to site drill holes, drilling, flow testing, reservoir engineering, and injection well drilling. The program did not, however, provide any financing or cost-share for the construction or installation of energy utilization systems (United States Department of Energy, 1980).

The primary objectives of the User Coupled Confirmation Drilling Program was to foster the economically viable use of direct application geothermal resource by the industrial and private sectors by:

1. Getting direct heat utilization started by absorbing a portion of the risk associated with the confirmation of hydrothermal reservoirs, while, at the same time;

2. Develop an experienced infrastructure of exploration, reservoir confirmation and utilization engineering consultants, contractors, and equipment manufacturers who will reduce reservoir confirmation risks in the future.

Although the program was in the strictest sense a cost-share program between industry and government, the program was structured so as to serve as a loan guaranty. A developer would finance the project out of in-house funds, or a loan could be obtained from a commercial financial institution using the U.S. DOE contract as evidence that project risk had been substantially reduced. The federal government agreed to pay between 20 and 90 percent of the total project cost based upon a formula which took into consideration the usability of the thermal fluids intersected by the drilling for the planned application. On a completely successful project, the Department of Energy cost-share was 20 percent, whereas on a completely unsuccessful project, the DOE cost-share was 90 percent.

In order to qualify for the program, proposals were required to contain evidence that:

1. There is a user who intends to use the resource if discovered;

2. The user or developer has or could obtain rights to required land and geothermal fluids and/or heat;

3. Other required permits could be obtained; and

4. Environmental considerations could be handled.

Although the program did not provide for system construction funding, it was designed so as to interface with the Geothermal Loan Guaranty Program in order to help ensure that projects could be carried through to completion.

The User Coupled Confirmation Drilling Program was in effect for only a short period of time and, although the program must be considered to have been successful in terms of confirming reservoirs, it did not achieve its primary objective--the establishment of the viability of direct application hydrothermal energy by the industrial and private sectors. The inability of this program to achieve its objective can be traced to the fact that funding was available only for drilling. There also remained a definite need to provide developers with money for engineering and economic feasibility studies. Many entities who could have conceivably participated in the program were unable to fund the preliminary engineering and economic studies needed to be eligible for a cost-share. In addition, a substantial number of recipients of funding under the program had severe difficulties in obtaining system construction funding because most conventional lending institutions continued to perceive geothermal development as high risk venture in spite of a proven reservoir, and although the Geothermal Loan Guaranty Program was to provide a means to secure construction financing, the small size of most projects negated the use of the GLGP because of reasons discussed earlier.

In order to capitalize on the positive aspects of the User Coupled Confirmation Drilling Program, and, at the same time, maximize participation and the chances for project completion, Congress passed the geothermal provisions of the Energy Security Act of 1980 (Public Law 96-294).

3.1.29 Geothermal Loan Provisions of the Energy Security Act of 1980

Title VI of the Energy Security Act provided for Feasibility Study loans, Reservoir Confirmation Loans, and System Construction Loans (United States Senate, 1980).

- Feasibility Study Loan Program

Feasibility study loans were authorized for direct applications of geothermal energy and were made available to "geothermal utility districts, geothermal industrial development districts, and other persons." (Person is defined to include municipalities, cooperatives, industrial development agencies, non-profit organizations, Indian tribes, and other entities including an individual, corporation, joint stock company, partnership, association, business trust, organized group of persons (whether incorporated or not), or receiver or trustee of any of the foregoing).

Loans were available to defray up to 90 percent of the costs of (A) studies to determine the feasibility of any direct application geothermal development; and (B) preparing applications for any necessary licenses or other federal, state, and local approvals required by such development.

The Secretary of Energy was given the authority to cancel any unpaid balance and any accrued interest on any loan granted under provisions of the Feasibility Study Loan Program if it was determined on the basis of the study that the geothermal development was not technically or economically feasible (Black, 1980).

The program thus reduced by a substantial portion the risk associated with the determination of the feasibility of utilizing direct application geothermal resources and served to remove one of the major criticisms of the User Coupled Drilling Program.

The determination of the engineering and economic feasibility of a project provided the developer with information vital to the pursuit of funding to initiate reservoir confirmation drilling. One of the main sources of funding for reservoir confirmation drilling was, however, also provided by the Energy Security Act.

- Loans for Geothermal Reservoir Confirmation

The Secretary of Energy was authorized, under Title VI of the Energy Security Act, to make loans to any person "to assist such person in undertaking and carrying out a project which (1) is designed to explore or determine the economic viability of a geothermal reservoir; and (2) consists of surface exploration and the drilling of one or more exploratory wells.

Loans were made available to developers of both electrical and direct application geothermal projects. Loans were limited to a maximum of $3,000,000, and no loan for confirming a resource for electrical generation could exceed 50 percent of the cost of such a project. However, if the loan was made to a person proposing to make application of the resources of the reservoir involved primarily for space heating or cooling or process heat, then the loan could be in an amount up to 90 percent of such costs.

As with loans for feasibility studies, the Secretary of Energy was authorized to cancel the unpaid balance and any accrued interest on the loan if he determined that the geothermal reservoir with respect to which the loan was made has characteristics which make that reservoir economically or technically unacceptable for commercial development. The loans bore interest at a rate equal to the rate in effect (at the time the loan was made) for water resource planning projects under Sec. 80 of the Water Resource Development Act of 1974 (42 U.S.C. 1962 (d-17(a)). The interest on such loans would, therefore, be several points below the prime.

The loans were to be repaid over a period not to exceed 20 years at a rate, in any year, not to exceed 20 percent of the gross revenue from the reservoir in that year. If revenues were inadequate to fully repay the principal and accrued interest within 20 years after production began, the remaining unpaid amount was forgiven (Black, 1980).

The Loans for Geothermal Reservoir Confirmation program was designed to replace the User Coupled Loan Program which was aimed strictly at promoting the confirmation of reservoirs for direct application geothermal projects and at the same time it was to serve as a supplement to the Geothermal Loan Guaranty Program by providing for geological assessment and reservoir confirmation activities related to electrical generation projects which were given very low priority under the GLGP.

Finally, the Energy Security Act provided construction loans for direct application projects.

- System Construction Loans

As an integral part of the Feasibility Study Loan Program, Congress authorized the Secretary of Energy to make a loan to any person to defray up to 75 percent of the cost directly related to the construction of a system for direct application geothermal development. Loans for the construction of electrical projects remained available under the provisions of the Geothermal Loan Guaranty Program.

No limit was placed upon the size of the system construction loan and the loans were repayable from revenues the same as for loans for feasibility studies and reservoir confirmation. Interest rates were equivalent to those for reservoir confirmation loans. The loans were repayable over 30 years; however they were not forgivable.

The loan provisions of the Energy Security Act were well designed to meet the needs of the geothermal community and build upon experience gained from the Geothermal Loan Guaranty Program and the User Coupled Confirmation Drilling Program. In order to ensure that the greatest possible benefit to direct application geothermal development would be gained from the program, the U.S. Department of Energy in promulgating rules and regulations proposed to establish a two-phase feasibility study program to be carried out in conjunction with the reservoir confirmation program. Under the first phase, a preliminary feasibility study loan (not to exceed $50,000 each) would be used to develop a conceptual design of a direct application system, identify site specific characteristics, identify government approvals required, and determining whether or not exploration and drilling should be undertaken.

Based upon the findings of the preliminary feasibility study, a loan would be made by U.S. DOE (not to exceed $3,000,000 each) to enable a borrower to conduct surface exploration and the drilling of exploratory wells.

After the successful completion of the reservoir confirmation activities, a loan would be made by DOE (not to exceed $200,000 each) to complete a detailed feasibility study and to apply for necessary licenses and other approvals associated with a direct application project.

The developer would then be eligible to apply for a system construction loan if the feasibility study determines, based upon the characteristics of the resources, that the project was both technically and economically sound (Black, 1980).

However, funding for Feasibility Study Loans, System Construction Loans, and Loans for Geothermal Reservoir Confirmation was unfortunately never requested from Congress by the present administration and the program was never put into effect. The need for these programs is as strong now as it was when the Energy Security Act was passed in 1980, but it is highly doubtful that funding would be made available against the policy wishes of the present administration.

The burden for providing such loans was, therefore, left up to the states, and unfortunately, very few states have had the required financial resources available for such programs. Other states, such as Washington, are prohibited from providing loans to the private sector by the state constitution.

Two state programs do, however, provide a certain amount of insight into how such loan programs can be financed and/or structures at the state level.

3.1.30 State Loan Programs

- Alaska Alternative Energy Revolving Loan Fund

The Alaska Department of Commerce established a revolving loan fund under the Business Loan Division. Loans of up to $10,000 have been available at 9½ percent interest for alternative energy projects, including geothermal resource development. The maximum loan period under this particular program was set at 20 years. (Basescu, et al., 1980)

- Oregon Small Scale Local Energy Project Loan Program

Oregon's Small Scale Local Energy Project Loan Program was established by the state legislature in 1979, and approved by a vote of the people in 1980.

Small scale local energy projects which are eligible for loans under this program include "any system, mechanism, or series of mechanisms of 25 megawatts or less, located in Oregon, that uses renewable resources, including, but not limited to,...geothermal...to supply energy, including heat, electricity, mechanical action,...to meet a local community or regional energy need in this state." (Oregon, 1983)

All small scale local energy projects proposed by an individual, small business, non-profit cooperative or corporation, or municipal corporation are eligible for a loan. Priority, however, is given to projects proposed by individuals and small businesses. Priority is also given to certain types of energy projects among which are groundwater heat pump systems and geothermal energy projects.

The Director of the Oregon Department of Energy may limit the amount of any loan, and may require such security upon such terms and conditions as he determines necessary to provide adequate security for a loan, or to protect the financial viability of the loan program.

The following loan limits have been established:

1. Residential groundwater heat pumps: $15,000;

2. Site acquisition: 10 percent of the project's capital cost;

3. Initial working capital: 3 percent of the project's capital cost;

4. Interim loan for preconstruction cost: 5 percent of the project's capital cost; and

5. Interim loan for initial construction cost: 10 percent of the project's estimated capital cost.

Loans are financed through bond sales and bear interest at a rate dependent upon the rate at which the bonds are sold (Oregon, 1983).

Federal and state loan programs have proven success records in promoting the development of geothermal resources by reducing the financial risk associated with exploration and development activities. Loan programs are, however, only one of many programs which governments can adopt to help ensure the economic viability of geothermal projects, and reduce the financial risk which developers must bear. Two other approaches which are available to provide assistance to developers are tax incentives and reservoir insurance.

3.1.31 Tax Incentives

Geothermal tax incentives may be enacted to provide tax savings for both developers and users. Such savings reduce the risk of the investment, and make geothermal much more economically attractive. The federal government, as well as several state governments, have enacted tax acts aimed at providing tax savings in order to encourage the development and use of both electrical generating and direct application geothermal resources. The most significant of these acts, from the developers point of view, has been the National Energy Act of 1978, which provides for the deduction of intangible drilling and allowed percentage depletion allowances. (Nimmons, 1978).

Prior to the 1978 passage of the Energy Security Act, federal tax treatment of geothermal resources was based mainly on judicial decisions and not statutory authority. In 1969, the 9th Circuit Court of Appeals held that the federal intangible drilling deductions and the percentage depletion allowances applied to geothermal drilling at the Geysers in Northern California. The Court decision was based on the finding that geothermal steam was "gas."

In 1975, the Internal Revenue Service (IRS) Code was revised to provide a 22 percent depletion allowance for any geothermal deposit that was determined to be a gas. The IRS, however, refused to follow either the Court decision or the new code provisions, and contested both the intangible drilling deduction and depletion allowance on activities and income from the Geysers (Wagner, 1978).

3.1.32 Intangible Drilling Cost Deduction

The Energy Tax Act of 1978 (Public Law 95-618) granted to developers of geothermal resources the right to deduct intangible drilling expenses from their tax liability.

A taxpayer investing in the drilling of a well for geothermal deposits can elect to expense the intangible drilling costs involved in the well in the same manner as an investment in oil and gas wells can expense their cost. Intangible costs include such things as wages, fuel, repairs, hauling, and incidental supplies, and can represent a significant portion of field development expenses.

Congress, by simply referring to existing law concerning oil and gas, chose to apply the intricate tax provisions, including judicial interpretations, which have prevailed in that area (Nimmons, 1978).

Because of the extensiveness of the literature which applies to intangible drilling costs, a review is beyond the scope of this paper. (The reader is, instead, referred to Miller's Oil and Gas Federal Income Taxation (CCH, 1977).)

The intangible drilling cost tax deduction has drawn strong criticism from developers in two major areas. First, slimhole temperature gradient and geochemical test wells are considered to be non-production wells, and, consequently, the costs of such wells may not be expensed, but must be capitalized and expenditures cannot be recovered until production revenues are generated. Second, geothermal disposal or injection wells costs are also required to be capitalized, and may not be deducted since they are not considered to be production wells. The cost of such wells can only be recovered through depreciation once production is established (Finn, 1980).

Both criticisms seem to be valid and could be easily remedied through an amendment to the Energy Tax Act.

3.1.33 Percentage Depletion Allowance

The Energy Tax Act of 1978 also extended the percentage depletion allowance traditionally available to oil and gas to geothermal. Percentage depletion permits the owner of a production well to compute deductions on a percentage of income produced rather than as a function of capital invested: as such, it may result in a deduction far exceeding the owner's actual investment over the life of a well.

Again, because existing law and literature are so extensive in this area, no attempt will be made to review or analyze specific provisions in this paper (see Miller's Oil and Gas Federal Income Taxation).

However, the highlights are as follows: For geothermal deposits, the act sets forth the percentage of gross income deductible for depletion, declining from 22 percent in 1978, to 15 percent for 1984 and years thereafter. The allowance is not subject to the restrictions on oil and gas depletion resulting from the Tax Reduction Act of 1975 (i.e., denial to integrated oil companies, limitation to 65 percent of taxable income, and limitation to a specified daily oil and gas production). The depletion allowance for geothermal is, however, subject to the limitations applicable to minerals (i.e., minimum tax on depletion in excess of the taxpayers basis, and limitations to 50 percent of taxable income) (Nimmons, 1978).

The only serious criticism which has been leveled at the Percentage Depletion Allowance Clause of the 1978 Energy Tax Act is the provision which lowers the allowable percentage deduction from 22 percent to 15 percent between 1980 and 1984 (Finn, 1980).

The Energy Tax Act of 1978 was thus extremely important to developers of geothermal resources. The act, however, has proven to be equally important to users because of its Residential Energy Credits and Business Investment Credit provisions.

3.1.34 Residential Energy Credit

The Residential Energy Credit provisions of the act affords individual taxpayers a credit for "qualified renewable energy source expenditures" made in connection with a dwelling unit used as a principal residence. Allowable expenditures include capital outlays, as well as labor costs incurred for "renewable energy source property" which, when installed in connection with a dwelling, transmits or uses, among other renewable resources, energy derived from geothermal resources.

The total credit allowed under provisions of the Energy Tax Act is 30 percent of the first $2,000, plus 20 percent of expenditures over $2,000, but not exceeding $10,000. (Nimmons, 1978)

The Energy Tax Act was, however, amended by the 1980 Windfall Profit Tax Act (Public Law 96-223), and the total tax credit allowed was increased to 40 percent of the first $10,000, or a maximum of $4,000.

Although Congress did not word the act so as to restrict the credit to geothermal temperatures of any specified temperature range, the Internal Revenue Service, in promulgating rules and regulations to implement the act, ruled that only geothermal resources whose temperatures are 50°C (122°F) or above are eligible for the tax credit. And, although no scientific or technical justification for such a restriction has ever been established, the IRS has steadfastly refused to allow tax credits for lower temperature geothermal resources. This is an extremely detrimental restriction in that few tax payers live in areas which have geothermal resources above 50°C at economical drilling depths, and thus have the option of utilizing resources on an individual basis. However, throughout much of the west, lower temperature resources, usable in conjunction with heat pumps, are widely available, and could be economically developed on an individual basis with the availability of the tax credit.

Two bills presently before Congress, S 1237 and HR 2927, would totally remove the temperature restriction from the IRS rules. However, many members of Congress have been reluctant to pass legislation which does not have an established temperature cut-off. And, although no temperature threshold has yet been found which is acceptable to all parties, the American Society of Testing and Materials has suggested a temperature of 4°C (38°F), and several members of the House of Representatives have expressed a willingness to accept this number (Rendon, 1984).

3.1.35 Business Investment Credit

The Energy Tax Act established a 10 percent tax credit for businesses investing in certain kinds of alternative energy property. The credit was increased to 15 percent by provisions of the Windfall Profit Tax Act which amended the 1978 Energy Tax Act in 1980. This credit is in addition to the regular 10 percent investment credit available for all business investments, and applies to equipment employed "to produce, distribute, or use" energy derived from a geothermal deposit, and includes equipment utilized for the generation of electricity but specifically excluding transmission equipment (Nimmons, 1978).

"Public utility property" is, however, expressly excluded from the definition of alternative energy property eligible for the additional investment credit. Public utility property is that used predominantly in the trade or business of furnishing or selling electrical energy or water, or gas or steam, through a pipeline or local distribution system, if the rates, therefore, are publicly regulated (Nimmons, 1978).

This is an extremely significant exclusion in that public utilities would typically construct, own, and operate electrical generating facilities. The exclusion could also have a serious impact upon the development of district heating systems because such systems would, in most cases, fall under the jurisdiction of state public utility regulatory authorities.

The IRS has, as with Residential Tax Credits, disallowed the taking of the Business Investment Credit if the geothermal resource is below 50°C (122°F). In addition, and potentially much more important, the IRS rules allow the Business Tax Credit only for systems which are exclusively geothermal. This restriction has been a serious impediment to proposers of hybrid geothermal electrical generating systems, as well as developers of geothermal district heating systems. S 1237 and HR 2927, which were introduced into Congress in 1983, would repeal the exclusive rule and allow the tax credit if, on a British thermal unit (Btu) basis, geothermal energy provides more than 80 percent of the energy in a typical year. If less than 80 percent of the the energy is supplied by geothermal energy, the credit shall apply to those portions of the system which produce, distribute, transfer, extrace, or use energy which is more than 50 percent supplied by geothermal energy on an annual Btu basis.

The Deficit Reduction Act of 1984, which was passed out of the Senate Finance Committee on April 2, 1984, modifies the rules regarding eligiblity for the alternative energy credit when qualified property is used at least 50 percent of the time with nonqualified property. Under these rules, dual purpose property that serves both alternate energy property and nonqualified property will be eligible for the energy credit, if at least 50 percent of the energy comes from qualified property. If less than 50 percent of the energy used comes from a geothermal source, the qualified investment in the property will be eligible for a partial energy credit that is equal to the percentage of geothermal source energy to the total energy used.

The enactment of federal tax incentive has served to encourage both exploration and use of geothermal resources, and, although rules adopted by the Internal Revenue Service have tended to lessen the impact upon the development of low temperature resources and district heating systems, the concept of providing tax incentives as a way of reducing the risks associated with geothermal development has proven to be extremely beneficial.

The states have also used tax credits to encourage development of geothermal resources, and a brief review of some of the state programs will provide the reader with a better understanding of the variety of forms which such programs can take.

3.1.36 State Tax Incentive Programs - Oregon

The state of Oregon has adopted both business and residential tax credits to encourage the use of geothermal resources.

- Business Tax Credits

A 35 percent tax credit is offered to businesses after the installation of renewable energy facilities. Geothermal facilities which qualify include direct use, electrical generation, and groundwater heat pumps. Integrated systems, using a combination of components of which geothermal can be a component, are also eligible and encouraged. The credit is taken over five years: 10 percent in each of the first two years, and 5 percent in each of the third, fourth, and fifth years. Any portion of a particular year's tax credit not used by the taxpayer in that year may be carried forward against the taxpayer's liability for up to three succeeding tax years.

All businesses which pay taxes in Oregon are eligible, including sole proprietorships, partnerships, and corporations. Businesses producing power or energy for resale are eligible, provided they are not a utility retailing to more than 100 customers (Oregon Department of Energy, 1982).

- Residential Tax Credits

A residential tax credit of 25 percent of the first $4,000, or up to a maximum of $1,000, is available to Oregon taxpayers for the installation of an eligible alternate energy device, and such device is for the applicant's primary or secondary place of residence. An eligible alternate energy device is defined to include a geothermal resource as a source of space heating, water heating, cooling, electrical energy, or a combination thereof. The geothermal system must, however, beneficially use temperature drops, according to the table below, in order to qualify. The rules also stipulate that low temperature geothermal resources may be used by geothermal-assisted heat pumps. In this case, however, the system shall be designed for maximum thermal efficiency and minimal disruption of groundwater resources, and the overall system coefficient of performance, including energy required to operate pumps, must be at least three. The temperature difference of any removed groundwater must meet the temperature requirements specified in the following table (Oregon, 1982).

Items which qualify as a geothermal device include, but are not limited to, the following:

1. Well drilling, casing, and down-hole heat exchangers.

2. Piping, control devices, and pumps which move the heat from the geothermal well to where it is used for space heating and/or cooling.

3. Geothermal-assisted heat pumps.

4. Liquid to air heat exchangers, ductwork, and fans installed with a geothermal well to distribute heat from the well into the heating system of the dwelling.

5. Consultant fees incurred during the design or construction of the geothermal device.

The table below specifies a minimum temperature difference that must occur between the inlet and outlet temperature of any geothermal device. The purpose is to minimize disruption of groundwater reserves by requiring that systems operate efficiently.

Temperature Range		Minimum Temperature Difference
Below 38°C	Below 100°F	8°F
38-54	100-130	12°F
54-71	130-160	15°F
71-88	160-190	20°F
88-104	190-220	30°F
104-121	222-250	45°F
Over 121°C	Over 250°F	60°F

3.1.37 State Tax Incentive Programs - Washington

The state of Washington, because it does not have a state income tax and thus cannot grant tax credits, has provided tax incentives in the form of a property tax exemption and a public utility tax exemption in order to encourage the development of the state's geothermal resources.

- <u>Property Tax Exemption</u>

Engrossed Senate Bill 3181, enacted by the 1980 legislature, provides that in valuing any building for property tax purposes, which has an unconventional heating, cooling, domestic water heating, or electrical system, that the value placed on the building shall not exceed the value which would have been placed on the building if it had a conventional system. (Chapter 155, Washington Laws of 1980)

- <u>Public Utility Tax Exemption</u>

Substitute House Bill 1419, also enacted by the legislature in 1980, provides an exemption from public utility taxation an amount equal to the cost of production at the plant for consumption within the state of Washington of electrical energy or gas produced or generated from renewable energy resources such as geothermal energy. Also exempted from public utility taxation were amounts expanded to improve consumer efficiency of energy end use, or to otherwise reduce the use of electrical energy or gas by the consumer. This second exemption would include the cost of geothermal district heating or other direct uses of geothermal energy.

In addition to the tax incentives which have been enacted in Oregon and Washington, Colorado, Idaho, and Montana have enacted legislation to provide income tax credits for investments in geothermal energy property. Colorado, Hawaii, Nevada, and South Dakota all provide for property tax exemptions. Nevada has enacted legislation to exempt non-producing geothermal leases from property tax.

Another tax incentive which can be provided is to exempt or reduce the amount of sales tax paid on equipment and/or services used in either geothermal exploration or utilization.

Grants, loans, and tax incentives all serve to encourage the development of geothermal resources, and, depending on how these programs are structured, reduce substantially the risk of investing in geothermal development projects.

Reservoir insurance is another method by which the risks of geothermal development can be reduced, and the need for such insurance to encourage development should definitely be considered.

3.1.38 Reservoir Insurance

In order to reduce the risk associated with geothermal exploration and development, and to encourage and accelerate the use of geothermal resources, federal as well as state governments have, as discussed above, instituted grant, loan, and tax incentive programs. Geothermal reservoir insurance can also serve as an extremely important means by which the risks of geothermal exploration and development can be substantially reduced.

The need and advantages of providing some form of reservoir insurance to help accelerate geothermal development was brought to the attention of the geothermal industry by Domenic T. Falcone in a 1979 memorandum addressed to "Utilities and Other Users Interested in Geothermal Resources." Mr. Falcone stated that "the field developer-operator can realize savings of considerable magnitude if there is a significant reduction in the time a developed field sits idle awaiting plant construction." He continued by suggesting that "the way to achieve this reduction in time-frame is to encourage plant construction to begin in advance of full field development, so as to dovetail, as far as possible, the readiness of satisfactory fuel with availability of the plants. Because utilities will be reluctant to initiate construction at early stages of field development, I would like to propose an insurance program written for the benefit of the utility so that should satisfactory field development not be reached, the utility will recover its sunk costs."

The insurance program proposed by Mr. Falcone was to have been paid for by the field developer-operator; the cost of which would have been more than covered by savings in inputed or real interest costs on money in the project.

Mr. Falcone's memorandum appeared to have had little effect upon the development of a geothermal reservoir insurance program by developer-operators, and the idea was not given full consideration until after the passage of the Energy Security Act in 1980.

In 1980, the Energy Security Act (Public Law 96-294 Title II, Subtitle B) (United States Senate, 1980) directed the Secretary of Energy to conduct a detailed study of the need for, and feasibility of, establishing a reservoir insurance and reinsurance program, and to establish such a program in accordance with provisions of the Act if the study affirmatively recommended and Congress concurs that the program be established. The study was completed in 1981 by the firm of Coopers and Lybrand, and involved five major tasks: 1) determine perception of risk by major market sectors, 2) determine the status of private sector insurance programs, 3) analyze alternative government roles, and 5) provide recommendations (Coopers and Lybrand, 1981).

Coopers and Lybrand found that various developers, users, and lenders had differing opinions on the need for a federal geothermal insurance program. Those firms which believed that such insurance would have little positive benefit stated the following 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 Guarantee Program is similar to a form of insurance that provides coverage against default regardless of cause and it is potentially less costly for the developer.

On the other side were those firms which believed that a federal geothermal insurance program would have a positive impact on their plans to develop geothermal energy. They cited the following reasons:

- Insurance might reduce risk to utilities and thus accelerate development.
- A well-defined insurance program might substantially increase lender participation.

Major firms generally felt that the availability of insurance would have little impact upon their plans to proceed with development, while smaller firms felt that increased availability of insurance would significantly facilitate their involvement in geothermal by greatly reducing risks.

Once the study had clearly established that there are significant risks involved in geothermal exploration and development, and that a reservoir insurance program was a viable means by which to reduce such risks, Coopers and Lybrand proceeded to evaluate alternative roles which government could assure in the establishment of a reservoir insurance program, and the cost effectiveness of such a program.

Five possible program alternatives which Coopers and Lybrand evaluated are as follows:

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.

The study determined that alternative number 3 would best meet the needs of developers, users, and lenders, while at the same time encouraging development of a private sector geothermal insurance program. The study also concluded that the program would most likely be a cost-effective means of dealing with geothermal project uncertainties. Coopers and Lybrand recommended that a reservoir insurance program, based upon the findings of the study, be established by Congress and the Department of Energy.

To date, the recommendations of Coopers and Lybrand have not, however, been reviewed by Congress, and the Department of Energy has not received the authority needed in order to establish a reservoir insurance or reinsurance program.

Whether or not the findings of such a study would be the same today is unclear. The development of skid-mounted well-head generators has substantially reduced the time between the drilling of the first production wells and when power can first be generated. Thus, the major advantage of such a reservoir insurance program, as envisioned by Mr. Falcone, appears to be substantially reduced. The well head generator has also made it possible to conduct long term reservoir testing while generating power and a positive cash flow before a decision to construct a large central generating plant must be made.

Reservoir insurance could, however, play a critical role in reducing the fears of conventional lending institutions, and thus serve to complement grant, loan, and tax incentive programs as a means of reducing the risks associated with geothermal exploration and development, and by doing so, accelerate the use of geothermal energy.

3.2 France

3.2.1 Introduction

The first geothermal energy project in France was at Carriere-sur-Seine in 1962 followed in 1969 by a second project in Melun l'Almont. The years 1976 to 1978 saw the completion of five operations: Villeneuve la Garenne, Creil Le Mee sur Seine, Blagnac, and Mont de Marsan. High temperature resources are currently being developed in the French overseas departments of Reunion and Guadeloupe but in continental France, with the exception of a high temperature project proposed for Mont Dore, geothermal energy development has involved low temperature resources. The presentation which follows thus refers to these types of resources.

At the end of 1983, 150 separate studies (including 26 inventories of resources) had been completed or were in their final stages of preparation, 80 operations had been approved, and the drilling of 60 operations had been completed (AFME, 1983a). Of these 60 operations, 11 were dry holes (it is to be noted that for the Paris and Aquitaine Basins the success rate is better than 92 percent) and 27 operations are presently functioning with a net annual production of heat equivalent to 75,000 tonnes of oil (the French production is traditionally expressed in terms of tonne equivalents de petrole, t.e.p., where 1 t.e.p. = 11,600 kWh). This production corresponds to the annual heating requirement of 70,000 homes (70 m^2). For the remaining 22 operations the heating distribution system will be completed in 1984 bringing the total production to 140,000 t.e.p. or the heating equivalent of 130,000 homes.

At the beginning of 1984, financial and legal infrastructures are firmly in place and the commercialization of this new industry is entering a new phase with a projected participation of geothermal energy in the French energy budget of 0.5 percent (1 million t.e.p.) by 1990 (Varet, 1982). The expansion of geothermal energy to include underground industrial waste heat storage, heat pumps operating on groundwater and shallow aquifers, and various combinations with solar energy will multiply considerably the contribution and scale of application of this new heat source.

Excellent summaries exist concerning the legislative (Varet, 1978; Varet, 1982; AFME, 1983), financial and commercial (Varet, 1982; AFME, 1983) sides of this industry. Overviews of the status of the geothermal industry in France in 1983 are given in Ferrandes (1983) and Gerard (1983).

3.2.2 Legislative Aspects

In the beginning of geothermal development the geothermal resource was treated as a groundwater resource. Specific legislation for geothermal energy was introduced in 1977 and 1978 with various related legislation in 1980 and 1981. A complete verbatim collection of this legislation is available in Varet (1978). Excerpts of varying levels of completeness are given in Varet (1982) and AFME (1983).

The geothermal resource is defined as a mineral resource by an amendment to the Mining Code of 1977 which identifies a new kind of mineral deposit, the geothermal resource. It is thus subject to mining legislation with specific applications to the geothermal resource defined in subsequent acts in 1978, 1980, and 1981. High and low temperature resources are distinguished on the basis of having a <u>well-head</u> temperature greater than or less than 150°C as measured during flow testing. The testing conditions are specified by the prefecture (Figure 3-1) following recommendations of the regional mines service.

A geothermal resource having a theoretical exploitable potential (relative to 20°C) of less than 200 thermies (1 kWh = 0.86 thermie) is considered to be a resource of minimum importance and thus exempt from the geothermal legislation. This translates into the definition of a minimum temperature of 20°C for a geothermal resource.

Another related legislative factor concerns the depth of the resource. All workings or drill holes that exceed 10 m are to be reported to the regional mines service and all workings or drill holes exceeding 100 m must first be authorized. (The depth limit is 80 m for the Paris region and 50 m for the Bordeaux region.)

Groundwater and environmental legislation become involved in geothermal work in terms of aquifer depletion, water disposal into surface waters and, in some special cases, of deep aquifers which are used for domestic consumption.

The exploitation of very low temperature resources using heat pumps enters into a gray area where the interfacing of the groundwater and geothermal legislation is not yet clearly defined. The official agency having final jurisdictional authority, AFME (see Figure 3-1 and Table 3-2), has side-stepped the issue for the moment in considering only those resources with a temperature of 30°C or greater. There is thus an important range of operations

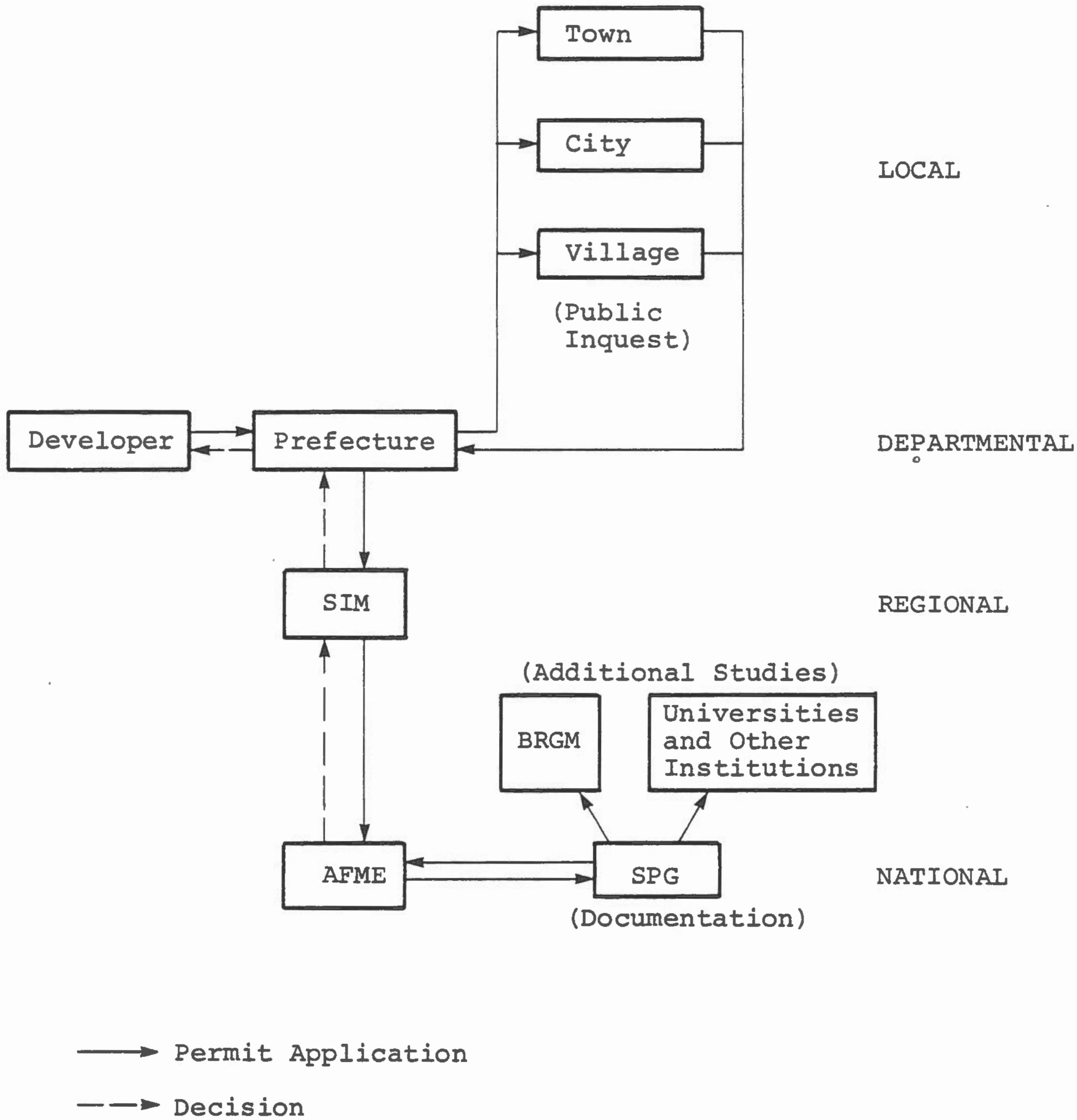


FIG.3-1

ADMINISTRATIVE INVOLVEMENT IN EXPLORATION PERMITTING IN FRANCE

ACRES

TABLE 3-2

GOVERNMENT ORGANIZATIONS ACTIVE IN GEOTHERMAL DEVELOPMENT IN FRANCE

	A. Existing Independently of Geothermal
CDC	Caisse de Depots et Consignations: National loan funds for public works.
CAECL	Caisse d'Aide a l'Equipment des Collectivites Locales: Regional loan funds for equipping collective housing.
CPHLM	Caisse Pour Habitations a Loyer Modere: Loan funds (national) for building low rent housing.
UNFOHLM	Union Nationale des Federations d'Organisme d'HLM: National loan funds for low rent housing.
PALULOS	National loan funds for improving insulation characteristics and heating systems of collective housing.
EPR	Etablissement Publique Regionale: Regional loan funds for public works.
HLM	Habitation a loyer Modere: Government or private companies which build low-rent housing.
BRGM	Bureau de Recherche Geologique et Miniere: National Geologic Survey.
SIM	Service Interdepartementale des Mines: Regional mines branch.
SOFERGIE	Lend-Lease Funds (private) for industrial projects which will reduce oil consumption. Created by legislation in 1980 (with fiscal advantages - see text).
	B. Organizations Created Specifically for Geothermal or Other New Energies
COMITE GEOTHERMIE 1974-1982	Organization with representation of technical expertise from public and private responsible for review of new projects: funding, permitting, technical reviews. Comite Geothermie incorporated into AFME.
AFME	Agence Francaise pour la Maitrise d'Energie. Agency created by congressional decree in 1982 with wide ranging authority for development and implementation of national energy policy. Within agency is one technical committee for the drilling aspects of geothermal and a second for the surface works. Agence also distributes aid to geothermal projects.
GEOCHALEUR	National Company created in 1978 which acts as legal, financial, and technical consultant to potential developers.
SAF	Geothermie Societe Auxiliaire de Financement Geothermie. Mutual insurance company created in 1983 to ensure short and long term risks. Principal sources of funding: AFME, CDC, and UNFOHLM with admission fee (3.2% of guaranteed investment up to a ceiling of 26,000 F in 1983) and annual premiums depending on hole depth (20,000 - 40,000 F per year).
SPG	Service Publique Geothermie. Created in 1983 with an agreement between AFME and BRGM to: (1) develop and maintain a computerized data bank for geothermal energy; (2) centralize all documentation for national and international geothermal interests and make it accessible to the public; and (3) publically promote geothermal energy.

(below 30°C and depths approaching 100 m) for which thermal exploitation of groundwater is feasible and for which the procedures and regulations must yet be established (Geotherma, 1983a and 1983b). The French government is presently looking into this aspect.

The development of a geothermal resource necessitates obtaining an exploration permit, an operating permit and a concession (exclusive right to exploit mineral deposits is granted by the national government as a concession). The exploration permit applies to a defined area and volume and expires after three years. The operating permit gives exclusive right to the use of a resource in a given volume for 30 years, renewable on request for 15 years. It can be revoked for serious violation in operating practices such as overexploitation, failure to respect reinjection conditions, or environmental considerations.

The exploration permit is requested from and delivered by the prefecture (Figure 3-1). The request is accompanied by an extensive report of the project including detailed information concerning the identity of the developer, the financing of the project, the location of drill holes, an environmental impact study, geologic targets, area involved in the project (defined on a map with a scale of at least 1:50,000), the actual volume to be exploited, magnitude of the energy production, use of the energy, and the time scheduling of the development. There is provision made that in case a high temperature resource turns out to be a low temperature resource, the exploration permit can be considered a low temperature permit.

The administrative process of permitting is illustrated in Figure 3-1. The prospective developer submits his request to the prefecture. The prefecture then initiates a public inquiry that lasts for at least two weeks. Public notice is given in two regional newspapers and is posted in the prefecture and in the city halls of all communities affected by the project. During this time all interested parties can express their objections or reservations as well as submit competitive bids. The results of the public inquiry are collected by the prefecture and passed on, along with the rest of the file, to the regional mines branch which in turn presents it to the AFME. The AFME considers all aspects of the project (subsurface and surface works) and submits a decision within a period of four months, or six months in the case of competitive bids. The decision is then transmitted by the prefecture to the developer.

The operating permit is also delivered by the prefecture (decision by the AFME). The request must be preceded by an environmental impact study. If this work (which is part of the exploration permit) is completed before the expiration of the exploration permit, the study does not need to be a part of the second request. In the event of the drill hole locations and/or operating conditions being different than described in the exploration permit, this study becomes necessary.

According to the Mining Code (and thus for geothermal work), information obtained in developing a resource is confidential for 10 years, after which it becomes public. This situation differs strongly from petroleum legislation which requires that all information, with the exception of seismic information, become public immediately. The tendency with respect to geothermal energy is that the AFME requests that all information, particularly well log information, be made available immediately to facilitate a logical and effective management of the nation's geothermal resources. It is possible that the legislation will be changed to formalize this procedure.

The AFME in convention with the BRGM also created, in 1983, the Service Publique Geothermie (SPG) for three principal functions:

- centralize all information concerning geothermal energy and make it available to the public;
- manage a computerized data bank so as to enable effective reservoir engineering;
- promote geothermal energy at all levels of the society.

3.2.3 Financial Aspects

Use of geothermal energy is characterized by a high initial investment and low operating costs. It is essential that interest charges be minimized. Also there is an important element of short term and long term risk which must be considered. The financial structure around the French geothermal industry includes government subsidies, low interest loans with special repayment schedules and conditions, and short and long term risk insurance.

The National government offers subsidies at three stages of development:

- 50 percent (maximum) of the feasibility study;

- 20 percent of the first hole costs;
- 20 percent of the surface works.

These subsidies are granted by the AFME and are essentially part of the permitting procedure. In addition the European Economic Community (EEC) offers subsidies (on the order of 20-40 percent of the project costs) for innovative projects of interest to the EEC.

Before a project is accorded a subsidy by the AFME, it must be demonstrated that the project in itself is a profitable operation. A study (part of the permit request) is made of the year-by-year costs of the project including interest charges, servicing, and major overhauls. The profitability is measured relative to the costs of a conventional fossil fuel system. The savings incurred by the geothermal system, expressed as a percentage of the total investment, must be 9 percent or better in order to be subsidized. In the beginning of geothermal development this lower limit was 6 percent.

Recently a risk factor has been assigned to all regions of France (Ferrandes, 1983) and the subsidies for the first hole will be accorded as a function of the risk. For operations in the Paris Basin where there is now a very low risk, it is probable that the subsidy for the first hole will be phased out entirely. In the beginning of geothermal development the subsidy granted for the first hole was a standard 30 percent.

Low cost public loan funds have been channeled through existing public structures such as loan funds for building low rent housing, for renovating large collective housing projects, regional and national public work loan funds, loan funds available to improve insulation characteristics and heating systems in order to conserve energy, and loan funds for equipping large collective housing projects. Many of these loan funds are administered at a regional level and are budgeted at a national level. Similar types also exist in other public sectors such as agriculture.

Three agencies have been particularly active in financing geothermal energy projects with low interest loans:

- Caisse de Depots et Consignations (CDC)
- Etablissement Public Regional (EPR)
- Caisse d'Aide a l'Equipment des Collectivites locales (CAECL)

In the beginning many of the EPR loans could be transformed into a subsidy in the case of a dry first hole.

The terms of the loans are highly variable. Highly privileged loans involve deferred payments or progressive interest charges and annuities. The deferred payment condition is very important; for instance, when the geothermal operation is completed before the housing. There can be a delay of two years before fees can begin to be collected. The EEC also has given loans to several projects of an innovative or experimental character.

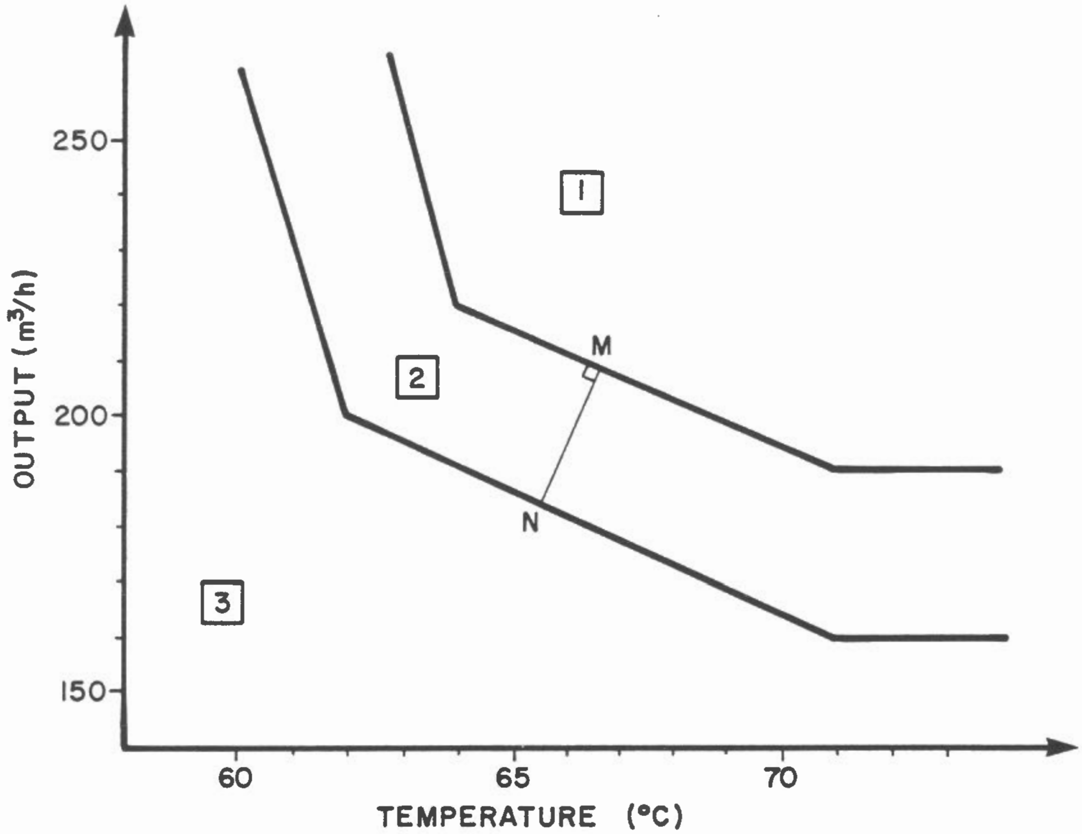
In 1980, legislation was passed to allow the creation of private companies known as SOFERGIES that can offer lend-lease financing to industrial projects that will result in a reduction of oil consumption. These companies, often subsidiaries of banks, have access to prime interest funds and, in addition, open up an avenue for banks to lend money over and above National quotas. This type of funding is of potential importance but as yet has not made any significant contribution to geothermal development.

The Societe Auxiliaire de Financement Geothermie (SAF Geothermie) was created in 1983 with the AFME, CDC, and the UNFOHLM being the major partners. The company is a mutual insurance agency which covers both long and short term risks. The developer pays a membership fee of 3.2 percent of the guaranteed investment (up to 26,000 F in 1983) and an annual premium proportional to the hole depth (on the order of 20,000 - 40,000 F per year).

The SAF Geothermie complements the AFME subsidy so that 90 percent of the costs are reimbursed in the case of a dry first hole. In case of partial success for the first hole, the coverage is negotiated, based on the output and temperature obtained (Figure 3-2).

In addition the SAF Geothermie covers the second hole risk (reinjection problems) and all subsequent operational losses due to factors such as premature lowering of output or temperature, corrosion problems, or long term reinjection problems. Both short term and long term risks are thus completely covered.

The previous system (1981-1982) involved a standard subsidy of 30 percent and a loan guarantee for the remainder in the event of a dry hole. This system in turn replaced a previous procedure (1975-1981) of highly privileged loans (interest rates of 1 to 4 percent over 15 to 20 years and deferred payments) which were transformed into subsidies in cases of dry holes. In the system of



1	Complete success:	AFME subsidy for first hole (up to 20%).
2	Partial success:	AFME subsidy is complemented by X% SAF Geothermie insurance. The amount X varies between 0 and (90% less the AFME subsidy) at M and N respectively.
3	Total failure:	AFME subsidy is complemented so that 90% of first hole costs are reimbursed. (Most often the project is abandoned.)

FIG.3-2

SAF GEOTHERMIE INSURANCE COVERAGE

1975 to 1981, the required budget became unwieldy and the bookkeeping became a nightmare! For the system of 1981 to 1982, large amounts of the budget were blocked and immobilized by the loan guarantees. The SAF Geothermie reduces the amount of immobilized capital and leads to much greater flexibility and range of aid.

Private industry funding played an important part in the first operations before a system of incentives was established. The principal factors were heating companies and oil companies.

3.2.4 Commercial Aspects

Geothermal energy development in France has taken place in a specific world economic situation and national political climate. With the oil crises of the 1970's, the entire world was alerted to that fact that fossil fuels are limited and all countries began to seriously examine ways of diminishing their dependence on oil and on the political and economic aspirations of other countries. This very naturally focused attention on new energy sources, and geothermal energy suddenly appeared as an important alternative energy source.

The second major factor of this general nature is the awakening in the French national consciousness of a strong desire for decentralized administration. In the municipal elections of 1978-1979, many new persons appeared on the political scene who were committed to increasing the autonomy of regional administration. An important part of the mandate of the present government elected in 1981 was the decentralization of the decision-making processes in national life. Low temperature geothermal energy use is a local affair in that it demands a superposition of user and resource. The national political climate thus greatly favored the development of geothermal energy. This influence is strongly reflected in the legislative, financial, and commercial structures which have emerged for the geothermal industry and which are tailored to enable local entities to manage their own heating systems from original resource to final product.

The potential users include municipalities, large housing projects (either public or private), agriculture, tanneries, malteries, mining, and industrial heating and processing (see Varet, 1982 and AFME, 1983). Up to the present time the most important users have been large housing projects.

There are often several organizations that enter into the same project. Legal structures exist that allow all types of mixtures of public and private interest to be both developer and/or operator (AFME, 1983).

- Private users can form a company to produce and distribute heat for their own use.
- Private interests can form a company to produce and distribute heat on a commercial basis.
- In a Societe d'Economie Mixte (SEC), both private and public interests are presented.
- In a Syndicat Mixte one or several of communities, public buildings (hospitals, airports, universities, etc.) and publically-owned housing developments can be represented. Private interests are excluded.

In the case of public users the four principal types of operating structures which are possible are outlined below.

- The municipality develops and operates its own system in accordance with municipal law.
- The community finances the project but contracts the the management and operation of the entire system (including setting the prices) to an operating company.
- The entire project is financed, developed and operated by an operating company.
- A private heating system is developed independently and heat is sold to the community on a strictly commercial basis.

Another variant is that there is one legal structure which operates the geothermal part of the operation and a second structure which operates the heating system itself.

It is evident that there are a large number of complex considerations involved in putting together a successful project. For this reason a national company, Geochaleur, was formed which acts as a consultant to prospective developers and which can set up all the financial, administrative and technical aspects of the operator. Geochaleur thus allows a prospective developer and/or user who has absolutely no experience in geothermal energy to quickly put together a viable project and get it underway.

The large variety of operating structures available to the geothermal industry and the creation of Geochaleur to thread through the administrative, financial, and technical maze have greatly facilitated the development of geothermal energy in France.

Another important factor for the success of geothermal energy in France is the mobilization of technical expertise. A Geothermal Department was created within the BRGM (see Table 3-2) under the direction of Mr. Varet. The team which was built up can deal efficiently with all aspects of the development of geothermal development (see, for example, the feasibility study of Aubertin et al, 1982). In conjunction with SNEA (Elf-Aquitaine), the BRGM undertook an exhaustive inventory of geothermal resources and heating needs in France. This inventory also served to develop a methodology for deriving reliable parameters, of interest to geothermal energy, from standard oil industry data.

The government undertook a vigorous public awareness campaign. Studies and inventories were sent to all high level administrations on the national and regional levels pointing out where geothermal energy could make a contribution. Brochures were sent out to all municipalities and towns with a geothermal potential and letters were written to municipalities and towns to arrange appointments to present geothermal energy to the various administrations. Public lectures were given in many settings. Special brochures were prepared and distributed in schools (La Geothermie, 1979). During the preparation of the inventory (which included a survey of heating requirements), many important contacts were made because the individuals and organizations interviewed concerning their heating needs were, of course, also potential users of geothermal energy.

It is evident that the strong government incentive program in terms of loans, subsidies, loan guarantees, risk insurance, and publicity has been a vital factor in the commercialization of geothermal energy. It will be seen in Section 3.2.5, however, that heating companies, major oil companies, and individual entrepreneurs played an important role at the beginning. The fact that many of the major problems concerning corrosion and reinjection had been addressed and that these efforts had given rise to a number of successful operations, set the stage for the large scale development fired by the oil crisis. SNEA continues to have a program of development. The development of petroleum and geothermal resources are highly complementary in that, often, the geothermal resources occur in parts of the basin which are of limited interest as a petroleum target. However the stratigraphic information is very valuable to both sectors.

For industrial applications one of the major drawbacks has been the time required to pay back the original investment. The break even point relative to fossil fuels is on the order of 2-5 years for an investment financed on a 15-20 year basis. Many industrial concerns hesitate to commit themselves to a particular location for more than six or seven years. The SOFERGIE lend-lease companies could be a positive factor in this area in the future.

In a commercial situation, pricing contracts are negotiated, often indexed to fossil fuel prices. (In that there are often a number of organizations involved with diverging political and economic aspirations, this negotiation can be a rather formidable affair.) For the owner-operators the rate for the individual users is basically the actual costs of the operation taking into consideration all the various operating, finance, servicing, and overhaul costs.

The geothermal resource requires a certain expertise to operate as it is not simply a case of turning on and off a hot water valve at the respective seasonal changes. In the large collectivities with owner-operators it appears that this aspect has not been fully appreciated. Perhaps as many as 50 percent of such operators do not know either the output or the temperature of their wells. Funds that should have been reserved for routine servicing have been spent elsewhere, with the result that no money is available to replace such items as downhole pumps. As more of these types of problems surface, public backlash could have a dampening effect on the development of geothermal energy.

Geothermal energy involves oil-field technology. However, the outputs of wells are an order of magnitude higher, the fluids are often corrosive, and drilling is done, almost by definition, in densely populated urban settings. This has demanded significant modification of oil-field technology. Drilling pads must be smaller. Rigs must be soundproofed to strict tolerance levels. Muds are continuously treated to avoid trucking for disposal. The economics of oil-field work allow the practice of "overkill" techniques. To keep geothermal costs reasonable it has been necessary to proceed with greater simplicity. Government has stepped in to standardize fees in certain areas. Ten years of experience have given rise to the French art of geothermal drilling.

One of the major technical problems is the development of pumps. Oil-field pumps must constantly be pushed to their technical limits to meet the output demands. The tendency has been to go towards long shaft pumps with the motor on the surface to facilitate maintenance. Recent interest has turned towards the turbo pump. Although Guinard, a French company, has begun to cater to the geothermal industry, there has not yet been a pump specifically designed for the geothermal industry.

The use of heat pumps greatly expands the application of geothermal heating to the heating budget and to use of shallower, lower temperature resources. With lower investment costs geothermal energy becomes accessible to much smaller communities (50 to 500 homes). There are 30 or 40 operations of this type in France. A French company (Geotherma) has been working on a project in Lund, Sweden, which exploits 23°C water at an output of 350 m^3/hour (reinjected) using an 18 MW heat pump.

Another area of consideration is what might be called energy management: use of underground aquifers to store heat from industrial processes, garbage burning, solar energy, etc. There are such projects in process at Montreuil (Ausseur et al, 1983) and Aulnay (Iris and DeMarsily, 1983). This type of use could be commercial in 3 to 5 years. Another project involving stockage of 180°C water is underway at Plaisir (Despois, 1983). These operations are very close to current geothermal energy uses and significantly increase the impact this industry can have on the energy budget of the nation.

The geothermal energy industry in France is presently facing vigorous competition from Electricite de France (EDF) and Gaz de France (GDF). GDF contracted to buy large amounts of natural gas from the USSR and Algeria and now has a surplus. EDF, with its nuclear energy program, has also a great abundance of energy to sell. It is essential that the marketing practices of EDF and GDF be harmonized with the national interest of a continued development of geothermal energy.

Low temperature geothermal energy in France is thus on the threshhold of becoming a full-scale industry. The economic viability of the resource has been demonstrated and at the same time specific problems have been localized. With the creation of the Institut Mixte de Recherches Geothermiques within the BRGM these problems have started to be resolved in a systematic way. On the other hand, with the present plateau in oil prices there is less psychological pressure for the moment for developing alternative energy sources. In France the surplus of national gas and electrical energy has exaggerated the psychological impact of the present oil market. Perhaps one of the greatest services to be done for geothermal energy development is to keep the public aware that the present trend in fossil fuel prices is simply a small inflection on the price curve that will inevitably continue to climb.

3.2.5 Selected Case Histories

The geothermal industry in France is the result of the successful interaction of public and private activities which laid its foundations. The development and application of legislation, financial structures, incentive programs, and commercialization techniques are illustrated in reference to actual case histories.

Early Development

The story of geothermal energy in France began in the early 1960's with Mr. Paouli, a director of the Office of Low Rent Housing (OPHLM) in Paris. He had heard of the warm water intersected in oil drilling and decided to try to heat a new housing complex at Carriere sur Seine with this water. He asked Elf-Aquitaine (SNEA) to drill the hole which was completed in 1962. However in the time that it took to finish his project the regulations concerning water disposal had been changed and he was obliged to reinject. Unfortunately he could not finance a second hole and the first geothermal well in France was cemented in.

One of the technical experts called in for the hearings for the Carriere sur Seine project was Mr. Maugis, a geologist formerly with SNEA. The subject attracted his interest and he set about to determine the optimal characteristics for a "doublet". This work he had carried out in SNEA in the spare time of his former colleagues in SNEA. In 1967, having worked out the optimal conditions, he managed to interest Enerchauffe, a heating company, in trying the new technology at Melun l'Almont. This operation went into production in 1969. However, simple iron heat exchangers and surface pipes were used and corrosion problems quickly stopped the operation. The geothermal system had been backed up with a conventional system so Enerchauffe simply switched to oil.

Enerchauffe then sold the operation to CGC (Companie Generale du Chauffe) who had sufficient capital to replace the surface pipes and install a titanium alloy heat exchanger. In 1972 the system was again functioning with an artesian output of 90 m^3/hour. (It was not possible to pump because of the diameter of the hole.)

By this time geothermal energy was being promoted by many persons in the geologic community, particularly in the universities, the regional mine services and BRGM. Many individuals were trying to find funding for various geothermal projects.

Mr. VanderBerghe, who had previously been the Director of BRGN, succeeded in selling the idea of geothermal energy to the mayor of Blagnac who contracted a heating company, UTEC (major shareholders were CGC and SNEA), to engineer the operation. The drilling was completed at the end of 1973. However the casing collapsed in early 1974 when the hole was pumped dry.

UTEC asked SNEA to save the hole. After two years of sorting out the technical and legal problems SNEA redid the hole. Mr. Housse of SNEA, on examining the available data, concluded that the first hole had not hit the objective but had stopped just above the reservoir. The second hole produced 50 m^3/hour at a well-head temperature of 60°C, confirming his assessment.

SNEA thus got interested in geothermal energy and decided that the economics of the operation must be maximized either by picking resources that could be exploited with a single well or by drilling doublets in localties with geothermal gradients. In 1976 SNEA completed Mont Marsan with an output of 300 m^3/hour at 61°C (AFME, 1983).

Total also entered the market with a project at Villeneuve la Garenne where they were involved in a large housing complex. They were able to obtain aid for the research aspect of using fibre glass casing to reduce corrosion. A number of problems were found, and because it was not possible to work in this casing, it was necessary to completely finish the hole before running any casing. There were also problems cementing the casing. This was a particularly serious problem at the top of the well where the Seine circulates through shallow surface deposits and cools the casing.

Expansion of the Industry

At this time the government was turning its attention to geothermal energy. A geothermal resource inventory was completed in 1976 (Housse and Maget, 1976). Various incentive programs were getting underway.

BRGM undertook the engineering of Creil, which was finished in 1976. The Creil operation represents the first of the new generation of projects based on government incentives. When the second oil crisis came in 1979 there were a variety of successful prototypes working and the financial, legislative, and commercial structures were in place and functioning. Geothermal energy became a significant element in the national response to this situation.

Reinjection becomes a necessity for environmental reasons in cases such as Carriere sur Seine. However it is also an important element in reservoir management to maintain a the aquifer pressure. Reinjection also provides a means of exploiting the energy stored in the solid phases in the reservoir.

The French approach to the question of reinjection has been flexible. The Aquitain Basin, Meriadec, Benauge, and Lormont projects were permitted on the basis of a single well. However for Pessac-Formanoir, the permit included the stipulation that provision should be made for a reinjection well. As the resource became more intensely exploited it was deemed necessary to introduce reinjection to maintain the aquifer. Reinjection has proved to be difficult at Mellerey. The operators have been allowed to discharge the water into surface waters until a solution is found. At the same time the BRGM has initiated a research program to master the reinjection problem.

Conflicting Interests

The interaction of the different levels of the administration is illustrated by the project at Dax. Until 1965 homes in Dax were heated by 64°C water from a hot spring. The area then developed a health spa industry using the hot spring water. The municipality subsequently raised the rates until private residences switched to oil and gas. With the intense use by the hospitals the hot spring temperature dropped to 54°C. When the geothermal project was posted, the spa industry raised strong objections on the grounds that the project would further damage the performance of the hot springs. A study was therefore contracted to a university and a site chosen for the well where there was considered to be no danger of interaction with the hot springs. With this the permit was granted. On completion of the well the spa doctors again raised many objections. Since they were well represented on the local town council, they managed to delay testing of the wells for three years (1979 to 1982). Tests were finally done in 1982, and it was shown that at an output of

100 m^3/hour there was a pressure drop in the hot spring but at 80 m^3/hour there was no effect. Application was made for operating at 80 m^3/hour but has not yet been approved.

A similar situation exists at Mont Dore, the location of the only high temperature geothermal project proposed so far in continental France. The local industry is centered around the hot spring activity in the region. In addition the area is renowned for its natural beauty. The local population has objected to the project on the grounds that hot spring activity would be affected and that a geothermal plant would spoil the scenery. The exploration permit has not yet been granted.

The interaction between geothermal uses and domestic uses has been involved in the Paris area (Ile de France). An aquifer of Albian age underlies Paris and provides high quality water for domestic consumption. It is therefore protected by legislation and, while being an interesting geothermal target, the resource has been reserved for domestic use. The legislation applies only to the Ile de France area and thus it is in principle permissible to exploit the aquifer where it underlies other areas. No such project has yet been carried out. The legislation in the Ile de France area is presently being reconsidered.

Insurance

Two cases have motivated the decision to develop second-hole and long-term risk coverage. At Mont de Marsan, the first hole completed in 1977 produced 300 m^3/hour. In 1980, a second hole was completed at 3 km distance into the same target but produced only

40 m^3/hour. The problem seems to be related to the irregularity of the fracture porosity. In this case the drill hole was destined to be a production hole. However it could have been a reinjection hole in which case it would not have been covered by the normal loan guarantees.

The second case is the operation at Melleray. The first hole had good production but the reinjection hole, drilled into the same target, presented many difficulties. Up to the present production waters have been disposed of into surface waters.

In the light of the unexpected reaction of these aquifers to reinjection it also became evident that there may also be some unpleasant surprises in terms of the long term behavior of the aquifers relative to the heat transfer models. It was thus evident that second-hole and long-term risk insurance was necessary and the SAF Geothermie was created.

An example of the financing of a project recently proposed for Alfortville is presented in Table 3-3. With this financing the annual costs of the operation are projected to become cheaper than a comparable fossil-fuel based operation after the first year. For 15 years (until the end of the repayment of the investment) savings are projected to be 25 percent, and thereafter are on the order of 44 percent per year. Figure 3-3, taken from Varet (1982), represents a generalized picture of the savings involved in adopting geothermal energy.

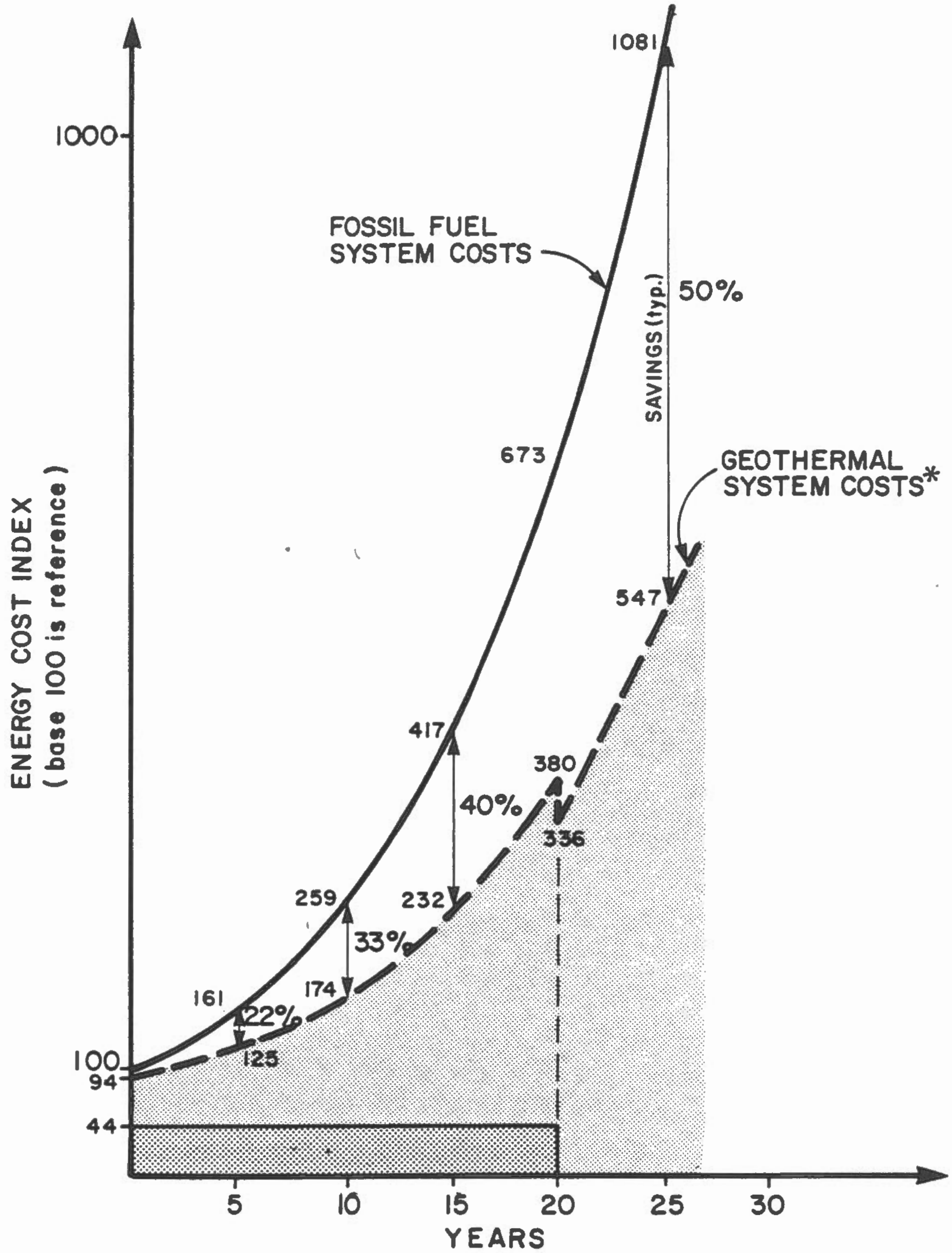
The geothermal heating systems for le Mee sur Seine (1977) and Cergy-Pointoise (1980-1981) were installed one or two

TABLE 3-3

FINANCING OF PROPOSED PROJECT AT ALFORTVILLE, FRANCE

Total Cost	53,989 KF
Subsidies	
Comite Geothermal	1,90 KF (first hole)
AFME	7,619 KF (surface works)
Loans	
EPR	1,930 KF (7 years at 9.50%)
CDC	8,011 KF (15 years at 11.75%)
CAECL	8,625 KF (15 years, progressive ratio 8-15%)
CAECL	25,874 KF (15 years at 15%)

*1 KF = 1000 F (1984 value)



*OPERATING COSTS

repayment of investment

servicing, auxiliary heating, electricity for pumping

FIG.3-3

GENERAL COMPARISON OF FOSSIL FUEL vs GEOTHERMAL SYSTEM COSTS

years before the building of the housing. This significantly reduced the installation costs. The loans negotiated had payment deferrals.

Another notable example of financing is the operation at Sevran-Aulnay which involved the participation of SOFERGIE funds (12 percent of the total investment). This project is also distinguished by the participation of the Kodak processing laboratories. Other examples of financing schemes are presented in La Geothermie (1979) and Luszcsynski (1983).

At Melleray and Mios le Tech, geothermal energy has been applied to greenhouse heating. Mios le Tech has been made economically viable in that the production well is a recovered, unsuccessful oil well. BRGM reworked the well by cementing in the bottom and perforating the casing at the water producing zone.

3.3 Commission of the European Communities (CEC)

The CEC has a geothermal energy program which provides financial aid to research projects or demonstration projects (annual budget of approximately $9 million). For research projects 50 percent of the costs are covered by the CEC, and for demonstration projects the usual aid consists of 20 percent grant and 20 percent highly privileged loan. (In the case of a dry hole, the loan becomes a grant.) The CEC program was tailored to the French experience. France has also been the most strongly represented recipient of the aid with 20-25 percent of the budget being allocated to French projects.

In that the CEC program favors new, innovative projects, it has provided a balance to the French approach which has focused on putting into production classic goethermal operations. On the other hand, it has tended to repeat as demonstration projects in member countries the types of operations that have already been realized as economically viable in France. The French point of view is that geothermal energy has been clearly demonstrated as a viable energy source and that the CEC should now have a program aimed at the large scale diffusion of the proven energy technology.

3.4 United Kingdom

Since 1977 the Institute of Geologic Sciences (IGS) has had a program of evaluating the low enthalpy geothermal potential in deep sedimentary basins and the possibilities of hot dry rock development in Caledonian Granites (Batchelor, 1983). This program has been funded jointly by the U.K. Department of Energy and the CEC. The status of these studies has been reported in Barley et al (1980) and Downing and Gray (1983). An earlier summary of the situation of geothermal energy in the U.K. is presented in Garnish (1976).

The low enthalpy program has given rise to inventories of the geothermal potential of the various basins (Downing and Gray, 1983) as well as the drilling of 2 deep exploration drill holes in the Wessex Basin near Southampton and one in the Larne Basin in Northern Ireland. In the Larne Basin a possible resource at 40-45°C was encountered and in the Southampton Basin the potential resource had a well head temperature of 71-74°C.

The Southampton well is currently being developed as the first geothermal energy demonstration project in the U.K. (Smith, 1983). The project is to heat a civic center, bus station, central baths, shopping center, offices, and some housing. The corporation developing the project agreed to include the geothermal option on the condition that a complete coal-fired back-up heating system also be installed. The Department of Energy agreed to cover the additional costs of including the geothermal energy system (drilling and well testing costs). The CEC gave 304,000 pounds sterling in aid, 50 percent as a grant and 50 percent repayable in case of commercial success. It was also agreed that the Deparment of Energy would recover 80 percent of the real profits (after early losses of the system have been recovered) until the original investment interest costs have been repaid. The Department of Energy is thus a sort of equity partner which puts up the risk capital.

Geothermal energy development in the U.K. got underway two or three years after France and has continued at a much slower pace (in the same period 29 operations were put into service in Franch and another 20 will be completed in 1984). Government funding has been channelled through the IGS. Up to the present time, most of the funding has been used for research studies, particularly for hot dry rock studies.

3.5 New Zealand

About 8 percent of New Zealand's electric power is produced from two geothermal fields. Geothermal energy has also provided heat and power for a pulp and paper mill. Direct uses are expected to expanded greatly in the future (Edwards et al, 1982).

New Zealand has a well-developed legal framework for geothermal development, described by Dench (1975). The Geothermal Energy Act of 1953 defines the geothermal resource to include all energy derived from the earth's natural heat excluding water at temperatures up to 70°C.

In New Zealand the sole right to use geothermal energy is vested in the Crown, regardless of land ownership; licenses to use it are issued by the central government. The Act does not clarify how to divide the energy between rival users, but in principal a developer should not be affected by the subsequent activities of others.

Generally a license is necessary before drilling for and using geothermal energy. No license is required for wells less than 61 m deep which are used for domestic purposes.

In 1953 the Act set the rental for geothermal energy as a fraction of the difference between the costs of the geothermal energy and the next cheapest source. In 1966 the Act was amended to relate the rental to the amount of net heat used. Dench suggests that, to encourage conservation, the rental could be based on the net heat extracted from the reservoir. This would also ensure that the heat withdrawn from the ground is monitored for reservoir engineering studies.

The Geothermal Energy Regulations of 1961 control standards of work during drilling and well operation. An inspector is appointed with the power to stop work if standards are unsatisfactory. Thus the effectiveness of the legislation depends on the inspector.

If the government closes a well (for safety, environmental, or other reasons), compensation may be payable, but not for the value of unexploited energy.

The City of Rotorua passed the Rotorua City Geothermal Energy Empowering Act in 1967, to enable the City Council to control geothermal development within the city.

Other legislation in New Zealand which affects geothermal development includes the following:

- numerous statutes related to protection of the environment;
- Water and Soil Conservation Act 1967;
- Clean Air Act 1972;
- Town and Country Planning Act 1953;
- Construction Act 1959;
- Boilers, Lifts and Cranes Act 1950.

3.6 Iceland

In Iceland the Energy Act of 1968 gives the right of ownership and use of geothermal resources to the landowner, subject to certain controls by the State (Torfason, 1975).

The geothermal resource may not be sold separately from the land except by permission of the State. In the case of sale, the local municipality and State have the first and second rights of refusal, respectively.

The government can expropriate geothermal resources for public purposes subject to compensation to the owner. However, the depth to which land ownership applies has not been defined. Therefore it has been argued that the State may still be able to claim ownership of underground geothermal resources without owing compensation to the landowners.

If a geothermal field lies under two or more properties, the ownership rights are to appraised by experts appointed by the local law court. However, settlement of such cases may be difficult without further guidelines on how to resolve resource development conflicts between owners.

Construction and operation of commercial-size electric power plants, including geothermal, must be authorized by the State. The development of geothermal energy for community space heating has been entrusted to the municipalities. Development of geothermal energy for other purposes (such as agriculture and industry) is generally not regulated by laws directed specifically to the geothermal resource.

3.7 Japan

Japan is an area of active volcanism with a significant high-temperature geothermal resource. Due to the escalation of fossil fuel prices in the 1970's, the government launched an extensive program in research and development of geothermal energy. A number of electric power plants exist, and direct industrial uses are under study.

As of the mid-1970's, a developer of a geothermal resource had to apply under the Hot Spring Law of 1948, and under the Natural Park Law if the resource was located within a designated park. Interpretation of the Hot Spring Law has been that hot spring eruptions are owned by the person who owns the land, although there is no definition of who should control the underground source. At the exploration stage, a potential developer would be interested only in borrowing the land in a manner similar to mineral exploration. The Japanese Mining Law designates mining rights for underground minerals, which are granted independently of land ownership.

The Mining Companies Council has drafted a law which defines the nature and position of a geothermal right which would be granted by the government. This draft was to be formalized into a bill for the Geothermal Resource Development and Promotion Law, which would be submitted to the Diet (Nakamura et al, 1975).

4.0 SURVEY OF LEGISLATION AFFECTING GEOTHERMAL DEVELOPMENT IN CANADA

4.1 Introduction

Under the terms of the Canada Constitution Act, natural resources fall under provincial jurisdiction, with resources in territorial lands under federal jurisdiction. Only British Columbia has legislation that specifically defines and regulates geothermal resources, yet, even in B.C., the legal definition of a "geothermal resource" restricts the application of the Act to moderate and high temperature resources. Most geothermal applications involve the use of heat extracted from groundwater. Therefore, it is expected that exploitation of the resource would directly or indirectly involve several kinds of provincial legislation, including:

- natural resource laws such as those governing ground and surface waters, brine, petroleum, natural gas (in some of the United States, geothermal steam is regarded as a natural gas and so is eligible for depletion allowances), mineral resources, and mining;

- land ownership and tenure laws that may include rights to various surface and subsurface resources;

- pollution control and environmental protection laws;

- pipeline legislation;

- utilities legislation (a person or company distributing heat or hot water may be defined as a utility and become subject to utilities regulations);

- corporation, factory, worker's compensation, and industrial safety laws;

- provincial and municipal corporate tax laws;

- royalty laws governing the extraction of natural resources.

In addition, there are some federal laws that would likely affect potential geothermal development, including:

- the Income Tax Act (see Section 5.0);

- the National Energy Act in the event that energy were exported outside a province;

- the Northern Inland Waters Act which governs the use of groundwater in the Yukon and Northwest Territories;

- the Clean Air, Fisheries, Canada Water, and Territorial Lands Act that would set pollution control standards and resource jurisdiction outside the provinces.

It is beyond the scope of this survey to analyze the effects of existing or hypothetical geothermal legislation on all these laws. Instead, this survey will highlight only those laws that would now most closely affect geothermal development. Information for this section was gathered mainly by telephoning the provincial and territorial government departments that are responsible for the environment, groundwater, energy, and natural resources.

The lack of geothermal resource legislation in most of Canada, and the lack of low temperature geothermal resource regulation in B.C., means that most geothermal development will take place under the terms of existing groundwater and natural resource laws. This will undoubtedly lead to uneven, and perhaps contradictory, treatment of the resource depending on which government department (mainly environment, energy, and natural resources) assumes primary responsibility for resource management. In addition, establishing leasing procedures and drilling practices, and setting tax, rental or royalty rates will remain unknown until development gets underway.

Several of the provincial governments interviewed thought it preferable to develop regulations in response to geothermal development rather than in anticipation of it. This pragmatic approach has the advantage of tailoring regulations to local conditions. This approach may also avoid creating regulations that are based too directly on oil and gas experience (as in B.C.), or other resources, that are but doubtfully applicable to geothermal resource development. On the other hand this requires that a prospective developer establish a very good working relationship with all of the government departments that may ultimately regulate the resource, in order that both government and developer anticipate problems that may be encountered and know what taxes or royalties can be expected. The absence of definite regulations governing geothermal development especially financial liabilities such as royalties, may prove a disincentive.

4.2 British Columbia

British Columbia is the only province with legislation directly affecting geothermal development. Because the Geothermal Resources Act (1982) is unique in Canada it will be described in more detail than other acts in this chapter. The Act and its regulations are administered by the Petroleum Resources Division of the Ministry of Energy, Mines and Petroleum Resources. Copies of the Act and regulations are included in Appendix A. The Act is, however, intended only for moderate to high temperature geothermal resources. Low to moderate temperature resources are not directly regulated by any Act but would indirectly be affected by provisions of the Water Act and the Petroleum and Natural Gas Act.

The Geothermal Resources Act defines a "geothermal resource" as "the natural heat of the earth and all substances that derive an added value from it, including steam, water, and water vapour heated by the natural heat of the earth and all substances dissolved in steam, water, or water vapour obtained from a well, but does not include:

(a) water that has a temperature of less than 80°C at the point where it reaches the surface; or

(b) hydrocarbons."

The right, title, and interest in all geothermal resources in the province are vested in the government. Apart from ownership of the resource, the Act defines permitting, leasing, operation, authorization and licensing requirements, and makes provision for royalties and unitization.

Two sets of regulations have been promulgated under the Act. The Geothermal Resources Administrative Legislations (B.C. Reg. 132/83) specify permitting and leasing procedures, and requirements for performance bonds and reports on expenditures. The Geothermal Drilling and Production Regulation (B.C. Reg. 170/83) specifies drilling practice, information requirements, sampling and storage of samples, reporting requirements, well testing, production, and waste disposal.

The Geothermal Resources Act and regulations very closely follow the Petroleum and Natural Gas Act and its regulations, particularly with respect to leasing and authorization procedures, drilling practice (for example, blow-out prevention), sampling and sample storage, and reporting.

A permit is needed for the exclusive right to explore for geothermal resources. The minimum area for which a permit may be issued is a "block" which consists of an area bounded by 5 minutes of latitude and 7 minutes 30 seconds of longitude. Blocks are tied to geodetic latitude and longitude and so have only a coincidental relationship to the actual location of a resource. Permits are awarded by a system of competitive bidding, by sealed tender, only on blocks that have been publicly posted. In order to get blocks posted for bidding, prospective developers must ask the Petroleum Resources Division to post them. Tenders must include a work program and cost estimates describing the type and extent of work that is proposed for the exploration area. Permits are awarded on the basis of which geothermal program is, in the Minister's opinion, the best. The permit costs $500 plus an annual rent of $1.00 per hectare. (The number of hectares in a block varies with latitude: at 50°N a block has about 8,300 hectares.) Only blocks can be rented but only part of a block need be explored.

Approximately one week after being awarded a permit the permittee must provide a performance deposit equal to the accepted work tender. The work obligation represented by the deposit will be reduced annually on the basis of the approval of an affidavit of expenditure and supporting exhibits. Failure to meet the committed work obligations may result in the forfeiture of the performance deposit. Payments may be made in lieu of work done.

The Act presumes most exploration will be done by drilling and consequently has extensive provisions for drilling test holes and wells. All drilling rigs must have a rig license issued under this Act or the Petroleum and Natural Gas Act. All cores and samples of cuttings from wells must be sent to the Division's Charlie Lake office at Fort St. John. During testing of blow-out prevention equipment, drilling crews must be supervised by personnel with supervisory certificates issued within the past 3 years by the Petroleum Industry Training Service. Daily reports, well summaries, well histories, and workover reports must be filed for all wells drilled. Reporting requirements for test holes are less rigorous. While actual drilling is covered in detail, only very brief regulations apply to disposal of drilling and production material, and well testing procedures. In order to conduct exploration by means other than drilling, one must notify, in writing, the commissioner of the titles branch of the Petroleum Resources Division.

In order to convert a permit to a lease, the permittee must submit a development plan for approval by the Minister. Leases are valid for 20 years and may be renewed. Neither lease rental rates nor royalty rates for geothermal production have been set, nor has any method of calculating the royalties been defined. Both the method and rates are to be determined by the Lieutenant Governor in Council (i.e. the Provincial Cabinet). The Minister is empowered to bind developers into a unitization agreement.

The Geothermal Resources Act can not be regarded in isolation. The Act uses definitions and several sections from the Petroleum and Natural Gas Act. Also, in case of inconsistency between a provision of the Utilities Commission Act or the Water Act and a provision of the Geothermal Resources Act, then the provision of the other two Acts prevails.

The temperature definition of a geothermal resource (at least 80°C at the point where it reaches the surface) means that all known hot springs in B.C. fall outside the jurisdiction of the Act. This has a bearing on potential direct use of geothermal resources. According to the Water Act, all springs are defined as surface water and are therefore regulated by the Water Management Branch of the Ministry of the Environment. Under the terms of the Water Act, groundwater rights are reserved to the Crown but the sections of the Act that pertain to groundwater are deliberately not used. No permits are required of well owners for the drilling, use, or disposal of groundwater. Regulations apply only to well drillers who must send copies of drill logs to the Water Management Branch. Most groundwater wells in the province are shallow, averaging about 50 m.

For low to moderate temperature geothermal resources that may exist in deep sedimentary basins (for example, in northeastern B.C.), drilling would likely be regulated by the Petroleum Resources Division under the terms of the Petroleum and Natural Gas Act. It is unclear whether one would need oil and gas rights prior to drilling. It is possible that one would need geothermal resource rights since some aquifer temperatures exceed 80°C. But until actual temperatures of the resource are established, the Division may require that both oil and gas and geothermal rights be acquired.

Most geothermal exploration and drilling in B.C. has preceded the proclamation of the new Geothermal Resources Act (June 7, 1982) and its drilling regulations (April 25, 1983). The Petroleum Resources Division has therefore had almost no experience in regulating geothermal exploration and development. Yet the present regulations require a great deal of judgement or discretionary application that may not be well-served by such reliance on petroleum-based regulatory experience. The Act also leaves a great deal yet to be regulated by either the Minister responsible or the Lieutenant Governor in Council. There is presently no regulation of such critical factors as royalty rates and lease rental rates.

The relationship of the Geothermal Resources Act to the B.C. Hydro and Power Authority (B.C. Hydro) Act is not known. Under the terms of the latter Act, B.C. Hydro has the authority to generate, develop, purchase, or otherwise acquire power; to require any person to sell power to it; and, under certain circumstances, to expropriate property, power projects, plants, rights, or privileges. Developers of geothermal energy for electricity or heat could be forced into an agreement with B.C. Hydro, on terms that may not economically justify the capital invested for geothermal exploration and development. Such matters require clarification in order to foster geothermal development in B.C.

4.3 Alberta

No geothermal legislation exists in Alberta and none is anticipated. Potential geothermal development would be most directly affected by existing groundwater and petroleum laws and regulations.

Ownership of groundwater resources is vested in the Crown. Under the terms of the the Groundwater Development Act, which is administered by the Department of the Environment, groundwater is defined as all water that exists below the surface of the ground. In theory this includes brines contained in deep aquifers, but in practice regulation of groundwater by the Department is restricted to shallow, fresh water resources. The Department regulates water use, water-well drilling practice, waste disposal, water quality, and royalties.

Brines that could be potential geothermal resources are routinely encountered in oil and gas exploration and development, all aspects of which are regulated by the Energy Resources Conservation Board, which administers the Oil and Gas Conservation Act and Regulations. The primary purpose of the Act is to ensure that drilling and production of oil and gas is done so as to prevent the waste of the oil and gas resource. In the absence of other legislation, prospective geothermal developers would have to drill in conformity with the Act and Regulations. Some examples of how this might affect geothermal development are given below.

The Act states that to drill a well, one needs the oil and gas rights for the location and a licence from the Board. Geothermal developers may have to acquire oil and gas rights. Drilling procedures would have to conform to oil and gas practice since in any given geothermal drill hole there would be a chance of encountering oil or gas. No well can be within 100 m of a building. The Board may modify this if the drilling is done on the building owner's property.

Production of brine must be approved by the Board and would be regulated like brines that accompanying oil or gas production. Up to two weeks of flow testing a well is permitted into tanks or earth pits as long as not more than 15 m^3 of brine per month is stored in an open pit at surface. Noxious gases that accompany production must be flared-off (burned). After two weeks, more permanent brine disposal systems must be installed.

Reinjection of brines is standard practice. The Board may specify the volume of reinjection and the formation into which reinjection is allowed. The Board usually refers reinjection plans to the Department of the Environment in order that they might ensure that shallow groundwaters are protected from contamination. There appears to be no difficulty in getting permission to reinject into the formation whence production comes, provided there is no interference with oil and gas production.

The Board has the power to modify any of the Oil and Gas Conservation Regulations. It also has the broad experience in regulating the drilling, pumping, and reinjection of brines. A potential geothermal developer would likely benefit from a close working relationship with the Board in order to expedite geothermal drilling and production.

4.4 Saskatchewan

No geothermal legislation exists in Saskatchewan and none is anticipated. Potential developers of geothermal resources face regulation by both the Department of the Environment and the Department of Energy and Mines.

All groundwater, irrespective of quality, depth, or intended use, is owned by the Province and is governed by the Groundwater Conservation Act. The Act is administered by the Department of the Environment. In order to get rights to use groundwater the prospective user must satisfy the Department of the Environment that the water is there to be exploited and the proposed well will not adversely affect existing users. Most water wells in the province are shallow, less than 150 m deep. Some industrial users exploit aquifers at 300 to 600 m depth, for example in water flooding operations and terminal recovery of oil and gas. The Department of the Environment sets royalty rates for water use depending on the amount drawn and its purpose. Disposal of water either at surface or down a well is regulated by both the Department of the Environment and Department of Energy. Reinjection wells must not contaminate fresh groundwater, nor fracture the formation into which water is injected, nor affect mineral or petroleum and gas rights within a 1.6 km (1 mile) radius.

Under the terms of the Oil and Gas Conservation Act any well that penetrates even potential oil and gas bearing strata requires a licence from the Department of Energy and Mines. Rights to petroleum and natural gas must also be acquired, usually through a competitive lease bid. The Department of Energy and Mines specifies procedures for drilling, well completion, and flow testing, and must approve plans for disposal wells.

Saskatchewan's first geothermal test hole was drilled on the University of Regina campus under the direction of Dr. L.W. Vigrass of the Energy Research Unit. Dr. Vigrass was helped by both the Department of Energy and Mines and the Department of the Environment who recognized the special nature of this project and modified some of the application and regulatory procedures. There was no competition for the oil and gas rights since the area is regarded as having little oil or gas potential. The planned disposal well was regarded by the Department of Energy and Mines as essentially the same as a disposal well for the oil and gas industry or for a potash mine.

Although Dr. Vigrass had few problems with the regulatory process he did see the potential for conflict between the jurisdictions of the two Departments involved -- Energy, and Mines and Environment. The absence of a definition of the resource makes it uncertain which department has primary responsibility. Also, because the University of Regina project was experimental and started at a time of rapidly rising oil prices, the authorities were willing to expedite the regulatory process by waiving certain obligations. They may not always be as helpful. A third source of potential problems is in the requirement that reinjection wells must not affect mineral or petroleum and natural gas rights within a 1.6 km (1 mile) radius. The operator of the well must prove this to the satisfaction of the Crown. Apart from being difficult to prove (especially for mineral rights) this does not provide immunity from future civil laws suits should anyone else demonstrate that the operator was wrong.

4.5 Manitoba

No geothermal legislation exists in Manitoba and none is contemplated. Regulation of potential geothermal development would take place under existing groundwater and natural resource legislation.

In Manitoba the rights to water resources are reserved to the Crown. Water well drilling and groundwater use are regulated by the Groundwater Resources Division of the Department of Natural Resources, under the terms of the Water Rights Act and the Groundwater and Well Water Act. Most of the water wells regulated by the Department are shallow (less than 150 m deep).

The Department of Energy and Mines regulates the mineral and petroleum industries through various regulations of the Mines Act. The Department's responsibilities include granting permits, setting worker safety standards, and setting royalties. Regulations that may have a bearing on geothermal operations include the Production of Wells Regulations, the Minimum Amount of Surface Casing Regulations, and the Salt Water Disposal Regulations. Since no one has attempted geothermal resource use (beyond heat pumps on domestic water wells) it is unclear which Department, whether the Department of Natural Resources or the Department of Energy and Mines, would have primary jurisdiction over geothermal exploration and development.

Presently the Energy Division of the Department of Energy and Mines is responsible for regulating energy supply (primarily hydro-electricity), utilization, and conservation. It is possible that this Division also would affect geothermal development but only insofar as development conflicted with higher priority energy sources.

4.6 Ontario

Ontario has an active program in promoting alternative energy development through cost sharing and demonstration projects designed to alleviate the perception of risk that might otherwise deter private investment. The programs are initiated or sponsored by the Ministry of Energy. The Alternative and Renewable Energy Group of the Ministry of Energy has programs in virtually every alternative energy source except geothermal.

No geothermal legislation exists and none is contemplated. Regulation of potential geothermal development would currently take place under existing groundwater and natural resource legislation.

In Ontario, groundwater rights follow the common-law doctrine of riparian rights. Thus the owner of the land also owns the groundwater resource beneath his property. Laws have been enacted, however, with the purpose of minimizing conflicts among users. The Water Resources Act and Regulations, which are administered by the Ministry of the Environment, regulate the quantity of water that may be drawn, water quality, and any interference between wells. The Ministry allows no interference in water volume and quality. Permits are required for all prospective groundwater use except for domestic and firefighting purposes or for volumes less than 50,000 litres per day. Permits specify well depth, volume, and disposal. Most water wells are fairly shallow; few are more than 150 m deep. New regulations are now being drafted to cover all aspects of water wells and disposal wells that are intended to better regulate existing practices and anticipate future problems.

The Environmental Protection Act also governs groundwater quality and protection of groundwater resources. This Act is also administered by the Ministry of Energy. Because the Act has only general provisions for groundwater resources, the actual regulation of the resource takes place under the Water Resources Act.

Ontario is an oil and gas producer and therefore has experience in the regulation of deep drilling, brine production, and reinjection. Petroleum exploration and development are regulated by the Ministry of Natural Resources under the terms of the Mining Act, for exploration north of the 51st parallel and in Lake Erie and the Petroleum Resources Act for everywhere else. The Exploration Drilling and Production Regulations of the Petroleum Resources Act specify that reinjection requires permission from the Minister and that wells must be cased in such a way that reinjection is confined only to formations specified by the Minister. For example, for gas and oil production that comes from the Dundee Formation (from depths of 120 to 150 m) and the Guelph Formation (at 300 to 450 m) reinjection of brine is permitted into the Detroit Formation (150 to 215 m) and several other formations at depths from 250 m to 750 m. Ontario would appear to have the regulatory experience to cope with geothermal development, mainly under the terms of its petroleum and natural gas laws and the Ministry of Natural Resources.

4.7 Quebec

Quebec has no geothermal development beyond limited use of heat pumps on shallow water wells. Conservation and alternative energy programs in biomass, municipal waste, and solar energy have been conducted by the Ministere de l'energie et des ressources (i.e. Ministry of Energy and Resources. Note that according to Quebec's French language charter only the French names of government departments are officially recognized. To assist the reader a translation is supplied.)

No geothermal legislation exists or is contemplated. Potential development would take place under existing groundwater, natural resource, waste disposal, and environmental laws.

Groundwater is defined by two Acts: the Mining Act and the Environmental Quality Act. In the former the definition of the term "mineral" (all natural solid, liquid, or gaseous mineral substances, and all fossilized organic matter) applies to water although "brines" (any natural aqueous solution containing more than 4 percent by weight of dissolved solids) are given separate consideration. The Environmental Quality Act defines water as surface and underground water wherever located.

The Mining Act is administered by the Ministere des richesse naturelles (Ministry of Natural Wealth), and the Environmental Quality Act by the Ministere de l'environnement (Ministry of the Environment). Under the Mining Act a licence must be obtained in order to drill for groundwater except in the case of a landowner drilling for water for domestic use. The Environmental Quality Act does not directly control water well drilling but makes general provision for safeguarding water quality and requires that waste disposal be approved by the Minister.

The Mining Act also has sections dealing with petroleum and natural gas resources, brines, and underground waste disposal. All petroleum and natural gas matters are regulated by the Minister-Delegate, Energy. It is unclear to what extent geothermal developers would have to conform to these Oil and Natural Gas Regulations. In order to explore for or exploit brine resources, licences are required from the Ministere des richesse naturelle. Reinjection could possibly be regulated by existing sections of the Mining Act that govern the use of reservoirs for waste disposal. The Act states that licences are required for the exploration of, such a reservoir and for the disposal of material therein. A storage lease is also required.

Given this variety of more or less pertinent legislation, geothermal development would not lack regulation. However, the developer would likely face ambiguity as to which regulations and which jurisdiction would most closely affect his project.

4.8 New Brunswick

No geothermal legislation exists in New Brunswick and none is anticipated. Potential geothermal development would take place under existing groundwater and petroleum resource laws.

In New Brunswick there is no prior assignment of the ownership of either surface or ground water. The right to the use and control of groundwater belongs to the title holder of the land under which the water is situated. Groundwater rights are thus a part of property rights and are affected by the provisions of the Property Act.° The property holder is entitled to use all the water that he can pump even if this causes wells on adjacent properties to dry up.

Water well drilling is governed by the Water Well Regulations of the Clean Environment Act administered by the Department of the Environment. The only limit on production permitted under these regulations is 10,000 gallons (45,000 litres) per day per well. Water Quality Regulations of the same Act prohibit contamination of groundwater aquifers. Most water wells in New Brunswick are shallow, less than 100m, and only a few have been used for heat pump use. Wells drilled exclusively for heat pump applications require that disposal wells be drilled lest the disposal of water at surface contravene the watercourse modification provisions of the Clean Environment Act.

Drilling and production of oil and gas is regulated by the Oil and Natural Gas Act which is administered by the Department of Natural Resources. Although no regulations have yet been promulgated they are likely to be very similar to those in place in Alberta. Extraction of brines from deep sedimentary basins would involve regulations affecting both oil and gas drilling and brine disposal. The Province has had production from the Stoney Creek gas and oil field near Moncton since 1909. From this the Province probably has sufficient regulatory experience to cope with any geothermal project utilizing deep sedimentary basins.

John Leslie and Associates drilled two temperature gradient holes in Carboniferous granite on behalf of the Earth Physics Branch of the federal Ministry of Energy, Mines and Resources. In order to protect the drilling operations from parties interested in mineral exploration, Leslie staked the ground he was drilling on, under the provisions of the Mining Act.

4.9 Nova Scotia

No geothermal legislation exists in Nova Scotia and none is anticipated for the foreseeable future. Geothermal development would take place under existing groundwater and petroleum resource laws.

The government of Nova Scotia has broad controlling powers over both surface and groundwater under the terms of the Water Act which is administered by the Department of the Environment. Water well drilling is governed by the Well Drilling Act. To use groundwater in Nova Scotia one needs to apply for a permit which specifies the volume that can be used and the methods by which it may be disposed. In the application for the permit one is required to prove that the resource exists and can sustain the proposed extraction rate. The extent to which these things must be proven depends largely on the amount that is required. Large volumes require more rigorous proof. About 30 heat pumps have been installed on mostly domestic water wells in the province. Reinjection wells are required for heat pump wells. Since most water wells in the province are less than 100 m deep the Department of the Environment has had no experience in licensing a deep geothermal well.

Deep drilling for oil and gas is regulated by the Department of Mines and Energy under the terms of the Petroleum and Natural Gas Act and Regulations. Little on-shore drilling has occurred in Nova Scotia and no oil, gas or brines have been produced. Geothermal developers would face a lack of regulatory experience on the part of the government authorities responsible for supervising such projects.

4.11 Prince Edward Island

No geothermal legislation exists in P.E.I. and none is anticipated. Geothermal development would take place under existing groundwater and petroleum resource laws.

In P.E.I., the right to surface and groundwater use vests in the owner of the land. Thus groundwater rights are part of property rights and are subject to the Real Property Act. However, according to the Towns Act, municipalities can prohibit well drilling within town boundaries. Fresh water wells are regulated under the terms of the Well Drillers Act by the Department of Community and Cultural Affairs (Environmental and Conservation Services Division). Drilling permits are required from the Minister responsible, only for wells greater than 6 inches (15 cm) in diameter or if production exceeds 50 gallons (227 litres) per minute.

On-shore petroleum exploration is regulated by the Oil and Natural Gas Act (and the Oil and Gas Conservation Regulations) which is administered by the Chief Officer and Conservation Engineer of the Department of Energy and Forestry. Wells drilled into deep aquifers would possibly have to conform to this Act, even though oil and gas were not sought, as well as the Well Drillers Act. Reinjection wells are provided for under the terms of the Oil and Natural Gas Act and Regulations. Water disposal plans and operations must be approved by the Conservation Engineer.

4.11 Newfoundland and Labrador

No geothermal legislation exists in Newfoundland and none is anticipated. Potential geothermal development will take place under existing groundwater and petroleum resource laws.

Groundwater rights are vested in the Crown in right of the Province. Water wells are regulated by the Department of the Environment which administers the Water Resources and Pollution Control Act. Groundwater is used as a water supply in several outports in the province. All water wells, other than for domestic water production, must be licensed by the Department of the Environment. Most water wells are shallow, less than 150 m.

On-shore, deep (to 900 m) drilling for oil and gas has only been undertaken in a few holes in Carboniferous strata in western Newfoundland. No discoveries have been made. All aspects of oil and gas drilling, production, and reinjection of waste brines are covered by the Petroleum and Natural Gas Act and Regulations which are administered by the Department of Mines and Energy. Prospective geothermal developers would have to take into consideration the limited regulatory experience of the Department, insofar as they may regulate a geothermal project.

4.12 Yukon Territory

No geothermal legislation exists in the Yukon and none is anticipated. Potential geothermal development will take place under existing groundwater and petroleum resource laws.

Under the terms of the Northern Inland Waters Act all groundwater rights are vested in the Crown in right of Canada.

The Act is administered by the Department of Indian Affairs and Northern Development. The Act establishes the Yukon Territory Water Board whose purpose is to provide for the conservation, development, and utilization of water resources "in a manner that will provide the optimum benefit of all Canadians and for the residents of the Yukon". Water wells for domestic use are excluded from the Act and so are not regulated. For other users, probably including geothermal non-electric use, a license is required from the Yukon Territory Water Board. Application for a license usually involves a public hearing so that objections from the community may be heard. Presently the Board regulates certain institutional users of groundwater, some communities with municipal water supply system and potential polluters such as the Cyprus Anvil Mine at Faro.

Drilling practice does not appear to be regulated beyond the need for relevant business licenses. In areas of prospective oil and gas resources, drilling and reinjection would be regulated by the Ottawa-based Canada Oil and Gas Lands Administration under the terms of the Canada Oil and Gas Act and the Oil and Gas Petroleum and Conservation Act as well as pertinent regulations.

4.13 Northwest Territories

No geothermal legislation exists in the Northwest Territories and none is anticipated. Geothermal development will take place under existing groundwater and oil and gas laws.

Groundwater resource ownership and usage is defined by the Northern Inland Waters Act, as in the Yukon, except that the principal regulatory agency is the Northwest Territories Water Board. Virtually all of the Board's regulatory experience is with large-volume water users or potential water polluters such as Pine Point and CanTung Mines. In contrast with the Yukon almost no groundwater is used in the Northwest Territories. Most communities use surface waters for domestic supply.

Exploitation of brines from deep sedimenary basins would probably involve regulation from the Ottawa-based Canada Oil and Gas lands Administration (COGLA) which operates under, and administers, the Canada Oil and Gas Act and the Oil and Gas Production and Conservation Act. COGLA has limited experience in such matters as reinjection, waste disposal, and water flooding but probably sufficient to cope with any prospective geothermal projects developed in deep sedimentary basins.

5.0 FINANCIAL FACTORS AFFECTING GEOTHERMAL DEVELOPMENT IN CANADA

5.1 Introduction

Innovations are first adopted by risk takers and opinion leaders. As information with respect to the results of these innovations becomes available, the perceived risk decreases and the innovation is adopted by the risk averse. This section identifies financial factors which surmount the risk barriers and encourage adoption of geothermal energy.

Provincial and federal assistance programs for research and development and demonstration studies increase the information available concerning geothermal energy. This type of assistance is crucial in the early stages when the technology has yet to be proven. As the body of knowledge increases, other incentives designed to encourage commercial adoption are required. Incentives such as capital assistance for investment, favourable tax write-offs and tax credits increase rates of return to private developers. Finally, consumer incentives create an awareness and demand among users.

As geothermal energy is still in its infancy, most assistance is directed towards research and demonstration projects. To assess the potential capital, tax and consumer incentives which may one day be applied to the geothermal industry, a survey of similar incentives to the oil and gas, mining and off-oil industries was conducted. Each section will identify the impact of these incentives, were they to be extended to geothermal energy.

5.2 Provincial Programs

This section surveys financial assistance and other government programs which influence the rate of return to private developers of geothermal energy.

Geothermal energy projects generally progress from the research and development phase (preliminary feasibility studies to identify resource potential) through the demonstration phase (wells drilled in areas of high potential), to the commercial development phase (resource used in commercial applications). Most Canadian geothermal energy projects are still in the research and development phase. Only British Columbia's Meager Creek and Saskatchewan's University of Regina experiments can be considered demonstration projects. It is not surprising, then, that most existing provincial programs are designed to offset research and development expenses. In addition, some provinces offer specific programs aimed at subsidizing demonstration projects.

Currently there are no provincial programs established which influence the rate of return to private commercial developers of geothermal energy.

The level of provincial support for geothermal projects tends to vary with the quality of the resource and the potential for development in each province. Some provinces have effectively concluded that geothermal potential is not promising enough to warrant the development of a geothermal industry, and therefore have provided little support. Even in provinces where geothermal development shows some potential, the level of provincial government assistance has been relatively modest. In many of these areas, there is a current abundance of conventional energy sources such as hydro-electric power or natural gas, and there has been little effective pressure on provincial governments to support geothermal development. Accordingly, much of the impetus for geothermal research has come from the federal government.

As part of the National Energy Program (NEP), a total research and development budget of $170 million per year has been provided, of which $40 million is distributed annually to renewable energy projects. $1 million is directed specifically to geothermal research and development. Approximately 20 percent of the $1 million is allocated to the National Research Council for engineering studies. The remaining 80 percent supports earth sciences studies and demonstration programs across the country.

In addition, funds for research and development projects were disbursed through the CREDA program (Conservation and Renewable Energy Development and Demonstration program), managed and funded by the federal and provincial governments and administered by the provinces. Under this program, $113 million over five years were made available to participating provinces. The objective of the program was "to develop and demonstrate promising new technologies or new applications which use renewable energy resources, conserve energy or make its use more efficient" (Canada Energy, Mines and Resources, undated). Although all types of off-oil energy were funded, the only geothermal project was the Meager Creek project in B.C. The CREDA project terminated in March 1984 and will be replaced by the ENERDEMO program to be administered by Energy, Mines and Resources Canada. ENERDEMO will be funded solely by the federal government and will provide funds for off-oil energy demonstration projects. Although the program has been announced, no guidelines have been issued and it is unclear just what priority geothermal energy will receive.

The final federally-administered program is the Remote Community Demonstration Program (RCDP) designed to promote an awareness in remote communities of off-oil opportunities. The $16 million, five year program is divided into two phases: the first phase supports preliminary studies on the availability of the resource, the second phase was designed to support demonstration projects. As of March 1984, the second phase has been transferred to the ENERDEMO program.

The following sections survey how the federal funding assistance has been used by the provinces, in addition to identifying further provincial programs of applicable value.

5.2.1 British Columbia

British Columbia is one of the most active supportors of geothermal energy. Earth sciences studies in the B.C. volcanic belts and small interior basins are supported under the federal NEP research and development budget.

Under the CREDA program, $27 million were allocated to British Columbia. The single geothermal project to receive funds under CREDA was the Meager Creek project. Federal funds of $750,000 were a small portion of the $12 million B.C. Hydro spent to drill three 3,000-m oil well size test holes.

B.C. has also used funds made available under RCDP to study the feasibility of geothermal energy in remote communities.

5.2.2 Alberta

Through the Alberta Canada Energy Research Fund, Alberta's Department of Energy and Natural Resources has supported studies and proposals to delineate the extent and characteristics of geothermal resources in the province. From 1978 to 1983, $340,000 was spent on such research and development phase projects. The Department had allocated $100,000 to $200,000 for engineering design studies leading to demonstration phase projects, but thus far, no proposals have been forthcoming.

Although Alberta has no specific geothermal energy incentive programs, the Exploratory Drilling Incentive Regulations (EDIR) of Alberta provides incentives to the oil and gas industry in this province.

The regulations define an "exploratory incentive well" as a petroleum or natural gas well located 4.8 km (3 miles) horizontally from a known producer or vertically 115 m below the base of known production. (Such wells are also eligible for a royalty holiday.) If no influencing well exists within three miles of the exploratory well, the well is considered an "A" well and the province pays approximately 35 percent of the drilling costs, depending on the depth of the well. If the exploratory well is within 2.4 km (1.5 miles) of a previously drilled dry hole, it is considered a "B" well and Alberta pays 75 percent of 35 percent of the drilling costs, again depending on the depth of the well. In the fiscal year 1982/83, Alberta paid $86.8 million under this drilling incentive program. The program expires March 31, 1984, and is currently under review. Industry members in Alberta have indicated that they would like to see the program continued.

5.2.3 Saskatchewan

The University of Regina has drilled a single 2215-m well on university land. Originally designed to be a supply-injection well arrangement capable of generating space heat for university buildings, this demonstration project was abandoned after the supply well was drilled.

The University of Regina project was divided into two phases. Phase One consisted of the preliminary research for the well involving a total outlay of approximately $800,000. Saskatchewan's Department of Energy and Mines contributed between $10,000 and $30,000 to Phase One activities. This grant did not originate from any specific provincial program, but rather was considered a one-time transfer. The bulk of the remaining funds came from the Department of Energy, Mines and Resources, Canada.

While the supply well was being completed, the province approved up to $1,000,000 for the project under CREDA. These funds were allocated to Phase Two of the project which involved a feasibility study and the drilling of the injection well.

Once the feasibility study was completed (at a cost of between $80,000 and $90,000), the payback period and potential for the province were considered too low. The project was deemed to be a test case rather than a true demonstration project and funding was terminated.

The feasibility study indicated that the geothermal resource increased in quality as one moved south-east of Regina. Unfortunately, it is difficult to match the resource to the end use in this geographic area. In addition, Saskatchewan had access to abundant and low price natural gas which makes the geothermal alternative less attractive.

As of December 1982, the Saskatchewan government has terminated payments made to the oil and gas industry under its Oil and Gas Exploration, Development and Production Incentive Regulations. Currently, no cash grants for exploration or drilling are available.

5.2.4 Manitoba, Ontario, Quebec

Due to the distribution of the Canadian Shield over these three provinces, geothermal gradients are very poor. Although these provinces, especially Ontario, support off-oil programs favouring solar or biomass energy sources, geothermal has not been targeted as an alternative energy source.

5.2.5 New Brunswick

The federal government has allocated $400,000 of its $1 million NEP research and development budget to the Atlantic provinces. Although breakdown on a provincial basis was not available, New Brunswick and Prince Edward Island have expressed the most interest in the geological and geophysical assessments funded by the program. These provinces have assisted the federal program logistically by offering personnel, maps and other relevant information.

From 1978 to 1983, the New Brunswick Department of Natural Resources spent between $25,000 and $30,000 on studies which evaluated the geothermal potential in New Brunswick. No funds were committed to drilling projects. These funds did not originate from a specific program designed to encourage geothermal development.

Currently, the department is proposing the allocation of $500,000 to a program which would fund research and some drilling in the geothermal field.

5.2.6 Prince Edward Island

As mentioned, Prince Edward Island and New Brunswick share the bulk of the $400,000 in research funds made available through the National Energy Program.

Although Nova Scotia and Newfoundland are included in the $400,000 geothermal research budget made available through the National Energy Program, the lower temperature gradients and the existence of offshore oil makes these provinces less active in geothermal development.

5.3 Tax Benefits for Off-Oil Energy Technologies

The federal government offers tax benefits for off-oil energy technologies via the Class 34 Tax Incentive Program. This incentive is an accelerated capital cost allowance which applies to machinery and equipment that save energy or use renewable sources of energy. Class 34 of the Income Tax Regulations lists eligible assets that can be written off as follows:

- over 2 years, if acquired within the eligible period but before November 12, 1981 (up to 50 percent in the first year and the balance in any subsequent year);

- over 3 years, if acquired within the eligible period but after November 12, 1981 (up to 25 percent on the first year, up to 50 percent in the second year and the balance in any subsequent year).

Without this accelerated write-off, the rates applied to these types of assets would be either 6 percent or 20 percent calculated on a declining balance basis (Canada Energy, Mines and Resources, 1980).

Class 34 is applied on an "end use basis". Equipment used in generation of small scale hydro, heat recovery, solar heating and biomass energy is included in Class 34. Geothermal energy generation is not an approved end use technology. Although equipment used in geothermal energy generation may be identical to eligible equipment under Class 34, unless geothermal technology is included in the Class 34 "end use" definition, the accelerated capital cost allowance cannot be applied.

The following eligible equipment under Class 34 is also used in geothermal energy production (extracts from the Income Tax Regulations pertaining to Class 34 Accelerated Capital Cost Allowance):

- "...storage equipment, control equipment, equipment designed to interface solar heating equipment with other heating equipment...used to heat a liquid or air to be used directly in the course of manufacturing or processing";

- "heat recovery equipment that is designed to conserve energy or reduce the requirement to acquire energy by extracting and reusing heat from thermal waste including condensers, heat exchange equipment, steam compressors used to upgrade low pressure steam, waste heat boilers and ancillary equipment such as control panels, fans, instruments or pumps";

- "production equipment and pipelines for distribution of heat".

Class 34 is currently under review to ascertain whether the objectives of the incentive program are being attained. If the review results in the extension or expansion of the incentive, federal officials believe that geothermal energy equipment may be included in Class 34.

The review will identify why certain clauses in Class 34 were used more frequently than others; and whether other incentives, such as direct subsidies, would be more efficient in encouraging business to use off-oil technology. This latter issue is of particular interest to institutions which do not pay taxes and, therefore, cannot benefit from tax incentives.

5.4 Tax Treatments for Petroleum, Mining and Research and Development

In countries that have an established geothermal industry, tax treatments for the resource have been based on similar legislation pertaining to the oil and gas and mining industries. The following sections review current Canadian tax legislation for these industries and how they can be applied to the geothermal industry.

5.4.1 Classification of Taxpayers

In Canada, the classification of taxpayers determines the tax treatment of oil and gas incomes and expenses. Taxpayers are classified as:

(1) principal-business corporations - if their principal business is the "production refining or marketing of petroleum, petroleum products or natural gas, or exploring or drilling for petroleum or natural gas" or other related business outlined in Section 66 (15)(h) of the Income Tax Act; or

(2) joint exploration corporations - if they do not qualify as a principal-business corporations or as individuals. A joint exploration corporation is defined as "a corporation that has not at any time since its incorporation had more than ten shareholders" according to Section 66(15)(g) of the Income Tax Act. Shareholders are assumed to make payments to the joint exploration corporation in respect of exploration and development expenses incurred. These expenses, including drilling, exploration, geological and geophysical expenses,

are incurred when exploring or drilling for petroleum and natural gas in Canada.

Depending on the method used to make the payments, the joint exploration company may renounce all or part of its Canadian exploration and development expenses to any shareholder, provided the amount renounced is not greater than the original payment the shareholder made. Expenses may be claimed each year or may be accumulated and claimed at a future date. However, the shareholder may only claim expenses for the period it was a shareholder.

If extended to the geothermal industry, the tax laws applying to joint exploration corporations could be used to offset the costs incurred by an industrial park sharing a geothermal well. Prior study would have to indicate that gradients sufficient to support an industrial park exist. Before drilling began, those members of the industrial park planning to use the geothermal energy would form a joint exploration corporation in which they were shareholders. The shareholders would contribute funds to drill the well and the joint exploration corporation would renounce these expenses to the shareholders once the industrial park was operating.

5.4.2 Canadian Exploration Expenses

Exploration expenses for both the oil and gas and mining industries are governed by the same legislation - Section 66.1(6)(a) of the Income Tax Act. Only the clause dealing with expenses incurred after May 6, 1974 will be discussed as this is the section most likely to be extended to geothermal energy.

Generally, Canadian exploration expenses are defined as those outlays or expenses made or incurred after May 6, 1974 that are expenses "including a geological, geophysical or chemical expense incurred by the taxpayer (other than an expense incurred in drilling or completing an oil or gas well or in building a temporary access road to, or preparing a site in respect of, any such well) for the purpose of determining the existence, location, extent or quality of an accumulation of petroleum or natural gas in Canada". [Section 66.1(6)(a) itemizes other interpretations and applications of the general clause given above.]

Principal-business corporations and individuals deduct Canadian exploration expenses to the extent of their income. Joint-exploration corporations and individuals deduct Canadian exploration expenses incurred after May 25, 1976, at a rate of 100 percent. Sections 66.1(2) and 66.1(3) detail how Canadian exploration expenses are to be deducted by principal-business corporations and others respectively.

The Canadian exploration expenses that apply to the oil and gas industry could easily be extended to cover similar expenses incurred in geothermal exploration. Both industries require geophysical research to ascertain the quality and location of the resource.

5.4.3 Canadian Development Expenses

Development expenses for the oil, gas, and mining industries are governed by Section 66.2(5) of the Income Tax Act. Generally, these expenses include the drilling of an oil or gas well in Canada, building a temporary access road to the well or preparing a site, to the extent that these expenses are not Canadian exploration expenses. Development expenses also include the cost of rights, licenses or privileges.

Development expenses can be claimed annually to an amount not exceeding 30 percent of the taxpayer's cumulative Canadian development expense at the end of the year.

Development of a geothermal resource also requires the drilling of a well; in fact, abandoned gas wells can sometimes be used as geothermal wells. It is reasonable then, to extend the tax legislation that applies to oil and gas development to include geothermal. In addition, Section 66.2(5)(a) already treats the costs of drilling salt water and other waste liquid disposal wells as Canadian development expenses.

5.4.4 Canadian Oil and Gas Property Expenses

Generally speaking, oil and gas property expenses are defined as the costs of any rights, licenses or privileges to explore for, drill for, or take petroleum, natural gas or related hydrocarbons in Canada. This clause also includes the cost of any oil or gas well in Canada or any rental or royalty.

According to Section 66.4(2) of the Income Tax Act, each year all taxpayers may deduct up to 10 percent of the value of their cumulative Canadian oil and gas property expense at the end of the year.

Drawing on the experience of the oil and gas industry, and the geothermal industry in the United States; rights, licenses or royalties of some kind are likely to be used in the geothermal industry. Provision could be made to extend the oil and gas property expenses legislation to cover the geothermal industry.

5.4.5 Other Oil and Gas Tax Treatments

Expenses incurred in the drilling of dry holes or bottom-holes are considered deductible drilling costs.

For federal tax purposes, royalties, lease rentals and mineral taxes paid to a government in Canada in respect to the production of petroleum, natural gas and related hydrocarbons are not allowed as an expense.

5.4.6 Depletion Allowances

Both the oil and gas and mining industries are subject to depletion allowances identified in Section 1201 of the Income Tax Regulations. For every $3 of eligible expenses, the taxpayer can claim $1 of depletion allowance, subject to a maximum of 25 percent of resource profits. Eligible expenses consist of Canadian exploration expenses and Canadian development expenses. Resource profits, defined in Section 1204, include the net income from the production of petroleum, natural gas or related hydrocarbons and the reserves from the sale of property after eligible deductions.

The depletion allowance laws in Canada are based on profits and bear no relation to the physical depletion of the resource. The depletion laws require that eligible expenditures be incurred before the allowance is claimed.

In other jurisdictions, the United States in particular, geothermal depletion allowances are related to the decrease in the quality of the asset. A complication that arises with this approach is the difficulty of defining a decrease in quality. The Canadian oil and gas and mining laws avoid these uncertainties by allowing a depletion allowance in name, but not in substance. It is highly likely that a similar approach will be used with geothermal depletion allowances.

5.4.7 Transfer of Ownership

Specific tax laws which deal with the transfer of ownership in the oil and gas and mining industries are of special interest to geothermal developers. Restrictions and special treatments of ownership transfer spread the development risks - a factor which will influence how quickly geothermal technology is adopted.

Purchase of Oil and Gas Properties

In those cases outlined in Section 66 of the Income Tax Act, Canadian exploration expenses, Canadian development expenses and Canadian oil and gas property expenses can be transferred from one corporation to another corporation provided the two corporations are not partnerships, syndicates, associations or individuals. By virtue of this law, a taxpayer other than the taypayer who incurred the expense, can claim it. These expenses can only be claimed against income generated from the transferred property. A maximum of 30 percent of the pre- transfer Canadian development expenses and 10 percent of the Canadian oil and gas properties expenses can be claimed. These limits are imposed to prohibit the purchase of gas and oil and mining property simply for tax minimization. In addition, a transfer requires that all or substantially all of the properties be acquired.

If the laws outlined above for the oil and gas and mining industries were to be extended to the geothermal industry, one could develop a scenario for the geothermal industry structure. In this scenario, a developer would drill the geothermal wells and develop them to the operating stage. The developer would incur Canadian exploration, development and oil and gas property expenses. The developer would then sell the operable geothermal system to an operator or user, transferring the applicable expenses.

This arrangement would spread risks between the developer and the operator/user. It is assumed that the developer in this scenario is an experienced driller who understands the risk-return tradeoffs embedded in the present tax laws. The operator or user on the other hannd, although not an expert in geological risk assessment, has an energy need and chooses geothermal energy because tax laws make it an attractive alternative. Institutions and corporations who are tax-exempt or in a loss position will be unable to take advantage of these arrangements.

Purchase of Stock

Individuals, partnerships, and corporations can "own" an oil and gas or mining corporation through the purchase of shares. Section 66 of the Income Tax Act identifies cases whereby an investor can make an agreement with an oil and gas or mining corporation to buy shares which allow the investor to claim Canadian development, exploration, and oil and gas property expenses incurred by the corporation. The corporation does not claim these expenses.

These regulations imply a second scenario in the geothermal industry. The developer in this case is a tax-exempt institution who cannot use the tax deductible expenses made available. This institution could be either a bona fide regulated provincial utility or an institution that is regulated as a utility because of the goods or services it provides. As it has incurred expenses which it cannot claim, the institution passes them on to other investors (not necessarily users) who can claim these expenses. In return, the tax-exempt institution receives funds which can be used to offset some of the capital costs incurred.

5.5 Tax Credits

Tax credits exist in the oil and gas industry and could be extended to the geothermal industry. Section 127(5) of the Income Tax Act states that an investment tax credit of 7 percent of the original cost of qualified property can be applied against Part 1 Federal Tax to the extent of the first $15,000 plus one-half of the balance of such tax. The percentage of original cost of qualified property may vary depending on the location. In certain "designated regions", the percentage may be 7 percent, 10 percent or 20 percent of the original cost. Qualified property includes prescribed new buildings, machinery and equipment acquired after June 23, 1975, that is used by the taxpayer primarily to operate an oil or gas well or to explore and drill for petroleum or natural gas.

Tax credits decrease the cost of qualified property that can be claimed for capital cost allowances, such as Class 34. These tax credits can be carried forward for five years. If modified to include the geothermal industry, the combination of the tax credit and the accelerated capital cost allowance to the oil and gas industry would enable private developers to depreciate their large investment in geothermal projects in a manner that would not interfere with their past earnings growth.

5.5.1 Alberta Royalty Tax Credit

The Alberta Royalty Tax Credit will return up to 50 percent of provincial royalties paid on petroleum or natural gas production up to a maximum of $2,000,000. This tax credit has varied from a 25 percent and $1,000,000 maximum in 1981 to a 75 percent and $4,000,000 maximum in 1982.

During the fiscal year 1982/83, Alberta returned $728 million under the Royalty Tax Credit. Forecasted expenditures in 1983/84 amount to $627 million. If royalities are to be paid by geothermal developers, some royalty tax credits are likely to be applied to this industry.

5.5.2 Saskatchewan Royalty Tax Holiday

Saskatchewan provides a one-year 100 percent royalty tax holiday to all oil producing wells. Exploration and deep development wells are subject to a three year holiday, while deep wells receive a five year royalty tax exemption.

5.6 Tax Treatments of Back-up Geothermal Heating System

As tax treatments for geothermal energy do not presently exist, it is not surprising that no tax treatments for back-up heating systems for geothermal are available. Some precedent is set by tax treatments of back-up heating units for solar energy. Although some solar equipment is eligible under Class 34 for accelerated capital cost allowance, costs not eligible under Class 34 include "back-up heating units for solar systems (e.g. furnaces) or any costs associated with structural modification of the building itself" (Extracts from the Income Tax Regulations pertaining to Class 34 Accelerated Capital Cost Allowance).

5.7 Consumer Incentives

Incentives to encourage the development and manufacture of off-oil technology have been supplemented by incentives to consumers to adopt these technologies. The following sections will describe the consumer programs that exist and indicate the possible applicability to the geothermal industry.

5.7.1 Canada Oil Substitution Program (COSP)

Through the Canada Oil Substitution Program, the Canada Department of Energy, Mines and Resources provides taxable grants to homeowners and tenants who convert from oil (as a heating fuel) to heat pumps, natural gas, electricity, wood, propane, solar or wind energy. The grant applies to both single family residences including centrally heated buildings containing two or more self-contained dwelling units and "individually heated buildings such as farm buildings, warehouses, factories, churches, schools, hospitals, homes for senior citizens, public libraries and similar specified public or community-owned buildings" (Canada Energy, Mines and Resources, 1982).

COSP will pay half the eligible costs of materials and labour for conversions of oil-fired heating systems to a maximum grant of $800" (Ibid). Eligible costs for the conversions of space heating, water heating and industrial process heating systems include:

- wiring, duct work and piping additions and modifications;

- control equipment, including load-limiting devices;

- unitary electric heating equipment such as baseboard heaters;

- central electric heating equipment such as ...electric boilers, electric heat pumps, electric storage heating equipment;

- dual energy systems such as wood-electric, solar-electric, and the like.

The COSP grant can be used to replace, adapt or supplement an existing heating system. If the recipient chooses to supplement an existing oil-fired system, oil consumption must be at least halved. Should the recipient decide to supplement a hot water or space heating system with an active solar heating system, at least one-third of the oil used must be replaced. Finally COSP will fund complete displacement of an oil-fired swimming pool heating system with an active solar heating system.

Several characteristics of COSP would encourage consumer adoption of geothermal technology, should the program be extended to include this off-oil energy form.

1. COSP is available to multi-unit dwellings and small industrial units. Geothermal energy would require such large end users to be economically competitive.

2. Those eligible costs that have been underlined are costs that would be incurred in geothermal conversion. Precedence for their eligibility already exists.

3. Some processes could use geothermal energy as a supplement to the existing energy requirements. COSP already accommodates such adaptations and supplementary conversions.

Although COSP would fund the users' internal conversion costs, the greatest cost of drilling the original well still remains as a disincentive.

5.7.2 Industry Energy Research and Development Program (IERD)

The Departments of Regional Industrial Expansion and Energy, Mines and Resources "encourage and assist Canadian industry to undertake research and development of new and improved products, and equipment that will reduce energy consumption "(Canada Energy, Mines and Resources, 1982).

The objective of the program is to encourage industry to increase the efficiency of existing systems and to use waste by-products as energy sources.

Eligible costs are itemized and include direct labour, direct material, consultation fees and a reasonable proportion of overhead. IERD can cover up to 50 percent of the total estimated cost of an approved project.

The program does not apply to projects which develop initial geothermal energy sources or any other primary sources. Once geothermal energy is in common use, IERD can fund projects designed to make the existing system even more efficient.

5.7.3 Canadian Home Insulation Program (CHIP)

Through CHIP, the Canada Department of Energy, Mines and Resources provides up to $500 for insulation improvements in homes of three stories or less. CHIP's objective is to reduce home energy consumption through better insulation, in 70 percent of the pre-1977 housing stock by 30 percent.

These taxable grants cover eligible costs including labour and material such as weather stripping, vapour barriers, etc., up to a maximum of $500. In most provinces, in order to be eligible for the grant, the home must have been built prior to January 1, 1971. This cutoff date has been recently extended, thus increasing the stock of homes eligible for the grant.

The CHIP program is both an incentive and disincentive to the acceptance of geothermal energy. As geothermal energy requires a high utilization factor to be economic, relatively low levels of insulation have the effect of increasing the load demand and realizing more benefit from the resource on a per-housing-unit basis. Alternatively, the increased insulation would decrease the load unless more units are hooked up to the system. For systems where the supply temperature is relatively low, insulation would allow for more effective use of the resource and less requirement for peaking boiler operation. The efficient level of insulation may well depend on the percentage of the total utilization factor absorbed by the process system. Once the usage approaches 100 percent, insulation could extend the usefulness of the resource without additional expansion.

5.8 Conclusion

As with most new technologies, geothermal energy will have to be proven before it is accepted as an alternative energy source. Governments can influence the rate of acceptance by decreasing perceived risks at the research and development phase, the demonstration phase and commercial development stage. Government funds for geothermal research and development are currently available and more programs are in the planning stages.

Geothermal exploration is just entering the phase where support for demonstration projects is required if the industry is to thrive. Although some funds are explicity directed to geothermal demonstration, more programs would increase interest in this field.

As the industry has not yet progressed to the commercial development phase, there are few government programs which influence the rate of return to private developers of geothermal energy. To understand the benefits and constraints such a developer might face, capital, tax and consumer incentives in the oil and gas, mining and other off-oil industries have been identified. Their potential impact on geothermal development has been analysed.

As geothermal development becomes a commercial reality, the effectiveness of incentives provided will be dependent on the industry's institutional organization. Some institutions may be tax exempt and unable to avail themselves of tax incentives. Other institutions may be able to renounce tax incentives to shareholders. It will be difficult to recommend particular incentives until the institutional organization is clarified.

6.0 COMMERCIAL FACTORS AFFECTING GEOTHERMAL DEVELOPMENT IN CANADA

6.1 Introduction

Geothermal energy development is not technologically new or experimental. Geothermal systems are in place and operating efficiently in numerous countries, generating electricity or supplying direct process heat. Unlike other oil reduction schemes and conservation efforts, which have received substantial interest in Canada in recent years, geothermal exploitation does not require basic research and development or experimental projects.

It is clear that geothermal systems can work, that other societies have found them to be economic, and that Canada has geothermal resources of varying quality which can be developed, and yet, there has been almost no commercial interest in geothermal development in Canada to date.

Although the total thermal energy capacity of the earth is enormous, its commercial value is dependent upon an ability to utilize the stored heat effectively. The majority of this heat is inaccessible, but exploitation is possible where favourable geologic and hydrological conditions combine to produce geothermal resources.

Worldwide interest in geothermal energy has historically focussed on development of high temperature (>150°C) geothermal systems, for electric power production. Invariably the occurrence of known, and often spectacular, surface manifestations (e.g. fumaroles, boiling springs and mud pools) associated with these high temperature systems prompted exploration and development. Power generation from intermediate temperature (90-150°C) geothermal resources, using binary-cycle technology, has also been successfully demonstrated, albeit on a small scale.

Direct use, non-electric applications using low temperature (<90°C) resources now predominate the geothermal industry. This reflects both the far greater abundance of accessible low temperature geothermal resources, compared to high temperature geothermal systems, and their more exploitable energy potential using existing technology and equipment.

Despite the rapid worldwide development of geothermal energy for both system-electric and direct-use applications since the oil crises of 1973 and 1979, the geothermal industry in Canada is still very much in its infancy. At present the only truly commercial development has been for resort and spa purposes at the major hot springs.

The rather slow development of alternative energy sources in Canada has primarily been due to an abundance of relatively inexpensive fossil fuels and electricity. However, this situation is changing. There is now a move towards both greater energy conservation and to adopting off-oil policies that will help to reduce consumption of fossil fuels and limit new electric power demand.

Unlike conventional fossil fuels, geothermal energy must be exploited close to the suitable resources. This places potentially severe constraints on development. The two critical aspects determining the successful commerciali-zation of geothermal energy are therefore co-location of suitable resources and appropriate development opportuni-ties, and economic competitiveness with other energy supply options. Institutional and financial factors, and broader socio-economic considerations (e.g. community characteristics, site physiography and climatic characteristics) are also important influences affecting the commercial environment for geothermal development.

If geothermal energy is to compete as a viable energy alternative there must be confidence among legislators, private industry, potential investors and the general public regarding its availabilty and reliability. In addition to legal, financial, and institutional aspects that are important for geothermal development, fundamental geologic criteria must be satisfied before successful commercialization can be considered.

Commercialization factors with respect to system-electric developments and direct-use developments are quite distinct. To a large extent, the market considerations influencing electric projects are more straightforward, the key factor being whether a particular geothermal project will provide power more economically than a conventional power plant. The significant constraints on geothermal electric projects are more likely to be resource-and technology-related than commercial.

The concerns facing direct-use applications are more subtle. Here, the commodity produced is not in all respects a direct substitute for other energy forms and yet the economics of potential projects are clearly influenced by other energy prices. The market itself is difficult to define since potential consumers must do more than just buy a product; they must also alter process systems to effectively use the product. In short, the commercial aspects of direct use systems are far more complex and inter-related.

6.2 Resource Assessment and Development Concerns

A potential developer contemplating an investment in a geothermal project faces formidable risks and uncertainties before even considering whether the market for the energy exists or can be created.

Naturally, all risks cannot be removed but as was indicated in Section 5.0, certain tax measures have been developed to ameliorate the financial losses which can be prevalent in any exploration activity. In addition, governments must establish an appropriate land tenure and regulatory infrastructure related to geothermal exploration to provide greater security and less uncertainty for prospectors and at the same time protect society's interests in development of the resource. The following sub-sections address these issues.

The search for geothermal resources is in many ways similar to prospecting in other extractive industries, where there must be a constant balancing of the probabilities for physical discovery against the outlook for commercialization. Assessment of these apparent risks and opportunities will determine whether investors will venture funds for exploration.

In the case of oil and gas or mineral sectors, there is, for the most part, a well defined market for the commodity, should it be discovered. However, uncertainties about future prices, government taxes or royalties, regulatory jurisdictions, land tenure rights or transportation feasibility will invariably deter exploration in any of these industries.

In the case of geothermal exploration, the technical risks are possibly less than for other extractive industries, simply because geothermal resources are more abundant than oil or silver, for example. Commercial uncertainties on the other hand, are far more prevalent. Jurisdictional, regulatory, tax and financial, and land tenure issues are almost completely unsettled and the market for geothermal energy is poorly defined.

Resolution to some of these issues will evolve as commercial projects become more imminent and familiar. Some of these matters, however, require attention in the nearer term. Some key areas where governments can at least initially remove some of the uncertainties involve assistance with geotechnical information and clear regulatory and land tenure institutionalization.

Resource assessment involves determining the location, extent and specific characteristic of a resource in order to evaluate its development potential. Parameters that determine the suitability of a resource for development include temperature, depth to resource, fluid quality, permeability and productivity, and the size or extent of the resource. All are a function of the geologic setting (Section 1.0), are site-specific for any given resource, and therefore have a direct bearing on the risks inherent in exploration and development of the resource.

A variety of studies have been conducted to assess the geothermal potential of Canada (Section 2.0). Attention has focussed primarily on assessment at a regional scale to identify an inventory of prospective geothermal resource areas. Few detailed site-specific investigations have been conducted. Reconnaissance exploration for high temperature resources in British Columbia at various volcanic centres, with detailed exploration and deep rotary drilling at Meager Mountain by B.C. Hydro (Section 2.2), and the Geothermal Research Project at the University of Regina, Saskatchewan (Section 2.3) are exceptions. Realistically however, from the viewpoint of economic development, Canadian geothermal resources are as yet poorly defined. Current assessment of their development potential is based on estimates of resource characteristics and therefore potentially have a wide margin of error. A primary technical constraint to commercial development of geothermal energy in Canada is therefore a lack of more specific resource assessment data. Accurate definition of resource characteristics is essential if the economic risks and uncertainties inherent in the commercial development of geothermal energy are to be clearly identified and subsequently addressed by financial and legislative aspects.

6.2.1 Resource Data Requirements

An increasingly popular and useful technique of providing resource data to decision-makers and industry in other resource fields is through resource inventory mapping. For example, in B.C., the Ministry of Energy, Mines and Petroleum Resources (Mineral Resources Division) compiles information received from oil and gas drilling, assessments from mineral prospectors, and data from federal and provincial field geologists.

At present, limited information exists for potential geothermal developers. A useful first step would be to classify and map all proven, potential, and inferred geothermal zones. A resource inventory map would not completely eliminate exploration risk, but it can lessen some of the economic risks associated with exploration.

The geothermal developer can therefore reduce capital expenditures required for pre-reconnaissance exploration, and can launch into detailed exploration. Furthermore, the resource inventory mapping serves to reduce the reticence of investors to consider exploring new regions, and can shorten the relatively long time frame for exploration actitivies.

6.2.2 Land Title and Resource Definition Issues

Because exploration drilling and well development is quite expensive, resource industries attach significant importance to the type of land resource tenure. The tenure system is not only important as a means of securing rights to explore, but as a means of protecting investments. Whether it is the development of a mine or an oil well, an investor will not proceed until it is certain that the tenure over the resources is guaranteed for the life of the capital goods installed to exploit them. In other words, the geothermal developer will not be prepared to invest in exploratory drilling, when a discovery may result in a flood of competitors to exploit the same aquifer. Aside from the economic risk, the geologic risk of overdrilling, reservoir depletion or degradation may develop in the absence of legislated regulations. Thus, for reasons of both economic protection and resource conservation, the type of tenure (fee simple, lease, licence) and the conditions attached to it (length, work requirements) are significant factors which must be addressed before exploration will proceed on a commercial scale in Canada.

In order for geothermal resources to be exploited efficiently, it is necessary to settle a number of jurisdiction and ownership issues, and secondly to establish a uniform legal framework. In the United States, differences over the definition and characterization of the resource have often led to involvement of the judiciary which have inhibited rapid exploration and exploitation of geothermal resources. In the Canadian context, the jurisdictional issue is less complex. Whether the resource is defined as a mineral, oil, gas, or water, the ownership and jurisdiction resides with the provincial Crown (the only exceptions would be lands under federal jurisdictions). This clarity in title to the resource provides an excellent opportunity to develop a comprehensive legal framework for access to the resource. Access concerns must be viewed in a province-by-province context based on the amount of Crown versus privatized land. In the Maritimes, where private ownership in fee simple is the dominant land tenure, the issue is of providing access to private lands. In other parts of Canada, applications for access to geothermal resources will be predominantly requested on provincial or federal lands. Despite these differences in land tenure, subsurface ownership of and jurisdiction over these resources is vested in the Crown.

Before proceeding to the drilling stage of exploration, individuals or companies interested in the development of geothermal resources must acquire rights to conduct exploratory activities on potential geothermal resource lands. To facilitate this exploration and reduce regulatory uncertainties, a system of allocating exploration rights to surface lands and subsurface resources must be developed. Such a system should not constitute a time-consuming burden on exploration, and must allow developers to secure their investment. At the same time, the access process must protect the public interest regarding return of resource value and protection of surface lands. Based on experiences of geothermal elsewhere, and the precedents established in the mineral, oil and gas sectors in Canada, two viable options can be identified: simple ownership and leasing.

(a) Fee Simple

One method is to sell or grant title to the requested site (be it Crown or private land) in fee simple to the explorer. Explorers would be given the rights to enter, locate, prospect and stake the land. Land could be purchased by whoever first staked claim, and this would include separating the rights to the surface lands and the subsurface resources. Ownership of the subsurface resources could either remain with the Crown or be disposed of to the explorer. In the latter case, the provincial government would automatically forfeit its ownership of all geothermal-producing deposits as they were discovered and developed. The provincial government's powers would be limited to direct taxation. Where ownership of the subsurface remained with the Crown, provincial proprietary measures could be applied if and when exploitation occurred. The example of Iceland is informative in this respect. Ownership of the surface entitles the landholder to sole proprietary rights to the subsurface resources. Since the country has a high distribution of private ownership, the rights of access to and exploitation of geothermal resources are vested with the private sector in fee simple. However, even though the rights to the geothermal resources have been transferred to the private sector, the government is still able to maintain legislative control over the conditions of its exploitation. For example, in the production phase parliamentary approval is required to establish power plants and municipal approval is required for space heating applications. Conditions on exploitation can also be attached since in the electrical market the distribution is controlled by government-owned utilities, and for space heating, the application is entrusted to municipal monopolies.

Factors favouring fee simple arrangements, from the standpoint of potential geothermal companies, would include:

(1) it would ensure that their investment would not be subject to the vagaries of government legislation; and

(2) shareholders and financiers may be more willing to invest in a project which illustrates that the company has already secured a tangible asset.

On the other hand, the purchase of land provides disincentives as well. The explorer's primary regulatory objective is to ensure freedom to enter, explore and exploit both Crown and private lands. Outright sale of surface and subsurface rights would necessitate significant front-end payments. Add this expenditure to those involved in exploratory drilling and an explorer could be faced with significantly higher initial fixed costs. In addition, an exploration company may end up with a substantial sunk investment in land inventory, which is not the best use of its venture funding.

If provincial governments wish to provide incentives to favour Canadian firms (which are mostly small compared to other nationalities), legislation must take these factors into account. Secondly, because it is not possible to determine the quality and quantity of geothermal reservoirs until exploration is completed, it is unlikely that explorers would be willing to invest in land purchase to gain access or the right to explore a geothermal site of unknown profitability. The developer who purchased the site would bear the entire uncertainty regarding the amount of resources, potential revenues, and costs of production. Therefore, the outright sale transfers virtually all of the risk to the buyer.

From the government's perspective, the resultant lack of exploration interest on the part of private developers would create minimal revenue from geothermal resources. It is clear that the government's ability to obtain a return from the sale of potential geothermal surface and subsurface lands would be limited unless a system similar to the Icelandic model (where geothermal resources and resource lands are privatized but access to markets is government-controlled) is adopted. Furthermore, under fee simple tenure, government's ability to control aspects of geothermal exploration and exploitation would be severely restricted.

(b) Leasing

Given the limitations of a fee simple resource tenure, legislators have often adopted leasing as the preferred method of providing access to resource lands. In contrast to the fee simple option where the provinces would grant ownership rights to the land and resources absolutely, the leasing system would have the province renting resources and lands conditional to requiring a permit fee, annual rental charges, and diligent work requirements. The leasing authority can also legislate conditions, restrictions, and stipulations regarding exploration procedures.

The most attractive feature of the leasing system is that it is flexible enough to accommodate a multitude of variables. Conversely, this feature can also become a liability because of the potential for creating an unwieldy regulatory maze. It is critical that a leasing system be able to balance the objectives of both the private and public sectors, and at the same time allow for uncomplicated regulatory procedures. An efficient leasing system should therefore provide incentives for the explorer in the form of security of tenure and investment, while offering regulatory control and revenue potential for the government. The discussion which follows examines how other jurisdictions have balanced these objectives, and their implications for future Canadian legislation.

Lease Terms

The purpose of the lease is to allow the applicant to test the resource to determine well productivity, injectivity, reservoir parameters and fluid chemistry. For the explorer, access needs to be acquired for a period which will allow adequate time to thoroughly examine these technical aspects. Consequently, developers hope to acquire flexibility in the length of the lease. However, because the value of geothermal resources will eventually rise (as exploration and exploitation technology improve, and conventional energy resources become either scarcer or more costly to produce), it would be an economically sound policy to acquire a permit and make no expenditures on it until it became profitable to develop the resource.

The Crown has the responsibility to ensure that the surface lands leased are not held merely for speculative purposes. To deter speculation, legislative authorities have included diligent work requirements and escalating annual rental fees in their geothermal regulations. However, because of the high risks involved, it may not be in the government's interests to require an initial fee for exploration permits, an annual escalating rent per hectare, or strict work requirements. A possible option would be to allow the explorers who exceed the required work requirements to subtract a percentage of their exploratory expenditures from the annual rental fee. The adoption of such a policy would not only deter the holding of land for speculative purposes, but it would increase the incentive for exploration. Although initial revenue for the government will be slightly reduced, this may be compensated by potential revenue gained from the exploitation phase.

Until recently, this reimbursement policy was in effect on U.S. federal leases. However, it was plagued by the necessity of having both industry and government maintain elaborate record keeping systems. To simplify this procedure, the reimbursement policy was replaced by regulations which allow the industry to select between:

- annually increasing their exploration expenditures; or
- paying an annually escalating rental fee.

Another issue of regulatory concern during the exploratory phase are the size limitations of the leases. In drafting regulations, it should be recognized that because of the variability in the spatial extent of a geothermal reservoir, no acreage limitations can be generally assigned as being too large or too small. These variables will have to be addressed by individual legislatures. However, consideration should be given to the following factors. If the maximum allowable size is excessive, then the industry may be subject to being monopolized by a single developer. Conversely, if the maximum allowable size is too small, then large developers will be deterred by having to repeatedly make expenditures on permit fees and their associated administrative expenses. On the other hand, if the minimum size is perceived as being too large, then small companies would be required to pay rental fees on acreage they have no intention of exploring.

In the Canadian context, where the developers' primary targets will be low temperature resources utilized for direct applications, explorers may not require sizeable permits (i.e. greater than 40 hectares). Nevertheless, because geothermal reservoirs cover large areas, and there is uncertainty in locating and estimating their dimensions, developers will wish to buffer their exploration areas from other explorers. Given this self-regulatory mechanism, there seems to be little justification for the government to enforce minimal size restrictions.

Leasing Approval Process

The two most common procedures for leasing geothermal land and resources to developers are through:

(1) public notice of tender (i.e. competitive bidding)

(2) application (first come, first served).

The procedure of procuring geothermal leases in France, British Columbia, and on state and federal lands in the U.S. differ, but they all include aspects of each of these methods. To protect their investment, the successful applicant receives exclusive rights to exploratory drilling and preferential rights to an exploitation lease (except in the U.S. where a lease also entitles the developer to exploitation rights).

On U.S. federal and many state lands, competitive bidding permits are not required unless exploration drilling exceeds 500 m. Below this depth, a two-tiered policy is in effect. On known geothermal resource areas (KGRA's), leases are subject to competitive bidding. If outside a KGRA, the lease is awarded to the first applicant. In the competitive bidding system, various criteria are utilized, ranging from cash bonuses to work programmes.

The French and B.C. systems are similar to one another in that they require bidding on all exploration permits regardless of the quality of the land. The application process is initiated by having the interested party submit a tender to the governing agency. The lead agency then posts the notice of public tender so that interested parties may compete with the initiating applicant. In B.C., the permit is awarded on the basis of the most comprehensive exploration programme. In France the applicant is judged on the basis of an extensive report which includes an environmental impact study.

The purpose of the American two-tiered approach is to encourage exploration of unknown lands, while maximizing the revenue potential from ownership of KGRA's. Where accurate knowledge of the resource exists, the American two tiered leasing system is an effective method of obtaining resource rent, without creating industry disincentives. In Canada, however, where the value of exploration lands and the economics of development remain uncertain, a bidding system which generates delays, risks and costs to developers, could act as a disincentive to exploration. For example, small exploration parties in B.C. may find the public tender process unfair because the process does not recognize the expenses incurred during the preliminary prospecting stages of exploration. An explorer may undertake considerable expense to identify a geothermal site, only to be outbid when the site is posted for public tender. To avoid suppressing the development of Canada's marginal geothermal resources, lease terms must be made attractive to potential investors. To promote interest in geothermal exploration, provincial legislators could consider the merits of the leasing-by-application approach.

Environmental Reviews

The French approach to lease approvals avoids the two-tiered competitive system, but the requirements are far more comprehensive, chiefly because much of the development occurs in urban surroundings. Since the applicant must address environmental impacts, use of the proposed energy, financing of the project, and scheduling of exploitation, applicants must expend significant time and money to apply. Until recently, applicants for leases on U.S. federal lands were also required to submit detailed operational and environmental plans before drilling took place. Plans were developed at great expense by prospective lessees to document the effects of developing a reservoir which may or may not exist. Should the developer be successful in discovering a development site, the plans would have to be modified to take into account the information obtained during the drilling programme. In short, the plans served no practical purpose to legislators and were costly for industry.

Recent amendments replaced this review process. The requirements for a comprehensive environmental review have been postponed until the developer chooses to exploit the resource. This amendment will serve to reduce time delays and costs before exploration, and will ensure that the environmental review is based on accurate data. Environmental standards during the exploratory drilling stage are now upheld through the enforcement of the guidelines set out in the National Environmental Policy Act.

The B.C. system of geothermal leasing has adopted a similar attitude towards environmental reviews as the U.S. To minimize the costs to explorers, and thereby maximize the incentives for exploration, environmental studies are not a major component of the leasing process. The environmental review for the exploration phase consists of a referral process after the lessee has acquired the lease and has indicated the drilling locations. The proponent submits a drilling plan to the lead agency, and it is this agency's responsibility to submit the plans to other departments for their input. Consequently, the onus is placed on the government to prove that the drilling will be environmentally damaging, rather than as in the French system, where the proponent must prove that the exploration will not be damaging. Environmental standards during the exploratory drilling stage are upheld through the enforcement of the guidelines set out in the Geothermal

Resources Act. Minimal delays or expenses are therefore incurred by the applicant in the B.C. bidding process.

6.2.3 Regulatory Options and Government Interests

On federal lands in the U.S., the right to exploit is included in the exploration lease; however, in France and in B.C., the exploration lease entitles the lessee only to preferential rights to development. To facilitate exploitation, and reduce regulatory uncertainties, conditions of exploitation must be established.

From the developer's perspective, the objective is to obtain profits from the investment equal to, or in excess of opportunities available elsewhere. From the legislator's perspective, the regulatory policy on exploitation should maximize the present value of social benefits over time. Based on the experience of other jurisdictions with respect to geothermal resources and other extractive industries, two options can be identified:

- profit sharing - a joint venture between the private and public sectors; and
- severance charges - royalties.

These two mechanisms have been selected because they have the ability to achieve the necessary balance between private and public interests. Profit sharing and royalty arrangements are desirable because they transfer some of the developer's risk to the government, and in return the government is assured a continuing share in any successful venture.

Royalties are a good example of this shared risk/profit concept. Normally, mineral royalty rates are based on either volume (physical amount of production), or profit (fixed percentage of the gross value). During favourable periods of exploitation (either high market value, or high volume demand), government revenue is large; during unfavourable periods, the developer avoids significant payments to the government.

However, this system of risk reduction would not be as effective for the geothermal industry in Canada. To maximize the profitability of geothermal applications, the load factor of the supply system must remain high regardless of demand. This is in contrast to the mining industry, where volume output is sensitive to demand. Consequently, a royalty on geothermal volume output would remain fixed.

Royalties based on gross value would also demonstrate a similar effect. The space heating charges applied to the consumer would likely be regulated by public utilities legislation. Consequently, the economic value of the resource would remain constant and hence the royalty rate would remain fixed.

Therefore, whether the royalty rates are based on volume or profit, they will be largely immune to the vagaries of the market place and instead would merely represent an almost constant cash drain on the developer. Thus, royalties are likely to only be practical on more successful projects.

Despite these limitations as they apply to the geothermal industry, royalties are an effective mechanism by which to obtain economic rent. In determining an equitable formula for royalties, legislators must attempt to establish a rate which will allow developers to recover their initial investment, and at the same time provide the public with a fair resource rent. There is one school of thought which believes that the only fair royalty is no royalty. Higbee (1980), for example, argues that the goverment should receive no revenue from geothermal because it is a renewable resource, and therefore subject to the same freedom from severance charges as solar and wind resources.

If legislators do proceed with royalties on production, there are various application methods, including a fixed royalty, a "floating" royalty, or a combination of the two. In California, for instance, geothermal lessees are required to pay a royalty of 10 percent on gross revenues. The economic problems of this fixed royalty charge were addressed by allowing the State Lands Commission to reduce or suspend royalties in cases where the royalty on gross revenue was deemed excessive.

Given the variability in exploration/exploitation costs, and the temperature of the resource, some developers may wish to avoid having a royalty established in advance of production. Instead, economic rent could be determined on a project-by-project basis. This "floating" royalty could be determined by considering exploration, delivery, and annual operations and maintenance costs.

The B.C. system, whereby the rate is established by the Minister responsible for geothermal resources, is one form of the floating royalty system. However, this system could act as a disincentive, because developers often prefer to know what the royalty arrangements are to be based on before proceeding with exploration.

Royalty rates on U.S. federal lands are determined by using a combination of fixed and floating royalty rates. The U.S. Geothermal Steam Act presently imposes a royalty rate which is fixed between 10 and 15 percent of volume or profit. The exact royalty rate is determined by a floating royalty which is based on a number of cost and revenue factors. The system has the dual advantage of providing the government with a guaranteed economic rent and, at the same time, providing developers with risk assistance.

Equity Participation

Aside from royalties, developers can shift some risks and governments can obtain economic rent through government participation in a partnership. The joint venture might include coverage of the entire operations, or it might provide for a division of labour. In the former instance, the government would be responsible for supplying input into both raising capital and supplying technical expertise.

In the division of labour scenario, one party may be responsible for exploring and exploiting the resource, another for distributing it, and a third to financing. One could readily imagine a system whereby a private firm could explore and develop the resource, sell it to a government utility to distribute, and have the project partially financed by the provincial and federal governments.

The economic and technical advantages of such a partnership can be considerable. Experience in other countries suggests that most geothermal exploration and development has been initiated and managed by private resource companies.

However, the regulated monopoly structure of utility services offers a marketing and investment vehicle the private developer would have difficulty duplicating. Consequently, in the disposition of the geothermal resource, utility companies can provide the necessary infrastructure. Thus, while utilities may not have the high risk capital or the mandate to discover geothermal resources, they may be more appropriate for operating the distribution system. Where utilities are not crown corporations, (i.e. many gas service companies) a potential conflict exists since these companies are not likely to welcome geothermal systems designed to displace natural gas consumption.

Like the royalty system, joint ventures can be utilized as an effective method by which goverment shares with the private sector in the risks and profits associated with geothermal development. Joint ventures also have the distinction of being effective in assembling expertise and increasing financial options, for several reasons. In general, the required returns on investment would be expected to be lower for government entities, be they Crown corporations, municipalities, regulated utilities, or other bodies. This occurs because governments have much greater capacity for debt financing and can usually borrow at lower interest rates than private venture companies. Therefore, the expected cost of capital could be significantly lower for government. Also, the government does not require profits over and above the returns to capital.

In fact, governments would be expected to require much more modest economic performance from a project than a private developer could withstand, provided other government or social objectives are met. In the case of geothermal developments, the government policy of reducing oil imports could justify a willingness to support projects that the private sector alone would not find attractive enough.

6.3 System-Electric Commercialization of Geothermal Resources

In general the thermal efficiency of geothermal power plants is significantly lower than that for conventional fossil fueled plants. Energy conversion technology must be matched to site-specific resource characteristics. Several geothermal system-electric technologies are possible. However, at present, resource temperatures generally in excess of 180°C are required for economic power generation, utilizing either dry steam from vapour-dominated geothermal resources or flashed steam supplied by hot water extracted from high-temperature, liquid-dominated systems. Binary systems, utilizing geothermal fluids at temperatures as low as 90°C, account for only 0.4 percent (13.85 MWe) of presently installed worldwide generating capacity.

Research and development programs aimed at electric power production from geopressured, hot dry rock (HDR) and magma resources are in progress. Commercialization of geopressured and HDR resources may be accomplished within the current decade; development of magma resources is expected to be long term (Hankin, 1980). In addition several types of hybrid combustion-geothermal power generation concepts have been studied. A combined gas turbine/geothermal steam turbine power plant could potentially achieve approximately 48 precent more output than two indepdendent plants using the same working fluid flow rates, because of the favourable synergistic characteristics of the hybrid plant (DiPippo, 1984). Other hybrid power plants that have been considered involve the use of geothermal fluid to supply the pre-heat to boiler feed, with conventional fossil fuels providing the high temperature thermal energy required for the generating cycle.

There are many uncertainties inherent in exploration and development of high temperature geothermal systems for power generation: e.g., exploration risk, drilling costs, unfavourable resource characteristics, resource depletion, problems of reinjection and waste disposal, scaling and corrosion, potential environmental conflicts, etc.

Table 6-1 summarizes results of a net energy analysis (i.e. comparison of total primary energy input requirements for manufacture, construction, installation and maintenance vs. energy output) for vapour-dominated, liquid-dominated, HDR and geopressured geothermal power development schemes in the United States, (Herendeen and Plant, 1981). All are net energy producers, i.e. having energy ratios exceeding unity (Table 6-1), in spite of the uncertainties associated with exploration and development.

As would be expected, development of vapour-dominated (i.e. high enthalpy) resources achieves the highest energy ratios, 13 $\pm$ 4. Development of high-temperature liquid-dominated resources yields energy ratios of approximately 4 to 5. Although these ratios are strictly generalizations they reflect the higher conversion efficiency of vapour-dominated systems and the reduced risks and overall development costs, relative to those associated with commercialization of high-temperature liquid-dominated resources.

A review of the worldwide status of geothermal power generation emphasizes the significant technological and economic advantages of system-electric development of vapour-dominated resources.

TABLE 6-1

ENERGY RATIOS FOR GEOTHERMAL SYSTEM - ELECTRIC TECHNOLOGIES

(Modified: Herndeen and Plant, 1981)

	NET POWER OUTPUT (MWe)* AND CAPACITY FACTOR	LIFETIME (YRS)	DATA SOURCE	ENERGY RATIO (ER)**	NOTES
A. Vapour-dominated systems.	106 @ 85%	25	Pacific Gas & Electric, (1973; 1977)	13 ± 4	Units 9 and 10, The Geysers.
B. Liquid-dominated systems.	50 @ 85%	30	Bechtel (1977)	4.4 ± 1	Imperial Valley (Heber, KGRA)
C. Hot Dry Rock					
35°C/km	50 (avg) @ 85%	30	EPRI; Republic (1979)	2.7 ± 0.9	ER strongly dependent on size of fractured induced.
45°C/km	50 (avg) @ 85%	30	EPRI; Republic (1979)	3.4 ± 1.0	
55°C/km	50 (avg) @ 85%	30	EPRI (1978); Republic (1979)	3.9 ± 1.1	
D. Geopressured	25 @ 85%	30	Rieman, Rios-Castellon, and Underhill (1976)	2.9 ± 0.9	Energy contained in methane not induced.

* Net after use of some electricity on site.

** $ER = \frac{\text{Net electrical energy output overtime.}}{\text{Primary non-reviewable energy input to build and operate over lifetime.}}$

6.3.1 International Electric Developments

Current worldwide geothermal power generation capacity totals approximately 3190 MWe, as shown in Table 6-2 (DiPippo, 1984). Although vapour-dominated geothermal systems are approximately twenty times less common than high temperature hydrothermal (liquid-dominated) systems (Healy, 1975) they account for 1755.35 MWe (i.e. 55 percent) of the total capacity generated. Of this 1755.35 MWe, 1246 MWe (nearly 40 percent of the world geothermal power capacity) are produced at The Geysers, California, a unique vapour-dominated geothermal system of enormous size and productivity. It is not surprising therefore that the United States is presently the world leader in geothermal power. Italy currently operates more geothermal power units (41) than any other country, for a total generating capacity of 457.1 MWe. All plants are dry steam type (DiPippo, 1984).

Geothermal power generation from high temperature hot water systems currenty totals 1419.49 MWe, or 44.5 percent of worldwide geothermal power capacity. In the Philippines geothermal power was first produced in 1977 and now totals 593.5 MWe, entirely from high temperature liquid-dominated systems. Other major producers from hot water systems include Japan (227.5 MWe), Mexico (205 MWe) and New Zealand (202.6 MWe) where the Wairakei power plant has now operated successfully for 25 years (Stacy and Thain, 1984) maintaining a load factor of approximately 90 percent since 1970. In contrast, development of liquid-dominated geothermal resources in the United States has not been so successful. Of the 37.7 MWe currently produced, 32.2 MWe generated by power plants exploiting the high saline (>200,000 ppm Total Dissolved Solids) hot water system in the Imperial Valley

TABLE 6-2

WORLDWIDE GEOTHERMAL POWER PLANTS

		Generating Capacity, MW	
COUNTRY	NO. UNITS	AS OF JUNE 1983	EXPECTED 1985
United States	24	1,283.7	2,122.3
Philippines	14	593.5	1,718.5
Italy	41	457.1	502.1
Japan	8	227.5	282.5
Mexico	10	205.0	700.0
New Zealand	14	202.6	202.6
El Salvador	3	95.0	95.0
Iceland	5	41.0	41.0
Indonesia	3	32.25	32.25
Kenya	2	30.0	45.0
Soviet Union	1	11.0	21.0
China	10	8.136	11.386
Portugal (Azores)	1	3.0	3.0
Turkey	1	0.5	40.5
Nicaragua	0	0	35.0
France (Guadeloupe)	0	0	6.0
TOTALS	137	3,190.286	5,858.136

cannot yet be considered as economically competitive with conventional energy sources, based on current energy supply and costs (DiPippo, 1984). Consequently, excluding production at The Geysers, commercial geothermal power generation in the United States from liquid-dominated geothermal systems totals 5.5 MWe, of which 3 MWe are produced in Hawaii.

Binary generating systems offer considerable potential for small to moderate scale power production. Lower geothermal resource temperatures can be used and better conversion efficiencies can be achieved. The geothermal fluids are maintained within a closed loop system throughout the production-reinjection cycle. Potential scaling and corrosion problems are eliminated as the fluids are not in contact with the turbine. After use, the geothermal fluids are reinjected so that the system is environmentally benign. At present the largest operational binary plant is the 10 MWe (nom.) Magmamax dual binary plant at East Mesa (Imperial Valley). A 65 MWe binary demonstration plant is under construction at Heber, also in the Imperial Valley.

6.3.2 System-Electric Development Potential in Canada

The potential for geothermal power development in Canada is confined to the Cordillera of British Columbia, Yukon and Western Alberta, within a broad thermal anomaly extending through west-central British Columbia and the southern Yukon. Only limited detailed exploration has been conducted and no commercially exploitable high temperature geothermal systems have yet been proven.

A 190-200°C geothermal resource has been identified at Meager Mountain following an extended exploration program, initiated in 1974. Results from three rotary exploration wells, drilled to depths of 3500 m, indicate that the resource is fracture-dominated but with limited flow capacity. Based on well test data, injectivities range from 2.3 to 4.0 L/s MPa. Permeability appears to be associated with a fault zone intersected at 1200-1600 m by the deep wells. Temperatures up to 270°C were recorded in impermeable rock at greater depth and are consistent with the high regional geothermal gradient (about 90°C/km) for the south flank of Meager Mountain. Of the three deep wells only MC-1, completed to 2511 m (M.D.) will sustain a discharge, producing a mass flow of 6.5 kg/s at a wellhead pressure of 85 kPa. From well test data it was concluded that "... the flow potential of the South Meager resource appears to be limited by the temperature of 190-200°C, the depth at which the resource has been intersected and the low permeability encountered by the present deep wells" (Stauder et al, 1983, p. 3-20).

Although economic production was not realized from the initial deep exploratory wells, high subsurface temperatures have been confirmed. The possibility of encountering favourable permeability elsewhere at depth at South Meager has not yet been fully tested. The commercial potential of the Meager Mountain resource remains unknown. B.C. Hydro and Power Authority have terminated the Meager Creek Geothermal Project. Data obtained during the history of the project remains proprietary. Furthermore until B.C. Hydro relinquish their land position at Meager Mountain no further exploration to confirm the high temperature resource of the area is likely.

The substantial reserves of fossil fuels and hydroelectric power in western Canada are a major disincentive to detailed and systematic exploration for geothermal resources suitable for system-electric development. Coupled with the current surplus of available power throughout the region, development of large-scale geothermal power generation projects is unlikely in the foreseeable future. For isolated communities, however, distant from regional grid supply lines and dependent on diesel or other fossil fuel supplies (at high transported costs), small-scale geothermal system-electric development would be an attractive alternative, where the energy cost is independent of any fuel costs.

With the present status of system-electric resource assessment in Canada, the chief disadvantage of considering small-scale electrical generation is exploration risk. Although a resource capable of providing only 1.5 - 3.0 MWe of power may be required, substantial exploration risk is still involved. Resource assessment for high temperature resources requires substantial risk capital to support land acquisition, surface exploration surveys (hydrology, geology, geochemistry and geophysics), temperature gradient drill holes, exploration drilling, and reservoir testing. Surface exploration can provide estimates of resource temperature, fluid characteristics and the possible extent of the resource. However, specific resource parameters, and more importantly permeability and actual production characteristics must be tested by drilling. Standard rotary (oil and gas) drilling rigs are normally required for geothermal system-electric exploration and development, the size varying according to projected depth to resource and local geologic conditions. Drilling costs are site-specific and highly variable. They are directly affected by subsurface geology, depth to resource, site accessibility and subsurface temperatures. Since drilling costs increase exponentially with depth they play a major role in determining the economic feasibility of a project, and the potential value of the resource. As with oil and gas drilling, a high element of risk is involved, i.e. potential for "dry" holes, subeconomic resource temperature, low permeability and production rates, drilling problems associated with difficult subsurface conditions, equipment failures, etc.

6.4 Direct-Use Commercialization of Geothermal Energy

Direct use applications of low to moderate temperature (20-150°C) geothermal resources have several significant advantages over geothermal system-electric development. Low temperature resources are more abundant and accessible, offer higher conversion efficiency (typically in excess of 75 percent), require shorter development schedules, can be exploited using simpler off-the-shelf conversion technology and have less expensive exploration and development requirements.

However, successful market penetration of low temperature geothermal energy requires that favourable market opportunities exist or be generated at, or in close proximity to, the resource. Successful commercialization is as much dependent upon attracting appropriate end-users as it is on the availability of suitable resources.

Table 6-3 illustrates the wide variety of potential direct use applications of low to moderate temperature geothermal resources (Lindal, 1974). As with high temperature resources, technology must be matched with site-specific resource characteristics.

Industrial processing applications normally require the highest resource temperatures (of the order of 150°C); temperatures of 80-100°C are appropriate for drying of agricultural products. For space heating, temperatures in the range 65-100°C are typically desired. Where heat pumps are incorporated this can be extended down to 13°C. For agricultural applications resource temperatures of 30-85°C are appropriate.

TABLE 6-3

APPROXIMATE TEMPERATURE RANGES FOR DIRECT-USE APPLICATIONS

(Lindal, 1974)

°C		
180	Evaporation of highly conc. solutions Refrigeration by ammonia absorption Digestion in paper pulp, Kraft	Temp. range of conventional power production (180–140)
170	Heavy water via hydrog. sulphide proc. Drying of diatomaceous earth	
160	Drying of fish meal Drying of timber	
150	Alumina via Bayers proc.	
140	Drying farm products at high rates Canning of food	
130	Evaporation in sugar refining Extraction of salts by evaporation and crystalization	
120	Fresh water by distillation Most multiple effect evaporations, concentr. of saline sol. Refrigeration by medium temperatures	
110	Drying and curing of light aggreg. cement slabs	
100	Drying of organic materials, seaweeds, grass, vegetables, etc. Washing and drying of wool	
90	Drying of stock fish Intense de-icing operations	
80	Space Heating Greenhouses by space heating	
70	Refrigeration by low temperature	
60	Animal husbandry Greenhouses by combined space and hotbed heating	
50	Mushroom growing Baineological baths	
40	Soil warming	
30	Swimming pools, biodegradation, fermentations Warm water for year-round mining in cold climates De-icing	
20	Hatching of fish; fish farming	

6.4.1 International Developments

In a 1980 survey of world use of low to moderate temperature geothermal resources (Gudmundsson and Palmason, 1982), 44 countries reported having geothermal resources of temperatures less than 150°C. Low temperature geothermal energy is actively utilized in 12 countries and installed worldwide capacity for direct-use applications totals approximately 8700 MW-thermal (above a reference temperature of 15°C). (See Table 6-4.) For optimum economic benefit, development has favoured large-scale projects. Higher energy load demands can justify deeper development wells, longer transmission distances, more sophisticated utilization, and exploitation of lower temperature resources. The technology, reliability, economic competitiveness and environmental acceptability of low temperature geothermal energy commercialization is demonstrated by the examples reviewed in Section 3, from several countries.

6.4.2 Direct-Use Development Potential in Canada

In Canada the development of low temperature (<90°C) geothermal resources for direct use applications offers greater potential than exploration and development of high temperature systems for power generation. In many respects however, the commercial development of low grade geothermal energy is more difficult to assess. The concept of co-location of geothermal resource and suitable markets or end-users is far more critical for the successful development of low temperature geothermal resources than system electric development. The fundamental limitation for direct-use development may not be accessible heat but geographically matching the available resources to appropriate market opportunities.

TABLE 6-4

WORLD USES OF LOW TEMPERATURE GEOTHERMAL RESOURCES (1980)

(Expressed as thermal power above 15°C)

	THERMAL POWER (MW)			
COUNTRY	A	(%)	B	(%)
Japan	4,475	(51.4)	81	(2.3)
Hungary	1,540	(17.7)	959	(27.7)
Iceland	1,127	(13.0)	1,096	(31.7)
U.S.S.R.	555	(6.4)	555	(16.0)
China	346	(4.0)	329	(9.5)
Italy	265	(3.1)	73	(2.1)
U.S.A.	225	(2.6)	221	(6.4)
France	56	(0.6)	56	(1.6)
Czechoslovakia	43	(0.5)	43	(1.2)
Romania	36	(0.4)	36	(1.0)
Yugoslavia	14	(0.2)	14	(0.4)
Austria	5	(0.1)	5	(0.1)
TOTAL	8,687	(100.0)	3,468	(100.0)

A: All utilization as defined in text.

B: Utilization excluding bathing.

While the potential applications appear numerous and varied, they would be limited in Canada for several reasons. Resource temperatures considered to be feasible in Canada are at the lower end of the temperature range indicated on Table 6-3, i.e. less than 100°C. With temperatures of this order, most of the "low temperature" industrial processes are excluded, leaving only space heating and a few agricultural uses in the practical range.

Unfortunately, most of these remaining low temperature applications are either quite seasonal or are relatively small scale operations. Thus, the principal use of geothermal resources in Canada is likely to be space and domestic hot water heating. Section 6.5, which discusses system economics, will provide further justification for concentrating on direct-use heating applications.

Assessment of the low temperature geothermal potential of Canada has been on-going since 1975, through a variety of studies (identified in Section 2.3) sponsored by the Department of Energy, Mines and Resources and the National Research Council. These studies have focused primarily on regional assessments of prospective deep sedimentary basin-type resources, in particular the Western Canadian Sedimentary Basin. Possible exploitation of shallow thermal aquifers and deep circulation (gradient heat) systems supplying hot springs for direct utilization has received less attention. Several research studies have reviewed possible direct-use applications and market opportunities for low temperature (deep sedimentary basin) geothermal resource development in Canada. Detailed site-specific exploration has been very limited; therefore the majority of the application studies are based on assumptions regarding resource parameters.

Although these studies demonstrate that favourable resource potential exists in Canada and that development would be economically competitive with traditional energy options, there is currently insufficient detailed information about these resources to adequately assess their commercial potential. Specific resource characteristics need to be defined for the low temperature geothermal resources that have been identified.

The characteristics of low temperature geothermal resources can vary considerably from one area to another, requiring the need for resource assessment on a site-specific basis. Development may be hindered by insufficient resource temperatures, inadequate flow rates, unsatisfactory water quality (high total dissolved solids, high gas content), and large depths-to-resource. Adverse resource characteristics will directly affect engineering considerations and the technical feasibility of resource development (e.g. materials selection, distribution system design, pumping requirements, need for auxillary or standby capacity, disposal requirements, potential environmental conflicts), and therefore also effect the cost of the energy produced.

Exploration and assessment of low temperature geothermal resources normally involves less effort then that required for system electric development. The extent and scale of the exploration effort required to confirm a resource is normally governed by the nature of the intended end-use or development objective. Direct-use applications have lower energy loads and require lower fluid volumes than system-electric applications and so can often be supplied by a single or a few wells. With the limited number of development wells required, comprehensive reservoir or aquifer testing is neither possible, nor entirely necessary. Potential low temperature resources are more abundant and accessible, increasing the probability for successful exploration. Rotary drilling equipment used in the oil and gas industry can also be used for exploration and development of deep sedimentary basin resources (Vigrass, 1979, 1980); conventional water well rigs can be used for shallow resources. Minor modifications to drilling equipment and procedures may be required to cope with elevated temperatures and corrosive fluids. Once drilling has confirmed a suitable resource development can proceed with a minimum of delay.

Accurate definition of site-specific resource characteristics is also important for effective resource management. Since the majority of the heat is stored in the rock and transferred to the reservoir fluids confined within them, production rates will determine the amount of effective thermal energy extracted from the resource. Once reservoir and production characteristics are known resource management can be optimized. Appropriate production levels can be established that will meet intended energy load requirements yet conserve the thermal energy of the resource. For this purpose, waste fluids are normally reinjected into the production reservoir or aquifer, to maintain reservoir pressures and minimize local drawdown and potential influx of cooler temperature fluids from adjacent formations.

The chemistry of the reservoir fluids will strongly influence reinjection requirements. For small scale direct use development, utilizing shallow thermal aquifers of good quality (i.e. low TDS) fluids, reinjection of waste fluids may not be necessary. Depending on local conditions, direct disposal to surface drainages may be permitted, or alternatively temporary ponding to facilitate solids precipitation and cooling, prior to subsequent release to surface waters. Should reinjection into the shallow aquifer be required, the additional cost involved would not substantially affect the overall project development costs.

For saline, high TDS, reservoir fluids that will typically be encountered in most deep sedimentary basin resources, reinjection will likely be mandatory for environmental reasons. The drilling costs for a production and reinjection well "doublet" therefore add substantially to development costs for deep sedimentary basin resources, together with the inherently greater risks involved with respect to encountering both favourable production and reinjection conditions. Coupled with the high capital cost of the surface pipe work and distribution network, well spacings for production-reinjection "doublets" become an importanat consideration for the economic viability of a large scale direct use development project. Well spacings must be compatible with reservoir and production characteristics and minimized to reduce the cost of the distribution network. Large well spacings can be avoided by directionally drilling one or both of the doublet wells (as is done in France, Section 3.2).Directional drilling is a common technique employed in the oil and gas drilling industry. The reduced capital cost of shorter surface pipework must be off-set against the additional cost incurred by directional drilling.

In spite of the substantial low temperature geothermal energy potential assessed for the Western Canadian Sedimentary Basin successful commercial development has not yet been realized. Detailed site-specific exploration has been limited to the Geothermal Research Project at the University of Regina (Vigrass, 1979). A single well (Well 3-8-17-19) was completed to 2215 m in 1979. Computations by Vigrass indicate a production rate of 100 m^3/hr, of 62°C fluid, at a 7 year drawdown of 140.5 m. Production is mainly from a 80.9 m section of the Deadwood Formation and a 30.2 m section of the Winnipeg Formation. The production fluids contain 10-12% dissolved solids. H_2S and dissolved O_2 were also present (Postlethwaite, 1980). Environmental mitigation precludes disposal of the produced fluids at surface. Consequently more comprehensive well and reservoir testing has been suspended until an injection (disposal) well can be completed. Funds for this stage of the project are presently unavailable.

Although valuable experience has been gained by the Geothermal Research Project at the University of Regina its present status is unlikely to promote development of low temperature deep sedimentary basin resources in Canada. Like the high temperature geothermal resource at Meager Mountain, B.C., the commercial potential of the low temperature resource at the University of Regina campus remains unconfirmed. Under these circumstances and in the absence of any historical production data and experience for other low temperature resource areas in Canada private industry and potential investors can not look confidently toward commercialization of low temperature resources. Although the resource potential is well recognized successful pilot development projects are needed to demonstrate the accessibility and availability of geothermal resources and take the geothermal industry in Canada beyond its present research stage.

With improved energy conservation and continued advances in new energy technologies, development of low temperature geothermal energy is under increasing pressure to compete with a variety of alternative energy resources. This will be an important factor throughout much of Central and Eastern Canada where, based on present assessments (Section 2), the geothermal potential is low.

In Ontario for example, the Ministry of Energy has embarked on a program to meet at least 5 percent of the province's primary energy needs with renewable and recoverable energy resources by 1995. These resources include municipal waste, timber industry residues (bark, sawdust, wood chips), industrial waste heat, agricultural crop residues, biomass, hybrid poplar plantations, water power, and solar and wind power. Like low temperature geothermal, the economic benefits of any one of these resources over other options is largely dependent on site-specific parameters and available fuel supplies.

6.5 Geothermal System Costs and Economic Considerations

6.5.1 Primary Loop Capital Costs

The cost structure of direct-use geothermal systems will to a large extent dictate the opportunities and constraints to commercialization of the resource. The quality and accessibility of the resource will be a major influence on system capital costs, while the extent and efficiency of the process application will be key factors affecting capital cost as well as unit energy costs.

Geothermal systems are exceedingly capital intensive, with drilling costs and distribution system installation costs typically representing the most significant items. The factors controlling the actual extent of these costs are quite different however.

A geothermal system actually involves the drilling and completion of two wells - one for extraction of the geofluid and another for reinjection. The capital costs of these wells are almost completely a function of depth drilled and the hardness of the material to be drilled. Figure 6-1 indicates the relationship of well costs to depth based on historical data from the U.S. As can be seen, there is a portion of well cost which is not variable with depth, namely the set-up costs. These would include preparation of the drill pad, clearing of the site and access as required, and mobilization of the drilling rig and crew. This fixed cost element would be in the $100,000 to $250,000 range for each well.

The remainder of the cost can be expressed as a function of depth. However, it should be noted that the cost per

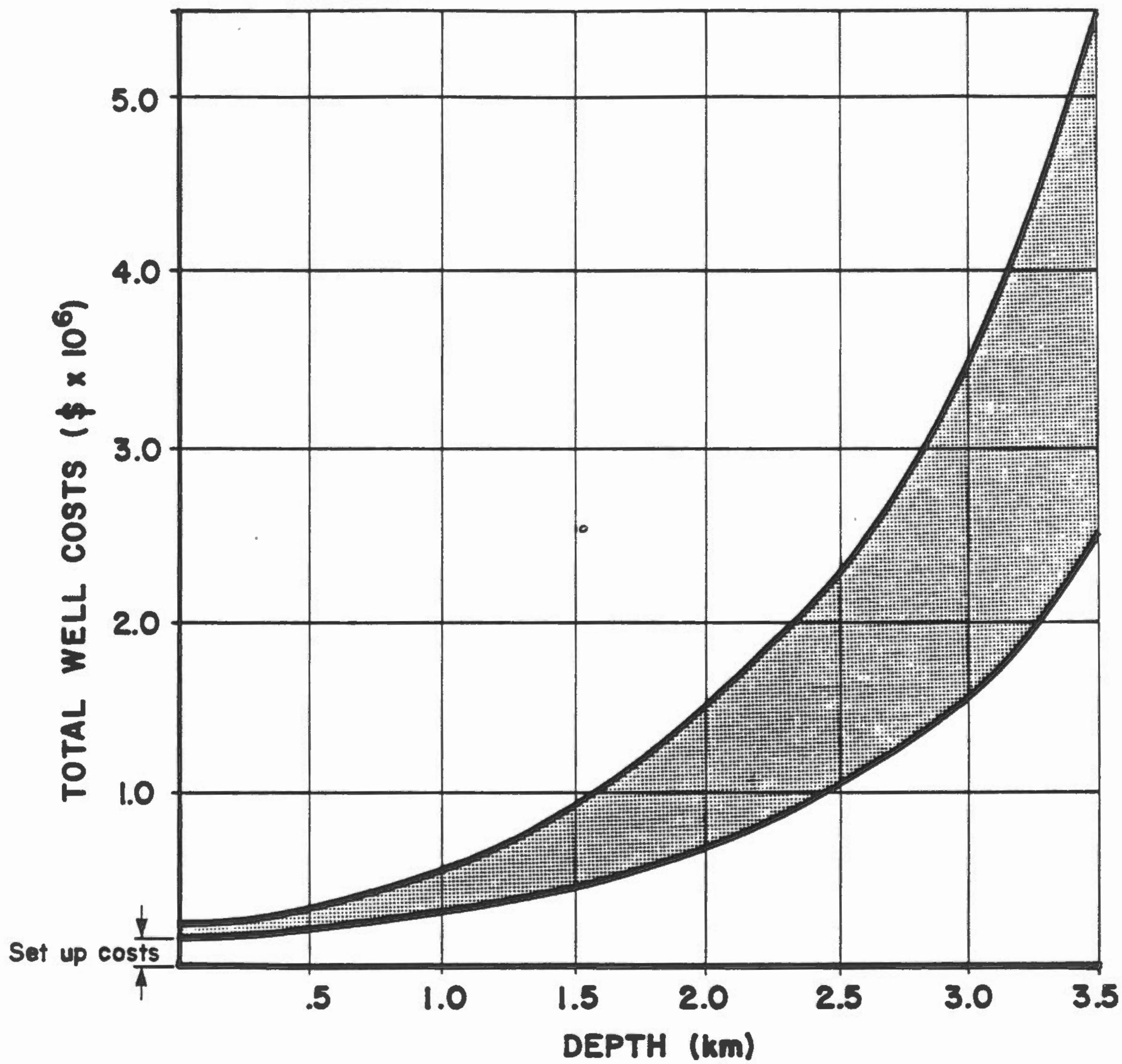


FIG.6-1

TYPICAL WELL DRILLING COSTS

metre drilled will generally accelerate with depth. In addition, the range of costs becomes more variable with depth, since the opportunities for encountering difficult rock conditions also increase. In general, well depths of about 2 km cost approximately $1.0 million. Beyond 2 km, costs begin increasing dramatically such that at 3 km, average costs would be expected to be near $2.5 million.

In addition to the capital cost of the wells, the primary geofluid loop will include the above ground wellhead equipment and piping, the downhole pumps and primary heat exchanger. These items will be dependent primarily on the flow rate of the system. Average flow rates would be expected to be in the 100 m^3/h to 150 m^3/h range. Capital costs for these items are estimated at between $350,000 and $450,000.

When these above ground costs are added to the well costs, the total capital costs for a single doublet, primary loop system are derived. For example, by reference to Figure 6-1, with wells at a depth of 2 km, the total cost would be approximately as follows:

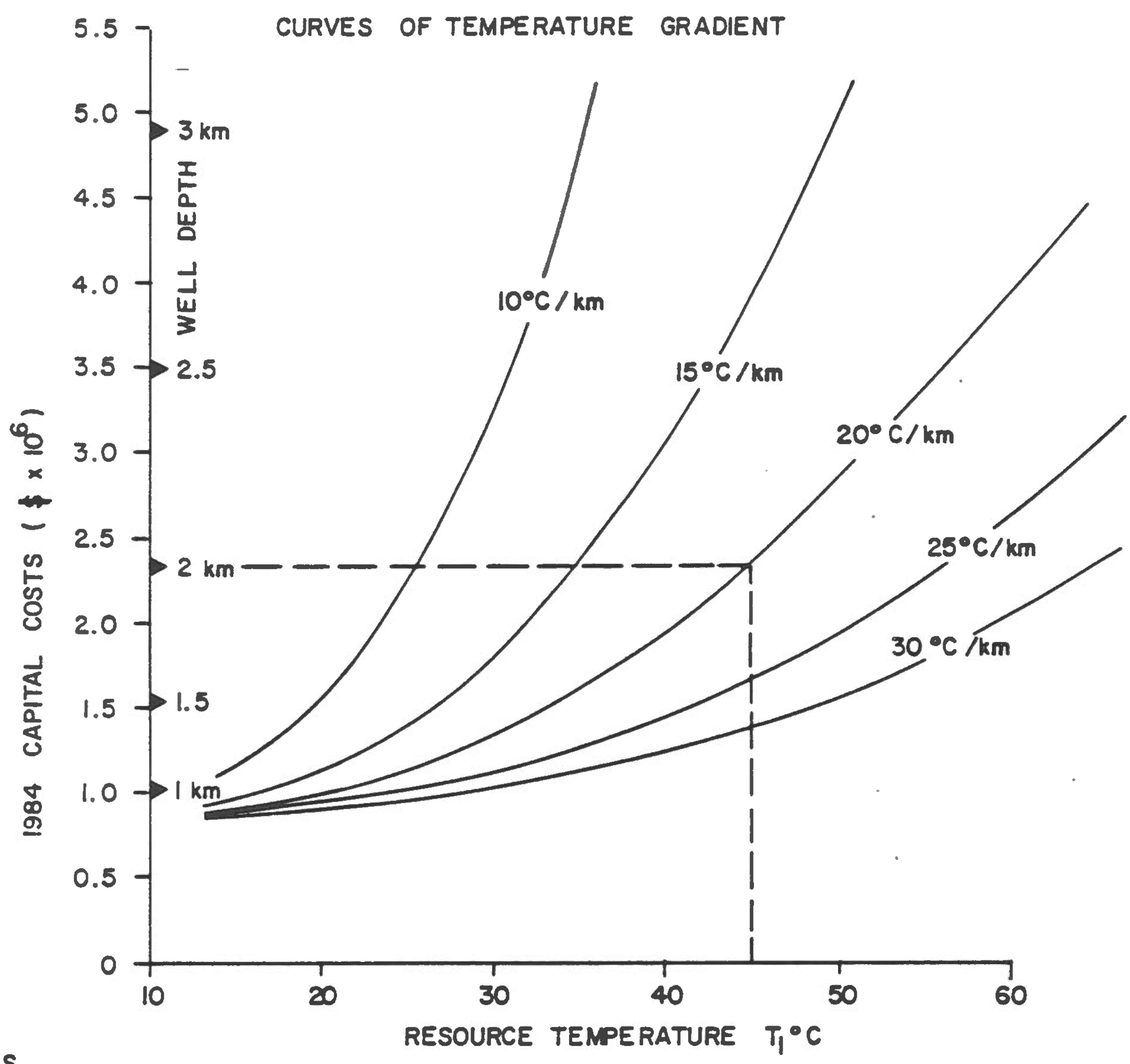
Production well	$1.0 million
Injection well	1.0 million
Above-Ground Equipment	0.4 million
Total:	$2.4 million

The depth of wells actually drilled for a particular geothermal project, and therefore the capital cost for the wells, will depend on the temperature gradients available, the resource temperature required and the availability of geofluid producing strata. Even if it is assumed that a number of strata with suitable characteristics are available at a given location, the potential developer of geothermal energy is still faced with making an economic choice as to the optimum depth. Here, the temperature gradient will be the key determinant.

Figure 6-2 illustrates the resource temperatures resulting from various combinations of capital cost and temperature gradient. Based on the example above, the 2 km wells with a capital cost of $2.4 million will yield a supply temperature of about 45°C if the gradient is 20°C/km. This 45°C level is about the minimum temperature requirement for a simple, direct transfer space heating application. Below this level, system enhancements such as heat pumps, radiant floor heating panels or supplementary conventional boilers must be considered.

Clearly, the system capital cost is extremely sensitive to gradients for a given level of resource temperature requirement. For example, to achieve the 45°C minimum supply temperature, the costs would be on the order of $4.0 million if the gradient is 15°C whereas at 25°C/km, the costs drop to about $1.5 million. Since the objective of the development is to obtain useful energy, the developer is concerned with the incremental cost of increasing the supply temperature. Figure 6-3 illustrates the dramatic effect temperature gradient has on this factor.

With only a 10°C gradient, it can be seen that average capital costs quickly become prohibitive if a supply temperature of greater than 20°C is required. At a 20°C gradient however, the incremental costs remain fairly constant in the range of 30°C to 50°C, increasing rapidly beyond 50°C. The minimum average cost range for a 30°C gradient lies between about 40°C and 70°C. Obviously, the



NOTES

1- MEAN SURFACE TEMPERATURE 5° C

2- COSTS ARE BROADLY APPLICABLE TO SINGLE DOUBLET OUTPUTS OF 150 m^3/h AND LESS, WITH WELL COSTS BASED ON REFERENCE CURVE OF FIG. 6-1.

3- COSTS INCLUDE TWO WELLS, WELLHEAD EQUIPMENT & PRIMARY HEAT EXCHANGER.

FIG. 6-2

GEOTHERMAL DOUBLET SYSTEM CAPITAL COSTS

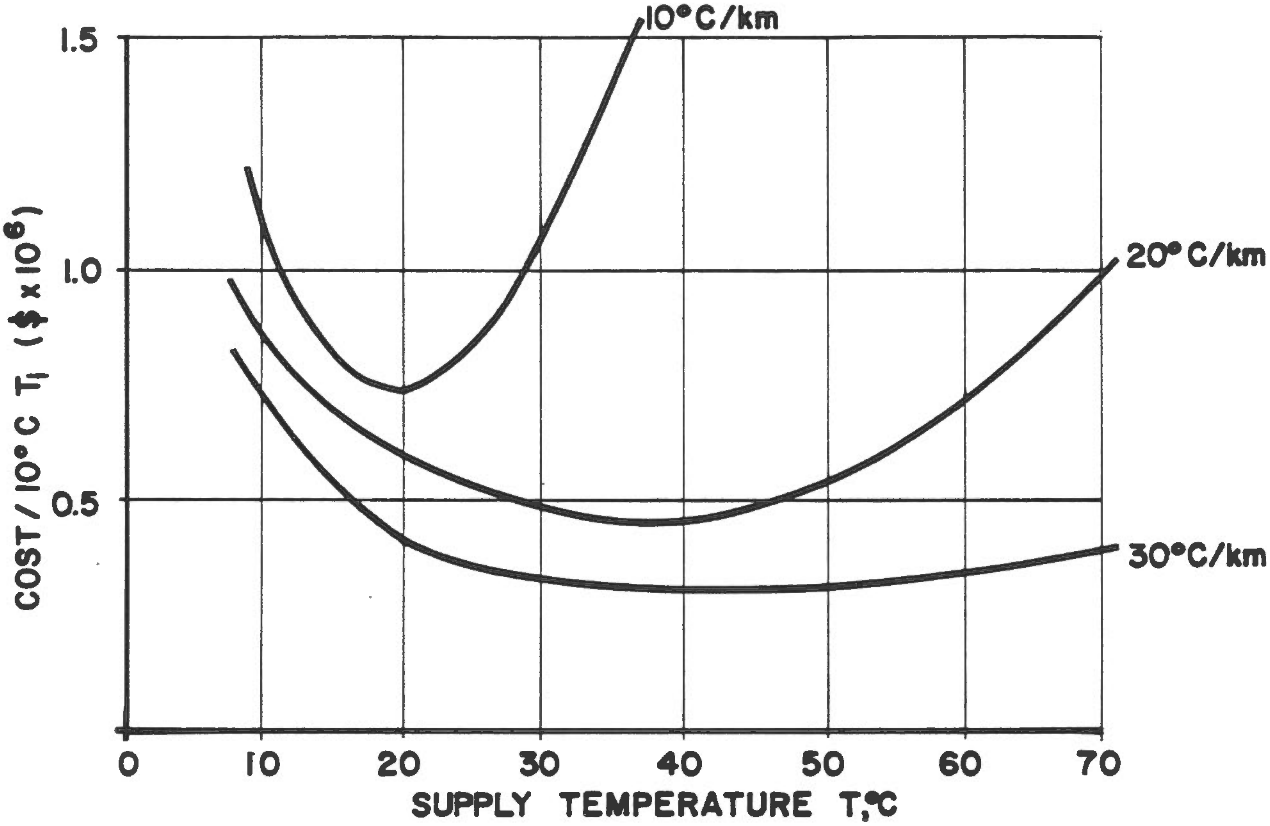


FIG.6-3

AVERAGE COST OF RESOURCE TEMPERATURE

economic range of supply temperatures would be higher at greater gradients and at the same time, average cost per unit of T_1, would be lower.

It is clear, given these relationships between capital cost and gradient, that all other things being equal, the developer is faced with determining the optimum level of capital costs (i.e. drilling depths) appropriate to the amount of energy which can be recovered. With relatively high gradients, it will be more economic to drill deeper, while with low gradients it is more cost effective to minimize well depth and increase the energy availability by extracting heat from the fluid more efficiently. Also, if gradients are very low (i.e. 10-15°C/km), consideration must be given to heat pump utilization to improve the heating efficiency of the system. In this case, the very high average capital costs arising from well development are substituted for the capital cost and operating cost of heat pumps.

6.5.2 Operating Costs

Pumping costs and operations and maintenance costs represent the most significant components of annual operating costs. As with most technologies, there is some opportunity to trade off capital costs against operating costs. In other words, it is possible to reduce capital costs by drilling shallower wells and increase operating costs by installing more pumping power to increase the flow rate. In general, however, the magnitudes of direct-use geothermal system operating costs are relatively small compared with the capital costs.

The major exception to this observation is where heat pumps are included in the system. Section 6.5.5 addresses this aspect in greater detail.

Operating costs for the primary loop are primarily dependent on the design flow rate and the price of electrical energy. Typical annual costs would be as follows:

Fixed Costs:	
O + M Labour	$ 40,000
Overhead Allowance	20,000
Equipment Replacement Allowance	30,000
Variable Costs:	
Pumping Costs	60,000
Chemicals and Supplies	20,000
Total Annual Operating Cost	$170,000

The pumping costs indicated above correspond to a flow rate of 100 m^3/h and electricity costs of 7¢/kWh. Higher electricity rates or higher pumping rates would make pumping costs even more significant in the system operating costs. Equipment replacements are actually capital costs which occur at regular intervals over the life of the project. Downhole and injection pumps would have a expected life of about 4 years and the well head equipment requires replacement every 10 years.

Since operating costs are relatively low for a geothermal system compared with a conventional fossil fueled system, the level of uncertainty about future economic assumptions is much reduced. With conventional systems, there is substantial exposure to risk of extreme increases in fuel prices, which represent a very high proportion of system costs. With geothermal, however, such increases would have only a modest impact on total system costs and unit energy prices.

6.5.3 Distribution System Costs

Given the nature of low temperature resources in Canada, the primary application will be for centralized district heating systems. The distribution network downstream of the primary heat exchanger can represent a significant portion of the total system capital cost. Studies of U.S. and European systems have reported distribution costs of between 20 percent and 50 percent of the total capital expenditures. The distribution system is comprised of the connections to back-up boilers, distribution mains and service piping, emitter systems and, in some cases, heat pumps.

The actual costs for the distribution system will be highly site-specific depending on the network arrangement, whether it is for a new installation or a retrofit, characteristics of the facilities, and so on. In general, the system costs are a function of user density, the temperature drop between supply water and return water, and the nature of the user buildings.

User Density

Traditional North American land-use patterns currently present a significant constraint on the adoption of district heating systems suitable for geothermal energy development. Effective utilization of geothermal energy requires that the space to be heated be spatially quite concentrated and quite large.

For residential applications, for example, French systems often have housing densities of between 60 and 70 units per hectare. This translates to a thermal load of about 50 MW per square kilometer (JIGA, 1983, p.97). In typical suburban areas of North America, however, housing densities are in the range 11 to 16 units per hectare for detached and semi-detached houses. Even multiple storey apartment buildings only average between 50 and 70 units per hectare in U.S. and Canadian urban areas (Allen, 1981).

Thermal load density is critical to the feasibility of district heating because distribution piping represents an enormous outlay if the user community is dispersed. Allen has provided the results of previous studies in the U.S. and Sweden which have established load density characteristics for typical urban land uses. These are presented in Table 6-5.

Order of magnitude heat distribution network costs, based on a number of operational projects and some now being completed in France, are indicated by Figure 6-4. The key factors influencing these costs are shown to be the total project size, the temperature drop in the system (and therefore the flow rate), and the load density. In general, when the density of housing units falls from 90 to 45 per hectare, the distribution system capital cost per housing unit increases by about 150 percent. It should be noted, however, that the range of housing densities indicated on Figure 6-4, (i.e. 40-90 units per hectare) is quite high. For densities below 40, it can be expected that costs would rise even more dramatically.

TABLE 6-5

TYPCIAL URBAN LOAD DENSITIES

Land Use	Thermal Load Density (MW/km2)	Prospects For District Heating
Downtown (high rises)	>70	Very Favourable
Downtown (multi-storied)	50-70	Favourable
City Core (commercial and multi-family)	20-50	Possible
Duplexes, Row Housing Townhouses	12-20	Questionable
Single Family Detached	<12	Unfavourable

Source: Allen, 1981, p. 588

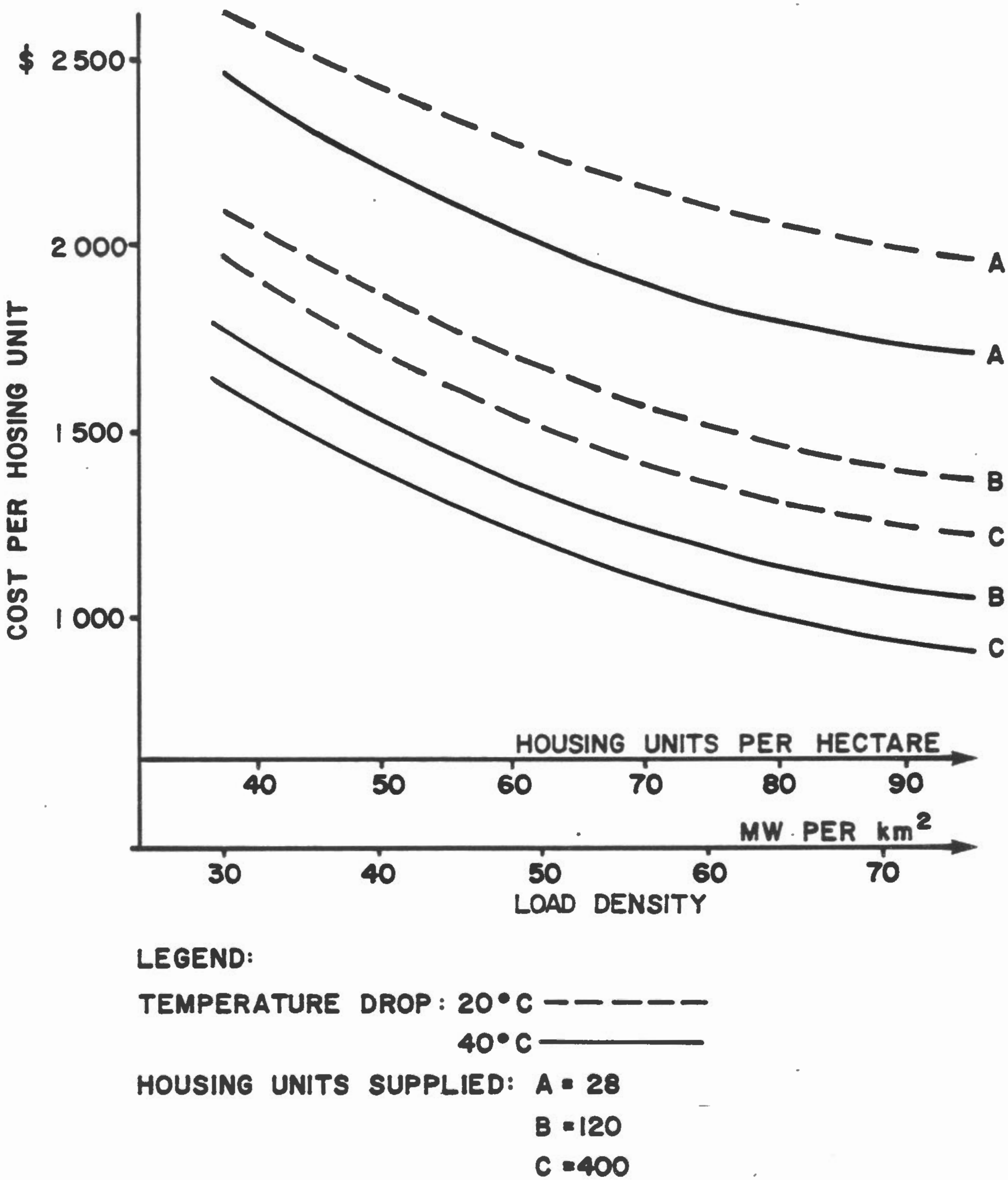


FIG. 6-4

DISTRIBUTION NETWORK CAPITAL COSTS

SOURCE : JIGA

On the basis of the classifications in Table 6-5, it is likely that the only locations in Canada where densities are great enough to make geothermal district heating commercially viable are the heavily built-up central cores of the major cities. In most other areas of the country, land use standards, zoning controls, settlement patterns and lifestyle demands have mitigated against high thermal load densities with the exception of some major institutional complexes such as universities, hospitals, penitentiaries and government complexes.

At the present time, district heating, requiring service lines to individual users, cannot be considered economic even if the energy supply is basically costless (e.g. waste heat recovery). Market penetration of a centralized heating system, however, where a substantial user complex is proximate to the central plant, could be quite favourable.

As noted above, adoption of such systems in European cities has been accomplished in many areas because the densities are present, hydronic heating systems are more common, and energy-conscious planning has been more prevalent.

In Finland, for example, new housing developments have been brought on-stream in a manner conducive to central heating. The complex is designed and implemented such that the heating system evolves. Basically, a small boiler substation supplies the initial buildings. Once the connected load grows sufficiently, this boiler is removed and replaced by a larger unit. As the complex continues to grow, each new building is designed to be connected to the central system. Eventually, the connected load is great enough to justify a geothermal system. Since the district heating loop is already in place at that time, the only incremental cost for the geothermal system is the primary loop.

In some countries, mandatory connection to the district heating system has simply been legislated while in others, financial incentives and guarantees have been offered to increase the load.

Building Types

Aside from the required density, it is necessary for the buildings to have appropriate piping and emitter systems and to be sufficiently insulated such that low temperature water can serve as a suitable source of heat.

Obviously, it would be much more expensive to retrofit a hydronic heating system in a complex of buildings that is currently heated electrically than it would be to install a suitable water system during initial construction. Similarly, system economics and the need for maximum utilization of the available heating energy require high efficiency emitters or radiators to achieve maximum temperature drop. For low temperature supplies, in-floor radiant heat tubing is the most cost effective means of using the resource.

Insulation too has an impact on the applicability of geothermal heating where low temperature resources are involved. Poorly insulated buildings in cold climates would require very substantial flow rates to obtain sufficient energy if supply temperatures are at the low end of the feasible range (i.e. 40-50°C). For this reason, many countries utilizing low temperature resources have coupled insulation standards and district heating planning to minimize total system costs.

6.5.4 Load and Utilization Factors

Since the capital costs of geothermal systems are quite high, it is imperative that the system be used to the maximum extent possible to be economic. Space heating demands are typically very cyclic, with distinct daily cycles superimposed on seasonal cycles, such that peak demands occur on winter nights while the demand is virtually nil during summer mid-days.

Given this pattern, a thermostat-controlled furnace or boiler is well suited to space heat applications because heat is supplied as required. With geothermal systems, however, the energy is supplied at a steady rate year round. If the system is designed to satisfy peak loads, then much of the energy is wasted since it is not required much of the time.

Figure 6-5 illustrates the demand pattern for a typical space heating process. Note that the peak requirement only occurs for a few hours each year. Furthermore, for some portion of the year, there may be no heat requirement (depending on climate) other than for domestic hot water.

If the load connected to a geothermal system is such that the peak demand is met by the system, a great deal of the available energy goes unused (Case A). Indeed, for the load curve shown in Figure 6-5, much less than 50 percent of the energy is utilized. With Case B, however, the reverse is true. Here, more than 50 percent of the energy is useful and the wasted heat energy is much less. In this case, the peak demand is met by supplemental boiler operation.

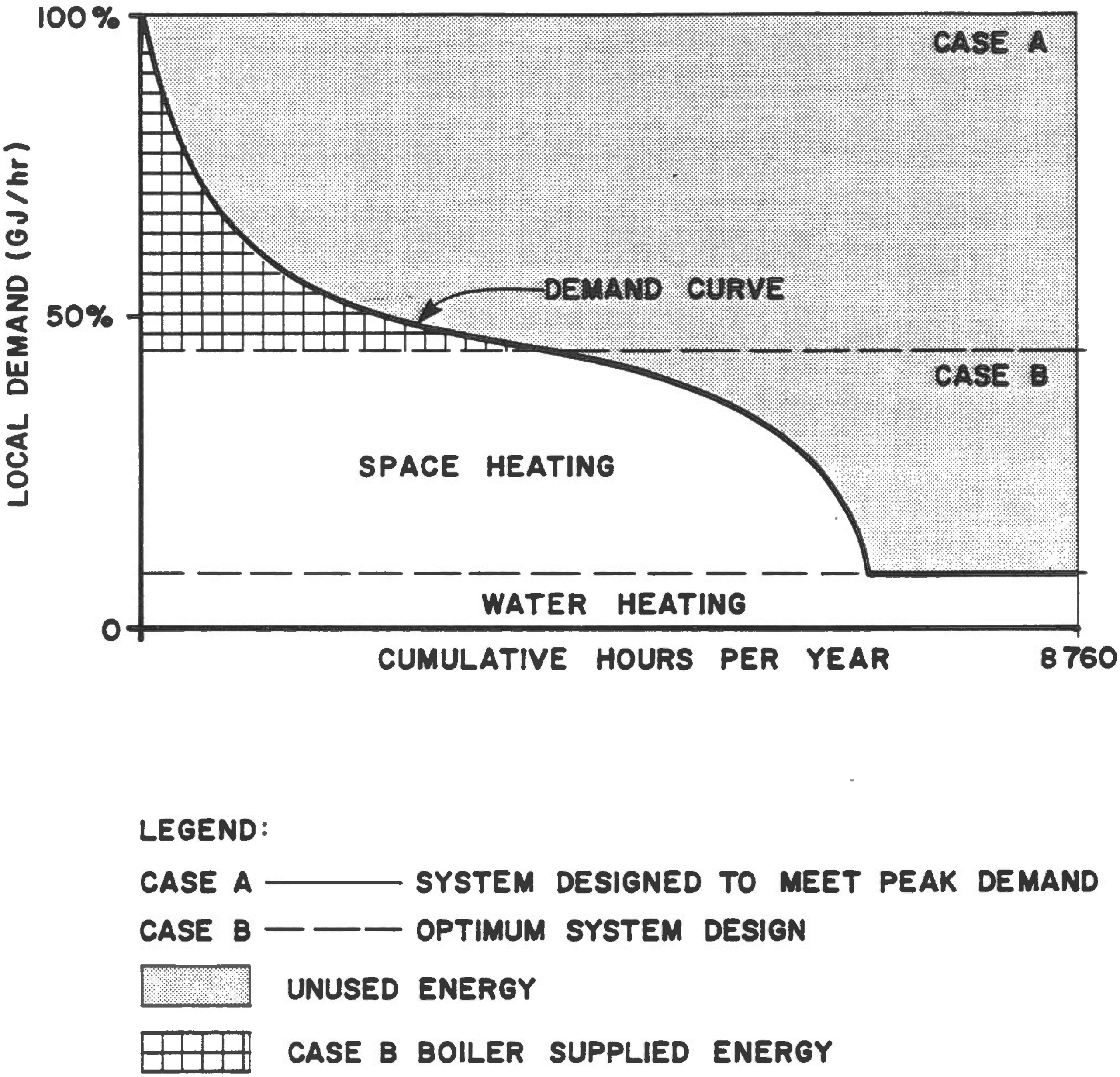


FIG.6-5

TYPICAL HEAT DEMAND FUNCTION

The energy not required for space heating (area to the right of the curve) can be used in some situations through storage mechanisms. The optimum load for any particular project would have to develop as part of the planning process. Typically, however, in northern climates, the geothermal system would be designed to supply between 75 percent and 90 percent of the total energy demand with the boiler supplying the remainder.

The design load factor is fundamental to the economic viability of a geothermal development. Because of the high fixed expenses associated with the cost of resource development, it is critical that the utilization of the available energy be maximized in order to minimize the unit, or average, cost of the energy supplied relative to conventional energy sources.

Temperature Drop

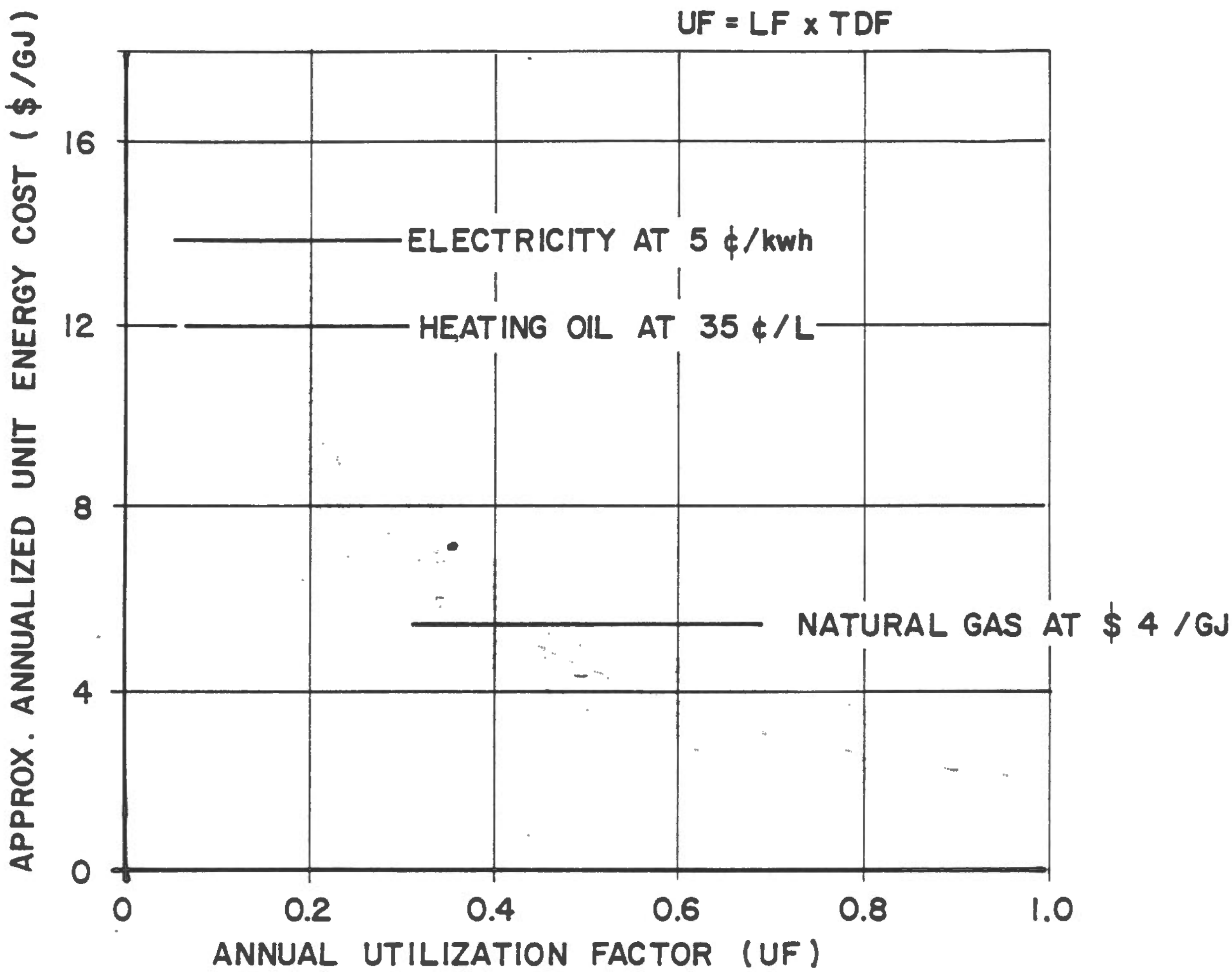
A further factor influencing the amount of energy supplied and used is the temperature drop between production of the geothermal fluid and reinjection of the fluid. At a given flow rate of, say 100 m^3/h, and a supply temperature of 60°C, twice as much energy is extracted from the system if the fluid is returned at 20°C rather than 40°C. Since the water is not very useful below 20°C, this temperature represents the minimum practical reinjection temperature.

Total energy supplied by a given system is a function of the temperature drop factor and the load factor. The product of these factors is defined as the annual utilization factor or the ratio of the actual energy delivered to the maximum energy available referenced to a minimum reinjection temperature of 20°C. In effect, the utilization factor is a measure of the energy leakages from the system arising because the load curve does not match the supply and because the fluid retains some portion of its energy when it is reinjected.

If a system is sized with a load factor (LF) of 0.6 (i.e. 60 percent of the area under Case B in Figure 6-5) is taken up by the load curve) and a temperature drop factor of 0.75 (e.g., supply temperature 60°C, return temperature 30°C), the resulting annual utilization factor is 0.6 x 0.75 = 0.45. That is to say that 45 percent of the energy supplied is effectively used by the process.

This utilization factor has a direct impact on the unit cost of energy from the system. Figure 6-6 indicates the effect of utilization on costs for a typical single doublet supply system (excluding the distribution system) with a resource temperature of 60°C and flow rate of 100 m^3/hour. For utilization factors below about 0.4, it can be seen that unit costs begin rising quite rapidly, while factors above 0.5 yield approximate unit costs below $4/GJ. To achieve a utilization factor of 1.0, the geothermal supply would have to be strictly base load and the return temperature would be at 20°C. At these levels, however, the unit cost would be a very economic $2/GJ.

Given the average prices for conventional energy fuels indicated in Figure 6-6, a utilization factor of 0.4 or better is required to compete with natural gas. To displace heating oil, utilization would have to be above about 0.2. Clearly, if sufficient connected load is available, geothermal can compete with conventional energy.



NOTES :

1. UNIT COSTS INCLUDE CAPITAL & OPERATING COSTS FOR SINGLE DOUBLET SUPPLY LOOP.
2. PRICES FOR OIL & NATURAL GAS ARE ADJUSTED FOR ASSUMED COMBUSTION EFFICIENCY OF 0.75.

FIG.6-6

TYPICAL GEOTHERMAL ENERGY COSTS vs UTILIZATION

6.5.5 Heat Pump Economics

Given the critical importance of achieving a high utilization factor to improve the economics of geothermal systems, heat pumps should be considered where the resource supply temperatures are relatively low. In the preceding discussion of utilization factors, it was noted that the minimum return temperature is about 20°C. If the resource is only 40°C, the absolute temperature drop is obviously limited. Inclusion of a heat pump allows for the lowering of the return temperature, say to 5°C, such that the temperature drop is 35°C rather than 20°C. This increase in temperature drop is directly proportional to the amount of energy supplied. In effect, the temperature drop factor becomes greater than 1.0.

In addition, since the high initial drilling costs are a function of depth, it may prove economic to drill shallower wells and use heat pumps in areas where the gradients are relatively poor. Therefore, heat pumps can improve the economics of geothermal systems by either upgrading the resource where temperature is inadequate or by amplifying a resource temperature without the expense or problems of drilling much deeper wells. However, there are costs associated with these gains.

Capital costs for heat pumps can themselves be quite significant and heat pumps are powered by high-grade energy such as electricity, which can also be quite expensive in many parts of the country.

Heat pumps can recover low-grade heat from water down to the 10°C region and boost it as high as 100°C. The actual gains are dependent on the coefficient of performance

(COP) of the pump. The COP is the ratio of the upgraded heat output to the thermal equivalent of the electrical energy input.

For example, a 75°C process water stream can be delivered from a 50°C source that is cooled through a range of 20°C with a COP of about 3.5. The heat pump would in the meantime consume about 736 KW per hour.

6.5.6 Implication of Economic Factors

Based on the foregoing discussion of factors influencing the economic viability of geothermal developments, it is clear that system planning will involve a careful analysis and matching of resource supply with process demand. In any case, the greater the utilization of the available energy, the lower, and therefore more competitive, is the unit energy price.

Successful commercialization of geothermal will largely depend on the creation of a suitable consuming market. Although many processes are capable of using the low temperature resources that are predominant in Canada, only those processes which have something approaching constant base load requirements are likely to be economic. A typical 2-shift, 5-day-per-week industrial process, for example, requires heat for only about 4,000 hours per year. This is not likely to be sufficient load to justify a geothermal development on its own. What is required would be several users with load profiles so that together, a large, constant base load can be supplied.

The greatest potential for achieving economic levels of thermal load and load density will be through direct utilization of geothermal energy for space heating and, possibly, cooling. Such systems can either take the form of a single well supplying a large building complex or formation of a geothermal heating district where geothermal fluids are distributed much as natural gas is distributed.

Probably the best known example of a district heating system is in Reykjavik, Iceland, where the system supplies close to 16,000 residential units with a population of over 100,000. Large storage tanks are used to meet varying flow demands while fossil-fueled boilers are used to boost temperatures during peak heating demand periods.

A recent geothermal project developed in Bordeaux, France indicates the scale of development involved in a single-well, low temperature system. The supply water is between 45°C and 50°C and the flow rate is 150 m^3/h. The connected load is the equivalent of 1,200 housing units. Loads on this order of magnitude will be necessary for geothermal energy to effectively compete with conventional fossil fuels.

If geothermal is to gain acceptance as a viable alternative energy supply in Canada, the institutional, financial, land-use and social criteria for encouraging centralized district heating must first be addressed. This is not a problem faced by geothermal promoters alone. The same constraints apply with respect to effective utilization of waste-heat recovery systems, cogeneration projects, some solar applications, biomass energy systems and other oil-substitution technologies.

Initially, it is likely that demonstration projects applying geothermal technology in large government complexes will be required to prove the applicability and economics of such developments. Subsequently, there will probably be a need for government support in private projects at least to the extent of offering incentives for hook-up to potential customers.

Another area that requires further consideration in Canada, from an economic viewpoint, involves the feasibility of heat pumps. Most of the investigation of resource availability and applications in this country has revolved around deep wells and direct use. Heat pumps introduce a number of factors in the feasibility equation which should be pursued further.

6.6 Competitive Environment

As noted in the discussion of direct-use system economics (Section 6.5), geothermal developments can compete with conventional sources of heat on a price basis given certain favourable circumstances. The principal conditions on these prices are the utilization factor, which is chiefly influenced by load density, the cost of the distribution system, which also is dependent on density, and the nature of the building stock to be supplied. In short, geothermal can offer a competitive alternative given the right consumer community, or market.

In order for geothermal heating to be viable, the demand and the supply must coincide spatially and the demand process must have a relatively high and constant base load requirement that is not more economically met by other energy supplies. These criteria introduce a wide range of market considerations which are discussed below.

6.6.1 Regional Demand Patterns and Market Opportunities

If a population density map were superimposed on a map of geothermal temperature gradients in Canada, there would be little coincidence of high population and high temperature. Possibly the area of greatest potential would be in the western section of Alberta from slightly north of Grande Prairie, through Edmonton and south to Calgary. This area is also rich in natural gas and oil resources. Regional market characteristics with respect to potential geothermal developments are outlined below.

British Columbia

In 1983, faced with a substantial near term increase in generating capacity and a general downturn in energy markets, B.C. Hydro dramatically reduced its energy demand projections. Factors such as the construction of the Revelstoke Dam hydroelectric station, due to add 1800 MW capacity to the system by late 1984, and a protracted economic recession, suggest a hydroelectric energy surplus through to the year 2000. This is a strong disincentive to exploration for system-electric type geothermal resources in B.C. Continued effort, however, is justified.

In off-grid areas, where both markets and resources occur in proximity, geothermal may be the appropriate means of electrical generation. As data are lacking, precise identification of these areas is premature but they might include parts of north-central B.C. and possibly Vancouver Island where many communities are dependent on diesel electric generation.

A second justification for continued effort is the recognition of the lead time inherent in development of new or innovative technology. Resources known or expected to occur in the more densely populated and relatively accessible parts of southwestern B.C. might be viable partly as research and demonstration projects.

Although the future for high grade or system electrical compatible resources in B.C. is somewhat in doubt, the question of the potential for low grade direct use resource application remains. There is ample evidence that both moderate temperature hydrothermal system and deep basin type resources occur.

At the present time, areas of northern, B.C. and Vancouver Island are not supplied with natural gas. These areas obtain virtually all of their space and water heating requirements from heating oil and wood. Where sufficient load occurs, geothermal development opportunities may exist.

Prairie Provinces (Alberta, Saskatchewan and Manitoba)

The main market opportunities in the Prairie provinces, identified by the coincidence of both high temperature gradients and relatively high population density, lie in the western section of Alberta from slightly north of Grande Prairie, through Edmonton and south to Calgary. These population centers with diversified industrial bases are most likely to generate energy intensive projects with uniform base load requirements. In Alberta especially, the relatively high exploration risk of initial geothermal systems can be partially offset by the use of holes already drilled by the oil and gas industry. The use of existing wells drilled in high temperature gradients can decrease the initial exploration risks and high capital costs of production/injection well systems.

Unfortunately, the current ready availability of natural gas as a competing energy source for space and process heat throughout the Prairie provinces puts geothermal at a cost disadvantage. In addition, these provinces experience low population density over widespread regions with underlying geothermal resources.

Ontario and Quebec

The Windsor, Ontario to Sherbrooke, Quebec belt is well populated and includes some excellent agricultural land, resulting in opportunities for geothermal space heating and (feed drying). Unfortunately, given the absence of identified geothermal resources, a regulatory vacuum, and the risks inherent in geothermal exploration, it is unlikely that geothermal resources will soon contribute to energy supply in Ontario and Quebec. Moreoever, such a resource would face stiff competition from other energy sources such as solar, wood, coal, oil, gas and electricity generated by thermal, hydro and nuclear plants which presently result in an excess of energy supply.

Atlantic Provinces

The Atlantic provinces generally lie over shallow low gradient geothermal resources. When coupled with heat pumps, low gradient geothermal energy for space heating becomes an attractive alternative. Some of these provinces have the option of drilling deeper wells to access higher quality gradients, provided the increased drilling costs can be economically justified. Two promising locations for geothermal development are located near Fredericton, N.B. and Halifax, N.S.

Geothermal resources are considered competitive energy sources in the Atlantic Provinces, which now burn costly imported oil or coal to generate electricity. There exist, however, good prospects for natural gas off Sable Island. This energy source may displace geothermal's economical advantage over the next few years, although it can be expected that the distribution system for natural gas will be quite costly.

6.6.2 Commercial Characteristics of the Resources

As a commodity in the market place, geothermal energy has a number of characteristics which differentiate it from other supply sources and, in some cases, limit its prospects for market penetration. Unlike most other extractive industries, geothermal developers must, to some extent, "create" the market in addition to finding and producing the resource. Some of the key factors influencing market conditions include:

(a) transportability of geothermal energy;
(b) "low grade" energy characteristics;
(c) economically feasible uses of the resource;
(d) price and availability of alternatives;
(e) market penetration factors.

Each of these matters is discussed in turn below.

(a) Transportability

Geothermal resources can meet specific localized needs (such as space heating and industrial processes) or, if used to generate electricity, can provide power for a broad range of non-local end uses. When used to generate electricity, the geothermal gradients must be of sufficiently high quality to efficiently drive generators. The costs of transporting geothermal electricity are no different from the transmission costs for hydro or thermal generated electricity, and depend on the amount of energy generated and the distance to be covered by new transmission lines. Since geothermal plants are likely to be smaller scale than major hydro and thermal projects, however, the economic distance for new transmission is likely to be proportionately less. Accordingly, it can be expected that geothermal electrical development will have to be close to the grid or capable of supplying a nearby non-grid community.

If not used to generate electricity, geothermal energy becomes a completely site-specific resource. Existing above-ground technology is capable of distributing geothermal heat only to the immediate vicinity, or of storing it for only a limited period of time. Pipelines used to transport warm water from the source to the use are not economic at low temperature levels. (At higher temperature levels, electricity generation is the more rewarding alternative.) Above-ground equipment (heat exchangers, water storage tanks, etc.) is considered to be standard technology but it is unlikely to be developed further to allow for economic transmission over great distances. Geothermal energy, therefore, suffers from limited transportability.

Competing forms of energy do not suffer from this limitation. Extensive distribution networks for oil and gas are in place to transport energy from the wellhead to the household furnace. Electric transmission grids span most of the country. With oil and gas, there is the added advantage that the flow can be synchronized with demand and surplus supply can be stored.

Costs of a pipeline carrying oil and one carrying water are roughly equivalent, yet the value per unit volume is much greater with oil. Also, with oil or gas, the product is consumed at the end of the line (at the burner tip); thus there is no need for a return line. The same cannot be said for geothermal energy. The building must be retrofitted for space heating with water to air heat exchangers and the warm water must circulate throughout the building. The cooled water is then removed from the building and returned to the primary exchanger via another pipeline.

The inconvenience of having to locate close to the resource and incurring retrofitting expenditures can significantly add to the cost of power development. Therefore, geothermal prices per unit of energy would be expected to be higher than other energy sources in many, although not all, instances.

(b) Low-Grade Resource

As discussed in Section 2.0, most of the geothermal resources in Canada are considered low grade energy sources. Generally the maximum temperatures available are below 100°C, so processes which require more intense energy are precluded from using geothermal. Low grade resources have relatively low heat content ratios, such that the actual amount of energy delivered, given the volume of fluid or the level of capital expenditures, is lower than for higher grade fossil fuel supplies.

However, geothermal is not necessarily inferior to other energy sources. The total amount of energy available from a single well is quite significant such that only very large heat users can contemplate geothermal development. In addition, processes which exhibit large, moderate temperature, base load demand patterns are ideally suited to using geothermal heat.

Geothermal energy systems based on low-grade resources may experience difficulty in supplying peak energy demands, especially if the peak demand is far greater than the average demand. The volume of energy supplied by a geothermal system is not very flexible, although heat pumps can provide some variability.

Conventional heating systems will be required to meet peak demands and to serve as back-ups for system security of supply. Increments in the volume of geothermal energy supplied will occur in step-wise fashion as new wells are brought on line. Thus, a process which anticipates increasing energy demand over time may not be able to increase the geothermal energy supply to match demand exactly. Temporary excesses of energy will be experienced as new geothermal resources become available.

The low-grade nature of the resource again presents constraints which are not encountered by users of conventional energy sources. Again, the geothermal user may demand lower rates as compensation for these limitations.

(c) <u>Economic Uses of Geothermal Energy</u>

Despite the constraints noted above, there are opportunities to realize substantial savings on energy costs given diligent project planning and suitable market conditions. Three types of user complexes which show good potential for economically using geothermal heat include institutional complexes, centralized district heating schemes and industrial parks.

Institutional complexes such as large hospitals, universities, office buildings and penitentiaries could use geothermal energy for space and water heating. These institutions require large stable sources of energy to function efficiently. The difficulty may well lie in locating these institutions close to the geothermal resource. Hospitals and office buildings certainly must locate near a population centre in order to provide their services.

Geothermal space heating for individual residential units is not an economical proposition. However, residential district heating is a viable alternative. Residential district heating assumes a coordinating body able to direct the activities of the participants. The coordinating body would identify the optimal size of district to receive the resource, and would ensure that each residence's needs were satisfied. Geothermal district heating could either be part of the original district design or could be retrofitted.

Industrial parks could use geothermal energy for space and water heating and also to support their process energy demands. The industrial park concept also presupposes a coordinating body similar to the residential district heating case.

(d) <u>Price and Availability of Competing Energy Sources</u>

Obviously, geothermal energy must gain its acceptance in competition with conventional energy sources, principally petroleum and natural gas. Current world oil surpluses and capped gas wells in Alberta and B.C. are indicators of excess supply causing soft prices for these energy supplies. Although these prices are not expected to prevail indefinitely, until such time as the prices of competing fuels increase the economic viability of geothermal energy will be under pressure.

As noted in Section 6.5, if the utilization factor for a geothermal system is high enough, the unit energy price can be less than those for heating oil and natural gas. However, unit prices are not the only variables consumers will consider when making fuel selection choices. In many cases, attractive units costs will not alone be enough to obtain substantial markets for geothermal.

As noted in the preceding paragraphs, geothermal cannot compete directly against fossil fuels in many circumstances simply because the energy intensity is not sufficient for many processes. The other constraints discussed above with respect to geothermal applications will persist. Substitution of fossil fuel energy with geothermal will in many cases require the user to scrap or reduce the utilization of conventional heating systems they are familiar with and which may have significant useful life remaining. At the same time, the user may have to incur substantial new capital costs. Such factors obviously make the economic choices difficult.

Private consumers will make their choices with respect to alternative heating systems on the basis of perceived total costs. For conventional systems, the most significant element of these perceived costs is the price of fuel. As long as fossil fuel prices remain relatively stable and controlled at less than world prices by government policy, the incentive to adopt geothermal systems will be lessened.

(e) Market Penetration Factors

If a geothermal developer can also use the energy for his own processes, market uncertainties are avoided. The decision becomes merely a matter of strict investment analysis. If in addition to being able to use all of the energy, the process system is already in place and retro-fit requirements are minimal, the attractiveness of the investment can be substantial. As soon as the primary loop is installed, such a user would immediately begin to reap benefits exactly proportional to the cost of the fossil fuel displaced. There need be no concern with market acceptance or appropriate prices because the system provides direct savings to the user without the need for any market transactions.

For the commercial developer of geothermal energy however, the situation is quite different since the intent is to sell the energy to other consumers. Here, market acceptance will be critical to the project. Given the high front-end outlays associated with geothermal systems, a developer cannot afford a protracted period of load development. The developer's revenues will be dependent on how many subscribers are hooked-up to the system, not on how much energy is available.

Pricing of the geothermal energy will have a large influence on the rate of load connection, or market penetration. Merely matching conventional energy prices will not likely be enough incentive to obtain substantial markets for geothermal. Under these circumstances, the rate of acceptance would probably be limited to only some percentage of the new construction added to a community. The price must be established such that it is attractive for existing buildings to be retrofitted. Also, since it is important that utilization be maximized, the rate structure should be designed to reward users who can take maximum advantage of geothermal, i.e. consumers with large base load requirements. Billing charges should be such that customers are encouraged to make the maximum use of the heat obtainable per unit volume of the warm water supplied. For example, a customer who pays a fixed rate per m3 drawn off reduces heating costs by efficiently extracting the maximum energy from each m3.

European experience indicates that some form of financial assistance is critical to the success of a system's early years when customer hook-ups are needed as rapidly as possible. Low interest loans, grants, tax credits and accelerated capital write-offs have all been employed to encourage customer retrofits and building conversions. Alternatively, hook-up costs can be incorporated in the rate structure such that these expenses are retired over the life of the project. Under these cirucmstances, however, it is likely that the developer would require financial assistance to reduce the carrying charges on the distribution system.

Marketing of geothermal energy will also require more than just the appropriate rate structure. As with any unfamiliar technology, there will be a reluctance on the part of consumers to be the first to embrace the new scheme. Consumer education, promotion and demonstrations will probably be necessary to provide broad-based support for the concept.

In Europe and in several states in the U.S., government agencies play a crucial role in the dissemination of information to interested developers and community groups. Often these agencies play a very proactive role in the promotion of geothermal, acting as central coordinating bodies which assist in the organization of the centralized heating system, obtaining financing, offering technical expertise and so on. For geothermal to progress in Canada, similar government support will be required.

The private sector is unlikely to be able to develop a geothermal industry without government involvement along these lines. Even if entrepreneurs are willing to proceed, a wide range of details must be addressed by government. These issues will range from zoning ordinances and building codes to financing plans and rate structures with numerous items in between.

The most likely form of government promotion of geothermal energy, in the early stages, will be through demonstration projects. Government and institutional building complexes are excellent candidates for alternative heating programs for a variety of reasons including:

- commonly large heating loads;
- high visibility in the community;
- publicly-supported facilities, thereby creating sentiment for cost-saving improvements;
- eligibility for certain types of financing not available to private sector;
- jurisdictions and controlling interests are less complex.

The marketing campaign on behalf of geothermal energy obviously faces many problems, but they are not insurmountable. Public awareness and interest must be generated and an important prerequisite for this will be a sense of government support for the resource. The natural resource is available and the technical means for expliting it are known, what remains is the policy objective to pursue it, the will to push on and a well-managed, concerted plan for implementation.

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APPENDIX A

B.C. GEOTHERMAL RESOURCES ACT AND REGULATIONS

GEOTHERMAL RESOURCES ACT

CHAPTER 14

Assented to June 7, 1982.

Contents

HER MAJESTY, by and with the advice and consent of the Legislative Assembly of the Province of British Columbia, enacts as follows:

PART 1

INTERPRETATION

Interpretation

1. (1) In this Act

"block" has the same meaning as in section 140 (3) of the *Petroleum and Natural Gas Act;*

"boundary" means a location's surface boundary and its vertical extension;

"commissioner" means the commissioner of the titles branch of the Petroleum Resources Division of the ministry;

"development plan" means a plan for the drilling of such number of wells as are, in the opinion of the minister, sufficient to enable production of a geothermal resource underlying a lease to begin, including the provision of piping, equipment, reinjection wells and controls required to produce the geothermal resource, but does not include plans for the commercial utilization of the geothermal resource or for converting it into any other form of energy;

"division" means the Petroleum Resources Division of the ministry;

"division head" means the assistant deputy minister designated in writing by the minister as having charge of the division;

"field" means

(a) the surface of land that is underlaid or appears to be underlaid by a geothermal resource, and

(b) the subsurface region vertically beneath that land surface

that is designated by the division head as a field;

"geothermal exploration" means investigation of the subsurface of land for the presence of a geothermal resource by means of

(a) seismic, gravimetric, magnetic, radiometric, electric, geological or geochemical operations,

(b) well drilling or test hole drilling, or

(c) any other method approved by the division head;

"geothermal resource" means the natural heat of the earth and all substances that derive an added value from it, including steam, water and water vapour heated by the natural heat of the earth and all substances dissolved in the steam, water or water vapour obtained from a well, but does not include

(a) water that has a temperature less than 80°C at the point where it reaches the surface, or

(b) hydrocarbons;

"geothermal rig licence" means a geothermal rig licence issued under section 12;

"geothermal well" means a well in which casing is run and that the minister considers is producing or capable of producing a geothermal resource from a geothermal resource bearing zone;

"holder of a location" means, in accordance with the context, a permittee or lessee;

"interest" means an undivided interest in a location;

"lease" means a disposition under section 8 of the right to produce, subject to this Act, a geothermal resource from a location;

"lessee" means a person in whose name a lease is recorded in the division records;

"location" means the area described in, and in respect of which rights are given by, a permit or lease;

"ministry" means the ministry of that minister charged by order of the Lieutenant Governor in Council with the administration of this Act;

"officer of the division" means a person employed in the division and authorized by the division head to give an approval under this Act;

"permit" means a permit issued under section 5;

"permittee" means the person in whose name a permit is recorded in the division records;

"produce" means extract or obtain from the earth;

"production plan" means a plan approved under section 4 (1);

"test hole" means a hole drilled or being drilled

(a) with a bore hole diameter of 100 mm or less, or

(b) to a depth not exceeding 600 m,

to obtain information about a geothermal resource, but does not include a hole drilled or being drilled for firing an explosive charge in seismic operations;

"unit" has the same meaning as in the *Petroleum and Natural Gas Act;*

"unitized operation" means the development or production of geothermal resources or the implementing of a program for the conservation of geothermal resources or the coordinated management of interests in them in, on or under a location, part of a location or a number of locations combined for that purpose under a unitization agreement under this Act;

"well" means a hole or shaft that is or is being drilled, bored or otherwise sunk into the earth

(a) through which a geothermal resource is or can be produced,

(b) for the purpose of producing a geothermal resource or for the purpose of injecting any substance to assist the production of a geothermal resource, or

(c) that

(i) extends deeper than 600 m,

(ii) has a bore hole diameter of more than 100 mm, and

(iii) is intended to obtain information about a geothermal resource.

(2) Sections 6 to 31 of the *Petroleum and Natural Gas Act* apply in respect of entry onto and use of land for the purpose of exploring for and producing geothermal resources.

(3) For the purpose of subsection (2), "produce" and "producing" in sections 7 to 11 and 16 of the *Petroleum and Natural Gas Act* have the same meaning as in this Act.

(4) Where there is inconsistency between a provision of the *Utilities Commission Act* or *Water Act* and a provision of this Act, the provision of the *Utilities Commission Act* or *Water Act* prevails.

PART 2

OWNERSHIP OF GEOTHERMAL RESOURCES AND GENERAL PROHIBITIONS

Geothermal resources vested in the government

2. The right, title and interest in all geothermal resources in the Province are vested in and reserved to the government and the government may dispose of them only under this Act.

Dispositions approved by Lieutenant Governor in Council

3. The minister may, notwithstanding Part 3, dispose of geothermal resources on terms approved by the Lieutenant Governor in Council.

Prohibitions

4. (1) No person shall produce a geothermal resource other than for testing purposes unless

(a) he does so in accordance with a plan for the production of the geothermal resources underlying the location of a lease,

(b) the plan is approved, with respect to matters of energy conservation and operational safety, by the minister, and

(c) he is the lessee of the location where the well that produces the geothermal resource is situated.

(2) No person shall drill or operate a well except within the boundaries of a location.

(3) No person shall drill a test hole unless a test hole program authorization has been issued for the test hole.

(4) No person shall drill or operate a well unless a well authorization has been issued for the well.

(5) No person shall, for the purpose of exploring for or producing a geothermal resource, operate a drilling rig or service rig except in accordance with a geothermal rig licence issued for the rig under this Act or a rig licence issued for the rig under the *Petroleum and Natural Gas Act*.

(6) No person shall conduct geothermal exploration other than by way of well drilling or test hole drilling unless he has notified the commissioner in writing in the form prescribed of his intention to do so.

PART 3

PERMITS AND LEASES

Permits

5. (1) The minister may issue or refuse to issue a permit, whether or not the requirements of this Act have been complied with, and his refusal is final.

(2) A permit shall define the boundaries of a location.

(3) A permittee shall pay a prescribed rent for the permit.

(4) A permittee has the exclusive right, subject to section 13 (2) and the regulations, to apply for well authorizations for wells to be drilled within the boundaries of his location.

(5) The minister shall not issue a permit

(a) except by public tender, and

(b) unless, at least 2 weeks before the day the permit is issued, a notice stating the terms on which the permit is available for disposition has been published in the Gazette.

(6) Where the minister refuses to issue a permit, any fee and rent that accompanied the application shall be refunded to the applicant out of the consolidated revenue fund.

(7) A permit expires on the first anniversary of the date of its issue or of its most recent renewal.

(8) Application for renewal of a permit shall be made to the commissioner who may, subject to the regulations, renew it.

(9) A permit shall not be renewed more than 7 times except on the written authorization of the minister and subject to the rents, terms and conditions he imposes.

(10) The minister may, when acting under subsection (9), authorize a renewal for a period of less than one year.

Permit: dimensions of location

6. (1) The maximum size of a location for which a permit may be issued is a block.

(2) The boundaries of a location comprised in a permit shall coincide with the boundaries of units unless the location is in an area provided for in subsection (3).

(3) In any area where the boundaries of units and blocks do not coincide with surveyed boundaries of sections, townships or another district lot system, the boundaries of a location comprised in a permit may, notwithstanding anything in this Act, be established to coincide with the surveyed boundaries of a section, a township or other district lot system.

Work requirements

7. (1) A permittee shall, each year in accordance with the regulations,

(a) carry out in respect of his location geothermal exploration of a prescribed value, or

(b) make payments in lieu of the work.

(2) A permittee shall record all work, including road construction giving access to the location, with the commissioner in the permit year in which it is done.

Leases

8. (1) Where a geothermal well has been drilled on a location and the permittee submits a development plan for the location that the minister considers satisfactory, the minister may, in accordance with the regulations and on terms and conditions he considers desirable, issue a lease in respect of the whole or any part of the location.

(2) The minister shall not issue a lease except to a person who holds a permit that includes the location of the lease, and when the lease is issued the permit expires with respect to the location of the lease.

(3) A lessee shall pay a prescribed rent for the lease.

(4) A lease expires on the 20th anniversary of the commencement of its term, and where renewed, expires

(a) on the 5th anniversary of its renewal, or

(b) where a production plan for its location has been approved, on the 20th anniversary of its renewal.

(5) Section 6 applies in respect of the issue of a lease.

(6) Subject to subsection (7), where the minister is satisfied that a lessee is not in default of any of his obligations under this Act or under the lease, he shall, on application by the lessee made within 90 days before the expiry of the lease, issue to the lessee a renewal of the lease.

(7) The minister may, where part of the location of the lease is the subject of

(a) a production plan,

(b) an agreement respecting royalty under section 17, or

(c) a unitization agreement under section 18,

confine the renewal of the lease to that part of the lease location.

Transfers and assignments

9. (1) The commissioner shall maintain a register in which shall be recorded transfers and other instruments affecting the title to permits and leases.

(2) A transfer or other instrument shall not be registered unless it complies with the regulations.

(3) On registration, a transfer or other instrument affecting the title to a permit or lease shall be deemed to be registered and be effective from the time that the commissioner receives the application to register it.

(4) Failure to register a transfer or other instrument affecting the title to a permit or lease does not invalidate it as between the parties to it, but subsection (3) governs its effectiveness for any other person.

(5) A holder of a permit or lease may transfer his permit or lease directly to himself jointly with another person, and where the permit or lease is held by more than one person, they may transfer it directly to one or more of their number either alone or jointly with another person, and a trustee or personal representative may transfer a permit or lease to himself individually where the making of the transfer is otherwise within his power.

Cancellation

10. Where a permittee or lessee fails to comply with

(a) a provision of this Act or the regulations,

(b) a notice or an order under this Act or the regulations, or

(c) a term, covenant or condition of his permit or lease,

the minister may give him notice to comply, and if the holder fails to comply within 60 days after the date the notice is received by him, the minister may, in writing, declare the permit or lease to be cancelled, and at the end of the day specified in the minister's declaration, the permit or lease terminates.

Default in rent

11. Notwithstanding anything in this Act, where a lessee fails to pay the rent payable under his lease, the lease expires on the 60th day after the date the rent was payable unless before the 60 days have elapsed he pays

(a) the rent, and

(b) for each 30 day period or part of it that he is in default a sum equal to 2% of the yearly rent.

PART 4

OPERATION AND CONSERVATION

Authorizations and licences

12. (1) Subject to the regulations, the division head or a person authorized by him in writing to do so may issue, subject to conditions, restrictions and stipulations he considers necessary or desirable, or may refuse to issue, a test hole program authorization, well authorization or geothermal rig licence.

(2) A geothermal rig licence expires one year from its date of issue.

(3) A person to whom a test hole program authorization or well authorization is issued (an "operator") shall deposit with the minister

(a) cash,

(b) Government of Canada and Provincial direct or guaranteed securities having a maturity of not longer than 3 years, or

(c) chartered banks', trust companies' or credit unions' certificates of deposit where supported by an appropriate letter giving direction concerning payment of the funds to the Minister of Finance,

in an amount prescribed by the regulations as security for the proper completion of the well or test hole in compliance with the Act and regulations.

(4) When the application for a well authorization or a test hole program authorization is not approved, the deposit shall be returned to the applicant in accordance with any directive of the Minister of Finance under section 19 (3) of the *Financial Administration Act*.

(5) The deposit or part of it may be refunded to the operator on completion of the drilling of the test hole or well in accordance with the Act and regulations to the satisfaction of an officer of the division.

Limitations on issue

13. (1) No well authorization shall be issued except to

(a) a permittee or lessee, or

(b) a person who has made an agreement with a permittee or lessee for the drilling or operation of the well.

(2) A person referred to in subsection (1) (b) may apply for a well authorization.

Access and inspection

14. (1) At any reasonable time, persons authorized in writing by the division head have the right, with respect to a geothermal resource,

(a) to enter on and inspect any well or place at which geothermal resources are handled, processed or treated, and any place used or occupied for those purposes,

(b) to inspect all equipment, plant and records relating to the resource, and

(c) to take samples or particulars or carry out tests or examinations.

(2) Where records required by the regulations to be kept are kept at a place other than a place referred to in subsection (1) (a), persons employed in the division and authorized in writing by the division head have the right, during normal business hours and after giving reasonable notice to the persons affected, to inspect the records, and for that purpose to enter the place where the records are kept.

(3) A person authorized by the division head to exercise any of the powers in subsection (1) or (2) shall produce on demand his authorization signed by the division head and his identification card signed by the minister.

Removal of equipment

15. A person who has failed to comply with

(a) this Act or the regulations,

(b) a notice given or order made under this Act or the regulations, or

(c) a term, covenant or condition of his permit or lease,

shall not remove or allow to be removed equipment from a location or former location without permission in writing from the commissioner.

Health and safety

16. (1) A person holding a permit or lease shall keep all machinery, equipment, test holes, wells and other facilities on the location in a safe condition.

(2) The duty imposed by subsection (1) continues after the expiry or other termination of the lease or permit, until an officer of the division issues a certificate of restoration certifying that

(a) all equipment, machinery, test holes, wells and other facilities on the location of the lease or permit have been removed, plugged or are otherwise in safe condition in accordance with prescribed standards, and

(b) the land surface of the location has been restored to a satisfactory condition in accordance with the regulations.

(3) The minister may refuse to accept a surrender of a permit or lease where an officer of the division has not issued a certificate of restoration.

(4) Where an officer of the division, after inspection of a location or well, considers that a method or practice being employed in connection with the location or well constitutes or may constitute a hazard to the health or safety of any person, or of the public, he may give notice of it in writing to the permittee or lessee of the location, or to the holder of a well authorization or test hole program authorization for the well, or to the agent or representative of any of them, setting out the remedial measures the officer requires be taken.

(5) Where the officer of the division considers that delay in implementation of the remedial measures would constitute a danger to any person or to the public, he may in the same notice or subsequently order in writing that

(a) the method or practice be discontinued, or

(b) all operations in the location or in connection with the well cease

until the matter is remedied to the officer's satisfaction.

(6) No person, knowing that an order has been made under subsection (5), shall continue a method, practice or operation contrary to the order.

PART 5

ROYALTY AND UNITIZATION

Royalty

17. (1) Every lessee who produces a geothermal resource for purposes other than testing shall pay to the government

(a) a royalty established by agreement under this section,

(b) an amount agreed under this section to be paid instead of royalty, or

(c) where no royalty or amount has been agreed under this section, the prescribed royalty.

(2) The minister may enter into an agreement approved by the Lieutenant Governor in Council

(a) establishing the rate of royalty and the method of calculating it, or

(b) by which the government receives, instead of royalty, a share of the income revenue or profit generated from the production of a geothermal resource.

(3) A lessee who fails to pay when it is due a royalty or an amount agreed to be paid instead of royalty shall pay interest on the unpaid amount at the prescribed rate calculated from the time the unpaid amount becomes due until payment is made.

Unitization agreement

18. (1) The minister may on behalf of the government enter into a unitization agreement for the unitized operation of a field or a part of it.

(2) Section 9 does not apply to an agreement entered into under this section.

Unitization order

19. (1) On receipt of an application for a unitization order from a lessee or group of lessees who hold locations that comprise at least 2/3 of the area proposed to be operated under the unitization agreement and who have agreed in writing to a proposed unitized operation, the minister may invite interested persons to make, within a time he specifies, submissions respecting the advisability of or necessity for a unitization agreement.

(2) After reviewing the submissions or on expiry of the time specified by him under subsection (1), the minister may reject the application or make a unitization order requiring that the plan of unitized operations proposed by the applicant be applicable to the whole of the proposed unitized area, or to any area situated in the same field that he determines, and the order is binding on all owners of interests in the area ordered by the minister to be subject to the plan of unitized operations.

PART 6

GENERAL

Inspection and confidentiality

20. (1) The register maintained under section 9 (1) shall be open to public inspection during normal office hours.

(2) Where the ministry receives

(a) a geothermal exploration report, or

(b) records or data respecting a well,

the report, records or data shall not be disclosed to any person except as authorized by the regulations.

Affidavits

21. An affidavit required under the regulations may be made before

(a) a person authorized under the *Evidence Act*, or

(b) the commissioner.

Offence and penalty

22. (1) A person commits an offence who contravenes section 4, 15 or 16 (6) or any regulation creating an offence.

(2) A person who commits an offence is liable on conviction to a fine of not less than $500 or not more than $5 000.

(3) Section 5 of the *Offence Act* does not apply to

(a) this Act, or

(b) the regulations.

Regulations made by minister

23. (1) The minister may make regulations of general application or related to a specific location or well governing the drilling of wells and test holes and the production and conservation of geothermal resources including regulations for the following purposes and regulations respecting the following matters:

(a) prohibiting the drilling of a well at any place within a prescribed distance of any boundary, roadway, road allowance, right of way, building of any specified type or any specified work;

(b) requiring permittees and lessees to submit an application and obtain the approval of an officer of the division before

(i) deepening a well beyond the formation from which production is being taken or has been taken,

(ii) recompletion of a well by perforating any casing with a view to producing a geothermal resource from any formation other than that from which production is being taken or has been taken,

(iii) suspending drilling,

(iv) ceasing normal producing operations,

(v) resuming drilling after a previous completion, suspension or abandonment of a well,

(vi) resuming production after a cessation of production,

(vii) reworking a well to alter its producing characteristics, or

(viii) abandoning a well,

and authorizing an officer of the division to direct the conditions under which approval is granted in any such case, and the methods to be employed in a drilling or abandonment operation;

(c) prescribing the conditions under which drilling may be carried out in water covered areas, and any special measures to be taken;

(d) prescribing the measures to be adopted to confine geothermal resources water encountered during drilling to its original stratum, and to protect the contents of the stratum from infiltration, inundation and migration;

(e) prescribing the minimum standard of tools, casing, equipment and materials that may be used for drilling, development and production of geothermal resources;

(f) to regulate the drilling of multizone wells, prohibit completion of a well as a multizone well without the permission of an officer of the division, prohibit the use of a well for the production from or injection to more than one zone without the approval of an officer of the division and authorize the officer of the division to grant his permission or approval subject to conditions the officer of the division considers necessary;

(g) prescribing measures for the protection of petroleum and natural gas deposits, coal seams, mineral deposits and any workings in them;

(h) requiring the provision of adequate well casing and proper anchorage and cementation;

(i) requiring and prescribing samples, tests, analyses, surveys, logs, records, other information respecting a geothermal resource or operation, the method of taking samples and submission of records and information to the division;

(j) prescribing the measures to be taken before drilling begins and during drilling and production to conserve geothermal resources and water;

(k) prescribing or limiting the methods of operation to be used during drilling and in the subsequent management of a well and the conduct of an operation for any purpose, including

(i) the prevention and extinguishing of fires, and
(ii) the prevention of wells flowing out of control:

regulating the location and equipping of production facilities:

regulating the conditioning or reconditioning of wells by mechanical, chemical or explosive means:

requiring the inspection of wells both during and after drilling:

requiring the capping or closing in of wells for the purpose of preventing waste:

requiring the cleaning out of a well:

regulating the unitization of a field for drilling and production:

regulating and prohibiting the release of well records and well data:

the naming of wells and production facilities;

measures to contain and eliminate spillage;

regulating production from a geothermal well;

the general conservation of geothermal resources, their waste or improvident disposition, and any matter incidental to geothermal resource wells' development, drilling, operation and production;

the methods and units to be used for the measurement of geothermal resources, and the standard conditions to which the measurements are to be converted.

ılation made under subsection (1) may provide that the division head may, particular location or well and subject to conditions the division head ıpt a person from the application of all or part of the regulation.

ptions granted under subsection (2) by the division head or an officer of d regulations made under this section other than regulations of general not regulations for the purpose of the *Regulation Act*.

e by Lieutenant Governor in Council

he Lieutenant Governor in Council may make regulations for the pur-:, or respecting geothermal resources.

t limiting subsection (1), the Lieutenant Governor in Council may make ıe following purposes and respecting the following matters:

ablishing the conditions under which persons are eligible to apply for issue and renewal of permits, leases, test hole program authorizations, ll authorizations, geothermal rig licences, registrations, recordings and er rights, privileges and services under this Act or the regulations, and procedures to be followed and the fees to be paid by them;

revocation and suspension by officers of the ministry in circumstances cified in the regulations of permits, leases, test hole program authoriza-s, well authorizations and geothermal rig licences and the powers to be cisable by those officers for those purposes:

application, with or without modification, of regulations made under ion 36 of the *Petroleum and Natural Gas Act* respecting geophysical oration, to exploration for geothermal resources;

iring persons holding leases to submit plans for any work that they ose and prohibiting the carrying out of that work without approval:

(e) establishing the conditions under which permits, geothermal rig lice leases, test hole program authorizations and well authorizations ma transferred;
(f) royalties and the amount or rate of a royalty that shall be paid in c where there is no agreement under section 17;
(g) prescribing the rent payable in respect of leases;
(h) prescribing the amount or method of calculation of security depos required under the Act;
(i) establishing the amount and kind of work to be performed by permitte and lessees on their locations and the time within which the work required to be done, providing for grouping, unitization, payments in lie of work and related matters, and authorizing, in circumstances specified i the regulation, the extension of time within which work required to be done on a location may be done where the permittee or lessee has been prevented from doing work by extraordinary physical conditions that are beyond his control and could not be foreseen by him;
(j) requiring lessees to provide surveys of their locations at their expense and setting standards for the surveys;
(k) establishing procedures for recording transfers and other instruments affecting the title to permits and leases;
(l) the granting, in respect of a test hole or well drilled or in operation before this Act came into force, of exemptions from provisions of this Act other than section 2;
(m) to meet any difficulties that may arise by reason of the repeal of the *Geothermal Resource Act* and the substitution of this Act;
(n) requiring persons drilling for or producing geothermal resources to keep records, and prescribing the information to be recorded in those records;
(o) requiring persons drilling for or producing geothermal resources to
  (i) supply samples and cores,
  (ii) disclose geological information respecting the resources
obtained by them in the course of the drilling and production.

Consequential Amendments

Hydro and Power Authority Act Amendment

25. Section 52 (6) of the *Hydro and Power Authority Act*, R.S.B.C. 1979, c. 188, is amended by adding "the *Geothermal Resources Act*," after "the *Forest Act*,".

Land Act Amendment

26. Section 47 (1) of the *Land Act*, R.S.B.C. 1979, c. 214, is amended
(a) in paragraph (a) (ii) by adding "geothermal resources and any" before "minerals,", and
(b) in paragraph (b) by adding "geothermal resources as defined in the *Geothermal Resources Act*," before "minerals".

Petroleum and Natural Gas Act Amendment

27. Section 1 of the *Petroleum and Natural Gas Act*, R.S.B.C. 1979, c. 323, is amended

(a) in paragraph (b) of the definition of "well" by adding "in connection with the production of petroleum or natural gas" after "formation", and

(b) in paragraph (c) of the definition of "well" by adding "respecting petroleum or natural gas" after "information".

Repeal

28. The *Geothermal Resource Act*, R.S.B.C. 1979, c. 154, is repealed.

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Victoria, 1982

B.C. Reg. 170/83 Filed April 25, 1983

GEOTHERMAL RESOURCES ACT
[Section 23]

Pursuant to section 23 of the *Geothermal Resources Act*, I make the attached Geothermal Drilling and Production Regulation.

BRIAN R. D. SMITH
Minister of Energy, Mines and Petroleum Resources

Geothermal Drilling and Production Regulation

Interpretation

1. In this regulation,

"Act" means the *Geothermal Resources Act;*

"development well" means a well that, upon approval of its well authorization, was located on a geothermal lease;

"exploratory well" means a well that, upon approval of its well authorization, was located on a geothermal permit;

"operator" means the owner responsible to the division for the drilling, completion, production and abandonment of a well or test hole;

"work-over" means any operation that has changed the producing interval or producing characteristics of a well by perforating, abandoning a portion of the well, running casing or any major or recently developed stimulation operation but does not include routine stimulation operations or the changing or replacement of equipment.

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Service of notice

2. (1) An operator of a well shall register an address within the Province with the division before operations commence.

(2) A notice or order issued under this regulation may be served on an operator by leaving it with a person at the registered address or by sending it by registered mail to that address.

Variation of program

3. (1) Subject to subsection (2), departure from or variance in a program of operations approved or prescribed under this regulation shall not be made without the approval in writing of an officer of the division.

(2) Where an emergency occurs and an immediate departure from or variation in the program is necessary, the division shall be notified immediately of the departure or variation followed by confirmation in writing.

Position of test holes

4. (1) No operator shall drill a test hole within
   (a) 10 m of a survey monument,
   (b) 20 m of a driveway or gateway,
   (c) 80 m of a school, church or other public building or a residence, or
   (d) 200 m of a water well.

(2) Where a test hole is drilled in the vicinity of a gas, oil, steam or water pipeline, electric cable, transmission line or utility, an operator shall ensure that every reasonable precaution is taken to ensure that the pipeline, electric cable, transmission line or utility is not damaged or its use interrupted.

Test hole information requirements

5. (1) Not more than 3 months after the date of rig release of the drilling rig from a test hole, the operator shall sumbit a report to the division containing the following information:
   (a) the name of the test hole program;
   (b) the survey relationship of the test hole drilled to the nearest corner of the legal subdivision or quarter unit in which the test hole is positioned;
   (c) the ground elevation of the test holes drilled in metres above sea level;
   (d) the total depths of the test holes;
   (e) a report of any lost circulation zones encountered or blow outs reported during the drilling of the test holes;
   (f) any other information that may be required by an officer of the division.

(2) Where a series of test hole cuttings is taken at a test hole, a set shall be forwarded to the division's Charlie Lake office, carriage prepaid, as soon as possible after total depth is reached, but not later than 14 days after the date or rig release.

(3) Two copies of each log, including temperature measurements, taken at a test hole shall be submitted to the division within 30 days after the date the log or measurement was taken.

(4) Information obtained from a test hole and recorded with the division as required by this regulation shall, for a period of 10 years after the date of release of the drilling rig,

be confidential and no officer or employee of the division shall release that information, other than to a public servant, without the written consent of the person who supplied the information.

Position of wells

6. No well shall be drilled within 80 m of
   (a) the right of way or easement of any road allowance or public utility,
   (b) a permanent building, installation or works,
   (c) a place of public concourse, or
   (d) a reservation for national defence

unless special circumstances exist and an officer of the division gives written permission to drill a well at a specified position.

Drilling near mine workings and underground storage

7. No well shall be drilled within 3 km of a subsurface mine working or underground storage facility except with the written approval of the division head and then only in accordance with any conditions he may specify.

Spacing for wells

8. The spacing of a well on a geothermal lease shall conform with the development plan submitted under section 8 (1) of the Act.

Well names

9. (1) The length of the well name, including the number which shall be followed by the letters "TW", shall not exceed 36 characters and spaces.

(2) The well name shall clearly identify by name, or an abbreviation acceptable to the division head, or by number or letter
   (a) the operator,
   (b) the area name, and
   (c) the site of the well
      (i) in the Peace River Block, by legal subdivision, section, township and range, or
      (ii) outside the Peace River Block, by quarter-unit, unit and block

with the details given in the above order, indicated by letters and numbers and separated by hyphens.

(3) In addition to the particulars required in subsection (2), a well name shall contain such other particulars as the applicant proposing the name desires and an officer of the division approves.

(4) A company whose name is identified in a well name shall file with the division an abbreviation of its name acceptable to an officer of the division, and only that abbreviation shall be used where it is necessary to abbreviate the name of the company in a well name.

Changes of well names

10. Where an operator wishes to change the name of a well, he shall submit an application to change a well name, together with a fee of $35, to the division and, if an officer of the division approves, the name may be changed accordingly.

Notification of commencement of drilling

11. The division shall be notified within 24 hours of the commencement of the drilling of a well.

Signs

12. Unless exempted by an officer of the division, an operator shall ensure that a legible and conspicuous permanent sign is displayed and maintained at a well showing the name of the operator and the name and legal description of the well.

Samples and cores

13. (1) Unless otherwise directed by an officer of the division, an operator shall take a series of samples while drilling a well, at depth intervals of 10 m, of the various formations which drilling penetrates, and the samples shall be washed, dried and preserved in bags tied in groups of 10 consecutive samples, each bag being accurately labelled with the name of the well and depth interval.

(2) The samples shall be forwarded to the division's Charlie Lake office, carriage prepaid, as soon as possible after total depth is reached, but in any case not more than 14 days after the date of rig release.

(3) An operator shall retain all cores taken from a well and shall store them in book fashion in wooden core boxes, accurately labelled on the body, not on the lid, of each box with the number and interval of the core, top, bottom and recovery in metres of the core and the name of the well from which the core was taken.

(4) Core boxes shall be of adequate construction satisfactory to an officer of the division; the sides of the boxes shall project above the level of the contained cores, lids shall be securely fixed to ensure safe transit and the boxes shall have an inside length of 80 cm.

(5) An operator shall take reasonable steps to protect boxes containing the cores from theft, misplacement or exposure to the weather and, after reasonable time has been taken for examination and analysis, he shall forward them to the division's Charlie Lake office, carriage prepaid, but in any case not more than 2 months after the date of rig release or such longer period as approved by an officer of the division.

(6) Core received by the division's Charlie Lake office in unsatisfactory core boxes may be reboxed by the division at the expense of the operator.

(7) No person shall, without the approval of the operator of the well and an officer of the division,

(a) destroy,
(b) slab or otherwise sample, or
(c) take out of British Columbia

a core from the operator's well.

(8) Core may be removed from the division's Charlie Lake facilities for the purpose of laboratory investigations that cannot be performed there but the removal is subject to approval by an officer of the division and to the following conditions:

(a) where a core is to be slabbed or where confidential core is involved, written authorization from the operator shall be obtained;

(b) an operator removing core from the facilities shall return the core within 3 weeks, unless special permission for a longer period is granted by an officer of the division;

(c) an operator removing core shall take every reasonable precaution not to damage or mix the core in core boxes.

(9) A person wishing to examine a core or samples at the division's Charlie Lake facilities shall give reasonable notice to the division.

(10) A fee of $20 per day for examining samples and $40 per well for examining cores may be made at the division's Charlie Lake facilities.

(11) A person shall pay a fee for removal of cores from the division's Charlie Lake facilities of $10 per well and, if the cores are not returned within 3 weeks, shall pay an additional daily fee of $20 per well up to a maximum of $80.

Tests, analyses, surveys and logs

14. (1) Immediataely on obtaining data and results of

(a) a bottom hole sample analysis,

(b) a pressure, volume or temperature analysis, or

(c) a measurement made on a well for the purpose of investigating the well's producing characteristics

the operator shall submit the information to the division.

(2) Before a well is completed, suspended or abandoned, the operator shall record a lithology log from the base of the surface casing to total depth.

(3) As drilling progresses, an operator shall record abnormal changes in well temperatures and drilling rates on the daily report.

(4) An operator shall submit 2 copies of each log to the division not more than 30 days after the date on which the log was taken, but a copy of the log shall be made available to an officer of the division on request.

Deviation and directional surveys

15. An operator shall make deviation surveys during drilling at intervals not more than 150 m in depth apart unless otherwise approved by an officer of the division.

Tools, casing, equipment and materials

16. An operator shall ensure that all tools, casing, equipment and materials used in the drilling or production of a well are in good condition and are adequate for the purpose for which they are used.

Casing requirements

17. (1) An operator shall set surface casing to a minimum depth of 15% of the expected total depth or intermediate casing depth, but in any case not less than 150 m below ground level and 25 m into a competent formation, using a method approved by the division head and in accordance with good practice, and the annulus shall be filled with cement to the surface unless otherwise approved by an officer of the division.

(2) An operator shall allow cement to set for not less than 12 hours under pressure before the cement plug is drilled out of the casing.

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(3) Where a float collar or float shoe is used, pressure at the surface may be released immediately upon completion of the cement job.

(4) An operator shall cement intermediate and production casing through all porous zones, but in any case not less than 150 m above the casing shoe, and shall test it in accordance with good operating practice, and shall allow the cement to set for not less than 24 hours before the cement plug is drilled out of the casing unless otherwise approved by an officer of the division.

(5) Where there is any reason to doubt the effectiveness of a casing cementation, an operator shall make a survey to determine the top of the cement in the annulus and shall take remedial measures where necessary.

(6) Where an operator intends to use a casing program, other than the one specified by the well authorization, he shall obtain the approval of an officer of the division before the casing is run.

Blow out prevention requirements

18. (1) The following classes of blow out prevention equipment shall be used for the depth of well specified:

- (a) Class A equipment shall be used on a well with a depth of not more than 1 850 m;
- (b) Class B equipment shall be used on a well with a depth of not more than 3 000 m;
- (c) Class C equipment shall be used on a well with a depth of not more than 5 500 m;
- (d) Class D equipment shall be used on a well with a depth of more than 5 500 m.

(2) The pressure rating of blow out prevention equipment shall be as follows:

- (a) for Class A equipment, 14 000 to 21 000 kPa;
- (b) for Class B equipment, 21 000 kPa;
- (c) for Class C equipment, 34 000 kPa;
- (d) for Class D equipment, 70 000 kPa.

(3) Where a well is being drilled, blow out prevention equipment of the appropriate class shall be continuously maintained so that the equipment

- (a) consists of a minimum of one annular preventer and 2 or more ram preventers, the latter to be comprised of a blank ram and one or more rams to close off around drill pipe, tubing or casing being used in the well, and
- (b) is connected to a casing bowl flange with the flange an integral part of the casing bowl and the casing bowl having 2 nominal 50 mm flanged outlets that are closed off by 50 mm high volume, high pressure, flanged valves.

Blow out prevention equipment

19. (1) Blow out prevention equipment shall

- (a) have steel lines or high pressure hoses of a type approved by the division head connected to the blow out preventer assembly, one or more for bleeding off pressure and one or more for killing the well;
- (b) consist of components having a work pressure equal to that of the blow out preventers, except that part of the bleed off line or lines located downstream from the last control valve on the choke manifold, and
- (c) have the valve hand wheel assembly in place and securely attached to the valve stem on all valves in the blow out prevention system.

(2) Bleed off lines shall be
  (a) a minimum nominal 76 mm diameter of uniform bore,
  (b) connected only by weld neck flanges that are perpendicular to the line to which they are attached,
  (c) equipped with a gauge connection where well pressures may be measured,
  (d) connected to
    (i) a choke manifold, and
    (ii) a mud tank through a mud gas separator, and
  (e) where the lines are downstream of the choke manifold, terminated in a slighty downward direction into an earthen pit.

(3) A choke manifold shall be
  (a) located
    (i) not less than 20 m from the well bore, or
    (ii) in a position outside the substructure that is satisfactory to an officer of the division,
  (b) designed to permit the flow to be directed through a full opening line or through either of the 2 lines each containing an adjustable choke,
  (c) equipped with an accurate metric pressure gauge and ancillary equipment readily available for installation to provide drill pipe pressure readings at the choke manifold and, where a well is more than 3 000 m deep, installed to provide continuous readings, and
  (d) enclosed by a suitable housing.

(4) A mud gas separator shall
  (a) be of a design to ensure personnel safety and adequate mud gas separation, and
  (b) be connected to a securely staked down inlet line and outlet line, and the outlet line shall
    (i) be at least one size larger than the inlet line, and
    (ii) terminate in an earthen pit or flare pit not less than 50 m from the well.

(5) An earthen pit shall
  (a) be excavated to a depth of not less than 2 m,
  (b) have side and back walls rising not less than 2 m above ground level,
  (c) be constructed to resist erosion by a high pressure flow of gas or liquid, and
  (d) be shaped to contain any liquids discharged into it.

(6) At all times where a well is being drilled
  (a) a valve shall be installed in the kelly assembly,
  (b) a full opening stabbing value that can be connected to the drill pipe, drill collars or tubing in the well shall be provided, and
  (c) choke manifold and bleed off lines shall be
    (i) securely tied down, and
    (ii) contain only pipe that is straight or has 1.57 radian bends in it and which is constructed of flanged, studded or welded tees, blank flanged or bull plugged on fluid turns.

(7) A full opening stabbing valve shall
  (a) have removable handles to facilitate handling by 2 men,
  (b) be stored with the valve in the open position in the dog house, or other location satisfactory to an officer of the division, so as to be readily available for use, and
  (c) have the valve closing handle attached to the valve holding stand.

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ut preventer

). (1) Where hydraulically operated blow out preventers are installed, a clearly
l operating control indicating direction of closure for the annular blow out
ter shall be located not less than 15 m from the well.

) The control valve regulating the closure of the annular preventer shall not have a
ocking device.

) A manual control for ram locking of a ram type blow out preventer shall be
d to the preventer.

) Where a ram type blow out preventer is used at a cased well that is being tested,
ted or worked over, the contol shall be attached and be not less than 5 m from the

) Where fluid under pressure is used to operate a blow out preventer, there shall be
e of sufficient pressure and volume to close the annular preventer, close a ram
er, open the annular preventer, open the hydraulically operated valve and retain a
e of 8 400 kPa on the accumulator system.

Where a nitrogen cylinder is used as an emergency pressure source, it shall have
nt volume to be capable of closing the annular blow out preventer and one ram
er and shall have a pressure of not less than 12 500 kPa remaining after such
n.

low out prevention equipment

(1) Prior to drilling out cement from a string of casing, each unit of the blow out
on equipment shall be pressure tested, first to a pressure of 1 000 kPa and then to
han 7 000 kPa for a period of 10 minutes and until the equipment passes the test
tor shall not proceed with further drilling.

Where a well is being drilled, tested during drilling operations, completed or
ver

(a) the appropriate blow out prevention equipment shall be operated daily and if found to be defective, the operator shall ensure that it is repaired before operations are resumed,

(b) the operator shall ensure that at least one person is on tour at the well site who
 (i) is trained in blow out prevention, and
 (ii) has a first line supervisor certificate issued within the past 3 years by the Petroleum Industry Training Service,

and evidence of his qualifications shall be made available to an officer of the division on request,

c) the operator shall ensure that the rig manager and the operator's representative at the well site
 (i) are trained in blow out prevention, and
 (ii) possess a second line supervisor certificate issued within the past 3 years by the Petroleum Industry Training Service,

and a copy of their qualifications shall be prominently displayed in the control centre during the drilling operations,

l) the operator's representative shall confirm with the division's Charlie Lake office that he possesses a valid second line supervisor certificate by a visit to the office or by phone before assuming first responsibility at the well site or as soon as reasonably possible thereafter, and

(e) the operator shall ensure that
(i) the Canadian Association of Oilwell Drilling Contractors placard or the operator's Well Control Procedures placard is prominently displayed in the control centre and is maintained so that it is legible at all times, and
(ii) a diagram of the trip tank and the trip tank volume indicator are prominently displayed in the control centre.

(3) A trip tank volume indicator shall specify the volume of the trip tank and the volume of each graduation on the scale.

(4) An operator shall report full particulars of all tests in the daily report and, in the case of a pressure test, the pressure applied and the duration of the test shall be recorded.

Operation of blow out prevention equipment

22. A rig crew shall have an adequate understanding of, and be able to operate, the blow out prevention equipment and, when requested by an officer of the division, the contractor or rig crew shall
(a) demonstrate the operation and effectiveness of the blow out prevention equipment, and
(b) perform a blow out prevention drill in accordance with the Well Control Procedure placard issued by the Canadian Association of Oilwell Drilling Contractors or as outlined by the Petroleum Industry Training Service, Blow Out Prevention Manual.

Maintenance of blow out prevention equipment

23. An operator shall maintain blow out prevention equipment so that its operation will not be impaired by low temperatures.

Drilling procedure

24. (1) Subject to subsection (2)
(a) where a mud tank is in use, the opeator shall install a device and maintain it so that it is visible to the driller's position, warning of a change of the fluid level in the mud tank or of an imbalance in the fluids entering and returning from the well, and the device shall be either electrically, pneumatically, hydraulically or mechanically operated and shall be maintained in working order at all times,
(b) the operator shall equip the drilling mud system with a trip tank with a volume of approximately 5 m^3 to accurately measure the fluid required to fill the hole while pulling pipe from the well and the trip tank shall
(i) be constructed so that the cumulative volume can be reliably and repeatedly read to an accuracy of 0.1 m^3 from the driller's position,
(ii) be tied into the mud return line,
(iii) be equipped so that drilling fluid can be transferred into and out of the trip tank, and
(iv) be located in, or within 10 m of, the shale shaker end of the mud tank and be readily accessible to afford visual observance of the fluid level, and

(c) the operator while pulling pipe from a well shall ensure that
  (i) the hole is filled with drilling fluid at such frequency as required so that the fluid level in the well bore does not fall below a depth of 30 m, and
  (ii) a permanent record of volumes that are required to fill the hole are retained and submitted as part of the daily drilling reports.

(2) Where it is impractical or unsafe to follow a procedure or precaution required by subsection (1), an equivalent procedure or precaution may be adopted to ensure safe operation.

Surface and sub-surface equipment

25. (1) An operator shall arrange the surface and sub-surface equipment of a well to permit any reasonable test that may be required by an officer of the division and shall include facilities to determine the well head fluid temperature.

(2) An operator shall ensure that the surface equipment includes such valve connections as are necessary to sample the water, brine or other fluid produced.

(3) An operator shall keep a detailed record of all sub-surface equipment in the well at all times prior to abandonment and shall make the record available to an officer of the division on request.

Uncontrolled flow

26. An operator shall take every reasonable precaution to prevent a well from flowing uncontrolled and shall immediately make a verbal report of any well flowing uncontrolled to the division and confirm it in writing forthwith.

Submission of information

27. On request by an officer of the division, the operator shall provide all information connected with or derived from the drilling, production or other work performed on a well.

Daily reports

28. (1) An operator shall keep a daily report at the site of a well being drilled or otherwise worked on.

(2) An operator shall submit a legible copy of the daily reports for each week within the ensuing week to the division, and copies shall be retained by the operator as part of his permanent record.

(3) A daily report shall set out complete data on all operations performed during the day, and, without restricting the generality of the foregoing, shall include
(a) depth at the beginning of and end of each tour,
(b) all casing data, including size, type, grade, weight, whether new or used, and the depth at which it is set,
(c) particulars of cementing,
(d) details of any water, brine or other fluid encountered, regardless of quantity,
(e) a report of any tests made,
(f) full details of all formation tests, except where the details are submitted on a confidential report form,

(g) details of all occasions when the blow out preventers are closed, with the reason for closure,
(h) details of any loss of drilling fluid into the formation,
(i) allocation of time to each operation,
(j) name of drilling contractor or service company and rig number, and
(k) the spud and rig release dates.

Well summary

29. (1) Not more than one calendar month after the date of the rig release of the drilling rig, the operator shall submit a signed well summary to the division.

(2) Where the initial completion or abandonment of a well is not carried out within one month of the release of the drilling rig or where a well is subsequently deepened, the operator shall submit a signed supplement to a well summary to the division giving details of the operations.

Well history reports

30. Not more than 2 months after the date of rig release of the drilling rig from a well, the operator shall submit a well history report to the division.

Work-over reports

31. (1) An operator shall submit a work-over report to the division not more than one month after a work-over operation.

(2) Where more than one work-over has been performed on a well, the work-over reports shall be numbered consecutively.

Release of information

32. (1) No officer of the division shall release the following information, except to another public officer, without the written permission of the person who supplied it:
(a) pool studies and reserve estimates submitted by an operator unless filed at an inquiry or public hearing;
(b) information submitted to the division not required by regulation.

(2) No officer of the division shall release, except to another public officer, information obtained from a development well and recorded with the division as required by this regulation until a period of one year after the date of release of the drilling rig.

(3) No officer of the division shall release, except to another public officer, information obtained from an exploratory well and recorded with the division as required by this regulation until a period of 2 years after the date of release of the drilling rig.

(4) The following information shall be open to the public at all times:
(a) position, elevation, current depth, casing and cementing data and the status of a well;
(b) all applications and submissions made to the minister or the division for the purpose of a public hearing;
(c) monthly production and injection of steam, brine or any fluids, for wells on regular production.

(5) Information may be released at any time with the written consent of the operator.

(6) Notwithstanding this section, the Lieutenant Governor in Council may release information at any time if he considers it in the public interest to do so.

B.C. Reg. 170/83

Electrical equipment

33. (1) An operator shall ensure that electrical equipment on a drilling rig located
(a) within 4 m of the centre line of the rotary table or blow out preventer stack,
(b) within 2 m of a shale shaker or an atmosphere separator,
(c) in an enclosed space containing a mud tank or a choke manifold, or
(d) in an enclosed space where combustible gases may accumulate
conforms to the requirements of Class 1, Division 2, Wet Locations in the Canadian Electrical Code.

(2) An operator shall ensure that electrical equipment on a drilling rig located within 20 m of the centre line of the rotary table or blow out preventer stack conforms with the requirements of Canadian Electrical Manufacturers Association 4 or equivalent Canadian Standards Association standards.

(3) An operator shall ensure that electrical equipment referred to in this section bears evidence of Canadian Standards Association or Underwriters Laboratories approval for use where it is located.

(4) Subsection (3) does not apply to a motor and motor control which is provided with a positive pressure air or inert gas purge system.

(5) No electrical equipment shall be used in an area referred to in this section unless it is essential to the processes being carried on there.

(6) Service equipment, panelboards, switchboards and similar electrical equipment shall, where practicable, be located in rooms or sections of the building away from hazardous areas.

(7) An operator shall ensure that no electrical generator is placed within 20 m of a well, separator, or other source of ignitable vapours.

(8) Purged traction motors shall be protected against entry of a spray of water into the motor.

(9) An operator shall ensure that positive pressure purge systems comply with Appendix G of the Canadian Electrical Code and are constructed
(a) to prevent escape of molten metal particles or sparks,
(b) to have a positive pressure of at least 2.54 mm of water, and
(c) to accommodate an audible or visual mechanical pneumatic or electric alarm system to announce the failure of purge pressure within the system.

(10) A purge pressure alarm system shall be used and, where it is electric it shall bear evidence of Canadian Standards Association or Underwriters Laboratories approval for the location in which it is used.

(11) The external surfaces of purged enclosures or motors and the purge egress shall not exceed 200°C.

(12) Where air purge is used, the compressor intake shall be located in a non-hazardous area and an air drying system shall be included as part of the purge system.

Grounding and bonding

34. An operator shall ensure that grounding and bonding conform to section 10 of the Canadian Electrical Code and in addition that the following are complied with:
(a) the non current carrying parts of electrical equipment are bonded to the neutral point of the system;

(b) the neutral conductor of supply circuits is not used for bonding on non current carrying metal parts of equipment;
(c) the non current carrying parts of the electrical equipment are bonded to the neutral point of the system if the system incorporates a neutral conductor.

Wiring and insulation

35. (1) An operator shall ensure that all wiring is in
(a) rigid threaded conduit,
(b) flexible armoured cable, or
(c) flex cord.

(2) Where flex cord is used it shall
(a) be of a type designed for extra hard usage,
(b) contain, in addition to the conductors of the curcuit, a grounding conductor,
(c) be connected to terminals or supply conductors in a manner acceptable to an officer of the division,
(d) be supported by cable trays or other suitable means in such a manner that there will be no tension on the terminal connections, and
(e) be provided with seals acceptable to an officer of the division at the places where the flex cord enters a box, fitting or enclosure which is required to be explosion proof.

(3) Receptacles and attachment plugs installed in areas referred to in section 33 (1) shall be of the type providing for connection to the grounding conductor of the flexible cord, and shall be approved by the Canadian Electrical Code for Class 1, Division 2, Wet Locations, except where such receptacles and attachment plugs are purged.

(4) Conductor insulation installed in areas referred to in section 33 (1) where condensed vapours or liquids may collect on or come in contact with the insulation on conductors shall meet Canadian Standards Association or Underwriters Laboratories standards for use under such conditions, or the insulation shall be protected by flexible armoured cable or by other means acceptable to an officer of the division.

(5) An operator shall ensure that no live parts of electrical equipment or of an electrical installation are exposed.

Removal of drilling equipment

36. An operator shall not remove a drilling rig from a well without first obtaining written approval from an officer of the division, unless the well has been drilled in accordance with the well authorization, or the drilling operations have been suspended or the well has been abandoned in accordance with the requirements of this regulation.

Plugging requirements of wells

37. (1) An operator shall submit an application to abandon a well to the division before abandoning a well and shall obtain written approval of the abandonment program from an officer of the division.

(2) Sufficient information shall be submitted to the division to allow the effectiveness of the proposed abandonment program to be evaluated, and a summary of any tests run and a copy of the logs run shall be submitted if requested by an officer of the division.

B.C. Reg. 170/83

Restoration of surface

38. (1) On completion of a well or final abandonment of a well, test hole or production facility, as soon as weather conditions permit, an operator shall

(a) clear the area of all refuse material,
(b) drain and fill excavations,
(c) remove concrete bases, machinery and materials not being used for production, and
(d) level the surface and leave the site in the condition as nearly as is reasonable to its condition when operations were commenced.

(2) An operator shall submit an application for a certificate of restoration to the division, after restoration of the surface of an abandoned well, test hole or production facility in accordance with this section.

(3) Where the owner of the surface consents in writing, an operator need not comply with subsection (1) (c) and (d).

Disposal of drilling and production material

39. (1) An operator shall ensure that a fluid produced from or used in a well or test hole does not

(a) create a hazard to public health or safety,
(b) contaminate any fresh water stratum or body of water or remain in a place from which it might contaminate any fresh water or body of water,
(c) run over or damage any land, highway or public road,
(d) pass into any body of water frequented by fish or that flows into such water, or on ice over such water, or
(e) pass into any body of water frequented by migratory water fowl or that flows into such water, or on ice over such water.

(2) An operator shall ensure that gaseous substances or odors produced from a well, test hole or production facility do not create a hazard to public health or safety.

(3) An operator shall dispose of fluid or gaseous substances produced from a well, test hole or production facility by a method approved by an officer of the division.

Measurement of fluid production

40. (1) An operator shall measure fluid produced from a well by a method approved by an officer of the division.

(2) An officer of the division may, on application by an operator, exempt the operator from complying with this section where special circumstances exist.

Well testing

41. (1) An operator shall production test a well using a method approved by an officer of the division.

(2) The operator shall submit a detailed report of the test to the division within 2 months of the date in which the test was completed.

Report of geothermal production

42. An operator shall submit a monthly report on production of a geothermal resource to the division giving particulars of dates produced, hours produced, volumes produced and pressures measured.

Exemptions

43. The division head may, in relation to a particular location or well and subject to conditions the division head specifies, exempt a person from the application of all or part of this regulation.

Offence

44. A person who contravenes a section of this regulation other than section 2 (1), 5 (4), 9 (3) or (4), 13 (6), (10) or (11), 31 (2) or 32 (1), (2) or (3) commits an offence.

APPENDIX B

WASHINGTON ADMINISTRATIVE CODE (WAC) 230
REQUIRED EXPLORATION AND DEVELOPMENT WORK

Draft Rules and Regulations
for Geothermal Resource Leasing

WASHINGTON ADMINISTRATIVE CODE (WAC) 230

REQUIRED EXPLORATION AND DEVELOPMENT WORK

Performance of exploration and development work is required by the anniversary date of the second year and annually thereafter until the end of the fifth year. Work shall be as follows:

Before the first two years of the lease have elapsed, the operator shall spend a minimum of $20 per acre; during the third year of he lease not less than $15 per acre; during the fourth year not less than $20 per acre; and during the fifth year not less than $25 per acre must be spent subject to approval by the department. To retain the lease past the end of the fifth year, the lessee must be proceeding with due diligence according to WAC 120.

The lessee may pay to the state the scheduled amount in lieu of the performance of development work or improvements; PROVIDED, that the lessee may pay the difference between the actual work performed and the work required.

When two or more leases are involved, exploration and development work, accomplished in excess of the required amount on one lease, may be credited on the other lease; PROVIDED, that operation of the leases has been unitized as per WAC 240.

The lessee may apply in writing to the department for a day-for-day reduction or waiver of required exploration and development work in any one lease year due to strikes, legal restrictions or acts of God which prohibit the lessee from performing work.

Reports of exploration and development work performed shall be the responsibility of the lessee and shall be submitted on the anniversary date of the second year and annually, thereafter, in a format approved by the department. Failure of the lessee to submit the required proof and evidence of work shall cause the lease to be in default and shall automatically terminate upon 30 days' notice (WAC 310). The lessee, his agents or associates shall not be eligible for a new lease of the premises for one year from the date of automatic termination.

Examples of unacceptable work or improvements are:

1. Travel or living expenses.

2. In the opinion of the department, construction of buildings and facilities not strictly for the production of geothermal energy or cascaded uses.

3. Processing or treatment costs.

4. Legal and attorney fees.

5. Contracted development work paid for but not performed.

6. Improvements and development work performed by a prior lessee except by approved assignment.

7. Reclamation work.

Proof of work reports shall contain sufficient information to indicate the type, amount and cost of work or improvements accomplished. Examples of acceptable types of work which may apply to meeting these requirements are listed below. These are examples only. All work must, in the opinion of the department, directly contribute to the exploration and development of the geothermal resource.

1. Drilling of production and/or reinjection wells and related operations.

2. Geophysical, geochemical and geologic surveys including mapping, data interpretations, temperature-gradient and heat-flow drilling in core holes 500 feet or more in depth and other exploration activities.

3. Engineering and construction of improvements including roads for access; buildings if used only for production of geothermal energy such as electric plants, cooling towers, equipment storage facilities, offices, and shops; maintenance and repair of such improvements; drill pads; pipelines; power and water systems; and treatment structures.

4. Moving machinery or construction materials which directly contribute to the development of the premises.

5. Approved property line surveys made to department standards.

APPENDIX C

PRICING DIRECT-USE GEOTHERMAL ENERGY
PRICING FORMULA DEVELOPMENT

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Pricing Formula Development

In an attempt to develop a pricing formula, a mathematical function was chosen that would allow both the owner and the user to benefit by increasing the amount of heat extracted from the resource. Parameters were then established which would yield reasonable results over established resource temperature ranges. The maximum temperature for direct-use was set at 350°F, the concept being that higher temperatures would probably be used for electrical power generation. The lower temperature range was established at 100°F. The logic here was that system costs rise rapidly as heat is extracted at temperatures lower than 100°F. Temperatures in the range of 85°F are suitable for both space heating and cooling using water-to-air heat pumps. In the cooling cycle, the heat pump receives the resource fluid, increases the temperature of the fluid, and injects fluid to the reservoir at a temperature higher than the temperature of the reservoir. Such a process would indicate that the landowner would have to pay a royalty to the user.

Most direct-use geothermal systems utilize heat exchangers to separate the geothermal (primary) fluid from the fluid in the secondary system which is normally clean or treated water. There are a few cases in which the geothermal fluid itself is sufficiently clean to be used throughout the system. As resource water quality deteriorates, heat exchangers are absolutely necessary to avoid scaling and corrosion of the secondary system. Efficient heat exchangers have approach temperatures in the neighborhood of 10°F between the primary and secondary fluids, leaving a net available resource temperature of 10°F less than that of the resource. Therefore, the formula evaluates net available resource temperature.

FORMULA: $\frac{340^\circ F - d}{653} = e^{-hr}$

WHERE: d = Discharge fluid temperature in °F
r = Royalty expressed as a decimal

A value for h is established by setting d = 180°F and r_s = some standard royalty (expressed as a decimal) agreed upon between the owner and the user based on the cost to develop and deliver the resource. Once h has been established, it remains fixed for that specific resource. d is given the value of the actual discharge temperature and r is calculated.

EXAMPLE: Assume r_s = 10%; then

$$\frac{340 - 180}{653} = e^{-h\ (.10)}$$

$$\ln \text{ of } \frac{160}{653} = .10(h)$$

$$h = \frac{-1.4064}{-.1} = 14.064$$

For a resource of 270°F and a discharge of 140°F:

$$\frac{340 - 140}{653} = e^{-14.064(r)} = 8.4\%$$

The reason for establishing the discharge temperature at 180°F to calculate h at the standard royalty is because typical existing space heating systems supply temperatures at 200°F, extracting 20°F, with fluid returning to the heat source at 180°F. Therefore, whatever value is established as the percentage by extracting enough heat from the resource to reduce the discharge fluid to 180°F. If the discharge fluid were higher than 180°F, the percentage royalty would be higher than 10 percent. If the discharge fluid were lower than 180°F, the royalty would be less than 10 percent.

If the assumption is made that pressures are maintained to keep higher temperature resources from flashing, then the energy output of a resource can be easily calculated to arrive at a royalty payment.

FORMULA: Btu/Hour = $(R_n - d)$ 500 (gpm)

WHERE: R_n = Net available resource temperature (resource temperature in °F -10°F)

d = Discharge fluid temperature in °F

For a 270°F resource with a flow of 1,000 gpm and a discharge of 140°F:

R_n = 270 - 10 = 260

d = 140

gpm = 1,000

Btu/hour = (260 - 140) 500 (1,000) = 60,000,000 = 60 MBtu/hour

At a price of $4.50/MBtu, the total energy value would be 4.5 x 60 = $270/hour, and the royalty payment with a R_s of 10% would be .084 x $270 = $22.68/hour.

As an example, the Klamath Falls Heating District has resource temperatures of 210°F (net available resource temperature 200°F), a discharge temperature of 160°F, and a peak flow of 1,390 gpm. The annual load factor for this district is 25 percent. This means that the system would operate for 2,190 hours per year based on the peak load. If this resource was evaluated at a 10 percent standard royalty, the royalty for 160°F discharge fluid would be 9.16 percent. The total annual energy delivered would be:

$$\text{Btu/Hour} = 40^{\circ}\text{F}\ (500)\ 1{,}390 = 27.8\ \text{MBtu/hour}.$$

Then, energy value per hour = \$3.50 x 27.8 = \$97.30/hour. Total annual energy value = \$97.30/hour x 2,190 hours/year = \$213,087/year and the royalty = \$213,087 x .0916 = \$19,519. The city could cut this amount in half by designing the heating district to extract 80°F with a discharge temperature of 120°F.