FINANCIAL RISK MANAGEMENT INSTRUMENTS

FOR

GEOTHERMAL ENERGY DEVELOPMENT PROJECTS

SUBMITTED TO

UNITED NATIONS ENVIRONMENT PROGRAMME
DIVISION OF
TECHNOLOGY, INDUSTRY AND ECONOMICS

PREPARED BY

DR. JIM COMBS
GEO HILLS ASSOCIATES
2445 EAST LAKERIDGE SHORES
RENO, NV 89519-5733

DECEMBER 2006

Table of Contents

Page

Financial Risk Management Instruments
For
Geothermal Energy Development Projects

1.0 Introduction

> *"This UNEP/GEF targeted research project aims to catalyze new thinking in the risk management area, examining existing instruments and approaches and suggesting potential modalities for new instruments that could be developed in partnership with private and public sector financial institutions. The project is being implemented in cooperation with the other GEF Implementing Agencies- the World Bank, UNDP-, GEF Scientific and Technical Advisory Panel, as well as a number of RE (*Renewable Energy*) financing relevant industry partners."*
>
> *"The project will identify risks associated with RE projects which could be effectively mitigated by financial risk management instruments, evaluate existing and emerging instruments, and identify the most promising modalities of such instruments where private sector actors are ready to play an active role."*
>
> *"The ultimate goal of the efforts is to bring about a faster and more systematic deployment of RE by supporting and positively influencing the development of markets for RE risk management instruments / approaches."*

The scope of the present Consultant work for the Working Group 3 will form a part of the research activities of the UNEP's overall research program under Assessment of Financial Risk Management Instruments for Renewable Energy Projects ("Research Project"), which is supported by the GEF grant. The objective of the present Consultant assignment is to conduct a technical research for the Working Group 3 in the area of financial risk management instruments for geothermal energy development projects.

The present Consultant research for Working Group 3 will cover broadly three areas of topics:

- ❖ *Brief description and analysis of unique risk characters associated with geothermal energy development and its technologies, and provide an* *overview of financial risk management instruments which are typically used;*

- *Highlighting the reservoir related risks for geothermal exploration, development, and operations, and collecting and summarizing the existing reservoir related risk mitigation instruments based on both public sector and private sector schemes in several countries (e.g., France, Germany, Iceland, Italy, Africa, Munich Re, etc.); and*

- *Assessment and recommendation of future development of reservoir related risk instruments.*

In an earlier scoping study for UNEP (2004) carried out by a consortium led by Marsh Ltd, some of the geological risks have been defined, and, if used properly, risk management measures can transfer certain types of risks away from investors and lenders and reduce the overall cost of financing RE projects. An analysis of and recommendations about the risk management measures presented in the UNEP scoping study are presented in Appendix A.

Geothermal exploration, development, and operations are subject to uncertainties which vary among different geothermal reservoirs and are similar to those typically associated with oil and gas exploration and development; however, there are several significant differences which are presented and discussed in Appendix A. The geographic area and sustainable output can only be estimated and cannot be definitively established because of the geological complexities of geothermal reservoirs. Furthermore, the largest risk for both the petroleum and geothermal industry includes unproductive wells.

An earlier research report by the author was associated with the definition of Partial Risk Guarantee (PRG) windows for the initiation of the World Bank-GEF Geothermal Energy Development Fund (GeoFund) for the Europe and Central Asia (ECA) region. The PRG windows were primarily designed to encourage entities in the ECA region to explore for and drill geothermal exploration wells to develop geothermal resources for electrical generation and/or direct use applications. The PRG windows were intended to partially insure geothermal energy project promoters/investors against (1) the short-term, up-front geological risk of exploration drilling, and/or (2) the long-term geological risk of developing and producing a geothermal reservoir with a lower-than-estimated temperature, higher than estimated mineralization, or difficulty with injection of geothermal fluids back into the subsurface. For officially launching the GeoFund program, a scoring model for the geological risk scenarios was adopted to implement the PRG windows.

The GeoFund Partial Risk Guarantee (PRG) Facility will be presented and discussed in this research project report. In fact, the PRG windows of the GeoFund will be one of the primary financial risk management instruments that will be presented in this UNEP Working Group 3 research report with respect to the exploration, development, and operations of geothermal energy projects.

There are inherent risks associated with any form of natural resource based development; however, these risks can be managed once a geothermal power generation project has been properly defined. The primary objectives of any geothermal power project include the following:

- Define the entities involved, their relationships and responsibilities;
- Establish a complete and fully integrated legal and contractural infrastructure;
- Allocate identified risks and management instruments; and
- Define characteristics for project financing.

2.0 Risks During the Exploration Phase of Geothermal Energy Projects

There are various risks, including geological risks that can impact the exploration for and development of geothermal energy projects whether for electrical generation and/or direct use applications. A key risk mitigation and management strategy is for geothermal energy project promoters/investors to adopt a phased approach associated with their geothermal exploration and development activities with a clear decision point at the end of each phase before proceeding to the next phase. The three initial exploration phases that are summarized in the next section were not included in the PRG windows of the GeoFund discussed earlier. Nevertheless, the data and information from these initial exploration phases will be the critical elements that will need to be evaluated by the UNEP Working Group 3 Technical Committee to determine whether the geothermal energy project promoters/investors will be considered for risk mitigation measures associated with the exploration-drilling phase of their specific geothermal energy projects.

2.1 Initial Three Geothermal Exploration Phases

The initial exploration phases include the completion of (1) an "office-type geothermal resource study" which would consist of a thorough literature review of available information directly related to geothermal energy (e.g., hot springs, fumaroles, tufa and silica mounds, etc.), regional geology and geophysical studies, results of mineral and hydrocarbon exploration, groundwater and geohazard investigations, as well as information obtained from analyses of aerial photographs and satellite imagery; (2) "field reconnaissance surveys and investigations" including primarily the acquisition and analysis of geology and geochemistry data, but also including environmental and social issues, local infrastructure availability, and possible project sites and transmission routes; and (3) "detailed geothermal exploration surveys" including geophysical techniques which may be able to provide deeply penetrating measurements that can be used to delineate a potential geothermal reservoir and assist in the designation of probable exploration drilling targets.

After these initial three geothermal exploration phases, i.e.,

(1) “office-type geothermal resource study”;
(2) “field reconnaissance surveys and investigations”; and
(3) “detailed geothermal exploration surveys”;

have been completed and the UNEP Working Group 3 Technical Committee has determined that the specific geothermal project is eligible for support under risk mitigation measures, the next phase of the geothermal exploratory program will be the planning, drilling, completion and testing of an exploration well. Because of the level of costs associated with the drilling, completion, and testing of geothermal wells, which can range from USD $1 million to $5 million, it is at the exploratory drilling phase where the need for well-defined financial risk management strategy and instruments becomes extremely important.

Before the first geothermal exploration well is drilled the possible outcomes of drilling and testing should have been thoroughly discussed and an unambiguous decision tree elaborated and agreed. For example, if the first geothermal well meets the anticipated production levels, then the decision to drill the second well may be unambiguous. However, if the first well is not productive, or marginally productive, then the decision could be to continue with the second well as planned, continue with the second well by changing its location or target depth, postpone a decision on the second well while the first well undergoes an extended well test program, or decide to abandon the geothermal project. Key indicators of success from geothermal exploration wells are high temperatures and permeability combined with production of a high-enthalpy fluid that is not acid and does not produce scaling over and above that normally expected for geothermal fluids.

2.2 Geological Risks of Geothermal Energy Projects

It is clearly advantageous to identify resource-related risks at as early a stage as possible in a geothermal exploration and development project. It may not be possible to closely quantify the probability of certain constraints during the early phases of a project, but if their consequences are sufficiently serious, such as magmatic acidity, then even a poorlyquantified assessment of the risk may be sufficient to force the decision to abandon a prospect – or at least abandon one particular portion of the resource sector of the geothermal prospect. Furthermore, it is clearly important to define the geological risks associated with the drilling of geothermal exploration wells. The probability of different risks occurring varies over several orders of magnitude. What really matters with respect to long-term geological risks of developing and producing a geothermal reservoir is how probable it is that a constraint will apply during the lifetime of a geothermal energy project. It is important to note that there is not an absolute formula to determine whether an investment in a geothermal energy project is feasible and/or whether a specific geothermal energy project should be eligible for RFP windows.

At an early phase of a geothermal exploration program, it is advantageous to work by analogy with other, better known geothermal resource projects in similar geological environments. Once the initial three phases of a geothermal exploration program are completed and analyzed, it is particularly useful and constructive to assemble all of the geoscientific data and develop a preliminary hydrogeological model of the prospective geothermal system in as much detail as possible. In addition, it is also helpful to recognize that certain factors are linked. For example, if the geochemical analysis of the surface manifestations associated with a geothermal resource contain a high gas content, it implies a high probability of calcite scaling, whereas a geologically young system may be hot but have a high probability of silica deposition.

In the exploration for commercial geothermal reservoirs, it is desirable to use geological, geochemical, and geophysical surveys that are capable of providing information about the following four characteristics, i.e., temperature, size, permeability and type of the geothermal fluids. It has been shown from numerous geothermal case histories that geological, geochemical, thermal, electrical, as well as active and passive seismic exploration surveys can provide data on the four characteristics and are, therefore, the most useful and important in identifying and delineating geothermal reservoirs; however, the geothermal reservoirs must be substantiated and delineated by additional exploration and exploratory drilling.

2.3 General Definitions and Specific Geological Risks

In the following subsections, each of the possible risk factors that may occur in geothermal exploration and development drilling are discussed together with approaches about how these geological risks might be predicted or identified at an early phase of the exploration — preferably prior to drilling. The PRG windows are intended to partially insure against (1) the short-term, up-front geological risk of exploration drilling, and/or (2) the long-term geological risk of developing and producing a geothermal reservoir with lower-than-estimated temperature, higher than estimated mineralization, or difficulty with injection of geothermal fluids back into the subsurface.

2.3.1 Reservoir Temperatures and Enthalpy of Fluids

The minimum reservoir temperature for a conventional flash steam geothermal power plant to operate efficiently is generally regarded as greater than 220°C. Very often only a part of the geothermal system will have a high enough temperature to be developed using a conventional flash steam power plant. The upflow zone in a geothermal system may be surrounded by outflows of hot water, which cool to sub-economic temperatures. However, lower temperature geothermal fluids can be utilized in binary cycle power plants (see Appendix B). Very high temperature geothermal resources may in some cases not be the most desirable because of the high silica content of such fluids, and the fact that at very high temperatures in the subsurface reservoir permeability may be reduced by ductile behavior of the geological formations. High enthalpy resources, i.e., two-phase or vapor-dominated reservoirs or portions of geothermal reservoirs, are more valuable than liquid resources since more of the geothermal fluid that is produced can be utilized rather than having to be injected back into the geothermal system.

The main method of assessing potential reservoir temperatures prior to drilling and testing of exploratory wells is by the use of geothermal geothermometry on waters and gasses collected from natural surface thermal features such as hot springs and/or fumaroles. Whether exploitable vapor-dominated zones may exist in the identified geothermal reservoir can be most likely determined by careful examination of the gas geochemistry and a prediction of the hydrologic behavior of the geothermal system. The deeper fluid levels in the geothermal reservoir will favor the existence of a vapor-dominated resource.

2.3.2 Geothermal Resource Size

The geothermal resource must be large enough, i.e., have a large enough areal and vertical extent, to supply the proposed geothermal development throughout its assumed economic lifetime with a comfortable margin. In other words, the geothermal system must constitute a sufficiently large volume of hot rock, a sufficient supply of fluids to extract the anomalous heat and permeable pathways for adequate fluid flow. The area of the resource is best estimated from geophysical surveying methods in which the electrical resistivity of subsurface rocks is measured and analyzed. However, the results of these geophysical surveys are usually ambiguous, since, for example, electrical resistivities can be affected by cool zones of fossil hydrothermal alteration, so the extent of the electrical resistivity anomaly may be larger than the true size of the geothermal resource. Petrological examination of altered rocks exposed on the surface will possibly reveal whether the system is deeply eroded and in which case fossil hydrothermal alteration is more probable. Evaluating the potential thickness of a geothermal system prior to drilling can be estimated from a combination of geological studies and geophysical surveying methods. However, until the initial geothermal exploration well has been drilled, completed and tested, the actual viability and thickness of a geothermal reservoir cannot be accurately determined.

2.3.3 Geothermal Reservoir Permeability

Permeability, i.e., the capacity of a porous material for transmitting a fluid, in geothermal reservoirs can either be of primary or of secondary origin. Primary permeability is due to porosity in the rock formation whereas secondary permeability is created by geological fractures and faulted structures. Fracture permeability is predominant in geothermal reservoirs existing in volcanic and metamorphic rocks. A geothermal reservoir must have sufficient connected permeability to permit the effective extraction of heat from the rocks by water, which passes through the rocks. This is normally the case in geothermal reservoirs developed in volcanic and metamorphic rocks, but is not necessarily so in intrusive, sedimentary, or metasedimentary rocks.

In order to obtain significant fluid flows from individual geothermal production wells, localized zones of higher permeability are required in the geothermal reservoir. Since geothermal well productivities vary by more than two orders of magnitude, successfully drilling and completing wells into the most permeable zones of a geothermal reservoir is a worthwhile challenge. At the same time, a high degree of fracture permeability in one predominant direction, i.e., anisotropy can be a significant disadvantage if it produces an effect to channel injected fluid rapidly back to production zones.

Permeability at depth in a geothermal system can be predicted by a careful study of the geology, particularly regional stratigraphy, which will allow a prediction of the bulk reservoir permeability, and, structure which will identify possible localized zones of high fracture permeability. In addition, geophysical surveys using seismic methods, including shear wave splitting can be extremely useful in defining zones of high fracture permeability prior to drilling geothermal exploratory wells.

2.3.4 Gas Content of Geothermal Fluids

The non-condensable gas fraction of geothermal fluids is primarily carbon dioxide, with the possibility of as much as five percent (5%) hydrogen sulphide in high temperature reservoirs. Non-condensable gas content is rarely a fatal constraint, and never a fire danger as indicated in the analysis of the UNEP report presented in Appendix A. Its effects are economically quantifiable, but not always accurately predictable. The gas content in steam from fumaroles can be measured, but this will not be the same as the gas content at depth. It cannot therefore be taken as a maximum or minimum value of likely gas levels in steam from geothermal wells in the same geothermal system. Gas content in steam may also vary with time in response to the production of geothermal fluids and to reservoir processes such as boiling.

High gas content in geothermal fluids is undesirable for three reasons, i.e.,

- it is often the cause of a high calcite scaling potential,
- it imposes an increased parasitic load on the power plant, through the need to evacuate gas from the turbine condenser, and
- it can possibly pose environmental problems for disposal.

2.3.5 Scaling and Surface Formation of Scale

The most common form of scaling in geothermal production wells, pipelines, and in the surrounding rock formations is calcite ($CaCO_2$). Calcite deposition is most common in more dilute alkaline-pH geothermal reservoirs, particularly those with high gas contents or relative low reservoir temperatures (e.g., < 200°C). Calcite scaling within the wellbore of a discharging well can cause significant declines in mass flow. Scaling in the wellbore necessitates regular workovers to remove the deposition or alternatively, antiscalant chemicals can be pumped into the well, to below the flashpoint in the wellbore, through downhole capillary tubing to prevent calcite scaling from occurring. During the detailed geological mapping of the geothermal project area, all tufa mounds and silica surface deposits should be recognized as noteworthy surface manifestations of both fossil and current geothermal activity.

Silica (SiO_2) deposition can pose a significant problem during exploratory well testing with the deposition of silica scale on test devices and during geothermal production operations due to scaling of silica in pipelines and injection wells. The higher the temperature of a geothermal fluid, the greater the quantity of dissolved silica in the fluid, and thus, the more readily the geothermal fluid can deposit silica when cooled or separated. The standard approach to controlling silica supersaturation is to modify the pH of the geothermal fluid and/or to design the fluid collection and disposal systems to operate at a steam/water separator pressure at which saturation with respect to amorphous silica is not exceeded.

2.3.6 Acidity of Geothermal Fluids

Acid fluids in geothermal systems can impose significant constraints on the development and utilization of geothermal fluids for power generation due to acid corrosion, which can cause major damage to well casing and surface pipelines, and scaling. The occurrence of acidity at depth in geothermal systems can be predicted from the geochemistry of surface thermal features. However, this may not be as simple as detecting the presence of acid fluids directly. There may be indirect indicators such as the occurrence of neutral $Cl\text{-}SO_4$ springs at high elevations, or a high magnesium content in surface springs. Gas sampling with the use of techniques aimed at identifying specific chemical components of the geothermal fluids may be required to distinguish between acidity of direct magmatic origin and secondary acidity.

2.3.7 Additional Identifiable Geological Risks

There are inherent risks associated with any form of natural resource based development, and several low risks, but identifiable geological risks, are associated with the development of geothermal energy projects. It may be possible to make some predictions of their likelihood based on geology and geophysics prior to exploratory drilling. Volcanic risk on a geothermal project is a difficult parameter to quantify both in terms of probability and impact since it is usually a low probability event but one with potentially disastrous consequences. For example, a geothermal project site near an active andesitic stratovolcano may have a high probability of being affected by minor ash fallout during the typical lifetime of the geothermal power project, but the consequences of this risk would be comparatively minor.

Small hydrothermal eruptions may sometimes occur at localized sites in a geothermal field without causing any damage, while catastrophic eruptions are less common. Hydrothermal eruptions remain a possibility for any hydrothermal system with a water level within a few hundred meters of the surface, but there is little that can be done to predict such an occurrence. It is unlikely to occur more frequently than on a scale of hundreds, or more probably thousands of years, and so is in the same category as volcanic risk for most geothermal fields, i.e., having potentially serious consequences but low likelihood of occurrence during the lifetime of a typical geothermal project.

Since most geothermal fields are located in tectonically active areas, there is an element of seismic risk. Active faults may move during earthquakes by up to several meters horizontally and vertically. However, because of the anomalously high temperatures in the subsurface containing geothermal systems, most of the tectonic movements are expressed as creep-type events and/or very small microearthquakes ranging in magnitude from $-2.0 < M < +3.5$ which are seldom detected by humans except with the use of very sensitive seismometers. However, these microearthquakes are critical to geothermal systems in that they are the mechanism, which continually provide for the activation of new and/or renew fracture permeability in the geothermal reservoirs. Assessing seismic risk involves identifying any site-specific factors through detailed geological mapping. It is important to identify active fault traces, and avoid siting critical or expensive facilities such as power plants over them.

2.4 Partial Risk Guarantee (PRG) Facility for Exploration

As noted above, the GeoFund Partial Risk Guarantee (PRG) Facilities will be one of the primary financial risk management instruments that will be presented in this UNEP Working Group 3 research report with respect to the exploration, development, and operations of geothermal energy projects. We will first discuss the GeoFund PRG windows with respect to the exploration phase of geothermal energy projects.

2.4.1 Risk Management Instruments During Exploration

The PRG windows will not be applicable to the initial three phases of exploration as discussed above in Section 2.1. PRG windows will apply to the specific geological risks associated with the drilling of the initial exploratory well at a geothermal prospect. The specific geological risks associated with exploratory well drilling were defined in Sections 2.3.1 through 2.3.6. Each of these geological risks must be evaluated by designing and completing measurements, during a geothermal well test program, of physical and chemical parameters, including as a minimum the determination of the wellhead temperature, wellhead pressure, wellhead flow rate, and geochemical analysis of the produced geothermal fluids and gasses. The determination of success and failure of the exploration drilling activities will be based on the ability of the geothermal well to produce the necessary quantity and quality of geothermal fluids to fuel the proposed geothermal electrical generation project (see Appendix B) and/or the proposed direct use application (see Appendix C). Further analysis of the success and/or failure of the exploration drilling activities to mitigate these geological risks must be compared with the technical and financial parameters necessary for an economically successful geothermal power generation project (see Appendix D). Further evaluation of the GeoFund PRG windows for a proposed geothermal project in an ECA country, i.e., Hungary, is provided in Appendix E.

2.4.2 Objectives and Scope of PRG

PRG windows are designed to provide a vital enhancement on private capital mobilization into geothermal energy development projects by mitigating the geological risks during exploration well drilling and during operation of geothermal wells for the initial years of the project. It is assumed that project promoters, sponsors and investors/lenders can efficiently, on a commercial basis, accept other risk elements in developing and operating geothermal energy projects. The primary objective of PRG windows will be to promote private investment by complementing the existing market capacity and sharing the risk with private and public partners.

PRG will cover eligible investment against specifically defined categories of geological risk. Alternatively, PRG will also provide a cover for eligible investment, which would substantially entail the geological risk elements, i.e., geology related risk. While PRG is intended to demonstrate a model for geological risk mitigating instruments, it is also envisaged that PRG could be flexibly applied to investment involving geology related risk in any specific circumstances justifiable in light of the overall objectives of the GeoFund program and the UNEP Working Group 3 consideration of financial risk management instruments for geothermal development projects.

While designed to cover eligible investment against specifically defined categories of geological risk during (1) the short-term, up-front geological risk of exploration drilling, and/or (2) the long-term geological risk of developing and producing a geothermal reservoir, it is anticipated that for commercially successful geothermal projects, the PRG cover should be repaid to the GeoFund with interest to maximize the financial sustainability of the PRG portfolio in the GeoFund. With this approach there will be a continual replenishment of the funds to apply to geological risk associated with additional geothermal electrical generation, and/or direct use, projects.

2.4.3 Eligible Investments and Beneficiaries

PRG cover should be available for any type of capital expenditures and investments through equity, debt, mezzanine, etc. by private sector entities (e.g. project sponsors, promoters, investors, commercial lenders, etc.), which might support the financing of geothermal energy projects for electrical power generation and/or direct use applications.

2.4.4 PRG Instruments

Broadly there will be two types of PRG coverage available, (1) a short-term cover for up-front geological exploration drilling risk, and (2) a medium and long-term cover for operational risk of geothermal wells. For each type of PRG, the guarantee coverage will be defined against the key parameters of the geothermal energy production, such as reservoir temperature, wellhead pressure, wellhead flow rate, geothermal fluid chemistry, etc (see Appendices B, C and D). In developing the PRG coverage, which is linked with geothermal performance of the guaranteed production and/or injection well, a scoring model needs to be established based on the estimated (i.e., predicted) and actual geothermal data such as wellhead temperature, wellhead flow rate, estimate of permeability, geochemical analyses of geothermal fluid and non-condensible gasses. Such scoring model and framework will be critical for quantifying the guarantee coverage in a transparent manner as well as managing and monitoring the geological risk covered under the PRG windows of the GeoFund. The

PRG windows should be designed to cover expected losses between twenty-five percent (25%) and seventy percent (70%).

2.4.5 Exploration Risk Guarantee (EXG)

Coverage: EXG should cover up to 70% of the cost of drilling, completion and testing in the event of total failure. EXG coverage for "partial" failure or "partial" success should be determined based on the scoring of key measurable parameters.

Tenor: Each EXG should have a tenor of up to nine (9) months from the start of the drilling of a well covered under the EXG.

2.4.6 PRG Application and Underwriting Criteria

While PRG will cover in principle the geological and geology related risk, other technical and commercial aspects including the safeguard issues of the project need to be carefully reviewed. With respect to PRG applications, technical and geological evaluation of the geothermal exploratory well under PRG coverage will be conducted and presented in the form and substance in accordance with the GeoFund operational guidelines. The technical and geological evaluation will be critical to control the probability of PRG payout and to maximize the financial sustainability of the PRG portfolio in the GeoFund.

2.4.7 Pre-Conditions for EXG Application

As indicated in Section 1.1, a key risk mitigation strategy for geothermal energy projects is to adopt a phased approach associated with the geothermal exploration and development activities with a clear decision point at the end of each phase before proceeding to the next phase. However, the three initial exploration phases that were summarized in Section 1.1 and described in greater detail for the proposed Hungarian Geothermal Power Project in Appendix E must be completed and are required elements for the project to be eligible for the PRG windows of the GeoFund. These initial exploration phases include the completion of (1) a thorough literature review of available information directly related to geothermal energy (e.g., hot springs, fumaroles, tufa and silica mounds, etc.), regional geology and geophysical studies, results of mineral and hydrocarbon exploration, groundwater and geohazard investigations, as well as information obtained from analyses of aerial photographs and satellite imagery; (2) field reconnaissance surveys and investigations including primarily geology and geochemistry data, but also including environmental and social issues, local infrastructure availability, and possible project sites and transmission routes; and (3) detailed geothermal exploration surveys including specific geophysical techniques (e.g., electrical resistivity surveys, magnetotelluric soundings, transient electromagnetic investigations, and seismic reflection and refraction surveys) which may be able to provide deeply penetrating measurements that can be used to delineate a potential geothermal reservoir and assist in the designation of probable exploration drilling targets.

The data and information from these initial exploration phases are the critical elements that will need to be evaluated by the UNEP Working Group 3 Technical Committee to determine whether the geothermal energy project will be considered for support under the PRG windows associated with the exploration-drilling phase of the specific geothermal project. Although there can be no absolute pre-drilling determination of whether a particular geothermal exploratory well will be successful, the technical evaluation data and testing methodologies described above are necessary for the UNEP Working Group 3 Technical Committee to assess the probability of successful well drilling with reasonable confidence. With a positive recommendation from the UNEP Working Group 3 Technical Committee based on their independent analysis of the accumulated data and interpretations of the three initial exploration phases and the designation of a probable exploration-drilling target by the geothermal energy project promoters/investors, the GeoFund should make a PRG commitment.

2.4.8 PRG Premium for EXG

PRG premium could be in theory determined by the probability of risk occurrence over the life of PRG facility for EXG. However, because of the peculiarity of the geological nature of each geothermal well and the lack of reliable data and technical methodologies, it would be very difficult to assess the probability of risk occurrence with a high degree of confidence level. Conversely, if the probability of risk occurrence is measured with high confidence, a project developer would be willing to proceed with the geothermal project by taking such calculated risk into account in developing financial feasibility, and the need for geological risk mitigation instruments will be diminished.

Given the experimental nature of GeoFund as a development vehicle for geothermal energy projects, PRG premiums will need to be determined with relatively greater emphasis on practical consideration of the PRG instrument's marketability than the theoretical consideration on the financial sustainability of the PRG facility. PRG premiums might be reviewed and adjusted during the implementation period based on the actual occurrence of geological risk events. Underwriting criteria may also need to be adjusted. Further study will be required before determining the final premium structure. As a preliminary figure, the PRG premium for exploration phase drilling should be as follows.

> For EXG: [---] % flat on the eligible cost of drilling. The maximum payout ratio will be 70%. Premium can be prorated in proportion to the payout ratio.

2.5 Risk Management Instruments for Geothermal Projects

Commercial insurance solutions are well established as risk management instruments for the oil and gas industry; however, the insurance industry is just starting to examine the opportunities and challenges of the geothermal industry including different business models and inherent risks. In Europe and North America, insurers and reinsurers have been providing many of the traditional risk management products for the petroleum industry to the geothermal industry, such as property damage, business interruption, machinery breakdown and construction – all risks.

With respect to risk management instruments for geothermal energy projects, insurers are often not dealing with a major public facility or large oil company; rather, they are dealing with smaller, entrepreneurial geothermal development firms with new or prototype technology. Further, there are different business models and balance sheet sensitivities for the entrepreneurial geothermal development firms, as well as unique technology or production facilities with which underwriters have to become familiar. However, progressive insurance companies and brokers are proving receptive to finding the proper coverage solutions for geothermal and other renewable energy projects.

One of the main obstacles with respect to the development of risk management instruments for geothermal energy generation projects may be the tendency of the insurance community to try to put the newer forms of energy into old product boxes designed for traditional energy suppliers, such as major public facility and large oil company. There is definitely a need for customization of coverages and linked products that provide a total solution for the risks of geothermal development entities and other renewable energy firms.

These total risk management solutions might include the potential bundling of small-scale projects and packaging of risk to achieve economies of scale. Improved actuarial data and technical risk information could help facilitate the development of solutions for geothermal energy projects. As more geothermal energy projects are initiated, a key challenge will be the new or prototypical nature of the technologies, which can make it difficult for the insurance industry to model accurately future loss projections and price risks appropriately.

The lack of information and data on historical loss patterns, coupled with the conservative risk nature of insurance underwriters, can definitely slow the growth of new product development for geothermal energy projects. There are considerable concerns about low insured values associated with small-scale projects, financial viability, and the ability to achieve underwriting profits.

Insurers and reinsurers need to build risk management instruments that make sense for geothermal technologies and actually tailor coverage to their particular risks. Progressive brokers can help facilitate the movement. If this can be accomplished in a consumer-friendly format, those brokers will be well positioned to educate geothermal energy firms about new risk management instruments.

3.0 Risks During Development Phase of Geothermal Energy Projects

The risks during the development and construction phase of geothermal energy projects can be divided into (i) geothermal reservoir risks and (ii) financing, construction, and completion risks. The geothermal reservoir risks (i.e., development risks) include:

- Project Site Control;
- Initial Characteristics of the Geothermal Reservoir;
- Permits and Regulatory Approvals;
- Production and Injection Well Drilling and Testing;
- Environmental Aspects and Mitigations; and
- Cultural and Archaeological Mitigations.

The financing, construction, and completion risks include:

- “Bankable” Geothermal Reservoir Report;
- Power Purchase Agreement (PPA) with End User;
- Special Purpose Entity;
- Non-recourse Project Financing;
- Credit Supported by PPA and Project Assets;
- Engineering, Procurement, and Construction (EPC) Contract;
- Interconnection and Transmission; and
- Force Majeure.

3.1 Geothermal Reservoir Risks During Development

The information and data expected from a successful geothermal energy exploration program will be characterized by the following indicating the possibility of a commercial geothermal reservoir:

- Recent, i.e., geologically young, volcanic flows and craters;

- Anomalous geochemical characteristics of rocks and fluids;
- Pervasive high silica fracture deposits and associated mineralization;
- Controlling fractures and structural patterns across the entire prospect;
- Geophysical anomalies such as low electrical resistivity areas;
- High geothermal gradients obtained from drilling and testing wells;
- Massive open fractures with ongoing documented microseismicity; and
- Large quantities of water for continual recharge of a geothermal reservoir.

At an early stage of a follow-on geothermal energy development program, it is advantageous and important to work by analogy with other, better known geothermal resource projects in similar geological environments. Once the initial geothermal exploration program has been completed and analyzed, it is particularly useful and constructive to assemble all of the geoscientific data (i.e., hydrological, geological, geochemical, geophysical, and exploration drilling information) and develop a preliminary hydrogeological model of the prospective geothermal system in as much detail as possible.

In other words, the geothermal energy exploration program supported by the PRG windows should have provided definition of subsurface temperatures, calculated geothermal gradients, hydrothermal alteration, geothermometer values, and well test data. The exploration well drilling data should have also provided information on zones of loss circulation, subsurface formation types, downhole temperature-pressure-spinner measurements, and discharge test data.

The geothermal energy project promoters/investors may be required to drill and test additional exploration wells in order to provide a more precise geothermal reservoir evaluation and delineation. In fact, if the exploration wells have been completed as slim holes (i.e., small diameter wells), there will be a need to drill and test a large-diameter exploration well. By increasing the wellbore diameter in the production zone to accommodate a 245mm liner rather than a 114mm liner, the flow rate from a geothermal well may be increased by at least four (4) times.

Data from the geothermal exploration surveys and the available borehole data, including the large-diameter exploration well will provide the information necessary to determine resource temperature and production characteristics as well as assist in defining the type and the installed capacity of the potential geothermal energy power generation facility (i.e., a binary or flash steam power plant). Additionally, the completion and thorough documentation of these exploration efforts will provide the data necessary for an independent evaluation (i.e., a "bankable" geothermal reservoir report) of the geothermal energy power project for development financing.

3.2 Financing, Construction, Completion Risks During Development

As noted above, the development financing is initially dependent on a "bankable" geothermal reservoir report, which is based on the complete and thorough documentation of the exploration data and the independent evaluation of the report by a disinterested third-party technical analysis and recommendations. However, as important as the reservoir report may be, the development financing is highly dependent on the Power Purchase Agreement (PPA) executed between the purchasing end user, typically an electrical utility, and the special purpose entity, which in the United States is typically a Limited Liability Company (LLC).

The PPA and the project assets, elements of which have been included in a set of cash flow projections that indicate that the development debt can be repaid during the time-period of the financing with a debt coverage ratio that is satisfactory to the financial institution, must support the credit. The geothermal energy project will be financed on a non-recourse project finance basis. Essentially all of the geothermal energy projects over the past several years have been constructed and completed with the use of Engineering, Procurement, and Construction (EPC) contracts. The financial institution will also include a careful analysis of the interconnection studies and transmission agreements between the purchasing end user and the special purpose entity.

Engineering, Procurement, and Construction (EPC) contracts typically pass all design development and construction risks to the contractor. The developer acquires a "bankable" turnkey geothermal energy project and, at least theoretically, pays a premium for the assumption of the risk by the contractor. EPC type contracting has worked well for many years in engineering and construction sectors where technology, e.g., geothermal energy power generation technology, has been proven and project specific risks such as geotechnical conditions, adverse weather conditions, and regulatory interventions have been relatively small compared to potential rewards. It has also been implicit in these arrangements that the underlying profitability of the geothermal energy project was sufficiently large enough to fund the assumption of risk by contractors.

EPC contracts are characterized by the following risks aspects and concepts:

- Fixed schedules;
- Fixed prices;
- Lump sum;
- Turnkey basis;
- Start-up testing;
- Acceptance tests;
- Commissioning;
- Performance guarantees; and
- Liquidated damages.

In an EPC contract, the EPC contractor agrees to deliver the keys to a commissioned geothermal energy project to the developer for an agreed price, on a fixed schedule with performance guarantees and liquidated damages for the failure of acceptance tests and timely commissioning. In fact, the EPC way of executing geothermal energy projects is gaining importance worldwide for the management risks during the development and construction phases of geothermal energy projects.

4.0 Risks During Utilization Phase of Geothermal Energy Projects

Operating geothermal power generation projects involves, among other things, general economic, financial, competitive, legislative, regulatory and other factors that are typically beyond the control of the geothermal developer. Changes in these factors could make it more expensive for the developer to operate their projects, could require additional capital expenditures, or could reduce certain benefits currently available to the developer. A variety of other risks affect geothermal projects, some of which are beyond control of the developer, including:

- The power generation project could perform below expected levels of output or efficiency;
- The geothermal reservoir fluids could be interrupted or unavailable;
- Operating costs could significantly increase;
- Energy prices paid by the utility could decrease;
- Delivery of electrical energy could be disrupted;
- Environmental problems could arise which could lead to fines or a shutdown of the facility;
- Power plant units and equipment could break down or fail;
- The operators of the geothermal project could suffer labor disputes;
- The government could change permit or governmental approval requirements;
- Third parties could fail to perform their contractural obligations; and
- Catastrophic events, such as fires, earthquakes, explosions, floods, severe storms or other occurrences could affect the geothermal power generation facilities.

Geothermal power generation projects in the western United States currently maintain the following types of insurance to provide financial risk mitigation:

- Property insurance,

- Business interruption insurance,
- Earthquake insurance,
- Catastrophic insurance, and
- General liability insurance.

If an insurable loss occurs, the proceeds of the insurance coverages will be paid to the financial institutions that provided the debt financing which typically represents about seventy percent (70%) of the capital cost of the geothermal power generation project. However, no one can provide any assurance that the insurance coverage afforded by the above-mentioned policies will be available in the future at commercially reasonable costs or terms or that the amounts for which the projects are or will be insured will cover all potential losses. Furthermore, no one can assure that the geothermal project developers will actually be able to obtain such policies or that the title insurer or its reinsurers will be willing or able to satisfy any claims which may be made under those policies.

Most earthquakes are powered by release of the stresses that accumulate over time, typically, at the boundaries of the plates that make up the lithosphere of the earth. Plate tectonics are the continual slow movement of tectonic plates at the outermost part of the crust of the earth. This motion is what causes tectonic earthquakes and volcanoes and has created most of the spectacular scenery around the world. The most severe of these tectonic earthquakes are located along compressional and translational plate boundaries. Stress builds up and the rocks slip suddenly, releasing energy in waves that travel through the crust of the earth and cause the shaking that is felt during an earthquake of magnitude greater that about 3.5. However, in areas of geothermal systems where high temperature occurs in the shallow crust, it is also significant that strain cannot build up and the stresses are released as geothermal microearthquakes.

For example, The Geysers is an active geothermal system within the Clear Lake volcanic field in Northern California. The earthquake activity in The Geysers area has been quite variable over time, in terms of the number of events and their magnitude range. There were no earthquakes (M >= 2.5) observed in the area of the geothermal field between 1949 and

1975 based on the Berkeley Seismological Laboratory 1992 Bulletin. However, with the installation of seismic instruments and the increase in the number of geothermal power plants in The Geysers, starting in 1976 essentially continuous microearthquake activity was observed in the geothermal field as well as the rate steadily increased to a rate of at least twelve (12) geothermal earthquake (M >= 2.5 and <=3.5) per year since 1984.

It has also been observed that distant tectonic earthquakes can cause microearthquakes in geothermal areas. For example, in 2002, the largest earthquake of that year was the November 3 magnitude 7.9 Denali earthquake in Central Alaska. The earthquake produced a 300km long surface rupture and was felt widely throughout Alaska and Northwestern Canada. The earthquake also caused oscillations in water bodies throughout North America and triggered small microearthquakes in The Geysers and Yellowstone geothermal areas.

In summary, because of the elevated crustal temperatures in geothermal areas, it appears that strain cannot accumulate to cause earthquakes greater than about M = 3.5. However, the long-term effects of earthquakes on geothermal systems are beneficial, because the tremors improve the permeability of the reservoirs by opening fissures and produce increases of fluid flow from the geothermal production wells.

Thus, although geothermally active areas are subject to frequent low-level seismic disturbances, no one can assure that seismic disturbances of a nature and magnitude to cause material damage to the power generation facilities, transmission lines, production and injection wells, gathering systems or other related facilities, or a material change in the nature of the geothermal reservoir, will not occur. In addition, no one can assure that insurance proceeds will be adequate to cover all losses sustained, or that insurance will continue to be available in the future in the amounts that might be formerly be carried or other amounts adequate to insure against losses from seismic disturbances.

4.1 Geological Risk During the Operation Phase

As noted above, the PRG windows should be applicable to geological risk during the medium-term to long-term operation of an eligible geothermal power generation, and/or direct use, project. The geological risks specific to the operational phase of a geothermal project will comprise those geological risks defined in Sections 2.3.1 to 2.3.6 and including Section 2.3.7. The PRG windows have been designed to support the medium- to long-term commercial viability of a geothermal project based on the technical and financial parameters presented in Appendices B, C, and D. The determination of a sub-optimal operational performance will be derived from the continuous monitoring and measurements of physical and chemical parameters, including as a minimum the determination of the wellhead temperature, wellhead pressure, wellhead flow rate, and geochemical analysis of the produced geothermal fluids and gasses as a function of time. For example, because of the premature breakthrough of injection fluids, the wellhead temperature of a production well will be degraded to the extent that the necessary geothermal fluid is no longer available to properly fuel the geothermal project. The injected fluids may also tend to plug fracture permeability in the reservoir because of the deposition of silica and therefore will cause difficulty with injection of geothermal fluids back into the subsurface formations.

4.2 Risks With Long-Term Geothermal Energy Production

There are risks associated with a number of undesirable geothermal reservoir related effects that may result from geothermal production. It may also be possible to make some predictions of their likelihood based on geology and geophysics prior to exploratory drilling. Production related effects might include some of the following. Withdrawal of geothermal fluids can lead to subsidence of the surface, even with injection of waste fluids, especially in unconsolidated subsurface formations. Similarly, the closer the geothermal reservoir is to the surface and the more compressible the formations, the higher the probability of subsidence.

Ingress of cold water may start to quench the geothermal system as it moves inward to replace hot water in response to pressure drawdown in the reservoir. However, the presence of impermeable lake sediments or a silica seal around the geothermal reservoir can prevent the ingress of cold water.

Waste fluids from a geothermal power plant which include hot brine and cooled condensate are normally injected back into the geothermal reservoir for the purpose of providing pressure support and to minimize environmental issues associated with a geothermal project. However, the injected fluids might return to the production wells via subsurface interconnections such as fault planes and permeable formations. If these returns occur rapidly, the geothermal fluid output from the geothermal production wells can be seriously degraded in terms of temperature and enthalpy.

4.3 Partial Risk Guarantee (PRG) Facility During Operations

As noted above, the GeoFund Partial Risk Guarantee (PRG) Facilities will be one of the primary financial risk management instruments that will be presented in this UNEP Working Group 3 research report with respect to the exploration, development, and operations of geothermal energy projects. We will now discuss the PRG windows with respect to the operational phase of geothermal energy projects.

4.3.1 Risks Management Instruments During Operations

The risks associated with the long-term operational phase of a geothermal energy project include:

- Continual delivery of adequate geothermal fluids;
- Proven geothermal conversion technology;
- Monitoring and management of the geothermal reservoir;
- Monitoring and management of the power generation facility;
- Uninterruptible transmission access; and
- Revenue realization from the end user PPA.

Each of these geothermal reservoir risks must be evaluated by designing and completing measurements, during the geothermal production and injection well test program, of physical and chemical parameters, including as a minimum the determination of the wellhead temperature and enthalpy, wellhead pressure, wellhead flow rate, and geochemical analysis of the produced geothermal fluids and gasses. The determination of success and failure of the production and injection drilling activities will be based on the ability of the geothermal well to produce and inject the necessary quantity and quality of geothermal fluids to fuel the proposed geothermal electrical generation project (see Appendix B) and/or the proposed direct use application (see Appendix C). Further analysis of the success and/or failure of the production and injection drilling activities to mitigate these geological risks must be compared with the technical and financial parameters necessary for an economically successful geothermal power generation project (see Appendix D). Further evaluation of the GeoFund PRG windows for a proposed geothermal project in an ECA country, i.e., Hungary, is provided in Appendix E.

4.3.2 Objectives and Scope of PRG

PRG windows are designed to provide a vital enhancement on private capital mobilization into geothermal energy development projects by mitigating the geological risks during exploration, production, and injection well drilling and during operation of geothermal wells for the initial years of the project. It is assumed that project promoters, sponsors and investors/lenders can efficiently, on a commercial basis, accept other risk elements in developing and operating geothermal energy projects. The primary objective of PRG windows will be to promote private investment by complementing the existing market capacity and sharing the risk with private and public partners.

PRG will cover eligible investment against specifically defined categories of geothermal reservoir risk. Alternatively, PRG will also provide a cover for eligible investment, which would substantially entail the geothermal reservoir elements, i.e., geothermal reservoir risk. While PRG is intended to demonstrate a model for geothermal reservoir mitigating instruments, it is also envisaged that PRG could be flexibly applied to investment involving geothermal reservoir risk in any specific circumstances justifiable in light of the overall objectives of the GeoFund program and the UNEP Working Group 3 consideration of financial risk management instruments for geothermal energy development projects.

While designed to cover eligible investment against specifically defined categories of geological risk during (1) the short-term, up-front geological risk of exploration drilling, and/or (2) the long-term geothermal reservoir risk of developing and producing a geothermal reservoir, it is anticipated that for commercially successful geothermal projects, the PRG cover should be repaid to the GeoFund with interest to maximize the financial sustainability of the PRG portfolio in the GeoFund. With this approach there will be a continual replenishment of the funds to apply to geological risk associated with additional geothermal electrical generation, and/or direct use, projects.

4.3.3 Eligible Investments and Beneficiaries

PRG cover should be available for any type of capital expenditures and investments through equity, debt, mezzanine, etc. by private sector entities (e.g. project sponsors, promoters, investors, commercial lenders, etc.), which might support the financing of geothermal energy projects for electrical power generation and/or direct use applications.

4.3.4 PRG Instruments

As noted above, broadly speaking there will be two types of PRG coverage available, (1) a short-term cover for up-front geological exploration drilling risks, and (2) a medium and long-term cover for operational risks of geothermal wells. For each type of PRG, the guarantee coverage will be defined against the key parameters of the geothermal energy production, such as reservoir temperature and enthalpy, wellhead pressure, wellhead flow rate, geothermal fluid chemistry, etc (see Appendices B, C, and D). In developing the PRG coverage, which is linked with geothermal performance of the guaranteed production and/or injection well, a scoring model needs to be established based on the estimated (i.e., predicted) and actual geothermal data such as wellhead temperature and enthalpy, wellhead flow rate, estimate of permeability, geochemical analyses of geothermal fluid and non-condensable gasses. Such scoring model and framework will be critical for quantifying the guarantee coverage in a transparent manner as well as managing and monitoring the geological risk covered under the PRG windows of the GeoFund. The PRG windows should be designed to cover expected losses between twenty-five percent (25%) and seventy percent (70%).

4.3.5 Operational Risk Guarantee (OPG)

Coverage: OPG should cover up to 70 % of the cost of maintenance and upgrading expenses beyond the original estimate or up to the maximum amount, whichever is lower. The maximum amount of OPG should be $1,000,000 per well.

Tenor: Each OPG will have a tenor of up to five (5) years from the start of operation of the geothermal project.

4.3.6 PRG Application and Underwriting Criteria

While PRG will cover in principle the geological and geology related risk, other technical and commercial aspects including the safeguard issues of the project need to be carefully reviewed. With respect to PRG applications, technical and geological evaluation of the geothermal exploratory, production, and injection wells under PRG coverage will be conducted and presented in the form and substance in accordance with the GeoFund operational guidelines. The technical and geological evaluation will be critical to control the probability of PRG payout and to maximize the financial sustainability of the PRG portfolio in the GeoFund.

4.3.7 Pre-Conditions for OPG Application

Once it has been determined by the UNEP Working Group 3 Technical Committee that the exploration associated with the development of the geothermal power generation project and/or direct use application has been successfully completed, the GeoFund should make a PRG commitment to the operational phase of the geothermal project. The primary long-term geological risks associated with the operational phase of a geothermal project include producing a geothermal reservoir with a lower-than-estimated temperature, higher than estimated mineralization, or difficulty with injection of geothermal fluids back into the subsurface formations. Additionally, in Section 2.3.8, there are risks associated with a number of undesirable geothermal reservoir related effects that may result from geothermal production. It may be possible to make some predictions of their likelihood based on geology and geophysics prior to completion of production and injection well drilling. These production related effects on the geothermal reservoir might include some of the following. Withdrawal of geothermal fluids can lead to subsidence of the surface, even with injection of waste fluids especially in unconsolidated subsurface formations. Similarly, the closer the geothermal reservoir is to the surface and the more compressible the formations, the higher the probability of subsidence. Ingress of cold water may start to quench the geothermal system as it moves inward to replace hot water in response to pressure drawdown in the reservoir. However, the presence of impermeable lake sediments or a silica seal around the geothermal reservoir can prevent the ingress of cold water.

Waste fluids from a geothermal power plant which include hot brine and cooled condensate are normally injected back into the geothermal reservoir for the purpose of providing pressure support and to minimize environmental issues associated with a geothermal project. The injected fluids can return to the production wells via subsurface interconnections such as fault planes and permeable formations. If these returns occur rapidly, the output from the geothermal production wells can be seriously degraded in terms of temperature and enthalpy. The injected fluids may also tend to plug fracture permeability in the reservoir because of the deposition of silica and therefore will cause difficulty with injection of geothermal fluids back into the subsurface formations.

The determination of a sub-optimal operational performance and the triggering of the PRG commitment will be derived from the continuous monitoring and measurements of physical and chemical parameters, including as a minimum the determination of the wellhead temperature, wellhead pressure, wellhead flow rate, and geochemical analysis of the produced geothermal fluids and gasses as a function of time. In other words, these geothermal parameters must be continually monitored and analyzed to document the sub-optimal performance of the geothermal project.

4.3.8 PRG Premium for OPG

PRG premium could be in theory determined by the probability of risk occurrence over the life of PRG facility for EXG and OPG, respectively. However, because of the peculiarity of the geological nature of each geothermal well and the lack of reliable data and technical methodologies, it would be very difficult to assess the probability of risk occurrence with a high degree of confidence level. Conversely, if the probability of risk occurrence is measured with high confidence, a project developer would be willing to proceed with the geothermal project by taking such calculated risk into account in developing financial feasibility, and the need for geological risk mitigation instruments will be diminished.

Given the experimental nature of GeoFund as a development vehicle for geothermal energy projects, PRG premiums will need to be determined with relatively greater emphasis on practical consideration of the PRG instrument's marketability than the theoretical consideration on the financial sustainability of the PRG facility. PRG premiums might be reviewed and adjusted during the implementation period based on the actual occurrence of geological risk events. Underwriting criteria may also need to be adjusted. Further study will be required before determining the final premium structure. As a preliminary figure, PRG premiums will be proposed as follows.

> For OPG: [----] % p.a. on the total amount of OPG payable during the OPG tenor. Premium can be prorated in proportion to the maximum payout amount.

5.0 APPENDICES

5.1 APPENDIX A

Analysis of and Recommendations about the UNEP Report Titled:

Financial Risk Management Instruments for Renewable Energy Projects – Summary Document

APPENDIX A

Analysis of and Recommendations about the UNEP Report Titled:

Financial Risk Management Instruments for Renewable Energy Projects – Summary Document

In the Executive Summary (UNEP, 2004) of the report developed by the United Nations Environment Programme Division of Technology, Industry and Economics ("UNEP"), the participants present an overview of risks specific to the financing of renewable energy projects. Risk management products currently available in the market as well as emerging instruments that could be applied to renewable energy projects are both discussed. New products, such as the GeoFund Partial Risk Guarantee (PRG) windows, based on partnerships between private and public sector risk managers are presented. In fact, throughout this appendix, it is pointed out that the application of risk management instruments to renewable energy projects requires financial innovation and a willingness to test new approaches. In addition, from the Foreward to the report comes the following:

> *"By providing concise technical information to risk management specialists and project developers, this report aims to contribute to a better understanding of risk management options for renewable energy projects. It is our hope that better understanding leads to greater deployment of clean energy technologies that meet development needs."*

The full study on which the Executive Summary is based is available online at the following web site: http://www.uneptie.org/energy/act/fin/index.htm.

In Table 3 (p. 18, UNEP, 2004), the key risks/ barriers associated with the development of geothermal power projects are presented. The key risk issues are listed as follows:

- Drilling expense and associated risk (e.g., blow out)
- Exploration risk (e.g., unexpected temperature and flow rate)
- Critical component failures such as pump breakdown
- Long lead times (e.g., planning permission)

Due to the significant upfront capital outlay for geothermal energy projects and the potentially lengthy period before revenue generation from the sale of electricity, financiers are particularly concerned with any risks and/or expenses that may delay or prevent the ongoing geothermal power generation project from meeting its debt obligations. “Operators Extra Expense” insurance has been adapted from the hydrocarbon industry and is often required by lenders for geothermal projects as the insurance product is designed to protect the policyholder from any extraordinary expenses or risks associated with drilling geothermal exploration wells. The main expenses that trigger the policy include (i.) costs associated with controlling a well or “blow out”, (ii.) costs of redrilling or restoring a well, and (iii.) costs of remedial measures associated with seepage and environmental mitigation.

Although seepage and pollution pose less of a risk during geothermal drilling compared to hydrocarbon drilling, the expenses associated with hiring specialists to control “blow outs”, and the potential casualties is still of major concern to financiers. Insurance cover for standard physical damage and the “Operators Extra Expense” insurance is becoming more widely available and cost-effective. Recently, a public/private initiative has been developed by Rölf & Partner with a private sector insurer for geothermal power projects in Germany (http://www.roedl.com/). The insurance cover provides protection against the flow rate from the geothermal wells not achieving an economically acceptable level.

These technological and operational risks are the principal deterrents to attracting appropriate commercial insurance cover for the development of geothermal power generation projects. The first key risk issue listed in Table 3 (UNEP, 2004) is drilling expense and associated risk (e.g., “blow out”). The risk of a geothermal well “blow out” is basically a non-starter. Over the past forty-five years, at least 1,100 geothermal wells have been drilled in the United States in various geological environments. Of the 1,100 geothermal wells drilled, there have been less than ten (10) “blow outs”; in other words, less than one percent (<1%) of the drilled geothermal wells in the United States has resulted in “blow outs”. In fact, the author can only name five (5) “blow outs” and three (3) of those were casing failures at depths less than 100 meters, all three of which were cured almost immediately with casing patch jobs. The risk associated with the drilling of hydrocarbon wells is much greater; in fact, some hydrocarbon “blow outs” have continued for periods of months and even years before they were controlled. The well drilling service companies specializing in the control of “blow outs” usually take long-neglected vacation time to participate in the control of geothermal wells because there is no risk of fire as with hydrocarbon wells, only the control of hot water.

Drilling expense is definitely a risk issue that must be addressed because of the costs of geothermal wells. Geothermal drilling costs (see Appendix D) vary depending on the geological nature of the reservoirs, the depth of the wells to be drilled, the local regulatory authorities, and the available well drilling service industries involved. Unfortunately, on many occasions, the supervision of the drilling of geothermal wells is essentially the responsibility of drilling superintendents and “tool pushers” that have only been involved with the drilling and completion of hydrocarbon wells. Since the geological environments associated with geothermal resources are typically characterized by high temperatures and somewhat corrosive geothermal fluids, as well as hard and abrasive reservoir formations found in geothermal environments, geothermal drilling is much more difficult and expensive than conventional hydrocarbon drilling. Most hydrocarbon drilling personnel have never been involved with the effects of excess temperatures that are typically associated with the drilling and completion of geothermal wells. Therefore, in the column on Table 3 (UNEP, 2004) labeled “Risk management considerations”, the limited experience of operators and certain aspects of geothermal drilling technology in different locations are definitely aspects that must be addressed in the GeoFund Partial Risk Guarantee (PRG) windows.

The second key risk issue listed in Table 3 is the most important one with respect to the risk management of a geothermal development project, whether for electrical generation and/or a direct use application. The primary reason for the failure of geothermal exploration drilling projects is the fact that the anticipated temperature and/or flow rate is not encountered in the geothermal wells that have been drilled and tested. This is the most important geological risk issue that must be stressed in the development of the mitigation measures associated with the GeoFund PRG windows.

Unfortunately, underwriting processes and mentalities are rigid and significantly inflexible to change and innovation, which is reflected in the tendency of the insurance industry to adapt existing products rather than develop new ones specifically for the renewable energy sector. For example, products that cover the resource supply risk better known as “exploration risk” associated with the drilling of geothermal wells are derived from conventional hydrocarbon exploration insurance. Resource risk is obviously very different for each natural resource technology and the risks for a failed geothermal well are particularly costly. In the “Risk management considerations” column of Table 3, this is definitely recognized as an issue that is characterized by limited resource measurement data. Geothermal wells must be drilled and tested in order to determine the potential of high-temperature geothermal fluids and their possible flow rates for fueling a geothermal electrical power generation project. If the drilling and testing of a geothermal well does not verify the parameters assumed prior to drilling, the failed geothermal production well (i) must be written off, (ii) must have an expensive leg drilled from the original wellbore, or (iii) must be converted into an injection well, and an additional geothermal production well must be drilled to provide the fuel necessary for the completion of the proposed geothermal power project.

The third key risk issue for geothermal power projects listed in Table 3 is presently a non-issue. In the 1980s and 1990s, pump breakdowns were critical component failures because of the fact that many of the pump failures occurred on a monthly, if not a weekly basis. In addition, spare pumps and parts were a problem. However, downhole lineshaft pumps, for example, which were expected to only function for a few months are now documented to survive for time periods of five (5) to seven (7) years before partial failure occurs. Furthermore, the present day replacement of a downhole pump is essentially a matter of hours, rather than days, providing a higher capacity factor for the continued baseload output from a geothermal power plant.

The fourth key risk issue in Table 3, i.e., long lead times (e.g., planning permission) for geothermal energy projects remains a serious problem in many venues. Planning approvals can be difficult, though not impossible. Although renewable power generation projects such as geothermal energy are being highly promoted as clean energy sources and deterrents to greenhouse gas emissions and global warming, the "NIMBY's" (i.e., individuals that constantly practice the principle of "not in my back yard") are still alive and ready to protest almost any proposed power generation project. Direct use geothermal projects are not in the forefront of protests and therefore are usually capable of avoiding the long lead times associated with many geothermal power generation projects. Nevertheless, for example, the Steamboat 2/3 geothermal power project of 40 megawatts located about 15 kilometers south of Reno, Nevada was permitted and placed online in a time period of essentially one year and six months. The permitting and environmental aspects of the project were completed in about seven months. In January of 1991, the first geothermal production well was spudded. By December of 1991, nine production wells and three injections wells plus the necessary pipelines, power facilities, and transmission interconnect were completed and electricity was flowing to the grid. Therefore, timely development of geothermal power generation projects can be accomplished.

The final "Risk management considerations" consist of the following: "Stimulation technology" which is still unproven for geothermal wells but can reduce exploration risk. Stimulation technology attempts to improve natural productivity, or to recover lost productivity, from hydrocarbon as well as geothermal wells through various techniques including chemical and explosive stimulation. Even in the best oil and gas, and geothermal reservoirs, it is commonly found that production wells will not discharge fluid at economic flow rates even though the wellbore itself may appear to be free of problems that would impede flow. Hydraulic fracturing, introduced in 1947, is applied routinely to more than half of all gas wells and a third of the oil wells completed in the United States. More than a million hydraulic fracturing treatments had been performed by the hydrocarbon service industry before the end of the 1990s, adding billions of barrels of hydrocarbon reserves. However, there is still a prominent need to develop technical expertise in areas directly related to geothermal well stimulation technologies.

Standard type well stimulation technologies are expensive, and there has been insufficient geothermal experience to support high-confidence estimates for its effectiveness in increasing geothermal well productivity. In other words, geothermal well stimulation technologies have not been developed to the degree of hydrocarbon well stimulation technologies. In addition, the development of geothermal stimulation technologies is quite costly and requires field-testing; however, geothermal well stimulation technologies must be developed and demonstrated to improve the economic and technical attractiveness of both existing and new geothermal power generation facilities. A key element will be developing an understanding of the fractures that can be activated by different stimulation technologies and how they interact with geothermal reservoirs.

In Table 4 of the UNEP (2004) Executive Summary, an overview of traditional insurance products available for renewable energy projects is presented. The risk transfer products enumerated all have some applicability to the development and operation of geothermal energy projects both for electrical power generation and for direct use applications. However, under the column labeled "Coverage issues/underwriting concerns", the participants in the study have indicated that there is a need for a risk transfer product for explosion and fire concerns associated with geothermal energy projects. This is another risk that is highly improbable because of the physical parameters associated with geothermal energy projects. Essentially all geothermal energy projects are characterized as low pressure and moderate-temperature applications. The typical inlet pressure for a geothermal turbine is equal to or less than ~8 bars and the inlet temperatures are less than ~170°C compared to the inlet pressure for a gas-fired turbine of as much as 35 bars and inlet temperatures of as much as 1,260°C. Furthermore, as indicated before, the probability of "sudden, accidental uncontrolled and continuous flow from the well (i.e., a geothermal well) which can not be controlled" is less than one percent and therefore not a significant risk factor.

Although geothermal projects are characterized by significant upfront capital investment for exploration, well drilling, and the installation of plant and equipment, and often suffer some degree of public protest, once the geothermal projects are placed in commercial operation the fuel source is secure for the tens of years of expected lifetime for the projects. Further, since the fuel source is associated in close proximity with the power plant, the developer has no concern about the worldwide fluctuations in the price of oil and natural gas. Transportation costs are eliminated and the environmental and social aspects of geothermal projects are defined and reasonably mitigated. Generally speaking, the risks specifically associated with drilling geothermal wells are not well understood and financiers and insurers are more concerned with the application of petroleum drilling industry expertise in the extremely different geothermal environment.

Reference:

UNEP, 2004, Financial Risk Management Instruments for Renewable Energy Projects – Summary Document, 47pp.

5.2 APPENDIX B

Geological Risk Analysis and Methodology for GeoFund Partial Risk Guarantee (PRG) Windows for Geothermal Electric Power Projects

APPENDIX B

Geological Risk Analysis and Methodology for GeoFund Partial Risk Guarantee (PRG) Windows for Geothermal Electric Power Projects

Introduction

The initiation of the World Bank-GEF Geothermal Energy Development Fund (GeoFund) for the Europe and Central Asia (ECA) region, in particular, its Partial Risk Guarantee (PRG) windows, is primarily designed to encourage entities in the ECA region to explore for and drill geothermal exploration wells to develop geothermal resources for electrical generation and/or direct use applications. The PRG windows are intended to partially insure geothermal energy project promoters/investors against the short-term, up-front geological risk of exploration, and/or the long-term geological risk of developing a geothermal reservoir with lower-than-estimated temperature, higher than estimated mineralization, or difficulty with injection of geothermal fluids back into the subsurface. For officially launching the GeoFund program, a scoring model for the geological risk scenarios must be adopted to implement the PRG windows. The primary objectives of the present appendix are to define the underlying methodology and framework for such a scoring model for geothermal power generation projects.

Geothermal reservoirs of steam and/or hot water, which are encountered at a few hundred meters down to several kilometers beneath the surface of the Earth, can be used to produce electricity as well as provide heat directly for multiple applications. For either the generation of electricity and/or direct utilization of geothermal energy, the geothermal fluid is brought to the surface through wells and a mechanical system–piping, separators, heat exchangers, and controls–delivers the fluid and/or heat for its intended use. The depth and cost of the production wells (see Appendix D) are important parameters to be considered in evaluating the geological risk of a geothermal project. After capturing the useful energy content of the geothermal fluid from the production well, a disposal system then either injects the cooled fluid underground or disposes of it on the surface if the geothermal fluid is essentially benign. The depth and cost of geothermal injection wells are similarly important parameters to be considered in developing a scoring model for the GeoFund PRG windows. The scoring model for the PRG windows, and the attendant geological risk insurance scheme, is primarily involved with the drilling of the geothermal wells that are necessary for the delivery of the fluids to the surface applications.

The fundamental parameters associated with the definition of a successful geothermal exploratory well are reservoir temperature, reservoir permeability, wellhead pressure, wellhead flow rate and geothermal fluid chemistry, in addition to the depth and cost of the wells. However, the most important parameters in the definition of a successful geothermal well for electrical generation and/or direct use applications are the measured wellhead temperature and measured wellhead flow rate. The relative permeability in the geothermal reservoir is a primary determinant on the magnitude of the wellhead flow rate for any geothermal well, but if the permeability is not great enough, the wellhead flow rate will be insufficient for the desired application. Similarly, for a pumped geothermal well, the reservoir permeability, or "productivity index (PI) / injectivity index (II)", will limit the flow rate from the well since pumps are limited in the amount of pressure increment that they can impart to the flow stream with the available motor power. In other words, if the productivity / injectivity index of the geothermal well is too small, this will limit the flow rate obtainable from the well. The fluid chemistry is also a major determinant in the useful application of the geothermal fluid produced from any geothermal well.

Methodology and Framework for Scoring Models of PRG Windows

The definition of a successful geothermal well for electrical power generation is highly dependent on the wellhead temperature of the geothermal fluids. With a wellhead temperature in excess of 190°C, the geothermal well can be expected to provide fuel for a flash steam power plant although there are additional considerations which will be described below. Similarly, a geothermal well with a wellhead temperature between 90°C and 190°C may be a successful fuel source for a binary geothermal power plant using isopentane, isobutane, or an ammonia-water mixture as the working fluid; however, there are additional considerations presented below.

There are different temperature ranges suitable for various direct use applications, which are described in the Lindal diagram. Typically, the agricultural and aquacultural uses require the lowest temperatures, with values from 25°C to 90°C. The amounts and types of chemical constituents, such as arsenic, and dissolved gases, such as boron, are a major problem with plants and animals; therefore, heat exchangers are often necessary. Space heating requires temperatures in the range of 50°C to 100°C, with 40°C useful in some marginal cases. However, geothermal, or ground-source, heat pumps extend the space conditioning temperature range down to 4°C. Refrigeration and industrial processing normally require temperatures over 100°C.

In order to define the underlying methodology and framework for a scoring model to implement the Partial Risk Guarantee (PRG) windows, the electrical application of geothermal energy will be considered first. The definition of the risk coverage consists of two end members, i.e., success and failure. The failure of a geothermal drilling project will result in the lack of adequate temperature, permeability, and/or flow rate from a geothermal well that has been drilled and tested. Therefore, the geothermal energy project promoters/investors that has drilled and tested the geothermal exploration well will have decided to properly plug and abandon the well. If this is the case, the GeoFund may then provide up to a maximum 100% return of the capital cost associated with the drilling and testing of the geothermal well under the PRG windows.

The other end of the spectrum consists of a successful geothermal well. The definition of a successful geothermal well for electrical power production must be presented in some considerable detail because of the interaction of several variables including the depth and costs of wells as well as the power conversion technology selected. However, the most sensible way to define “success” is in terms of how much electricity the geothermal well could generate. If a successful geothermal well is defined as one that will produce 3 megawatts (MW) or more of electrical power, then for a single-flash condensing steam type power plant, the input to the turbine-generator will be approximately 30 tonnes per hour of 5-bar separated steam. Therefore, for the successful generation of 3 MW, the total wellhead flow–water plus steam–would be a significant amount more than the 30 tonnes per hour from a liquid-dominated reservoir and would primarily depend on the reservoir temperature approximately as presented in the table below:

Reservoir Temperature (°C)	Minimum Total Wellhead Flow Rate (tonnes/hour)
340	60
320	77
300	90
280	106
260	128
240	159
220	208
200	299
180	515

Since the wellhead flow is two-phase for these reservoir temperatures, the wellhead pressure dictates the wellhead temperature, e.g., for a wellhead pressure of 5 bars, the saturation temperature will be approximately 152°C, so long as there is not a significant amount of dissolved salts or noncondensible gas in the flow stream. The considerable increase in the minimum total wellhead flow rate, is the primary reason that for geothermal reservoirs below 200°C or so, the preferred conversion technology is binary technology even though there is the necessity of using a downhole pump in the geothermal wells.

For the generation of electricity from a binary geothermal power plant with downhole pumps, there are two principal issues. The downhole pump will bring the geothermal fluid to the wellhead in a pressurized (all-liquid) condition at a wellhead temperature approximating the reservoir temperature. This means that for 3 MW of gross electricity generation per geothermal well, the wellhead flow rate needed would depend on reservoir temperature essentially as presented in the following table:

Reservoir Temperature (°C)	Downhole Pump Flow Rate (tonnes/hour)
220	115
200	140
180	180
160	270
140	480

Most downhole pumps appear to be designed for maximum flow rates around 400 tonnes per hour, which is the main reason that geothermal reservoirs with temperatures below about 150°C or so are not consistently used for electrical power generation.

The other issue with pumped/binary electrical generation systems is the reservoir permeability, or "productivity index" for the well. The productivity index for a well is defined as follows:

$$PI = M / (P_{sp} - P_{fp}),$$

where M is the mass discharge rate, P_{sp} is the stable (static) feedzone pressure as estimated from shut-in temperature, water level, and pressure data, and P_{fp} denotes the measured flowing feedzone pressure in the discharging well. Downhole pumps are limited in the amount of pressure increment that they can impart to the flow stream by the available motor power. If the productivity index of the geothermal well is too small, this will limit the flow rate below the amount required for 3 MW. To keep the parasitic loads (i.e., the electricity required to power the downhole pump) down to ten percent (10%) or less of the generating capacity of the geothermal well (i.e., 300 kW or less) and to generate enough pressure to maintain all-liquid wellhead conditions, the minimum productivity index required will be approximately as presented in the table below:

Reservoir Temperature (°C)	Minimum Productivity Index (tonnes/hour per bar)
220	3
200	4
180	6
160	13
140	44

Since the minimum productivity index is quite large for reservoir temperatures below about 150°C or so, these type reservoirs are not consistently used for electrical power generation.

A final consideration in defining a successful geothermal well for electrical power generation is the fact that the amount of electricity that can be generated from the output of a particular geothermal well depends considerably on what kind of power plant that is designed and constructed. The initial set of electrical power outputs presented above was for a conventional single-flash condensing steam plant. It is possible to generate a bit more electrical power out, particularly for low temperature geothermal resources, by switching to a hybrid-type power plant. In this case, the separated water is not just injected back into the ground, but is first passed through a small "binary-type plant" to generate more electricity before going back downhole. The geothermal well in this case is still presumably self-discharging, so no downhole pump is involved. However, the hybrid-type power plant costs more to design, construct, and maintain.

Reservoir Temperature (°C)	Minimum Total Wellhead Flow Rate (tonnes/hour)		
	Backpressure Flash Steam Power Plant	Single-Flash Condensing Steam Power Plant	Hybrid Steam Power Plant
340	126	60	55
320	162	77	68
300	189	90	77
280	223	106	88
260	269	128	101
240	334	159	117
220	437	208	139
200	628	299	171
180	1082	515	219

Going the other direction, it is possible to use a simple backpressure flash power plant, which is the least expensive to build by a large factor. However, there are environmental benefits that must be considered in utilizing a backpressure plant. A backpressure will need about 60 tons per hour to 65 tons per hour of five-bar steam to generate 3 MW, compared to about 30 tons per hour of steam for the single-flash condensing plant. The minimum total (water + steam) wellhead flow requirements to obtain 3 MW from a geothermal well using these three types of power plants are approximately as presented in the table below:

Another frequently used geothermal power plant is a dual-flash condensing steam plant. Usually, the performance of a dual-flash condensing steam plant will be roughly comparable to that of the hybrid steam power plant. Of course, the “success threshold” (i.e., 3 MW per geothermal well) should probably depend upon the cost to design, construct and maintain the power plant that will be using the fuel. The “success threshold” will also depend on the anticipated depth and cost of the geothermal wells. It will be important to do an economic analysis in which the drilling costs are balanced against plant capital and O&M costs. However, the economic analysis will be highly dependent on the price being paid for the electricity generated using geothermal energy.

It is possible to scale the flow rate figures up and down in proportion to the power output. For example, if the “success threshold” is raised from 3 MW per well to say 5 MW per well, it is only necessary to multiply all the ton/hour figures in the tables by (5/3) = 1.6.

With the completion of a successful exploratory geothermal well, the ECA entity (i.e., the geothermal energy project promoters/investors) should be capable of producing electricity from the geothermal reservoir, which has been identified and delineated. Therefore, the GeoFund subsidy that has been extended to the ECA entity should be repaid with an interest component from the eventual sale of electricity.

Unfortunately, between these two end members (i.e., success and failure), its quite difficult to define an overall guarantee coverage, i.e., what percentage ratio of the guarantee should be covered by the GeoFund PRG windows, e.g., 25% or 70% of the total cost of the exploratory geothermal well.

5.3 APPENDIX C

Geological Risk Analysis and Methodology for GeoFund Partial Risk Guarantee (PRG) Windows for Geothermal Direct Use Projects

APPENDIX C

Geological Risk Analysis and Methodology for GeoFund Partial Risk Guarantee (PRG) Windows for Geothermal Direct Use Projects

There are different temperature ranges suitable for various direct use applications, which are described in the Lindal diagram (Figure 1). Typically, the agricultural and aquacultural uses require the lowest temperatures, with values from 25°C to 90°C. The amounts and types of chemical constituents, such as arsenic, and dissolved gases, such as boron, are a major problem with plants and animals; therefore, heat exchangers are often necessary. Space heating requires temperatures in the range of 50°C to 100°C, with 40°C useful in some marginal cases. However, geothermal, or ground-source, heat pumps extend the space conditioning temperature range down to 4°C. Refrigeration and industrial processing normally require temperatures over 100°C.

For direct utilization of geothermal energy, the geothermal fluid is brought to the surface through wells and a mechanical system–piping, heat exchangers, and controls–delivers heat for its intended use. The depth and cost of these geothermal wells are important parameters to be considered in evaluating the geological risk of a geothermal project. After capturing the useful energy content of the geothermal fluid, a disposal system then either injects the cooled fluid underground or disposes of it on the surface if the geothermal fluid is essentially benign. Again, the depth and cost of geothermal injection wells are similarly important parameters to be considered in developing a scoring model for the GeoFund PRG windows.

The fundamental parameters associated with the definition of a successful geothermal exploratory well are reservoir temperature, reservoir permeability, wellhead pressure, wellhead flow rate and geothermal fluid chemistry as well as depth and cost. However, the most important parameters in the definition of a successful geothermal well for direct use applications are the measured wellhead temperature and measured wellhead flow rate. The relative permeability in the geothermal reservoir is a primary determinant on the magnitude of the wellhead flow rate for any geothermal well, but if the temperature and permeability of the geothermal resource are not great enough, the wellhead temperature and flow rate will be insufficient for the desired direct use application.

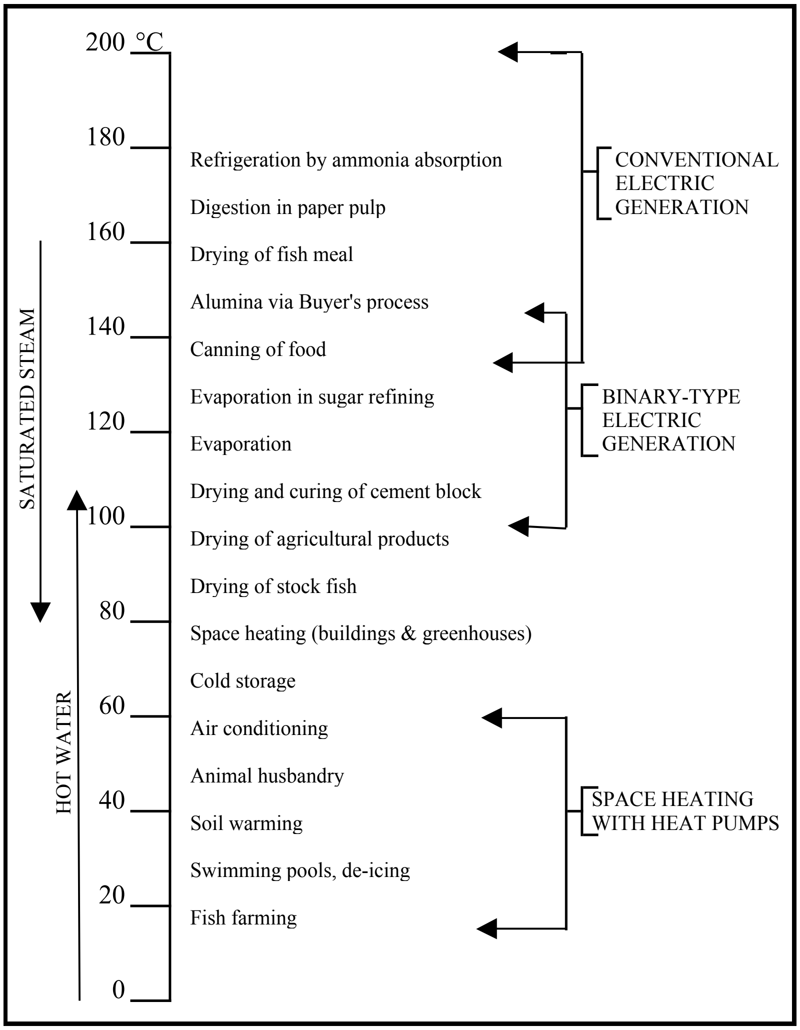


Figure 1. Lindal Diagram (adapted from Gudmundsson, et al.,1985)

The successful designation of a geothermal well and design of mechanical systems involving heat transfer, specifically for direct use geothermal systems, is heavily dependent on temperature of the geothermal fluid. Temperature is used to cause heat to flow from point A to point B. Heat normally flows from a high temperature to a low temperature. In other words, some temperature difference, or ∂T (delta T) must exist to cause the heat to flow from one place to another. With a greater temperature difference, the heat flow is greater. The temperature difference is particularly important since it frequently governs feasibility, equipment selection and flow requirements for the direct use geothermal system.

In direct use geothermal systems, the goal is to cause heat to flow out of the geothermal well and into a process, e.g., aquaculture, greenhouses, buildings, industrial processes, etc. To accomplish this heat transfer, it is often necessary for the heat to flow out of the geothermal fluid through equipment, i.e., heat exchangers of various types, which constitute a thermal resistance to the heat flow. To overcome this thermal resistance, a temperature difference or ∂T must be allowed for at each point where heat is transferred. Understanding the magnitude of the temperature differences required is key to the evaluation of an individual application and the determination of a successful geothermal well.

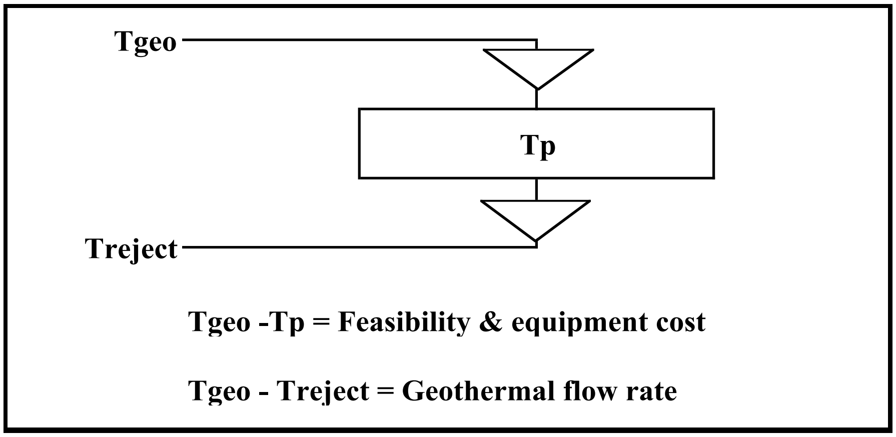
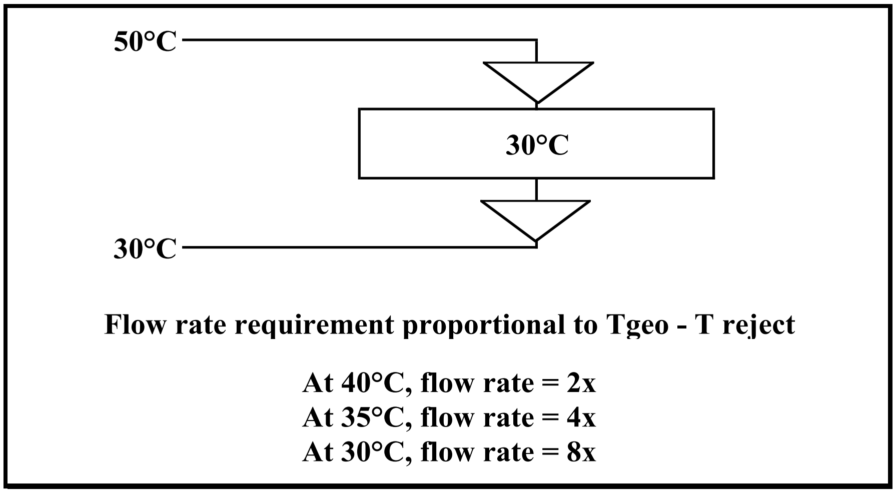


Figure 2. Fundamental Direct Use Temperature Differences

Two primary temperature differences govern direct use project feasibility, flow requirements and design of the direct use equipment. These elements are illustrated in a simplified way in Figure 2 (Rafferty, 2004). The first is the difference between the geothermal fluid temperature entering the system (i.e., Tgeo) and the process temperature (i.e., Tp). This temperature difference determines whether or not the direct use application will be feasible and the geothermal well will be declared a successful one.

For a direct use geothermal project, the temperature of the geothermal fluid (Tgeo) entering the system must be above the temperature of the process (Tp) in order to transfer heat out of the geothermal fluid and into the process (i.e., aquaculture pond, building, greenhouse, etc.). Furthermore, Tgeo must be sufficiently above the process temperature to allow the system to be constructed with reasonably sized heat transfer equipment. The greater the temperature difference, ∂T, between the geothermal resource and the process, the lower the cost of the heat exchange equipment. The key question is how much greater than the process temperature does the geothermal fluid need to be for a given application to be economical.



Flow rate requirement proportional to Tgeo - T reject

At 40°C, flow rate = 2x
At 35°C, flow rate = 4x
At 30°C, flow rate = 8x

Figure 3. Direct Pool/Aquaculture Pond Heating

The second temperature difference is the one between the geothermal fluid entering the system and leaving the system (Treject in Figure 2). This determines the wellhead flow rate necessary to meet the heat input requirement of the application. The greater the temperature differences between the entering and exiting temperatures, the lower the flow rate required. Obviously, the geothermal fluid temperature is fixed based on the reservoir temperature. The process temperature, Tp, plays a significant role since the exiting temperature, Treject, cannot be lower than the process temperature to which heat is being provided. In addition, the specifics of the direct use application and the heat transfer equipment associated with it also influence the temperature required. There are two broad groups of direct use applications with similar characteristics in terms of heat transfer, i.e., aquaculture and pools, greenhouses and building space heating.

Aquaculture pond heating, as illustrated in Figure 3 (Rafferty, 2004) is among the simplest geothermal direct use applications. It is often accomplished by allowing the available geothermal fluid to flow into the pond to provide the necessary heat input. In the example of

Figure 3, geothermal fluid is available at a temperature of 50°C and the pond is maintained at a temperature of 30°C. If the geothermal fluid is added directly to the pond, then the exit temperature is the same as the pond temperature or 30°C. It is useful to examine what would happen to the geothermal flow requirement if a lower temperature resource were available. If only 40°C geothermal fluid was available, the flow rate would need to be twice the flow rate with a 50°C geothermal fluid. If only 30°C geothermal fluid were available, the flow rate would need to be eight times the flow rate with a 50°C geothermal fluid. Obviously, as the available geothermal fluid temperature decreases, the flow rate requirement to heat the pond rises very rapidly. For applications of this type, reasonable geothermal fluid flow rates generally require the heat source water be delivered to the pond, or pool, at a temperature of a least 10°C above the desired pond temperature (Rafferty, 2004).

In many pool and aquaculture applications, the geothermal fluid cannot be used directly for heating purposes. In these situations, it is necessary to place a heat exchanger between the pool water and the geothermal fluid to accomplish the necessary heat transfer. It remains necessary to adhere to the previous rule of thumb of delivering the heating fluid to the pool at a temperature of at least 10°C above the pool temperature. Since the heat must first pass through a heat exchanger, an additional ∂T is required to accommodate this heat transfer. It remains necessary to adhere to the previous rule of thumb of delivering the heating water to the pool at a temperature of at least 10°C above the pool temperature. Another effective rule of thumb is that the geothermal water on the "hot" side of the heat exchanger must be at least 5°C above the temperature of the water being heated on the "cold" side, i.e., the pool side, of the heat exchanger. Thus, for this example, the geothermal fluid would need to be at least 45°C on the hot side of the heat exchanger. The water to be heated is returned from the pool at a temperature of 30°C. The geothermal fluid exiting the heat exchanger must be at least 35°C to meet the heat exchanger ∂T requirement.

If geothermal fluid was available above 45°C, the additional temperature would allow reduced geothermal flow rate and reduced heat exchanger size. Maintaining the exiting geothermal fluid temperature fixed at higher available geothermal fluid temperatures would minimize flow rate requirements. Thus, raising the geothermal exiting temperature would minimize heat exchanger cost.

Heating of greenhouses and buildings often involves the transfer of heat to the air in the structure using some type of water-to-air heat exchanger. Assume a home is to be heated and the air maintained at 22°C. To accomplish the heating of the home, it is necessary to deliver the heated air to the enclosed space at a temperature of at least 15°C above the space temperature. This would result in a supply air temperature of at least 37°C. There are two reasons for the 15°C ∂t between the supply air and the enclosed space. The first is to limit the required quantity of air circulated to meet the eating requirements to reasonable levels. The closer the supply air temperature is to the enclosed air space temperature, the greater the air flow required to meet the heating needs. At less than the 15°C difference, fan and duct sizes become large and fan power consumption can be excessive. The second issue is occupant comfort. At supply air temperatures below about 35°C, the temperature of the air approaches human skin temperature. This can result in a "drafty" sensation for occupants, even if the desired air temperature is maintained.

Furthermore, the second issue is that the temperature of the geothermal fluid delivered to the air heating device, usually referred to as a coil, must be at least 10°C above the temperature of the desired supply air. This requirement is a result of the desire to limit the size of the coil. Although it is possible to design a coil capable of operating at less than the 10°C ∂T, its cost and resistance to air flow are such that this is not normally practical. The 10°C ∂T rule of thumb also applies to the return side of the air heating coil. If the air returning from the home to be heated is 22°C, then the geothermal fluid exiting the coil can be no less than 10°C above the return air temperature. Thus, to maintain the home at 22°C, a geothermal resource temperature of 50°C would be required. This example assumes that the chemical characteristics of the geothermal fluid are suitable to use directly in the coil. Often, this is not the case, since coils normally have tubes constructed of copper and geothermal fluids often contain hydrogen sulphide, a chemical that attacks copper.

In cases where the geothermal fluid must be isolated from the heating system equipment, a plate heat exchanger is normally placed between the geothermal fluid circuit and the "fresh" water circuit to protect the heating equipment. The difference in this case is that with the isolation heat exchanger in place, an additional temperature difference is needed to accommodate the heat transfer through the heat exchanger. Just as in the case of the heat exchanger described for the aquaculture/pool application the ∂T required for this heat exchanger a about 5°C. The geothermal resource fluid now required to meet the needs of the geothermal direct use system would be 5°C higher or 55°C.

These rules of thumb are exactly that. It is possible in all cases to bend the rules and design direct use systems and equipment for geothermal fluid temperatures closer than the guidelines provided. The values provided are intended for initial evaluation of direct use geothermal applications and for determining whether the geothermal well that was drilled to provide the geothermal fluids is a successful well.

References

Gudmundsson, J.S., D.H. Freeston, and P.J. Lienau, 1985, The Lindal Diagram, ***Geothermal Resources Council Transaction***, vol. 9, no. 1, p. 15-19.

Rafferty, K., 2004, Direct-Use Temperature Requirements: A Few Rules of Thumb, ***Geo-Heat Center Bulletin***, Oregon Institute of Technology, June 2004, p. 1-3.

5.4 APPENDIX D

Geothermal Power Projects—Technical and Financial Data

APPENDIX D

Geothermal Power Projects—
Technical and Financial Data

Introduction

The initiation of the World Bank-GEF Geothermal Energy Development Fund (GeoFund) for the Europe and Central Asia (ECA) region, in particular, its Partial Risk Guarantee (PRG) facility, is primarily designed to encourage entities in the ECA region to explore for and drill geothermal exploration wells to develop geothermal resources for electrical generation and/or direct use applications. The PRG windows are intended to partially insure geothermal energy project promoters/investors against the short-term, up-front geological risk of exploration, and/or the long-term geological risk of developing a geothermal reservoir with lower-than-estimated temperature, higher than estimated mineralization, or difficulty with injection of geothermal fluids back into the subsurface. For officially launching the GeoFund program, a scoring model for the geological risk scenarios must be adopted to implement the PRG windows. The primary objectives of the present appendix are to provide some technical and financial data that are necessary to define the underlying methodology and framework for such a scoring model.

Geothermal reservoirs of steam and/or hot water, which are encountered at a few hundred meters down to several kilometers beneath the surface of the Earth, can be used to produce electricity as well as provide heat directly for multiple medium- to low-temperature applications. For either the generation of electricity and/or direct utilization of geothermal energy, the geothermal fluid is brought to the surface through wells and a mechanical system–piping, separators, heat exchangers, and controls–delivers the fluid and/or heat for its intended use. The depth and cost of production wells are important parameters to be considered in evaluating the geological risk of a geothermal project. After capturing the useful energy content of the geothermal fluid, a disposal system then either injects the cooled fluid underground or disposes of it on the surface if the geothermal fluid is essentially benign. Again, the depth and cost of geothermal injection wells are similarly important parameters to be considered in developing a scoring model for the GeoFund PRG windows.

The scoring model for the PRG windows, and the attendant geological risk insurance scheme, is primarily involved with the drilling of the geothermal wells that are necessary for the delivery of the fluids to the surface applications and the disposal of the spent geothermal fluids.

The fundamental parameters associated with the definition of a successful geothermal exploratory well are reservoir temperature, reservoir permeability, wellhead pressure, wellhead flow rate and geothermal fluid chemistry, in addition to the depth and cost of the wells. However, the most important parameters in the definition of a successful geothermal well for electrical generation and/or direct use applications are the measured wellhead temperature and measured wellhead flow rate. The relative permeability in the geothermal reservoir is a primary determinant on the magnitude of the wellhead flow rate for any geothermal well, but if the permeability is not great enough, the wellhead flow rate will be insufficient for the desired application. Similarly, for a pumped geothermal well, the reservoir permeability, or "productivity index (PI) / injectivity index (II)", will limit the flow rate from the well since pumps are limited in the amount of pressure increment that they can impart to the flow stream with the available motor power. In other words, if the productivity / injectivity index of the geothermal well is too small, this will limit the flow rate obtainable from the well. The fluid chemistry is also a major determinant in the useful application of the geothermal fluid produced from any geothermal well.

As noted above, the definition of a successful geothermal well for electrical power generation is highly dependent on the wellhead temperature of the geothermal fluids. With a wellhead temperature in excess of 190°C, the geothermal well can be expected to provide fuel for a flash steam power plant although there are additional considerations. Similarly, a geothermal well with a wellhead temperature between 90°C and 190°C may be a successful fuel source for a binary geothermal power plant using isopentane, isobutane, or an ammonia-water mixture as the working fluid.

There are different temperature ranges suitable for various direct use applications, which are described in the Lindal diagram (see Figure 1 of Appendix C). Typically, the agricultural and aquacultural uses require the lowest temperatures, with values from 25°C to 90°C. The amounts and types of chemical constituents, such as arsenic, and dissolved gases, such as boron, are a major problem with plants and animals; therefore, heat exchangers are often necessary. Space heating requires temperatures in the range of 50°C to 100°C, with 40°C useful in some marginal cases. However, geothermal, or ground-source, heat pumps extend the space conditioning temperature range down to 4°C. Refrigeration and industrial processing normally require temperatures over 100°C.

In order to define the underlying methodology and framework for a scoring model to implement the Partial Risk Guarantee (PRG) windows, the application of geothermal energy must be considered first. The definition of the risk coverage consists of two end members, i.e., success and failure. The failure of a geothermal drilling project will result in the lack of adequate temperature, permeability, and/or flow rate from a geothermal well that has been drilled and tested. Therefore, the geothermal energy project promoters/investors that has drilled and tested the geothermal exploration well will have decided to properly plug and abandon the well. If this is the case, the GeoFund may then provide up to a maximum 100% return of the capital cost associated with the drilling and testing of the geothermal well under the PRG windows.

The other end of the spectrum consists of a successful geothermal well. The definition of a successful geothermal well for electrical power production or a direct use application must be presented in some considerable detail because of the interaction of several variables including the depth, cost, as well as the power conversion technology selected. However, the most sensible way to define “success” is in terms of the quantity and quality of geothermal fluid the well can produce.

In order to determine the relative success of a geothermal well and to provide a framework for a scoring model to implement the GeoFund PRG windows, it is important to consider some of the technical and financial parameters associated with the historical and projected drilling of geothermal wells and the relative costs associated with the development and completion of operating and projected geothermal power projects. In the following tables, technical and financial parameters are presented for two operating geothermal power projects in the western United States, (i.e., the 55 MW Dixie Valley Geothermal Power Project in north-central Nevada and the 57 MW East Mesa Geothermal Power Project in the Imperial Valley of southern California). Additionally, the projected technical and financial parameters for a small-scale (i.e., ~3.5 MW) geothermal power project to be developed in southeastern Hungary, which is an ECA country and therefore eligible for the GeoFund PRG windows, are presented.

Dixie Valley Geothermal Power Project

The Dixie Valley Geothermal Power Project (Dixie Valley) is located about 200 km east and north of Reno and about 120 km east and north of the city of Fallon in Churchill County, Nevada. The power plant consists of a Fuji dual flow turbine-generator. The power generation plant is water-cooled and utilizes a liquid-dominated geothermal fuel source. The electrical power project of 60.5 megawatts (MW), with a net salable output of approximately 55 MW, began operation in July 1988. In order to deliver the electricity generated at Dixie Valley, the developer had to construct a 354-kilometer, 230-kV, transmission line at a cost of approximately $35 million to interconnect to the grid of the purchasing utility, Southern California Edison.

Dixie Valley is the largest non-volcanic geothermal system in the Basin and Range Province. The Dixie Valley geothermal reservoir lies within a basin bounding set of faults produced as a consequence of Cenozoic extension throughout the northern Basin and Range Province of the western United States. The extensional processes are directly responsible for both the permeable fault zones and the high heat flow necessary for the circulation of thermal waters. Most wells produce from a zone of fractured Jurassic-age rock located above the trace of the main fault. These Jurassic rocks have undergone a long and complicated structural history that includes both Mesozoic compressional and Cenozoic extensional events.

The geothermal production and injection wells range in depth from 2,500 m to 3,500 m in the Dixie Valley geothermal field. The eight (8) production wells have an average flow rate of about 295 tonnes per hour and were drilled and completed at an average cost of about $3.5

million. The average temperature of the geothermal fluid provided to the turbine-generator is 241°C. The ten (10) injection wells have an average cost of about \$3.0 million. The drilling costs as a percentage of the capital costs of the project minus the transmission line cost are equal to 42.96%. The drilling costs as a percentage of the total capital costs of the power project are equal to 34.12%. Additional technical and financial data for the Dixie Valley Geothermal Project are presented in a table below.

East Mesa Geothermal Power Project

The East Mesa Geothermal Power Project (East Mesa) is located in the Imperial Valley of southern California about 100 km east of San Diego, California. The geothermal project consists of four binary power plants ranging from 6.5 MW to 24 MW, consisting of a 73.2 MW power plant complex, with a net salable output of 57 MW. The generating complex is comprised of sixty-eight (68) ORMAT® Energy Converter (OEC) units arranged in three cascading levels which were synchronized to the grid in December 1986. The power generation complex is water-cooled and utilizes a liquid-dominated geothermal fuel source. The geothermal electricity is wheeled over the Imperial Irrigation District transmission grid for delivery and sale to the transmission grid of Southern California Edison.

The hydrothermal activity in the Imperial Valley is associated with crustal extension and magmatism from a buried spreading center related to the East Pacific Rise. The extensional processes and magmatism are directly responsible for both the permeable fault zones and the high heat flow necessary for the circulation of thermal waters. The East Mesa geothermal reservoir is a moderate-temperature (i.e., 157°C to 177°C) reservoir producing from Tertiary sandstones and siltstones, which are underlain by Late Cretaceous granitic basement rocks. The sandstones are hydrothermally altered by interaction with the circulating geothermal fluids.

The geothermal production and injection wells range in depth from 1,800 m to 2,500 m in the East Mesa geothermal field. The twenty-nine (29) production wells have an average pumped flow rate of approximately 295 tonnes per hour and were drilled and completed at an average cost of approximately \$1.5 million. The average temperature of the geothermal fluid provided to the heat exchangers is 150°C. The six (6) injection wells have an average cost of about $1.0 million. The drilling costs as a percentage of the total capital costs of the power projects are equal to 24.81%. Additional technical and financial data for the East Mesa Geothermal Project are presented in a table below.

Proposed Hungarian Geothermal Power Project

MOL Hungarian Oil and Gas Company ("MOL") is a leading integrated oil and gas group in Central and Eastern Europe which recently requested a grant from the United States Trade and Development Agency to provide technical assistance to assess the feasibility of economically developing medium enthalpy geothermal power plants (i.e., geothermal fluids in the temperature range of 140°C to 180°C) using existing shutin, non-productive, hydrocarbon wells. MOL has suggested that geothermal production and injection wells can be constructed from these non-productive hydrocarbon wells. From shutin hydrocarbon wells, well drilling and cost information, as well as potential reservoir data, are available in addition to information from flow test operations, including temperatures, pressures, and flow rates. Therefore, MOL is eligible for consideration under the GeoFund PRG program.

Hungary is well known as a country of favorable conditions in terms of geothermal resources since most measured geothermal gradients are higher than the worldwide average. According to the results of numerous published geothermal assessments, Hungary has the largest underground thermal water reserves and geothermal energy potential of low and medium enthalpy in Europe. Measured geothermal resource temperatures in Hungary range from 10°C to 254°C. In addition, at least six regions of Hungary have shutin hydrocarbon wells which have temperatures in the range of 140°C to 160°C and flow rates of approximately 250 tonnes/hr to 650 tonnes/hr, which is equivalent to a range of 1.6 MW to 7.2 MW per well.

The Pannonian Basin is encircled by the Carpathian Mountains and the crust of the earth beneath the basin is relatively thin (i.e., ~25 km) due to sub-crustal erosion. The thinned crust sank isostatically. Tertiary sediments primarily fill the basin that was thus formed. Pannonian sediments are multilayered, composed primarily of sandy, shaly, and silty formations. Although the Lower Pannonian sediments are mostly impermeable, the Upper Pannonian and

Quaternary formations contain numerous porous, permeable sand and sandstone beds. At greater depths in the Pannonian Basin, carbonate rocks of Triassic age having a secondary porosity represent another type of geothermal reservoirs. These can be fractured and/or karstified rock masses with continuous recharge and important convective fluid motions. About twenty percent (20%) of the Hungarian geothermal wells produce from the deep karstic aquifer contained in the carbonate formations.

The total estimated cost presented by MOL personnel for the Pilot Project in Hungary is USD $16 million and the output from the doublet would be between 2 MW and 5 MW (see Appendix E). It is assumed that the average net salable output of the project will be ~3.5 MW based on the data presented that the re-completion of a typical hydrocarbon might be capable of fueling a power module of 1.6 MW to 7.2 MW. Since the well drilling phase of the Hungarian Pilot Project consists of a doublet fueled by the re-completion of at least two shutin hydrocarbon wells versus the drilling and completion of two new geothermal wells, the cost of the drilling phase of the geothermal power project is only about 34% of the total capital costs. However, if the drilling phase had consisted of the drilling of two new geothermal wells, the drilling phase in the table below would have been approximately USD $9.5 million. Thus, the drilling phase of the project would have been about 45% of the total capital costs since the power plant and transmission line costs would have remained the same. Additional technical and financial data for the Hungarian Geothermal Project are presented in a table below.

Dixie Valley Geothermal Power Project, Nevada, USA

Geothermal Power Facility Consists of a Single-Unit, Double-Flash Plant

Geothermal Power Facility Output in megawatts (MW) =	55
Online Availability Factor of Geothermal Power Facility =	99%
Transmission Line (230-kV) to Interconnect to Grid in km =	354
Cost of Transmission Line =	$35,000,000
Number of Production Wells =	8
Average Flow Rate per Production Well in tons/hour	295
Number of Injection Wells =	10
Average Minimum Depth of Wells in meters =	2,500
Average Maximum Depth of Wells in meters =	3,500
Average Cost of Production Wells =	$3,500,000
Average Cost of Injection Wells =	$3,000,000
Average Temperature (°C) Input to Turbine Generator Unit =	241
Operation and Maintenance Costs for Plant and Field in cents/kWh =	1.22
Electricity Sales Price in cents/kWh =	7.37
Wells: 8 production @ $3.5 M each & 10 injection @ $3.0 M each =	$58,000,000
Capital Costs of the Project minus Transmission Line Cost =	$135,000,000
Drilling Costs as Percentage of Capital Cost of Project =	42.96%
Capital Costs of Project Minus Transmission Line Cost per kW =	$2,455
Total Capital Costs of the Geothermal Power Project =	$170,000,000
Drilling Costs as Percentage of Total Capital Cost of Project =	34.12%
Total Capital Costs of the Geothermal Power Project per kW =	$3,091

East Mesa Geothermal Power Project, California, USA

Geothermal Power Facility Consists of Four Separate Binary Plant of 6.5 to 24 megawatts.

Geothermal Power Facility Output in megawatts (MW) = 57

Online Availability Factor of Geothermal Power Facility = 99%

Transmission Line (230-kV) to Interconnect to Grid in km = Not Available

Cost of Transmission Line = Not Available

Number of Pumped Production Wells = 29

Average Flow Rate per Pumped Production Well in tons/hour 316

Number of Injection Wells = 6

Average Minimum Depth of Wells in meters = 1,800

Average Maximum Depth of Wells in meters = 2,500

Average Cost of Production Wells = $1,500,000

Average Cost of Injection Wells = $1,000,000

Average Temperature (°C) Input to Binary Turbine Generator Units = 150

Operation and Maintenance Costs for Plant and Field in cents/kWh = 0.90

Electricity Sales Price in cents/kWh = 7.37

Wells: 29 production @ $1.5 M each & 6 injection @ $1.0 M each = $49,500,000

Capital Costs of the Project minus Transmission Line Cost = Not Applicable

Drilling Costs as Percentage of Capital Cost of Project = Not Applicable

Capital Costs of Project Minus Transmission Line Cost per kW = Not Applicable

Total Capital Costs of the Geothermal Power Project = $199,500,000

Drilling Costs as Percentage of Total Capital Cost of Project = 24.81%

Total Capital Costs of the Geothermal Power Project per kW = $3,500

MOL Geothermal Power Project, Hungary

Geothermal Power Facility Consists of a Doublet Binary Plant of 2 to 5 megawatts.

Average Geothermal Power Facility Output in megawatts (MW) =	3.5
Assumed Online Availability Factor of Geothermal Power Facility =	95%
Transmission Line (230-kV) to Interconnect to Grid in km =	Not Available
Cost of Transmission Line =	$2,500,000
Number of Pumped Production Wells =	1
Average Flow Rate per Pumped Production Well in tons/hour	263
Number of Injection Wells =	1
Average Minimum Depth of Wells in meters =	3,000
Average Maximum Depth of Wells in meters =	4,000
Average Cost of Production Wells =	$5,000,000
Average Cost of Injection Wells =	$4,500,000
Average Temperature (°C) Input to Binary Turbine Generator Units =	170
Operation and Maintenance Costs for Plant and Field in cents/kWh =	1.50
Electricity Sales Price in cents/kWh =	8.90
Wells: 1 production @ $5.0 M each & 1 injection @ $4.5 M each =	$9,500,000
Capital Costs of the Project minus Transmission Line Cost =	$18,500,000
Drilling Costs as Percentage of Capital Cost of Project =	51.35%
Capital Costs of Project Minus Transmission Line Cost per kW =	$5,286
Total Capital Costs of the Geothermal Power Project =	$21,000,000
Drilling Costs as Percentage of Total Capital Cost of Project =	45.24%
Total Capital Costs of the Geothermal Power Project per kW =	$6,000

5.5 APPENDIX E

Proposed Geothermal Power Generation Project in Hungary

APPENDIX E

Proposed Geothermal Power Generation Project in Hungary

Background

MOL Hungarian Oil and Gas Company ("MOL") is a leading integrated oil and gas group in Central and Eastern Europe and the largest company in Hungary by sales revenues. MOL has an enterprise value of approximately USD $4 billion and is the Hungarian leader in all of its core businesses. The core activity most important to the development of geothermal resources is its exploration and production of crude oil, natural gas, and gas products.

MOL recently requested a grant from the United States Trade and Development Agency to provide technical assistance to assess the feasibility of economically developing medium enthalpy geothermal power plants (i.e., geothermal fluids in the temperature range of 140°C to 180°C) using existing shutin, non-productive, hydrocarbon wells. Within Hungary there are more than 8,000 hydrocarbon wells with the majority owned by MOL and geothermal production and injection wells can be constructed from these non-productive hydrocarbon wells. From shutin hydrocarbon wells, well drilling and cost information, as well as potential reservoir data, are available in addition to information from flow test operations, including temperatures, pressures, and flow rates.

Hungary is well known as a country of favorable conditions in terms of geothermal resources since most measured geothermal gradients are higher than the worldwide average. According to the results of numerous published geothermal assessments, Hungary has the largest underground thermal water reserves and geothermal energy potential of low and medium enthalpy in Europe. Measured geothermal resource temperatures in Hungary range from 10°C to 254°C. In addition, at least six regions of Hungary have shutin hydrocarbon wells which have temperatures in the range of 140°C to 160°C and flow rates of approximately 250 tonnes/hr to 650 tonnes/hr.

The proposed geothermal Pilot Project of MOL in Hungary will consist of the re-completion of at least two, shutin, hydrocarbon wells in order to develop one geothermal production and one geothermal injection well. The geothermal reservoir and the proposed doublet will most likely be appropriate for a binary cycle type power plant because of the expected temperature of the geothermal fluids (i.e., 100°C to 150°C). MOL anticipates that the Pilot Project will generate from about 2 to 5 megawatts of electricity. The project will include well completion or reconstruction into geothermal production and injection wells, pipelines between wells and the power plant, injection pumps, the power plant, and connection to the grid. All of the geothermal fluids will be injected into the reservoir to guarantee the renewable nature of the energy source. Site power for operation of the power plant and water injection will be used from the plant prior to dispatch to the grid. In Hungary, production of electricity in this manner establishes the right to possess the "Green Certificates".

Historical Geothermal Aspects

The utilization of geothermal energy has a long tradition in Hungary. Surface manifestations of geothermal resources have been known since ancient times. In fact, thermal springs of Budapest were used during the Roman Empire as well as later in the medieval Hungarian Kingdom. The peak of geothermal utilization activities occurred in the late 1970s when a total of 525 geothermal wells were registered. The 30 best had production temperatures in excess of 90°C, with total thermal power capacity of these wells estimated at 1,540 megawatts thermal; however, utilization was seasonal and the efficiency was rather low. Today, the utilization of geothermal energy in Hungary has decreased substantially while the geothermal technologies and the efficiency of geothermal energy utilization have increased.

The Pannonian Basin region of Hungary is recognized for its higher-than-average terrestrial heat flow (i.e., ~0.09 W/m^2, compared to the worldwide average heat flow of ~0.06 W/m^2); the high geothermal gradients (i.e., ~0.05 °C/m, compared to the worldwide average geothermal gradient of ~0.025°C/m); and the vast extent of deep aquifers indicate an important low-enthalpy geothermal resource. Many aquifers within the Tertiary section of the basin sediments have been found to contain over-pressured water with low to moderate (i.e., 40°C to 100°C) temperature. Artesian waters from wells intersecting these geothermal aquifers have been used for spas, space heating, and greenhouse horticulture for more than 100 years.

Subsurface Geological Parameters

The Pannonian Basin is encircled by the Carpathian Mountains and the crust of the earth beneath the basin is relatively thin (i.e., ~25 km) due to sub-crustal erosion. The thinned crust sank isostatically. Tertiary sediments primarily fill the basin that was thus formed. Pannonian sediments are multilayered, composed primarily of sandy, shaly, and silty formations. Although the Lower Pannonian sediments are mostly impermeable, the Upper Pannonian and Quaternary formations contain numerous porous, permeable sand and sandstone beds. The latter formed the Upper Pannonian aquifer, which is the most important thermal water resource in Hungary.

The individual sandy layers of the Upper Pannonian have various thicknesses between one and thirty meters. The horizontal extent of the sandy layers is not exceptionally large, but the sand lenses appear to be interconnected forming a hydraulically unified system. Moreover, the Upper Pannonian aquifer has an areal extent of about 40,000 square kilometers, an average thickness of 200 to 300 meters, a bulk porosity of about 20 to 30 percent, and a permeability of 500 to 1,500 milliDarcies. The hot water reservoir appears to have an essentially uniform hydrostatic pressure distribution with local recharge or discharge only slightly modifying this pattern. Most of the geothermal wells in Hungary produce hot water from the Upper Pannonian reservoir system.

At greater depths in the Pannonian Basin, carbonate rocks of Triassic age having a secondary porosity represent another type of geothermal reservoirs. These can be fractured and/or karstified rock masses with continuous recharge and important convective fluid motions. About twenty percent (20%) of the Hungarian geothermal wells produce from the deep karstic aquifer contained in the carbonate formations.

Typical mass flow rates of the Upper Pannonian geothermal wells can range between about 70 and 100 tonnes/hour. The production temperatures vary regionally but the best geothermal area is in the southeast of Hungary near the cities of Szeged, Szentes, and Hódmez vásárhely. Most Hungarian geothermal wells operate without any artificial production methods (e.g., downhole pumping) as the geothermal reservoirs are driven by both compaction and dissolved gas.

MOL Geothermal Exploration Activities

MOL personnel have already conducted geological, hydrogeological, geochemical, and geophysical surveys and studies to identify and quantify geothermal resources in Hungary. Geological and hydrogeological surveys and studies have involved mapping hot springs or other surface thermal manifestations and the identification of favorable geological structures. These data are used to recommend where production wells can be drilled with the highest probability of encountering a favorable geological structure.

Geochemical surveys, including isotope geochemistry data, conducted by MOL personnel are a useful means of determining whether the geothermal system is water-dominated or vapor-dominated, of estimating the minimum temperature expected at depth, of estimating the homogeneity of the geothermal fluid, of determining the chemical composition of the fluids, and of determining the source of the recharge water.

MOL personnel have also conducted geophysical surveys to assist in the determination of the shape, size, depth and other important characteristics of the deep geological structures that may contain the potential economic geothermal reservoir. These geophysical surveys and the physical parameters that were anticipated have included the following: thermal surveys (temperature), electrical and electromagnetic methods (electrical resistivity), seismic surveys (propagation velocity and attenuation of elastic waves), gravity surveys (density), and magnetic surveys (magnetic susceptibility).

Geothermal exploration activities underway or completed by MOL personnel have addressed at least nine geothermal resource characterization objectives, including:

1. Identification of geothermal phenomena
2. Determination of whether a useful geothermal reservoir might exist
3. Estimation of the areal extent and size of the geothermal resource
4. Classification of the geothermal resource as water-dominated or vapor-dominated
5. Location, areal extent, and relative depth of the productive zones
6. Determination of the relative heat content of the fluids to be discharged
7. Compilation of data which can be used to evaluate future activities and monitoring information
8. Assessment of pre-exploitation values of sensitive environmental parameters
9. Characterization of parameters that might cause problems during additional field development

Once these types of exploration studies and surveys have been completed and a potential geothermal resource has been identified, exploratory geothermal drilling must be carried out to further qualify and quantify the parameters of the geothermal reservoir. Since the geological environment is typically characterized by high temperatures and somewhat corrosive geothermal fluids, as well as the hard and abrasive nature of reservoir formations found in geothermal environments, geothermal drilling is much more difficult and expensive than conventional hydrocarbon drilling. Each geothermal well can cost from approximately USD $1 million to USD $5 million to drill and each geothermal project may consist of as few as 10 production and injection wells to more than 100 production and injection wells depending on the size of the geothermal power project. In fact, drilling can account for 30% to 50% of the total cost of a geothermal power project. The objectives of the drilling phase of a geothermal power project are to prove the existence of an exploitable resource, to delineate the extent and the characteristics of the resource, its suitability for use in a geothermal power plant. However, in the case of the Hungarian geothermal program, the shutin hydrocarbon wells have already been drilled, completed, and tested.

Technical Description of the Pilot Project in Hungary

Based on worldwide experience, a typical geothermal power plant is suitable for baseload operation and is highly reliable with capacity factors in excess of 90% compared to the 30% capacity factors of wind turbines. Several proven technologies are available and are used worldwide to produce electrical energy from geothermal resources; however, medium enthalpy projects, such as the one proposed for development in Hungary, use binary cycle technologies, which are fueled by moderate temperature fluids (i.e., 105°C to 180°C) from geothermal reservoirs.

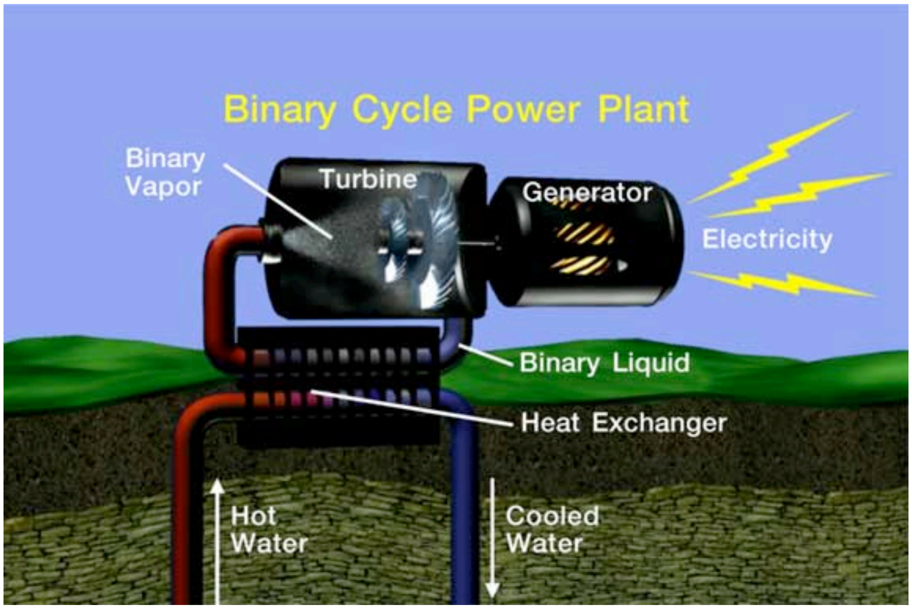


Figure 1. Schematic Diagram of a Binary Cycle Geothermal Power Plant.

In binary cycle power plants (see Figure 1), hot geothermal fluids are passed through one side of a heat exchanger to heat a working fluid on the other side of the heat exchanger. The working fluid, usually an organic compound with a low boiling point such as iso-butane or iso-pentane, is vaporized and passed through a turbine to generate electricity. The geothermal fluid that has passed through the heat exchanger may be used in a direct use application such as an industrial or agricultural process if the direct use facility is near enough to the power plant and economically feasible.

The turbine-generators and work areas of the power plant are usually housed in a simple steel building, with cooling towers, piping and separators located on a small footprint site of only a few hectares. Production and injection wells are usually situated within a radius of not more than one kilometer from the power plant. Insulated pipelines from the production wells to the inlet to the turbines carry geothermal fluids. The production and injection pipelines can bridge over or pass under roads as well as allow, for example, farming activities to continue. The power project is then interconnected to the local or regional grid.

Pilot Project Capital Costs and Electricity Price

The total estimated cost presented by MOL personnel for the Pilot Project in Hungary is USD $16 million broken down as follows:

Phase	Cost
Site, well doublet and connecting pipeline completion, operation tests	$5,500,000
Binary Cycle Power Plant	$8,000,000
Installation of the connection to electric power grid	$2,500,000
Total	**$16,000,000**

Since the well drilling phase of the Hungarian Pilot Project consists of the re-completion of at least two shutin hydrocarbon wells versus the drilling and completion of two new geothermal wells, the cost of the drilling phase of the geothermal power project is only about 34% of the total capital costs. However, if the drilling phase had consisted of the drilling of two new geothermal wells, the initial phase in the table above would have been approximately USD $10.5 million rather than USD $5.5 million. Thus, the drilling phase of the project would have been about 50% of the total capital costs since the power plant and transmission line costs would have remained the same as presented in the table.

Hungary is committed to developing renewable energy and therefore requires that the local distribution companies must purchase renewable energy. Hungarian law states that purchase of power generated by using renewable energy, such as geothermal resources, may not be refused if its transfer capacity exceeds 0.1 megawatts, if the technical conditions in uploading are satisfied, and if the price for the electricity does not exceed the level determined by the pricing authority. The Act on electric No. 110/2001 and Ministerial Decree No. 56/2002 fix the price of renewable electricity at HUF 18.40 Ft/kWh (i.e., USD $0.089/kWh) subject to inflation and adjustments for fossil generated electricity avoided costs through 2010.

If it is assumed that the re-completed hydrocarbon well will provide enough geothermal fluid to produce either 2 megawatts net (MWn) or 5 MWn to the grid, that the operating costs of the binary cycle geothermal power project will be about USD $0.015/kWh, that the capacity factor of the power plant will be approximately 95% and that the electricity price is USD $0.089/kWh, the net revenue per year to MOL for the 2 MWn project will be USD $1,231,656 and it will take about 13 years to recover the capital costs of the Pilot Project. If the project can produce 5 MWn to the grid, the yearly revenue to MOL will be USD $3.079,140 and the payback period will only be about 5 years.

Reference:

Definitional Mission Report – Hungary, **Enviromation Inc**., Project Sponsor: The MOL Group, Dr. Marta Kramer, Marketing Manager, MOL Hungarian Oil and Gas Plc., Refining and Marketing, H-1093 Budapest, Lozraktar u. 30 Hungary