ESMAP
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GEOTHERMAL HANDBOOK: PLANNING AND FINANCING POWER GENERATION

ESMAP MISSION

The Energy Sector Management Assistance Program (ESMAP) is a global knowledge and technical assistance program administered by the World Bank. It provides analytical and advisory services to low- and middle-income countries to increase their know-how and institutional capacity to achieve environmentally sustainable energy solutions for poverty reduction and economic growth. ESMAP is funded by Australia, Austria, Denmark, Finland, France, Germany, Iceland, Lithuania, the Netherlands, Norway, Sweden, and the United Kingdom, as well as the World Bank.

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FOREWORD

Developing countries face multiple and complex challenges in securing affordable and reliable energy supplies to support sustainable economic development. These challenges can be addressed by increased access to modern energy infrastructure, enhanced energy security through supply diversification, and transition to low carbon paths to meet rising energy demands.

There is broad consensus that renewable energy has a major role to play in addressing these challenges. In recent years, support for renewable energy investment has become a mainstream activity for multilateral development banks and their clients. The World Bank, for instance, has supported geothermal development in Africa, Asia, Europe, and Latin America. Global analytical work and technical assistance on clean energy are also one of the major program areas of the Energy Sector Management Assistance Program (ESMAP).

This handbook is dedicated to geothermal energy as a source of electric power for developing countries. Many developing countries are endowed with substantial geothermal resources that could be more actively put to use. On top of the benefits stemming from its renewable nature, geothermal energy has several additional advantages, including the provision of stable and reliable power at a relatively low cost, around the clock, and with few operational or technological risks.

However, several factors have hindered countries from developing geothermal resources. These factors are mostly related to the high upfront costs and the risk involved in geothermal resource exploration, including drilling. The initial exploration and confirmation of the resource is vital for soliciting the interest of the private sector to build and operate geothermal power plants. This handbook is written in an effort to assist developing countries around the world in scaling up the use of geothermal energy in their power sector development strategies. This is not an all-inclusive technical guide. The main objective is to provide decision makers and project developers with practical advice on how to set up, design, and implement a geothermal development program.

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ACRONYMS AND ABBREVIATIONS

Acre	4,050 square meters
ADB	Asian Development Bank
AFD	French Development Agency
AfDB	African Development Bank
ARGeo	African Rift Geothermal Development Program
bbl	Barrel (oil)
BOO	Build, own, and operate
BOT	Build, operate, and transfer
BTU	British thermal unit = 0.29 Watt-hour
C	Celsius
Capex	Capital expenditure
CDM	Clean Development Mechanism (of the UNFCCC)
CEG	Comision de Energia Geotermica
CER	Certified emission reductions
CFE	Federal Commission for Energy (Mexico)
CIF	Climate Investment Funds
cm	Centimeters
CO_2	Carbon dioxide
CPA	CDM project activity
CSP	Concentrated solar power
CTF	Clean Technology Fund
DBFO	Design, build, finance, and operate
EA	Environmental assessment
EBIT	Earnings before interest and taxes
EBITDA	Earnings before interest, taxes, and depreciation /amortization
ECA	Europe and Central Asia (WB region)
EDC	Energy Development Corporation (Philippines)
EGS	Enhanced (engineered) geothermal system
EIA	Environmental impact assessment
EMP	Environmental management plan
EPC	Engineering, procurement, and construction
ESMAP	Energy Sector Management Assistance Program
F/S	Feasibility study
FCFE	Free cash flow to equity
FCFF	Free cash flow to the firm
FCFP	Free cash flow to the project
FI	Financial intermediary
FIT	Feed-in tariff
FO	Fuel oil
g	Gram
GDC	Geothermal Development Company (Kenya)
GEF	Global Environment Facility
GHG	Greenhouse gas
GJ	Gigajoule
GoK	Government of Kenya
GRI	Geothermal risk insurance
GW	(GWe) Gigawatt (electric) =1 million kW
GWh	Gigawatt-hour
GWh/a	Gigawatt-hours per annum (year)
GWPI	Geothermal well productivity insurance
H_2S	Hydrogen sulfide
HDR	Hot dry rock (also called EGS)
HFO	Heavy fuel oil
IAEA	International Atomic Energy Agency
IEA	International Energy Agency
IFC	International Finance Corporation
IFI	International financial institution
IP	Investment plan
IPP	Independent power producer
IRR	Internal rate of return
ISOR	Iceland GeoSurvey (Iceland-based geothermal consulting company)
ITH	Income tax holiday
KenGen	Kenya Electricity Generating Company
KfW	Kreditanstalt fur Wiederaufbau (development banking group of Germany)
kg	Kilogram
km	Kilometer
kW (kWe)	Kilowatt (electric) = 1,000 Watt
kWh	Kilowatt-hour
L	Liter
LCOE	Levelized cost of energy
LDC	Load duration curve
LNG	Liquefied natural gas
m	Meter
m a s l	Meters above sea level
MBTU	1 million BTUs
MDB	Multilateral development bank

MEMR	Ministry of Energy and Mineral Resources (Indonesia)
MIGA	Multilateral Investment Guarantee Agency
MSD	Medium speed diesel
MT	Magneto telluric (sounding)
MW	(MWe) Megawatt (electric) = 1,000 kW
MWh	Megawatt-hour
NCG	Non-condensable gases
NEF	National Energy Fund (Iceland)
NG	Natural gas
NGO	Nongovernmental organization
NPC	National Power Corporation (national power utility of the Philippines)
NPV	Net present value
O&M	Operation and maintenance
ODA	Official development assistance
OECD	Organization for Economic Co-Operation and Development
OPF	Obra Publica Financiada (Mexico)
ORC	Organic Rankine Cycle (binary system)
PGE	Pertamina Geothermal Energy Corporation (Indonesia)
PLN	Perusahaan Listrik Negara (national power utility of Indonesia)
PNOC	Philippine National Oil Corporation
PoA	Program of activities
PPA	Power purchase agreement
PPP	Public-private partnership
PV	Present value
QC	Quality control
R_e	Required return on equity
RPS	Renewable portfolio standards
SAGS	Steam-above-ground system (steam gathering system)
SREP	Scaling-up Renewable Energy Program
TA	Technical assistance
TEM	Transient electro magnetic (sounding)
TGC	Tradable Green Certificate
TWh	Terawatt-hour (1 TW = 1,000 GW)
UNDP	United Nations Development Program
UNEP	United Nations Environment Program
UNFCCC	United Nations Framework Convention on Climate Change
UNU-GTP	United Nations University Geothermal Training Program
US$	United States dollar (currency)
UTC	United Technology Company
WACC	Weighted average cost of capital
WB	World Bank
WBG	World Bank Group

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MAIN FINDINGS AND RECOMMENDATIONS

The use of geothermal steam for electricity production began in the early 20th century, with the first experimental installation built in Larderello, Italy, in 1904. As of 2011, about 11 GW of geothermal power capacity has been built around the world, most of it in the last three decades. However, electricity generated from geothermal sources still only represents 0.3 percent of the world's total power generation.

The exploitable geothermal energy potential in several parts of the world is far greater than the current utilization, and geothermal power has an important role to play within the energy systems of many countries. It has been estimated that nearly 40 countries worldwide possess enough geothermal potential that could, from a purely technical perspective, satisfy their entire electricity demand. Geothermal resources have been identified in nearly 90 countries and more than 70 countries already have some experience utilizing geothermal energy. Currently, electricity from geothermal energy is produced in 24 countries. The United States and the Philippines have the largest installed capacity of geothermal power, about 3,000 and 1,900 MW, respectively. Iceland and El Salvador generate as much as 25 percent of their electric power from geothermal resources. While geothermal energy potentially has a number of uses, including direct heating, this handbook focuses specifically on developing geothermal resources to generate electricity.

BENEFITS OF GEOTHERMAL ENERGY. Geothermal energy has many attractive qualities stemming from its renewable and fossil-fuel free nature, as well as the ability to provide stable and reliable base-load power at a relatively low cost. Once a geothermal power plant is operational, it will produce a steady output around the clock, usually for several decades, at costs competitive with other base-load generation options, such as coal. Technological risks involved are relatively low; geothermal power generation from hydrothermal resources—underground sources of extractible hot fluids or steam—is a mature technology. For medium sized plants (around 50 MW), levelized costs of generation are typically between US $0.04 and 0.10 per kWh, offering the potential for an economically attractive power operation. Development of a domestic renewable energy resource provides the opportunity to diversify sources of electricity supply and to reduce the risk of future price rises due to increasing fuel costs.

ENVIRONMENT AND SOCIAL CONSIDERATIONS. From a global environmental perspective, the benefits of geothermal energy development are beyond dispute. Carbon dioxide (CO_2) emissions from geothermal power generation, while not always zero, are far lower than those produced by power generated from burning fossil fuels. Local environmental impacts from replacing fossil fuels with geothermal power tend to be positive on balance—due primarily to the avoided impacts of fuel combustion on air quality and the avoided hazards of fuel transportation and handling. Of course, like any infrastructure development, geothermal power has its own social and environmental impacts and risks that have to be managed, and the affected groups must be consulted throughout project preparation and development. The impacts from a geothermal power development project are usually highly localized; few if any of them are irreversible; and in most cases mitigation measures can be readily implemented.

BARRIERS TO DEVELOPMENT. Given the advantages of geothermal power, the question has to be asked why the level of its utilization today is not higher than it is. One answer is that geographically, hydrothermal resources suitable for power generation are not very widespread. Indeed, estimates are that geothermal resources in the form of hot steam or fluids are only available on 1/4 to 1/3 of the planet's surface. Technologies and exploitation techniques that could increase this share are not yet fully available. Another answer is that from an investor's standpoint geothermal projects are risky—with geological exploration risk (or resource risk) often considered the greatest challenge—and capital intensive, with a mid-range estimate of investment costs close to US $4 million per MW which further increases risk, since project returns become more sensitive to financing costs.

A more detailed review of the pros and cons of geothermal development reveals that many advantages of geothermal energy have their limitations. For example, while land and space resources are less of a constraint for geothermal power in achieving the needed scale than for most other power generation technologies, the maximum capacity of the plant is ultimately limited by the heat production capacity of the reservoir. Even the renewable nature of geothermal energy is not unconditional, as the capacity of a reservoir to replenish itself can be compromised by unsustainably high withdrawal rates or by failure to reinject the geothermal fluids.

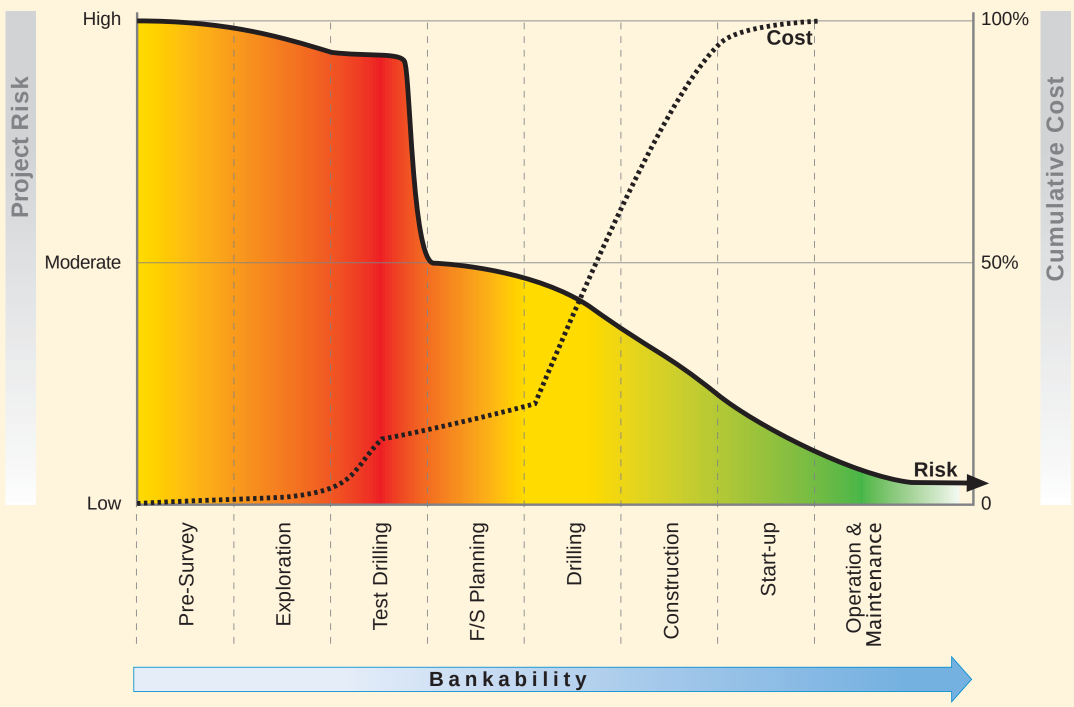
PHASES IN GEOTHERMAL DEVELOPMENT. To better understand the nature of the risks that are specific to geothermal power, it is helpful to consider the project cost and risk profile through the various stages of project development as shown in Figure 0.1.

A geothermal power project can be divided into a series of development phases before the actual operation and maintenance phase commences:

- preliminary survey;
- exploration;
- test drilling;
- project review and planning;
- field development and production drilling;
- construction; and
- start-up and commissioning.

FIGURE 0.1

Project Cost and Risk Profile at Various Stages of Development



Source | Authors.

A full-size geothermal development project typically takes from 5 to 10 years to complete. Due to this long project development cycle, geothermal power is not a quick fix for any country's power supply problems, but rather should be part of a long-term electricity generation strategy.

Many of the risks of geothermal development are essentially the same as in any grid-connected power generation project: completion or delay risk, off-take risk, market demand or price risk, operational risk, and regulatory risk. The elevated level of financing risk due to high upfront costs is common for most other renewable energy technologies.

However, there are additional risks specific to geothermal. The upstream/exploration phases, and especially the test-drilling phase, can be considered the riskiest parts of geothermal project development. The test drilling phase is much more capital intensive than all the previous phases, while still fraught with uncertainty. Significant investment is required before knowing whether the geothermal resource has enough potential to recover the costs. As Figure 0.1 shows, test drilling can account for up to 15 percent of the overall capital cost, which is required at a point when the risk of project failure is still high.

The resource risk (or exploration risk) reflects both the difficulty of estimating the resource capacity of a geothermal field and the costs associated with its development. Oversizing the power plant is a risk closely related to resource risk, but it needs to be specially mentioned for two reasons. First, oversizing the plant magnifies the resource risk by concentrating investment resources in a given location—as opposed to spreading it by building smaller plants in several geologically independent fields. The second reason is related to sustainability of the geothermal operation: excessive plant capacity can lead to unsustainable extraction rates resulting in pressure drops or even reservoir depletion.

Balancing the probability of success against the cost of failure to reach the best expected outcome can be handled by formal techniques such as the use of a decision tree. The potential project developer is essentially faced with one of three choices:

- go ahead immediately with production drilling and risk project failure;
- undertake test drilling at a known cost but potentially reduce the risk of project failure through the knowledge gained; or
- decide that the prospect is not sufficiently attractive to make it worthwhile risking money even for testing.

The technique allows analysis and adoption of choices that maximize the expected value of geothermal development by applying probabilities to various project outcomes. Monte Carlo simulation is another probabilistic technique that can be applied for a more detailed analysis of the collective impact of many variables.

KEY ELEMENTS OF SUCCESSFUL GEOTHERMAL DEVELOPMENT. The existence of exploitable geothermal potential in the country, while essential, is only a prerequisite for a successful geothermal development effort. There are four key elements supporting such an effort:

- availability of sufficiently accurate geothermal resource data and other relevant information;
- effective and dedicated institutions;
- supportive policies and regulations; and
- access to suitable financing for the project developer.

RESOURCE INFORMATION. Information is the first key element that supports the development of a geothermal project or program. The country government has an important role to play in making geothermal resource information available to potential developers and investors. At a minimum, the government should keep public records on such geothermal attributes as seismic data (events, fractures, etc.) and deep drilling data (temperature, pressure, faults, permeability). A reliable conceptual model of the entire underlying geothermal system (or, at a minimum, the field or reservoir under development) has to be available. Information on groundwater resources is also essential, since groundwater should not be contaminated with geothermal reservoir fluids and is a potential source of cooling water for the power plants, among other uses.

INSTITUTIONS. The second key element is the strength of institutions and their structural organization with respect to geothermal energy development. A legal framework for geothermal resource use—starting with the definition of property rights—is needed to provide a foundation for these institutions. While the right of ownership to the resource generally rests with the state, various forms of private sector participation in the exploration, development, and exploitation of the resource have evolved in many countries.

Geothermal exploration and exploitation rights in particular areas are granted by governments or regulators by means of concessions, leases, licenses, and agreements. Granting of these rights should be based on the following three principles: a clear legal and regulatory framework; well-defined institutional responsibilities; and transparent, competitive, and non-discriminatory procedures, including adequate measures for controlling speculative practices.

The experience of countries that have been successful in geothermal power development points to the importance of a number of common factors: a dedicated national geothermal exploration and development organization (or company) capable of handling large-scale infrastructure projects consistent with international and industry standards; a committed and adequately staffed ministry or similar department of government in charge of the energy sector whose functions include explicit planning for geothermal energy development; an adequately staffed and committed national power utility; and a capable regulator—especially, in the context of a liberalized electricity market—whose functions include the enforcement of the country's renewable energy policies and balancing the interests of generators and consumers.

The agency in charge of geothermal exploration and development can be a government agency or, more often, a state-owned company with the requisite industrial capabilities. Examples include the Geothermal Development Company (GDC) of Kenya, Pertamina Geothermal Energy Corporation (PGE) in Indonesia, the Energy Development Corporation (EDC) in the Philippines, and the integrated state power company (CFE) in Mexico. The latter two examples suggest that the company in charge of geothermal exploration may not necessarily have geothermal energy as its sole focus, since geothermal development in the Philippines and Mexico is led by a state-owned oil company and by an integrated state power company, respectively. In all cases, the core agency or company is a vehicle through which the government of a country attempting to scale up its geothermal power takes an active role in absorbing (with international donor support as appropriate) a significant portion of the resource risk.

SUPPORTIVE POLICIES. The third key element of successful geothermal energy development is the presence of supportive policies for attracting private investors. This is especially true if the country decides to move beyond a project-by-project approach to one that creates the right environment for investments in a scaled-up, nationwide effort to deploy geothermal power.

Governments around the world use a wide range of policy and regulatory instruments to support the deployment of renewable electricity. Most renewable energy sources receive public support in several different forms. Countries with strong renewable energy development agendas have introduced either feed-in tariffs (FITs) or quota obligations, such as renewable portfolio standards (RPS), as their core policy.

Geothermal power stands out as a special case among renewable energy sources, and the scope of application of such policy instruments needs to be carefully considered in the specific context of a particular country. Attention should be given to approaches that facilitate financing for the test drilling phase, as this is the key to reducing risk to a level that becomes more attractive for private financing. Policies that support improved returns during the operating phase, such as FITs and RPS, are generally less effective at overcoming the exploration risk hurdle, especially in countries lacking a track record in geothermal development. There are only a few examples of FIT schemes being applied to geothermal power, with most of the examples found in continental Europe. Africa and Asia have seen budding interest in using feed-in tariffs for geothermal, but in some cases the efforts have resulted in policies that set a ceiling price instead of a FIT (for example, Indonesia).

Government support to public-private partnerships (PPPs) involving build-operate-transfer (BOT) or similar contracts may be a logical policy choice for countries seeking a more limited commitment to geothermal power development, such as reaching a particular milestone in a country's power system expansion plan or even developing an individual project. The BOT model used in the Philippines and the Mexican *Obra Publica Financiada* (OPF) model demonstrate the effectiveness of the approach.

After proving the commercial viability of its geothermal sector through a series of successful PPP contracts in which the government takes most of the exploration and resource risk, the country may consider transitioning to models that allocate more of this risk to the private developer. Two basic approaches can be considered.

The first approach consists of inviting proposals from private companies to develop new geothermal sites through concessions or PPPs in which more of the exploration or resource risk is taken by the private developer. However, the developer or investor in this case will require compensation for the increased risk through a higher off-take price of electricity or through other means. Many countries have preferred to directly fund the risky upstream phases due to this trade-off. Indeed, the developing countries actively engaging the private sector in geothermal development today (e.g., the Philippines) have previously deployed large volumes of public funding and official development assistance to finance geothermal resource exploration.

The second approach—a national policy commitment to support geothermal power generation, such as FIT, while phasing out public support in the upstream phases—has a chance of success if: (a) geothermal exploration and resource confirmation resulting from prior public support is well advanced in many areas of the country, so there is substantial scope for immediate "brownfield" rather than "greenfield" development; (b) the companies expected to respond are financially able to take the residual exploration risk, including, if necessary, through balance sheet financing rather than seeking loans; and (c) the off-take tariff or FIT is sufficient to compensate the developer for the incremental cost relative to lower cost generation alternatives, if any.

Increasing private participation in the sector can also be accomplished by privatization of the national geothermal development company and its assets. However, this does not necessarily lead to further geothermal development by the incoming private sector entities. Such privatization, therefore, needs to come with explicit commitment of the investor to further geothermal development.

FINANCE. The fourth key element of successful geothermal energy development is finance. Scaling up geothermal power development requires active participation by both the public and private sector. Reliance solely on commercial capital for geothermal development is rarely viable even in developed country markets. In developing countries, where the challenges involved in attracting private capital to geothermal projects are often greater, the commitment of the public sector—including the country government, international donors, and financial institutions—is an essential element of success in mobilizing capital.

The respective roles of the public and private sector in mobilizing finance for geothermal development depend on the particular circumstances of the country, including the government's fiscal situation, the government's preference for the level of private sector participation; the desired level of vertical integration of the geothermal development market; and other factors.

If private sector financing of geothermal projects is envisaged, the costs of capital need to be carefully considered as the financiers may require a high premium for the risks involved. This is true for both debt and equity capital; and the role of the latter needs to be especially emphasized. While debt financing typically covers the greater part of the capital requirements (commonly 60 to 70 percent of the total project cost), lenders usually require that a significant amount of equity be invested in the project as well. Private equity investors, however, are likely to require relatively high rates of return on their invested capital. A required return on equity of 20 to 30 percent per year is not unusual, due to risks noted earlier.

In addition, from an equity investor's perspective, risk factors include risks associated with the financing structure (leverage). For example, return on equity is sensitive to changes in the terms of debt financing. These terms include, among others, the interest rate, maturity period, grace period (if applicable), and the debt-equity ratio.

One of the options to bring return on equity above the threshold rate required by the private investor is for the government (or international donors) to grant-finance a portion of the costs of the initial project development, including exploratory drilling. An illustrative example in Chapter 3 of this handbook shows the impact of a government or donor commitment to absorb 50 percent of the costs during the first three years of a 50 MW geothermal power project. Such investment cost sharing in the early stages of the project can increase the private investor's estimated return on equity to a level that is sufficiently attractive to the investor, without the need for government to subsidize or raise the tariff for the consumers.

Internationally, many different development and financing models have been utilized for geothermal power development. Various models have been adopted even within a single country, either consecutively nationwide or at the same time in different fields. The financing structures and the corresponding risk allocations can vary widely. However, a review of models used historically allows identifying the following common patterns.

MODELS OF GEOTHERMAL POWER DEVELOPMENT. The upstream phases of geothermal project development tend to rely heavily on public sector investments, while private developers tend to enter the project at more mature phases. The project development cycle (and sometimes the broader geothermal market structure) may be vertically integrated or separated (unbundled) into different phases of the supply chain. In an unbundled structure, more than one public entity and/or more than one private developer may be involved in the same project at various stages.

Eight different models of geothermal power development are identified in this handbook. On one extreme is a model in which a single national entity implements the full sequence of phases of a geothermal power project. This is financed by the national government, in conjunction with any grants from donors and loans from international lenders. In this model, risk is borne almost entirely by the government, either directly or through sovereign guarantees of loans. The burden on public finances is reduced only by revenues earned from the sale of electricity and by donor grants, if available. This model has been utilized in several countries including Kenya, Ethiopia, and Costa Rica.

On the other extreme is a model exemplified in the fully private development led by an international oil company, Chevron, in a recently launched 100 MW geothermal project in the Philippines. Chevron has the financial resources to fund the project using hydrocarbon revenue and to take all the risk from exploration to power generation. Similar private developments can be found, for example, in Australia and Italy.

Apart from the two extremes with respect to the public and private sector roles, there is a broad spectrum of additional models to be found. Sometimes, more than one state-owned company or more than one level of government is involved in the provision of funds for geothermal development, while the private sector role is limited (e.g., Iceland, Indonesia, and Mexico). In other cases, PPP structures are utilized in which the private participant plays an active role (e.g., El Salvador, Japan, Turkey, new development in Kenya and Indonesia, and the former model in the Philippines based on BOT contracts).

RISK MANAGEMENT THROUGH A PORTFOLIO APPROACH. Whether the project is public or privately owned, exposure to resource risk should be managed carefully. Ways to limit exposure to this risk are based on the risk diversification principles long employed by extractive industries, such as oil and gas. To the extent possible, a portfolio of moderately sized projects should be undertaken in parallel rather than implementing large projects in sequence. Countries with extensive inventories of identified geothermal fields are well placed to benefit from the application of a portfolio approach to test drilling. For example, a country's geothermal development company could have an investment portfolio consisting of multiple projects to develop geologically independent geothermal fields and could construct the first moderately sized geothermal power plant in each (or some) of the fields. It is generally recommended that each geothermal project should initially utilize only a portion of its respective geothermal reservoir's production capacity to maximize the returns on information from operations. Subsequently, additional plant capacity may be added so the degree of utilization of each field's productive capacity would increase gradually over time.

To summarize the point on resource risk management, a strategy minimizing resource risk exposure could consist of the following approaches: portfolio exploration, in which the country explores and evaluates multiple geothermal fields, thereby increasing the probability of finding at least one viable site and reducing the chance of overlooking significant development opportunities; parallel development of the fields selected from the portfolio to reduce time and costs; and incremental or stepwise expansion, reducing the risk of reservoir depletion and pressure drops by developing a geothermal power project in cautiously sized steps determined by reservoir data.

A stronger role for institutional investors in supporting geothermal development could be achieved through increasing the involvement of insurance companies. The availability of large portfolios of geothermal projects offers fertile ground for insurance schemes, since risk management through diversification is the foundation of the insurance industry. To reduce the cost of coverage, such schemes will have to rely initially upon public sources of subsidized capital (including grants from governments, donors, or climate finance).

DEVELOPMENT ASSISTANCE. Official Development Assistance (ODA) available from multilateral and bilateral development banks, as well as from climate finance facilities, has a key role to play in supporting geothermal energy development. The concessional nature of capital supplied by climate finance vehicles, such as the Clean Technology Fund (CTF) and the Scaling-up Renewable Energy Program (SREP), coupled with the involvement of major international development organizations, such as multilateral development banks (MDBs), creates unique opportunities for leveraging capital from various other sources to support low carbon investments.

Considerable efforts and resources in recent years have been devoted to attempts to set up funds that use concessional financing to mitigate geothermal resource risk. Two significant programs, the Europe and Central Asia (ECA) GeoFund and ArGeo, supporting the development of such funds have been initiated under the auspices of the World Bank. In both cases, the Global Environment Facility (GEF) has been the main source of concessional capital. The design and operation of these programs has helped the international community learn valuable lessons and develop a better understanding of the available options for the future.

Key principles underlying the design of a successful global or regional MDB-supported facility to promote geothermal development have emerged from this experience that can be summarized as follows:

1 | The facility needs to be well staffed and professionally managed.

2 | It needs to have a critical mass of concessional capital sufficient to leverage co-financing from the market at large—including private sector debt and equity.

3 | The greatest impact from concessional financing on the bankability of a typical mid-size geothermal power project can be expected when such financing is for the test drilling phase of project development.

4 | Success during the test drilling phase is key to bridging the crucial gap between the early start-up phases that are unlikely to attract debt financing and the more mature phases of the project when financiers begin to see the project as increasingly bankable.

5 | The geographic scope of the project portfolio should cover areas containing well established and highly promising geothermal reservoirs, principally those suitable for electricity generation. The areas should also be sufficiently wide to allow for a diverse portfolio of geothermal project locations to reduce the concentration of resource risk.

6 | The operational procedures of the facility should include incentives for the management to apply prudent investment risk management principles and techniques.

Possible designs for a donor-supported geothermal development facility include: a direct capital subsidy or grant facility; a loan (on-lending) facility; and a risk guarantee or insurance facility. The choice of the design depends on the particular circumstances of the country or region and of the donor agencies involved. In principle, any of these designs can reduce the private investors' risk and thus reduce the risk premium for the return on equity and the overall cost of capital, opening up new opportunities for attracting investments to scale up geothermal power.

GEOTHERMAL ENERGY FOR ELECTRICITY PRODUCTION

HIGHLIGHTS

- Geothermal fields are generally found around volcanically active areas that are often located close to the boundaries of tectonic plates. Nearly 40 countries worldwide possess sufficient geothermal potential that could, from a technical perspective, satisfy their entire electricity demand with geothermal power.
- Electricity from geothermal energy is produced by 24 countries. The United States and the Philippines have the largest installed capacity of geothermal power, about 3,000 MW and 1,900 MW, respectively. Iceland and El Salvador generate as much as 25 percent of their electric power from geothermal resources.
- Geothermal power generation from hydrothermal resources can be expected to grow from 11 GW in 2010 to 17.5 GW by 2020 and to about 25 GW by 2030. Most of this increase is expected to happen in Pacific Asia, mainly Indonesia; the East-African Rift Valley; Central and South America; as well as in the United States, Japan, New Zealand, and Iceland.
- Geothermal is a commercially proven renewable form of energy that can provide relatively cheap, low carbon, base-load power and heat, reducing a country's dependence on fossil fuels and CO_2 emissions.
- The development of geothermal power generation cannot be regarded as a quick fix for any country's power supply problems, but should rather be part of a long term electricity generation supply strategy.
- Geothermal power projects are best developed in steps of 30 to 60 MW in order to reduce concentration of resource risk and to minimize the risk of unsustainable exploitation of the geothermal reservoir.
- Investment costs per installed megawatt can vary widely, from US$ 2.8 million to US$ 5.5 million per MW installed for a 50 MW plant, depending on factors such as the geology of a country or region, quality of the resource (e.g., temperature, flow rate, chemistry), and the infrastructure in place.
- Despite its high upfront costs, geothermal power can be competitive and complement other sources of generation thanks to high capacity factors, long plant lifetimes, and the absence of recurring fuel costs.
- Levelized costs of energy from hydrothermal resources are usually found to be between US$ 0.04 and 0.10 per kWh.

INTRODUCTION TO GEOTHERMAL ENERGY

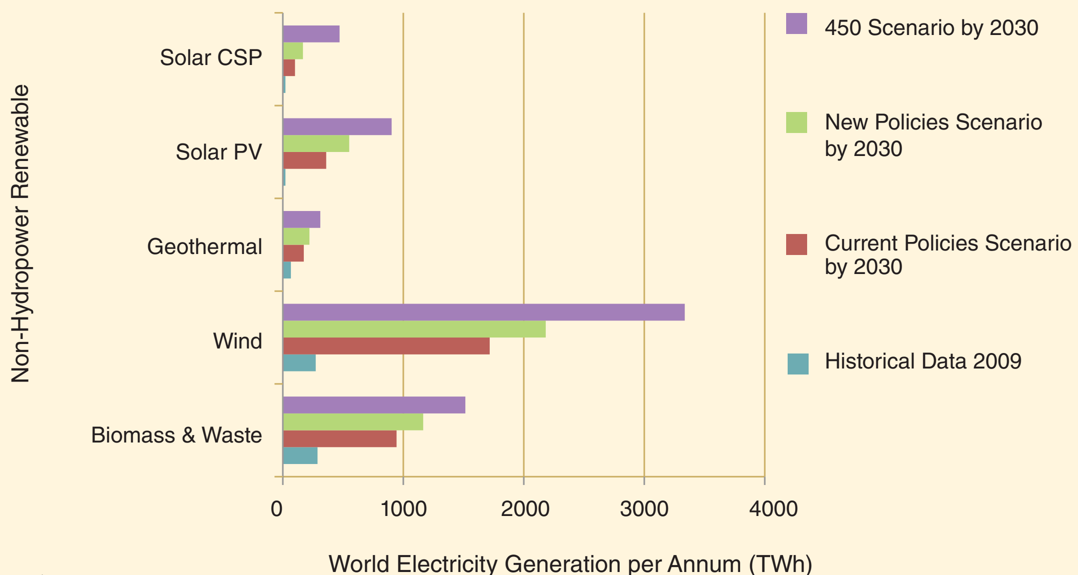
Up until a century ago, geothermal energy was known mostly as a source of heat for spa and bathing purposes. The use of geothermal steam for electricity production began in the 20th century—with the first experimental installation built in Larderello, Tuscany, Italy in 1904. A 250 kWe geothermal power plant began operation there in 1913 (Kutscher 2000). Today, about 11 GWe of geothermal power capacity has been built around the world, with more than a five-fold increase taking place in the last three decades.

The share of geothermal power in the overall energy balance of the world is still quite small, at about 0.3 percent (IEA 2011a), with the prospect of growing to 0.5 percent by 2030 in the International Energy Agency's (IEA) conservative Current Policies Scenario or to about 1.0 percent in the aggressive 450 Scenario.[1] The scale of geothermal power generation is also modest when compared with other renewable energy sources (Figure 1.1).

However, the exploitable geothermal energy potential in some parts of the world is far greater than current utilization, offering scope for significant investment in scale-up.

FIGURE 1.1

World Electricity Generation (TWh) from Non-Hydropower Renewables by 2030



Source | Authors based on (IEA 2011a).

[1] The Current Policies Scenario provides a baseline for how global energy markets would evolve if governments made no changes to their existing policies and measures. The 450 Scenario assumes that measures are taken to limit the long-term concentration of greenhouse gases (GHGs) in the atmosphere to 450 part per million of CO_2 equivalent to mitigate climate change (IEA 2011a).

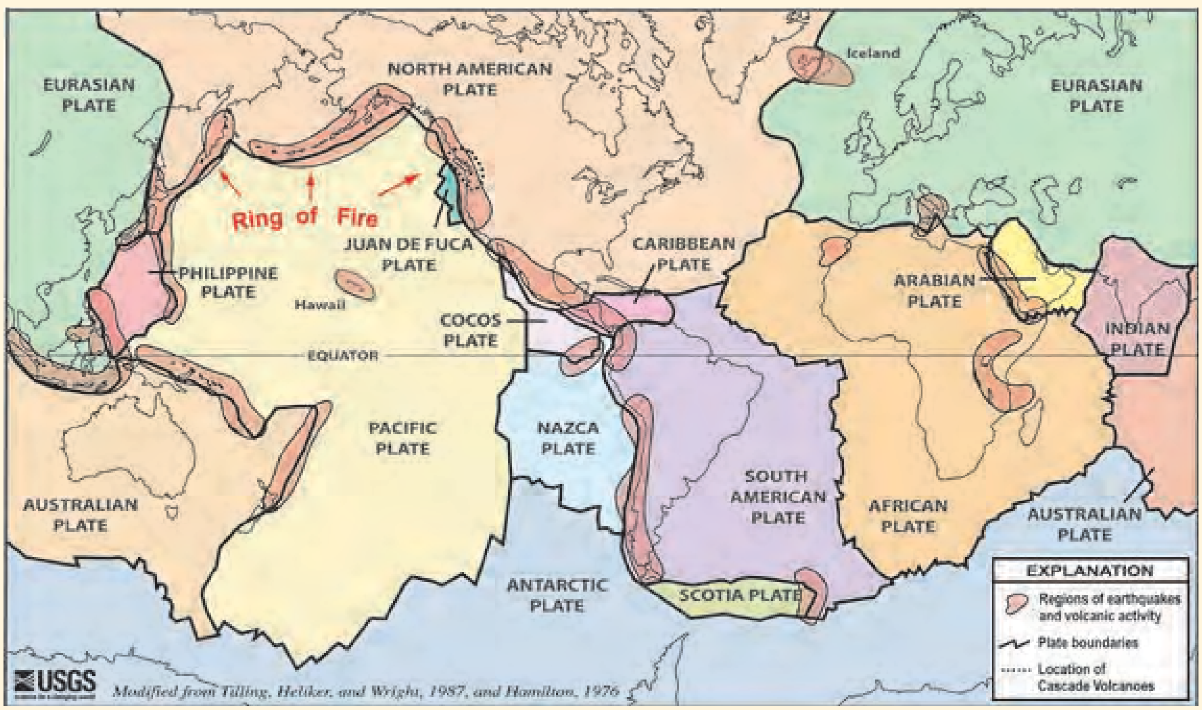
Geothermal Resource Availability, Typology, and Uses

What is Geothermal Energy and where is it Found?

Geothermal heat is constantly produced by the Earth from the decay of radioactive material in the core of the planet. The heat is moved to the surface through conduction and convection. In the crust, the temperature gradient[2] is typically 30°C per kilometer but can be as high as 150°C per kilometer in hot geothermal areas.

If even a small fraction of the Earth's heat could be delivered to the points of energy demand by humans, the energy supply problem would be solved. The global technical potential[3] of the resource is huge and practically inexhaustible. However, tapping into this tremendous renewable energy reservoir is not an easy task.

FIGURE 1.2
World Map of Tectonic Plate Boundaries



Source | US Geological Survey.

2 A temperature gradient describes the changes in temperature at a particular location. In geophysics, it is usually measured in degrees Celsius per vertical kilometer (°C/km).

3 Technical potential represents all projects which could be implemented globally, if all geothermal resources could be found and utilized. The economic potential refers to those projects that would be economically and financially viable.

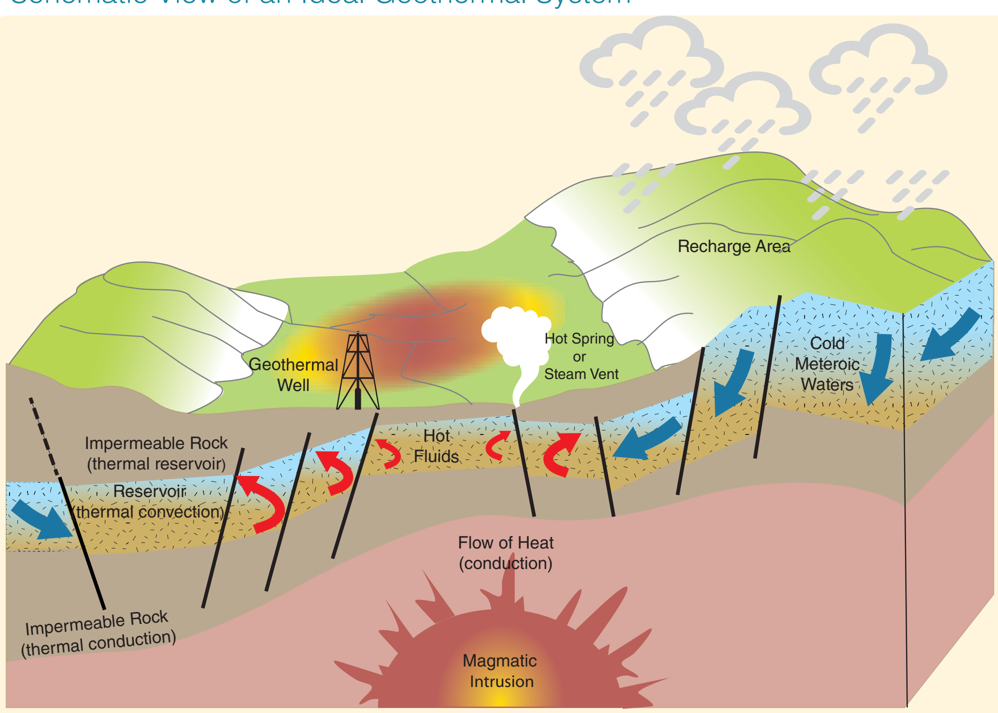
The best geothermal fields are generally found around volcanically active areas often located close to boundaries of tectonic plates. As shown in Figure 1.2[4], there are only a few major areas in the world which are rich in hydrothermal potential. Although some of the geothermal resources are located in populated, easily accessible areas, many others are found deep on the ocean floor, in mountainous regions, and under glaciers or ice caps.

Furthermore, the current commercially available geothermal power technology relies upon the availability of hydrothermal resources—underground sources of extractible hot fluids or steam—to energize the power plant. Therefore, when discussing geothermal resources, this handbook maintains a consistent focus on high-temperature (or high-enthalpy[5]) hydrothermal resources suitable for power generation.

Even though the greatest concentration of geothermal energy is associated with the Earth's plate boundaries, some form of geothermal energy can be found in most countries; exploitation of geothermal systems in normal and low geothermal gradient areas for home heating has gained momentum during the last decade. Ground source heat pumps can be utilized almost anywhere in the world to produce heat from the ground near the surface, or from surface water reservoirs.

FIGURE 1.3

Schematic View of an Ideal Geothermal System



Source | Dickson and Fanelli 2004.

[4] USGS on www.cnsm.csulb.edu

[5] Industry professionals often use the terms "high-enthalpy" and "high-temperature" as synonyms when describing geothermal resources (Elíasson 2001). Enthalpy is a measure of the total energy of a thermodynamic system including the latent heat of vaporation/condensation. As such, it more accurately describes the energy production potential of a geothermal system that includes both hot water and steam.

Figure 1.3 shows the components of a typical hydrothermal (steam or water based) volcanic-related geothermal system, which are, from bottom to top:

- The magmatic intrusion (also called hot body, where hot magma intrudes exceptionally far into the Earth's crust) is often caused by tectonics of the continental plates.
- The actual geothermal reservoir is where hot steam or water are trapped under high pressure beneath a tight, non-permeable layer of rocks and is heated by the magmatic intrusion below.
- The geothermal wells tap into the geothermal reservoir and access the hot steam or fluid, then transfer it through pipelines to the power plant, after which the fluids are usually returned into the reservoir.
- Fresh water or precipitation comes from recharge areas like lakes, rivers or the seas and provides cold meteoric waters, which slowly seep through the ground to lower layers through cracks and faults in the rocks.

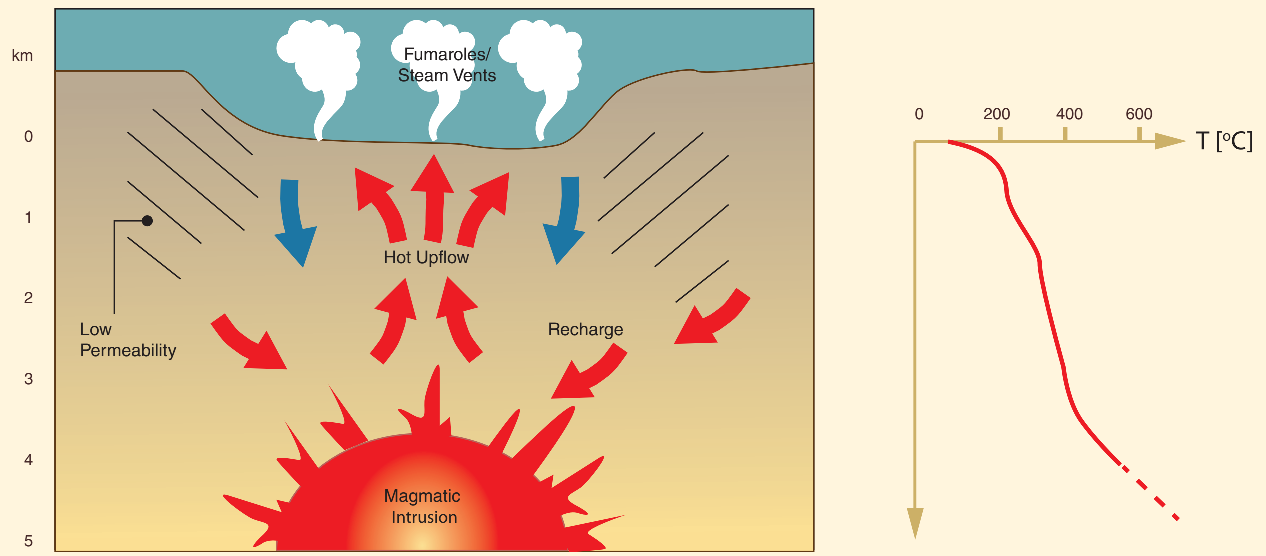
Classification of Geothermal Systems[6]

Geothermal resources are classified in various ways based on heat source, type of heat transfer, reservoir temperature, physical state, utilization, and geological settings. When defined on the basis of the nature of the geological system from which they originate, the different categories are as follows:

- **Volcanic geothermal systems** are in one way or another associated with volcanic activity. The heat sources for such systems are hot intrusions or magma. They are most often situated inside, or close to, volcanic complexes, such as calderas, most of them at plate boundaries but some in hot spot areas. In volcanic systems, it is mostly permeable fractures and fault zones that control the flow of water (Figure 1.4).
- In **convective fracture controlled systems** the heat source is the hot crust at depth in tectonically active areas, with above average heat flow. Here geothermal water has circulated to considerable depth (> 1 km), mostly through vertical fractures, to "mine" the heat from the rocks.
- **Sedimentary geothermal systems** are found in many of the world's major sedimentary basins. These systems owe their existence to the occurrence of permeable sedimentary layers at great depths (> 1 km) and above average geothermal gradients (> 30^{o} C/km). These systems are conductive in nature rather than convective, even though fractures and faults play a role in some cases. Some convective systems (such as convective fracture controlled systems) may, however, be embedded in sedimentary rocks (Figure 1.5).
- **Geo-pressured systems** are analogous to geo-pressured oil and gas reservoirs in which fluid caught in stratigraphic traps may have pressures close to lithostatic values. Such systems are generally fairly deep.
- **Hot dry rock (HDR) or enhanced (engineered) geothermal systems (EGS)** consist of volumes of rock that have been heated by volcanism or abnormally high heat flow, but that have low

[6] The following discussion is based on Saemundsson, Axelsson, and Steingrímsson 2011.

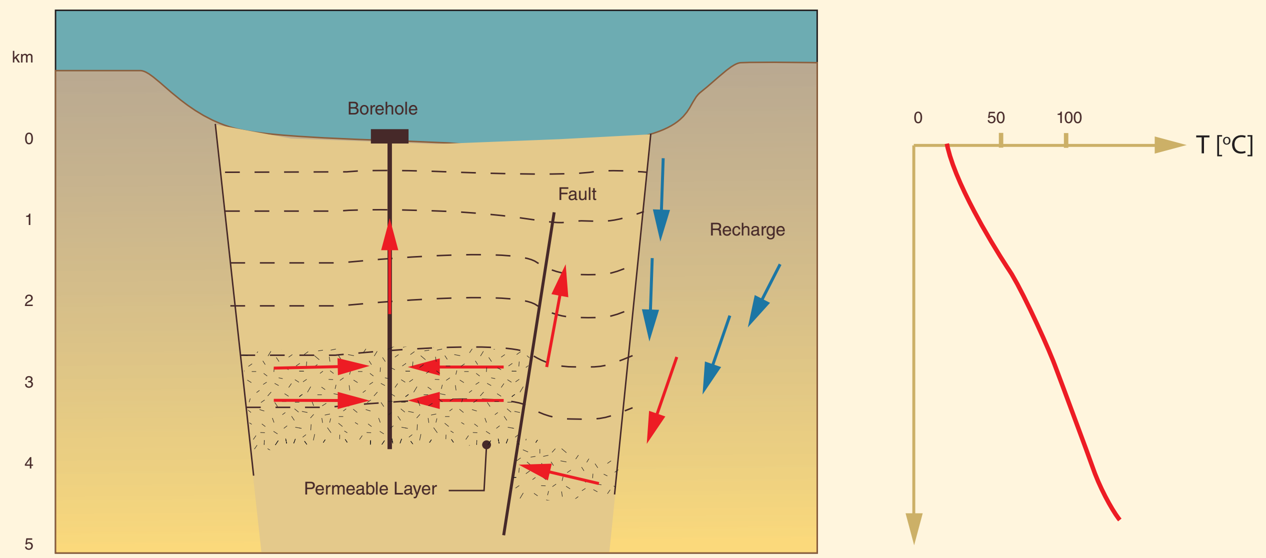
FIGURE 1.4
Conceptual Model of a High Temperature Field within a Rifting Volcanic System



Source | Saemundsson, Axelsson, and Steingrímsson 2011.

The temperature profile to the right represents the central part of the model.

FIGURE 1.5
Schematic Figure of a Sedimentary Basin with a Geothermal Reservoir at 2-4 km Depth



Source | Saemundsson, Axelsson, and Steingrímsson 2011.

The temperature profile to the right shows a typical sedimentary geothermal gradient profile.

permeability or are virtually impermeable; therefore, they cannot be exploited in a conventional way. However, experiments have been conducted in a number of locations to use hydro-fracturing, also known as “fracking,” to try to create artificial reservoirs in such systems, or to enhance already existent fracture networks. Such systems will mostly be used through production or reinjection doublets.[7]

BOX 1.1

What is a Geothermal System (as Opposed to a Reservoir, or Field)?

- **GEOTHERMAL SYSTEM** refers to all parts of the hydrological system involved, including the recharge zone, all subsurface parts, and the outflow of the system.
- **GEOTHERMAL RESERVOIR** indicates the hot and permeable part of a geothermal system that may be directly exploited. For a geothermal reservoir to be exploitable, it needs to have sufficient natural heat that transforms to pressure and brings the steam to the surface.
- **GEOTHERMAL FIELD** is a geographical definition, usually indicating an area of geothermal activity at the Earth’s surface. In cases without surface activity, this term may be used to indicate the area at the surface corresponding to the geothermal reservoir below.

Several EGS pilot projects have had problems with induced seismicity, which created minor earthquakes, and the commercial viability of the technology has not been successfully proven yet. The EGS technology will not be discussed in detail in this handbook.

Shallow resources refer to the normal heat flux through near surface formations (< 200 m deep) and to thermal energy that is stored in the rocks and warm groundwater systems near the surface of the Earth’s crust. Recent developments in the application of ground source heat pumps have opened up new possibilities for utilizing these resources.

Factors that Determine the Likely Use of a Geothermal Resource

The use of geothermal resources is strongly influenced by the nature of the system that produces them. Broadly speaking, the resources of hot volcanic systems are utilized primarily for electric power generation, whereas the resources of lower temperature systems are utilized mostly for space heating and other direct uses.

Consideration of a number of factors is required to determine the optimal use of a geothermal resource. These include the type (hot water or steam), rate of flow, temperature, chemical composition, and pressure of the geothermal fluid, and depth of the geothermal reservoir. Geothermal resources vary in temperature from 50° to 350°C, and can either be dry, mainly steam, a mixture of steam and water or just liquid water. Hydrothermal fields are often classified into high, medium, and low temperature fields. This division is based on inferred temperature at a depth of 1 km; high temperature fields are those where a temperature of 200°C or more is reached at a depth of 1 km; and low temperature fields are those in which the temperature is below 150°C at the same depth.

[7] A production well used to withdraw geothermal water/steam, combined with a reinjection well to return the water back into the reservoir, is called a doublet.

High temperature fields are all related to volcanism whereas low temperature fields draw heat from the general heat content of the crust and from the heat flow through the crust. Another temperature subdivision has been proposed, an intermediate or medium temperature system between the two main categories. Medium temperature fields have temperatures between 150° and 200°C and are included in this guide because they can be utilized for power generation by binary power plants, which are discussed later in this chapter.

Following a similar resource classification based on temperature, Table 1.1 summarizes their most likely uses and the technologies involved.

TABLE 1.1
Types and Uses of Geothermal Resources

RESOURCE TYPE BASED ON TEMPERATURE	GEOGRAPHICAL AND GEOLOGICAL LOCATION	USE / TECHNOLOGY
High: >200°C	Globally around boundaries of tectonic plates, on hot spots and volcanic areas	Power generation with conventional steam, flash, double flash, or dry steam technology
Medium: 150-200°C	Globally mainly in sedimentary geology or adjacent to high temperature resources	Power generation with binary power plants, e.g., ORC or Kalina technology
Low: <150°C	Exist in most countries (average temperature gradient of 30°C/km means that resources of about 150°C can be found at depths of about 5 km)	Direct uses (space and process heating, etc.) and, depending on location and power tariff offered, power generation with binary power plant

Source | *Authors.*

Pros and Cons of Geothermal Energy

The benefits of geothermal energy are many. The most obvious advantage may be the environmental benefits due to its fossil-fuel-free nature, a common feature of practically all renewable energy technologies.

There are several advantages that distinguish geothermal energy from other renewable energies. Geothermal power is ideally suited to operating around the clock as a stable source of base-load power, regardless of weather and other climatic phenomena. Such a resource helps utilities more accurately plan and schedule power generation to meet their load demand. Secondly, despite its relatively high investment costs per kilowatt installed, geothermal power has a fairly competitive cost per kilowatt hour produced as a result of its high availability factor[8] and the absence of combustible fuel costs. Over the long life of a geothermal plant, these two factors compensate for the high upfront investment costs. Thirdly, geothermal power is a technically and commercially proven and mature technology, unlike many other renewable energy technologies that are still relatively new and that involve a significant degree of technological risk. Finally, geothermal plants are scalable to utility size (over 50 MW) without taking up much land or space. This is a valuable feature for a power system as

[8] Geothermal power plants are extremely reliable and typically operate more than 95% of the time, with some plants at over 99%. This compares to availabilities of 60%-70% for coal and nuclear plants (Kutscher 2000). In this handbook, the availability factor of modern geothermal installations is generally assumed to be 90% when built and operated as intended. However, it must be noted that circumstances of specific geothermal projects built around the world vary widely. Many installations use outdated technology and some operate far below the originally intended capacity. The geothermal power output reported by IEA points to a world average capacity factor of less than 70% (WEO 2011).

it allows economies of scale to be achieved. From an environmental standpoint, this is also a plus if geothermal plants are located in areas of high scenic value, as they often are.

Given the advantages of geothermal power, the question has to be asked why the level of its utilization today is not higher than it is. The short answer from a geographic standpoint is that hydrothermal resources suitable for power generation are not found in every country. It is estimated that hydrothermal resources in the form of hot steam or fluids are only available on one-quarter to one-third of the planet's surface. Technologies and exploitation techniques that could increase this are not yet fully technically proven. The short answer from an investor's standpoint is that geothermal projects are risky, with exploration risk (or resource risk) often considered the greatest challenge as will be detailed later in this handbook. On a more technical level, the explanation is that many of the advantages of geothermal energy have limitations or offsetting factors.

The main advantages and downsides or challenges associated with geothermal power generation are summarized below as "pros" and "cons."

1 | PRO | Geothermal energy is a renewable source since the Earth endlessly generates heat at its core through radioactive decay. Even though geothermal power generation usually depends on a reservoir of hot water or steam (i.e., geothermal fluid), the volume extracted can be reinjected, making its exploitation sustainable when appropriately managed.

CON | In some individual reservoirs, pressure has dropped (or resources have become depleted) due to an unsustainably high withdrawal rate and/or failure to reinject the used geothermal fluid. Addressing problems associated with inadequate reinjection practices can be complex and costly.

2 | PRO | Utilization of geothermal power instead of fossil fuels, such as oil, gas, coal, etc., can reduce emissions of CO_2 and local air pollutants to low, often negligible levels per unit of energy produced.

CON | In certain resource areas, geothermal fluids or steam contain substantial amounts of hydrogen sulfide (H_2S) and other non-condensable gases (NCGs), such as CO_2, that can have environmental impacts if released to the atmosphere. However, since NCG have to be removed from the steam before it enters the turbine, geothermal fields with high NCG concentrations cannot be used for power generation.

3 | PRO | Geothermal power facilities require less land compared to hydropower with storage or coal power plants.[9] Their land requirements also compare favorably with those of grid-connected wind or solar power.

CON | Geothermal resources are often found in remote locations, requiring the construction of transmission connections and other infrastructure to make the sites accessible. This increases the indirect requirements for land (or rights of way). Location in areas of high scenic value can increase the licensing burden for companies.

4 | PRO | Geothermal power is practically free from dependency on fossil fuels, thus providing an excellent hedge against energy price shocks and contributing to energy security.

[9] Generally, an average geothermal power plant is estimated to use between one to eight (1-8) acres of land per megawatt, compared to 5-10, and 19 acres per megawatt for nuclear and coal power plants respectively. Large hydropower requires over 275 acres of land per megawatt for an adequate size reservoir (US DOE 2006).

FIGURE 1.6

The Pros and Cons of Geothermal Power

ADVANTAGE	DOWNSIDE/CHALLENGE
Globally inexhaustible (renewable)	Resource depletion can happen at individual reservoir level
Low/negligible emission of CO_2 and local air pollutants	Hydrogen sulfide (H_2S) and even CO_2 content is high in some reservoirs
Low requirement for land	Land or right-of-way issues may arise for access roads and transmission lines
No exposure to fuel price volatility or need to import fuel	Geothermal "fuel" is non-tradable and location-constrained
Stable base-load energy (no intermittency)	Limited ability of geothermal plant to follow load/respond to demand
Relatively low cost per kWh	High resource risk, high investment cost, and long project development cycle
Proven/mature technology	Geothermal steam fields require sophisticated maintenance
Scalable to utility size without taking up much land/space	Extensive drillings are required for a large geothermal plant

Source | Authors.

CON | The geothermal resource (heat or steam) cannot be traded and is location-constrained (the power plant cannot be situated too far from the resource). This reduces the choices for an efficient location of the power plant, which is often integrated into a single entity with the steam supplier. The constraint on location often entails the need for grid expansion and/or reinforcement.

5 | PRO | Geothermal provides reliable base-load power. Once a power plant is operational, it will produce a steady output around the clock, usually for several decades.[10]

CON | The ability of geothermal power plants to follow the demand for electricity is limited, and attempting to do so can increase power generation costs.

6 | PRO | Under favorable geological conditions, power generation from geothermal resources is amongst the least cost options for power generation and can in many instances compete with

[10] Geothermal plants are extremely reliable and typically operate more than 95% of the time, with some plants at over 99%. This compares to availabilities of 60%-70% for coal and nuclear plants (Kutscher 2000). In this handbook, the availability factor of geothermal installations is generally assumed to be 90%.

nuclear, coal, and gas on levelized generation costs.

CON | Despite the low levelized cost of generation that creates the promise of a reasonable profit margin, geothermal projects are not easy to finance. The high upfront risks, such as geological/resource risk, the need for high upfront investment, and the long project development cycle, make geothermal projects, especially in their exploration and test drilling phases, less attractive than other types of power generation projects for the private sector.

7 | PRO | Geothermal power generation has been around for more than a century and presents few technological unknowns. To produce electricity, conventional steam cycle turbine generation is usually employed. The operational risks and maintenance requirements are well known and manageable.

CON | A geothermal steam field requires sophisticated maintenance. In many cases, additional costs are incurred due to periodic drilling of make-up wells to replace older wells which have lost some of their steam production potential. Challenging problems with scaling[11] may also arise in specific areas where the field contains high levels of minerals, requiring the design of special features for the power plant, the use of chemicals, or the frequent cleaning of wells—all of which increase operational costs.

8 | PRO | Economies of scale can be achieved by sizing the geothermal plant to a utility scale (50 MW to several hundred megawatts). Land and space resources are less of a constraint to achieving the needed scale than with the case of most other power generation technologies.

CON | Extensive production well drilling is required for a large-scale geothermal plant, and can test the limits of sustainability of a given field in several ways. While proper reinjection can usually prevent reservoir depletion, the maximum capacity of the plant is limited ultimately by the reservoir's heat production capacity. Building one large power plant instead of several smaller ones in different locations may unnecessarily concentrate the resource risk. Also, while the area occupied by each production well will be modest, the area of the entire steam field may increase considerably, creating potential land use or environmental issues. In addition, the efforts to determine the optimal size of the plant in relation to the field may result in a longer lead time to the start of plant operation.

CURRENT UTILIZATION OF GEOTHERMAL RESOURCES

Electricity has been generated commercially from geothermal steam since the early 20th century, and geothermal energy has been used for direct heating purposes since ancient times.[12] However, the development of geothermal power generation started in earnest in the early 1980s and can be partially understood as a response by power producers to the first oil crisis in 1972. It has taken around 40 years to develop the existing 11 GW of currently installed power generation capacity (Figure 1.7).

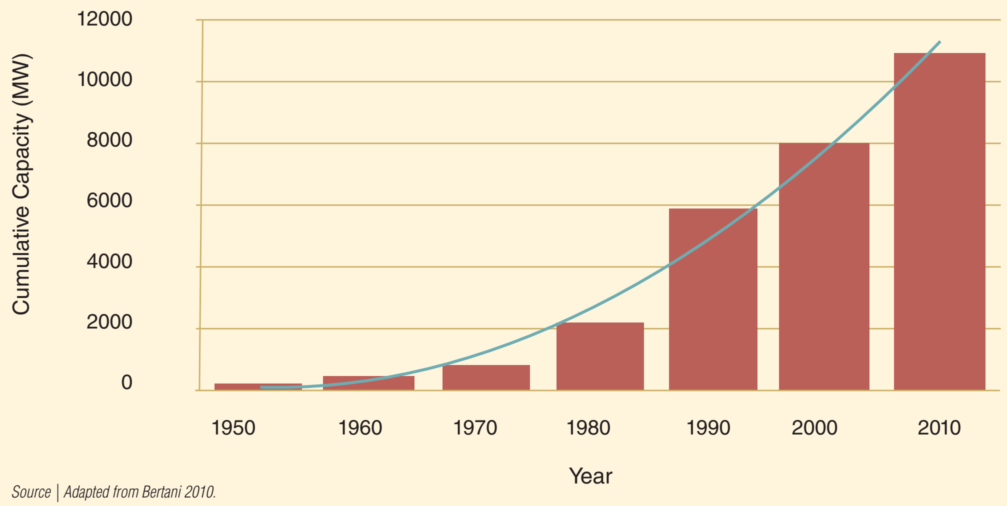
Geothermal resources have been identified in nearly 90 countries, with geothermal utilization recorded in more than 70 countries. As of 2010, electricity is produced by geothermal energy in 24 countries. Iceland and El Salvador have the highest share of geothermal power in their country energy mix,

[11] Scaling refers to the formation of a deposit layer (scale) on a solid surface (e.g., in a boiler, pipeline, heat exchanger or other equipment of the power plant) or within the steam field, including in the wells.

[12] The term "direct use" refers to applications other than power generation (e.g., home heating, bathing, greenhouses, cooling, etc.).

FIGURE 1.7

Global Geothermal Capacity from 1950 (in MW)

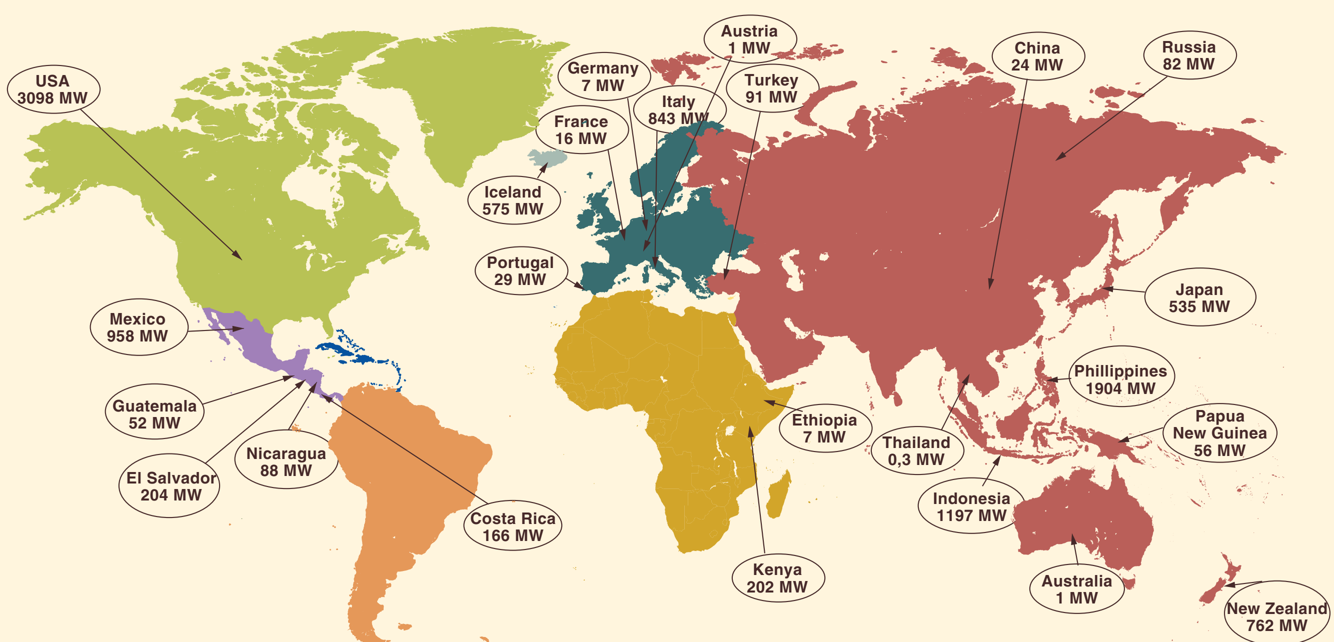


Source | Adapted from Bertani 2010.

generating about 25 percent of their electrical power from geothermal resources. The United States and Philippines have the biggest installed capacity of geothermal power plants, 3,000 MW and 1,900 MW, respectively. The 24 countries using geothermal resources for power generation are shown in Figure 1.8.

FIGURE 1.8

Geothermal Power: Installed Capacity Worldwide



Source | Based on Bertrani 2010.

Nearly 40 countries worldwide are considered to possess sufficient geothermal potential that could, from a technical rather than economic perspective, satisfy their entire electricity demand with geothermal power. The largest among these—with a total electricity demand equal to or exceeding 1 GW that could be met by geothermal power—are Indonesia, the Philippines, Peru, Ecuador, Iceland, Mozambique, Costa Rica, and Guatemala (Earth Policy Institute 2011).

TABLE 1.2

Geothermal Power Generation—Leading Countries

	INSTALLED IN 2010 (MWe)	COUNTRY TOTAL POWER GENERATION (GWh)	GEOTHERMAL GENERATION (GWh)	SHARE OF GEOTHERMAL (%)	POPULATION (2008), IN MILLIONS	MWe INSTALLED PER MILLION INHABITANTS
USA	3,093	4,369,099	17,014	0.4	307	10
Philippines	1,904	60,821	10,723	17.6	90.3	21
Indonesia	1,197	149,437	8,297	5.6	227.3	5
Mexico	958	258,913	7,056	2.7	106.4	9
Italy	843	319,130	5,520	1.7	59.8	14
New Zealand	628	43,775	4,200	9.6	4.3	146
Iceland	575	16,468	4,038	24.5	0.3	1,917
Japan	536	1,082,014	2,752	0.3	127.7	4
El Salvador	204	5,960	1,519	25.5	6.1	33
Kenya	167	7,055	1,180	16.7	38.9	4
Costa Rica	166	9,475	1,131	11.9	4.5	37
Sources |	*Bertani 2010*	*IEA 2009b*	*IEA 2008*	*Authors' calculations*	*World Bank data*	*Authors' calculations*

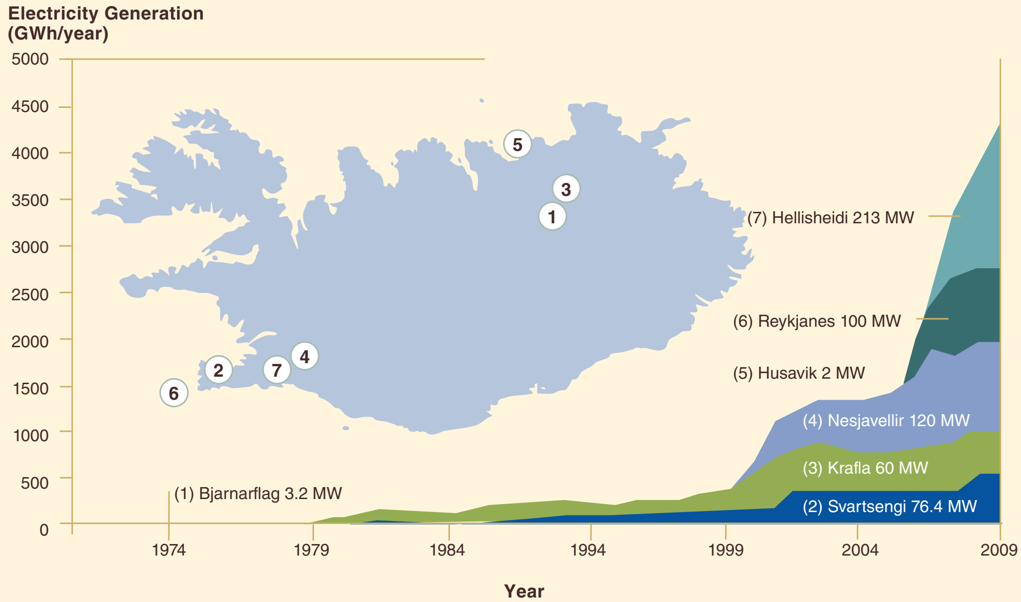
Note | MWe stands for megawatts electric, only power generation is considered.

Recent developments in Iceland are noteworthy with large increase in geothermal resource utilization taking place in recent years. In 2011, Iceland had an installed geothermal generation capacity of 575 MW, a reflection of the country's strong commitment to this form of energy. While 75 percent of Iceland's electricity is still generated from hydropower, around 25 percent comes from geothermal resources. Figure 1.9 shows the scale of current utilization.

A point to note is that, while Iceland built its geothermal industry at least three decades ago, large increases in geothermal resource utilization in the country started only in the early 2000s and further ramped up in just a few recent years, including the years of the economic crisis of 2008. This demonstrates that a country with rich geothermal potential and established industry can scale up its geothermal development program relatively rapidly given the political will. The motives for accelerated development of geothermal energy in Iceland have included the desire to diversify the energy supply sources away from the increasingly scarce and environmentally problematic hydropower; and pursue international leadership in geothermal development based on the know-how established at home.

FIGURE 1.9

Generation of Electricity Using Geothermal Energy in Iceland by Field, 1969 to 2009, Orkustofnun



Source | *NEA 2010.*

Geothermal Industry Snapshot

The geothermal industry is small relative to its conventional peers, but it contains numerous well established producers. In 2010, the global geothermal power industry had operational power plants with an installed capacity of around 11 GW, producing about 70,000 GWh that year. Based on revenues from electric power generation, the total turnover of the geothermal industry can be estimated to be between US$ 3.5 and US$ 7 billion per year.

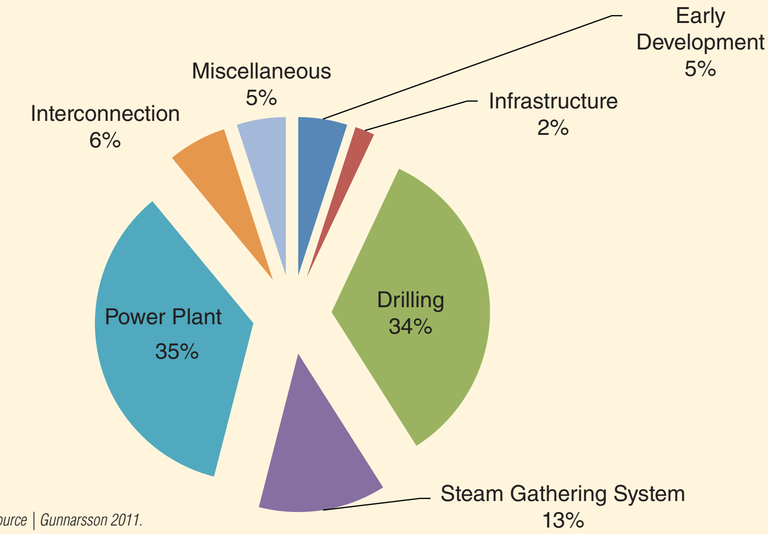
The geothermal power industry based on hydrothermal resources can be characterized as fully mature in terms of technology and its phase in the industry development cycle, but it has fairly attractive prospects for further growth in the medium to long term.

To understand the geothermal industry and its market structure, it is useful to start by breaking the geothermal power production process into components (or phases), each representing a separate line of company operations. The proportion of overall cost for each component is illustrated in Figure1.10, which is based on the case of Iceland and shows drilling (including test drillings)[13] and the power plant construction to be the two largest components in terms of cost or value added.

[13] The share of drilling costs at 34% in Figure 1.10 reflects the Icelandic experience. Internationally, this share tends to be somewhat higher (e.g., about 45% of the total project investment, as shown in Table 1.6).

FIGURE 1.10

Investment Cost Breakdown of Utility Scale Geothermal Power Development Based on Data from Iceland



Source | *Gunnarsson 2011.*

In principle, the market structure and competitive environment is different for each component in the value chain.

Table 1.3 describes key features of the market at each stage of geothermal power production. As the table shows, each development phase can be viewed as a separate business segment, with a market structure being anything from highly concentrated (oligopolistic), as in the case of manufacture and supply of geothermal turbines and generators, to highly competitive, as in the case of power plant construction and installation of steam gathering systems.

A peculiar feature of the drilling segment is the interaction with the oil and gas industry. Generally, while the drilling techniques for geothermal energy are somewhat different from drilling techniques for oil and gas, the type of equipment used in both cases is often the same. On the one hand, geothermal drillings can be done by oil and gas companies, contributing to greater geothermal production capacity and expanding the overall geothermal market size. On the other hand, the geothermal industry competes with oil and gas companies for drilling rigs, and this competition sometimes causes rig costs to rise to levels that are difficult for geothermal companies to pay.

The market environment for the manufacture and supply of power plant equipment for geothermal energy generation is very competitive for most types of equipment, except for turbines and generators (gensets), which currently are available from only a small number of large suppliers. Japanese companies currently have the largest share of the geothermal genset market. Combined, the three market leaders (Mitsubishi, Toshiba, and Fuji) have produced about or over 80 percent of all gensets sold to date. Ormat from Israel/USA and UTC/Turboden from USA/Italy are the market leaders for binary power plants, which are preferred for low and medium temperature resources (based on Bertani 2010).

TABLE 1.3

Market Structure of Various Segments of Geothermal Industry

DEVELOPMENT PHASE/ BUSINESS SEGMENT	INDUSTRY/MARKET STRUCTURE
Early Development	Approximately 5 companies worldwide specialize in early geothermal development/exploration as their main line of business.
Infrastructure	Infrastructure development (such as, access road work, drill pads, water and communication systems) is usually handled by the domestic construction sector.
Drilling	Less than 5 companies worldwide specialize in geothermal drilling as the main line of business; more than 20 additional companies worldwide (including large oil and gas and mining companies) may conduct geothermal drilling as a secondary line of business.
Geothermal Power Plant Equipment	Heat exchangers, cooling towers, condensers, pumps, valves, piping, etc., are off-the-shelf products, with many suppliers competing in the market.
Geothermal Turbines and Generators (gensets)	Competition in this segment is limited to 3 to 5 companies supplying large and medium size conventional flash turbines and generator units.
Power Plant Construction and Steam Gathering System	The market for power plant construction and pipeline installation is highly competitive, as this work can be performed by many steel work companies.
Interconnection	Substation and transmission line construction and maintenance is a highly competitive sector, using the same equipment as other power projects.
Operation and Maintenance	More than 20 companies worldwide, often assisted by local or domestic companies.
Miscellaneous	Feasibility studies and power plant design and engineering can be provided by more than 20 companies worldwide, partly assisted by local or domestic companies. However, only around 3 companies have a solid track record in the design of power plants when difficult geothermal fluids are involved.

Source | *Authors.*

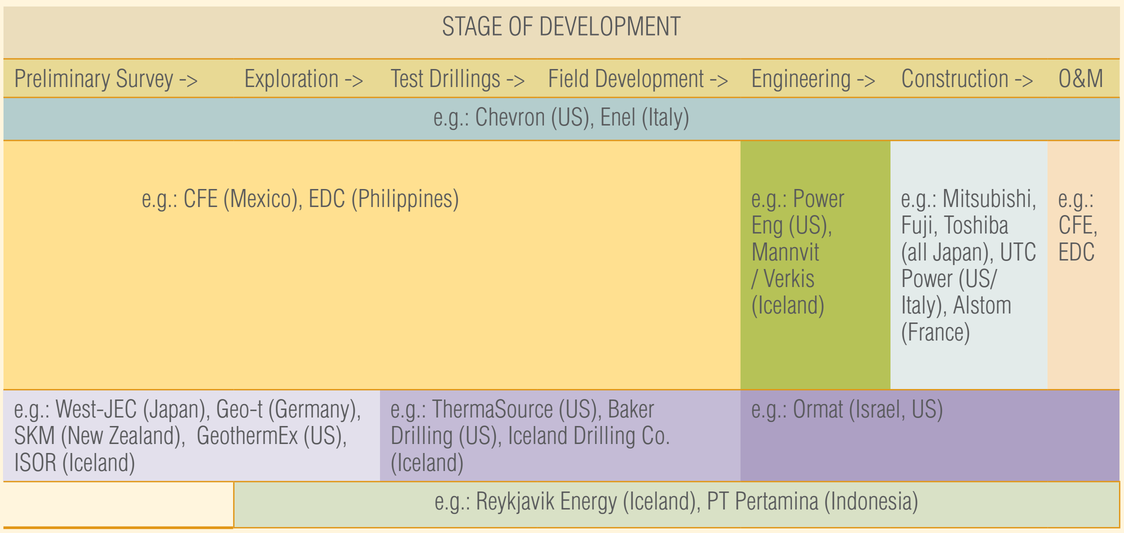
Once the equipment has been supplied, the construction of a geothermal power plant has to be done on-site, requiring a customized design in most cases. Geothermal expert knowledge is required for the lead contractor, but the marketplace for geothermal power plant construction itself is competitive. Smaller units, especially binary, can be purchased as turnkey units.

It should also be noted that although some companies operate in several production segments, only very few of them are vertically integrated in the sense of operating in all segments from early development to power plant construction and operation. Vertical integration requires a comprehensive set of technological know-how and technical expertise dedicated to geothermal power that is rarely found within one company. For example, exploration of the geothermal field can only be done by a company experienced in geosurvey techniques. Only a few power companies in the geothermal business have geosurvey and drilling competences and equipment in-house.

As further illustrated by Figure 1.11, some of the vertically integrated geothermal developers may be better known for their operations in other sectors, such as oil and gas (e.g., Chevron) or conventional electric power (e.g., Enel).

FIGURE 1.11

Geothermal Industry Structure



Source | Authors.

NOTE | The list of companies in the diagram is not comprehensive, and ESMAP/World Bank do not endorse any company mentioned in this report.

In terms of size of installed geothermal plant capacity owned and operated by a single company, the market leaders are listed in Table 1.4. The table shows the largest geothermal power producers, with installed capacity over 300 MW. In most cases, these companies are both steam field operators and power plant operators.

TABLE 1.4

Companies Owning Geothermal Capacity Over 300 MW in 2010

COMPANY	COUNTRY	CAPACITY INSTALLED (MW)	OPERATIONS IN COUNTRY
Calpine	USA	1,310	USA
Chevron	USA	1,087	Philippines/Indonesia
CFE	Mexico	958	Mexico
Enel Green Power	Italy	915	Italy/Latin America
Ormat	Israel	749	Globally (Binary)
EDC	Philippines	707	Philippines
Terra Gen	USA	337	USA
Contact Energy	New Zealand	335	New Zealand
Reykjavik Energy	Iceland	333	Iceland
CalEnergy Generation	USA	329	USA

Source | Based on Bertani 2010.

This list of the largest producers of geothermal electricity shows that they are usually either strong multinational companies (e.g., Chevron) or large, state-owned electricity utility companies (e.g., CFE from Mexico, or former state-owned companies like EDC in the Philippines) for which geothermal power generation is a secondary business. In some cases, geothermal power generation will be related to the producer's main business through mining and drilling activities; in other cases, it is linked to power generation or transmission.

The Largest Geothermal Fields of the World

Table 1.5 shows that the world's largest geothermal fields (in terms of installed power generation) are located in North and Central America, Italy, and Southeast-Asia.

TABLE 1.5
Geothermal Sites Generating Over 3,000 GWh/a (2010)

COUNTRY	NAME OF FIELD	ENERGY GWh	CAPACITY INSTALLED MW
United States	The Geysers	7,062	1,595
Mexico	Cierro Prieto	5,176	720
Philippines	Tongonan	4,746	716
Italy	Lardarello	3,666	595
Indonesia (Java)	Salak	3,024	377

Source | Based on Bertani 2010.

FUTURE UTILIZATION SCENARIOS

Both the theoretical potential and the technical potential for geothermal power generation are very large. However, for policy and investment decisions, it is the economic potential that matters: that part of the technical resource base that could be extracted economically in a competitive market setting at some specified time in the future. Over the short to medium term, the economic potential consists of sites that are known and characterized by drilling or by geochemical, geophysical, and geological evidence of a potentially commercially viable geothermal energy source.

Several experts have provided projections on the future development of geothermal power generation from hydrothermal resources. A well known approach originates from Italy (Bertani, 2010) and estimates that the globally installed capacity could reach 18 GW in 2015, and about 70 GW in 2050. The IEA tends to use the same approach (IEA 2011a). These targets are ambitious because they would require the installation of new geothermal power plants at a pace far exceeding the historical trend. They include the development of all economically viable projects worldwide, with a significant share coming from medium or low temperature development projects with binary power plants.

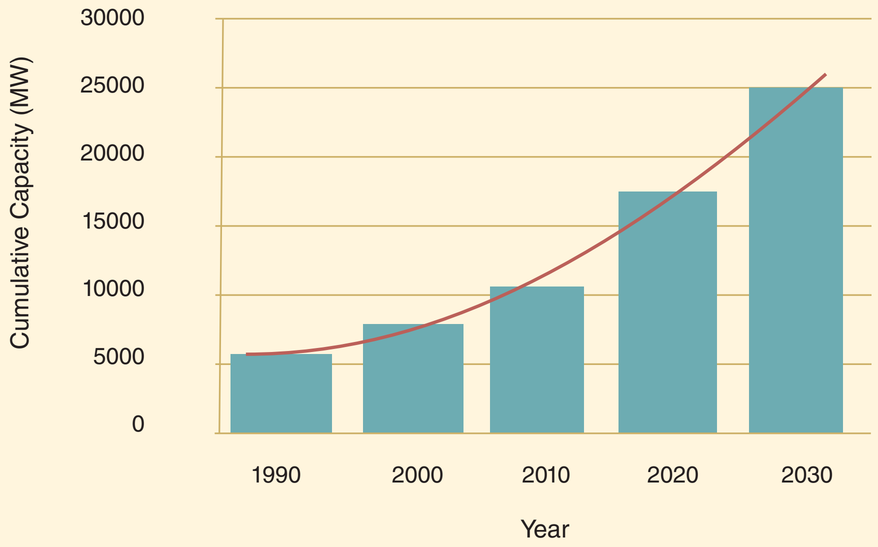
A more conservative approach, utilizing more modest projections for 2020 and beyond, is used for the purposes of this handbook. Based on information on currently planned projects and those that are actually under construction, by the year 2020 the worldwide increase in geothermal power generation (from hydrothermal resources only) is expected to take place in the following parts of the world:

- **Pacific Asia |** Indonesia, with its enormous geothermal potential, has a very ambitious power expansion plan and could develop an additional 2,000 to 3,000 MW within this timeframe. The Philippines will likely add less than 1,000 MW by 2020, depending on the success of government efforts in mobilizing private sector developers to invest in expansion of the existing geothermal capacity. Malaysia and Papua New Guinea also offer notable prospects. Other countries in the region might develop several projects, but are not likely to contribute greatly to the global increase.
- **Africa |** Apart from Pacific Asia, the East-African Rift Valley is the region with the strongest hydrothermal potential. In this region, Kenya leads in developing geothermal power. With the full backing of the Kenyan government and encouraging institutional developments, including the recent creation of a dedicated public company, Geothermal Development Company (GDC), Kenya is planning to add 2,000 MW of capacity by the end of this decade. Such development, however, still depends on the ability to exploit new geothermal fields, and information about the resources there still remains limited. Based on 2011 project preparations, Djibouti and Ethiopia are the other countries in the region likely to increase their installed capacity by 50 to 200 MW. The situation in the countries of the western branch of the Rift Valley (Zambia, Burundi, Rwanda, the Democratic Republic of Congo, and Uganda) is more uncertain, because they have not yet conducted test drillings to prove the commercial viability of potential resources. Nevertheless, due to strong interest from their governments and promising results from exploratory activities, some pilot projects might be developed. Tanzania, Eritrea, Sudan, Somalia, Malawi, Mozambique, Madagascar, Comoros, and Mauritius, and several North African countries also offer good prospects.
- **Latin America |** Mexico, Costa Rica, Nicaragua, and El Salvador are likely to continue developing new geothermal power projects with a total added capacity of 500 to 1,500 MW by 2020. Other countries (e.g., Peru, Chile, and Argentina) might start developing their first projects before 2020. Guatemala, Honduras, Panama, Colombia, Ecuador, Bolivia, and several Caribbean island states, including Cuba and Haiti and Dominica, also offer good prospects.
- **United States, Japan, New Zealand, and Iceland** are well-established producers and are likely to continue developing geothermal power projects. Japan, with a significant geothermal potential, might consider increasing its focus on geothermal after its 2011 nuclear incident. However, in the conservative projection made here, no significant increase in capacity in any of these countries, except the United States, is expected by 2020.

Any additional installed capacity would come from Indonesia (2,500 MWe); followed by Kenya (1,500 MWe); the Philippines (500 MWe); Ethiopia, Djibouti and Rwanda (400 MWe in total); Central America and Mexico (800 MWe in total); and the United States (800 MWe). These figures represent a total of 6,500 MWe of new installed capacity worldwide by 2020. If added to the 11,000 MWe installed in 2011, this results in an estimated 17,500 MWe of newly installed capacity by 2020.

FIGURE 1.12

Projected Global Geothermal Capacity until 2030



Source | Authors.

Assuming the same capacity growth rate through 2030, the global geothermal capacity installed by then could be about 25,000 MWe. Additional capacity can be expected to come from the current front runners (USA, Mexico, New Zealand, Japan, and Iceland), as well as from some European countries (e.g., Italy, Greece, Balkan countries), Turkey and its eastern neighbors, and several Middle Eastern countries, such as Yemen. Australia and some South Pacific island states also may be able to utilize their hydrothermal resources for power generation.

Looking to 2050, significant additions in installed capacity also can be expected in the following countries and regions:

- **Pacific Asia |** Malaysia, Papua New Guinea
- **Africa |** Tanzania, Eritrea, Sudan, Somalia, Malawi, Zambia, Burundi, Rwanda, Uganda, Democratic Republic of Congo, Mozambique, Madagascar, Comoros and Mauritius, and several North African countries
- **Latin America |** Guatemala, Honduras, Panama, Colombia, Ecuador, Bolivia, and several Caribbean island states, including Cuba and Haiti

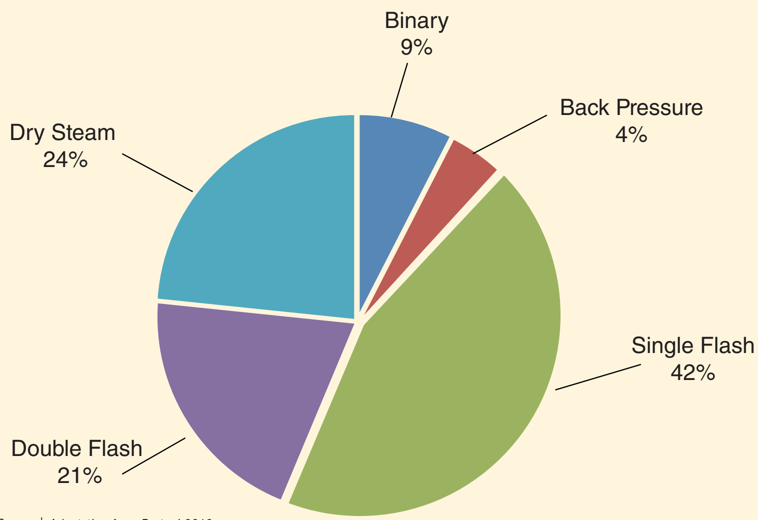
TECHNOLOGY OVERVIEW

Power Generation by Available Technologies

This handbook follows a standard classification based on the definitions for five different types of power plants: binary, single flash, double flash, back pressure, and dry steam. The relative share in power generation in 2010 for each of these technologies is reflected in Figure 1.13. No other technologies are used to generate power from geothermal resources. Utility scale electricity generation mainly takes place in conventional steam turbines and binary plants, depending on the characteristics of the geothermal resource.

FIGURE 1.13

Geothermal Power Generation by Various Technologies, 2010 (% of total 67 TWh)



Source | Adaptation from Bertani 2010.

Single or Double Flash Plants: Condensing Units or Conventional Steam Cycle

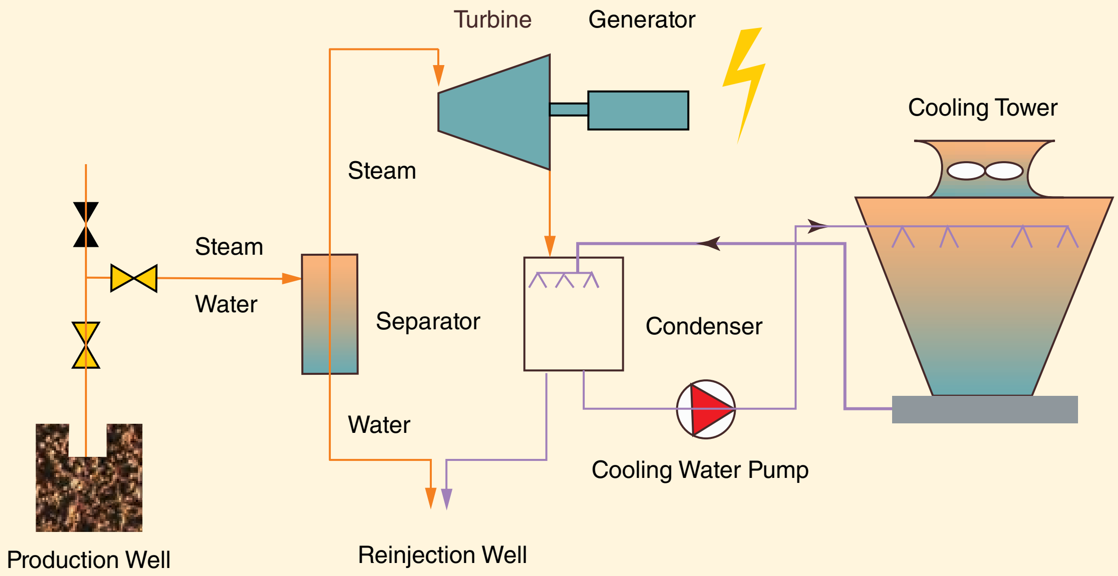
Commonly built in sizes from 25 to 60 MWe, a "condensing unit" (also called a conventional steam cycle) is the standard technology used to generate power from fluid or steam with temperatures above 200°C. In Figure 1.14, the flow of high temperature fluids is indicated in red and the flow of the cooling water in blue.

The most common version of the condensing unit is the single flash steam plant, usually the most economical choice for high-enthalpy liquid dominated resources. The hot water or liquid vapor mixture coming from the wellhead is directed into a separator, where the steam is separated from the liquid. The steam is expanded through a turbine and then usually reinjected, together with the separated brine, back into the reservoir. The brine could, however, be used by a "bottoming unit"[14] or in another application, such as heating, cooling, or multiple use.

[14] Bottoming units use the residual heat from the main power plant to generate additional power.

FIGURE 1.14

Concept of Condensing Geothermal Power Plant



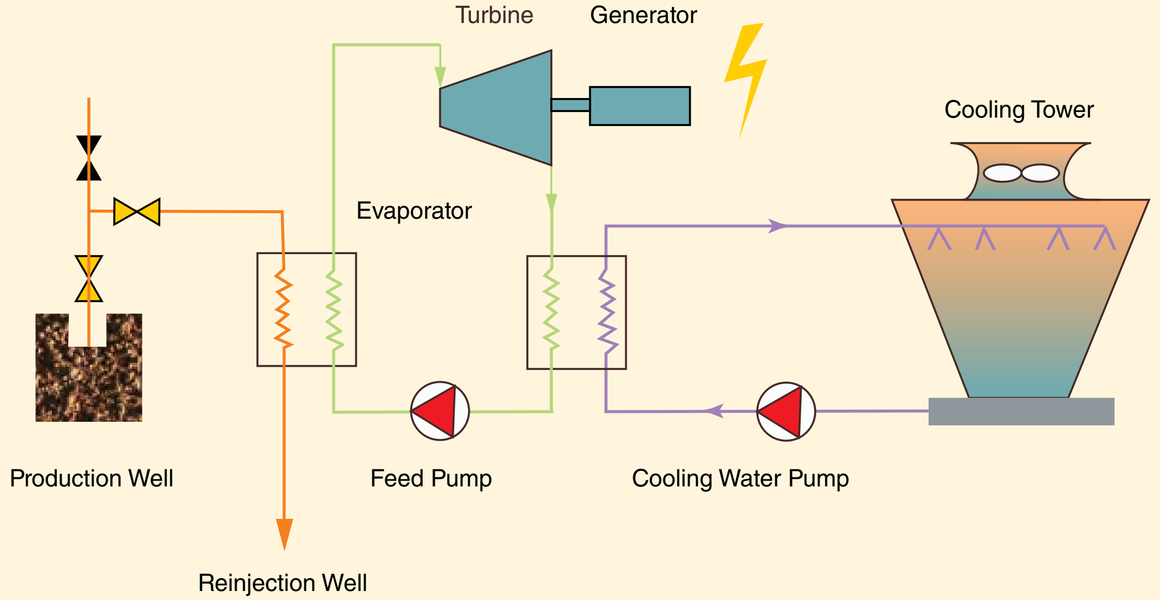
Source | Modified from Dickson and Fanelli 2004.

A double flash steam cycle differs from a single flash cycle in that the hot brine is passed through successive separators, each at a subsequently lower pressure. The steam is directed to a dual-entry turbine in which steam at different pressures flow to different parts of the turbine. This increases overall cycle efficiency and better utilizes the geothermal resources, but at an overall increase in capital cost. The decision as to whether or not a double flash plant is worth the extra cost and complexity can only be based on a thorough economic evaluation of the cost of developing and maintaining the geothermal fluid supply, the power plant costs, and the value of the electricity to be sold (Bloomquist and Knapp 2002).

Binary Plants

Generating electricity from low or medium temperature geothermal fluids and from the waste hot fluids coming from separators in liquid-dominated geothermal fields has made considerable progress since improvements were made in binary fluid technology. Binary plants utilize a secondary working fluid, usually an organic fluid (typically n-pentane) with a low boiling point and high vapor pressure at low temperatures as compared to steam. The secondary fluid is operated through a conventional Rankine cycle: the geothermal fluid yields heat to the secondary fluid through heat exchangers, where the secondary fluid is heated and vaporizes. The vapor produced drives a turbine, then is cooled and condensed, and the cycle begins again.

FIGURE 1.15
Concept of Typical Binary Power Plant, ORC, or Kalina



Source | Modified from Dickson and Fanelli 2004.

Binary plant technology is a cost-effective and reliable means of converting the energy available from liquid-dominated geothermal fields with temperatures up to 200°C into electricity. By selecting suitable secondary fluids, binary systems can be designed to utilize geothermal fluids with temperatures well below 100°C. However, such low temperatures would severely impact the financial viability of projects, depending on their location, their direct use options, and the power tariff offered.

Competing with the above mentioned Organic Rankine Cycle (ORC) plants, another binary system, the Kalina cycle, utilizes a water-ammonia mixture as the secondary working fluid. This technology was developed in the 1990s and is used commercially, particularly in Iceland and Japan.

Binary power plants are commonly used as bottoming units. In these applications, the binary plant uses the waste fluids coming from the separators as well as the residual heat from a main power plant. For example, steam with a temperature of 250°C which is utilized by the main power plant (usually a conventional steam (flash) plant) can, depending on fluid chemistry, have a temperature when leaving the turbine of 120° to 170°C after expansion. Instead of condensing this steam by means of air-cooling or cooling towers, it can be efficiently used to generate more power by the bottoming unit and thereby increase the overall efficiency and economy of the entire power plant unit. However, bottoming units add significantly to total project costs. These costs affect the power generation costs per kilowatt hour and might reduce the margin between generation cost and the power tariff paid by the off-taker or utility company. The resulting reduction in operational profit is the reason why project developers do not deploy bottoming units in many cases. On the other hand, from the country perspective, producing 10 to 20 percent more power out of the same resource could be very economic, since installation of a few bottoming units could easily substitute for building an entire new power plant in terms of output. In addition, due to each geothermal reservoir's limited potential for steam production, it could be worth considering using the resource as efficiently as possible and evaluating the value of specific policy incentives to ensure that the economics and financials of such projects match.

Binary units can be produced in very small sizes (0.1 to 5 MW), even as container module units. Small mobile plants can not only reduce the risk inherent in drilling new wells but also help meet the energy requirements of isolated areas.

Other Technologies

Dry steam | Dry steam technology can be used when a geothermal reservoir produces pure hot steam, as in some areas of the United States (especially California), Italy, Indonesia, and to a lesser extent Japan and New Zealand. The technology is similar to flash or conventional steam, except a separator to separate fluids and steam is not necessary; units are large and operate with high efficiency.

Back pressure units | Back pressure units are steam turbines that exhaust the incoming steam, whether dry or wet, directly to the atmosphere. This makes them compact, simple to install and run and the cheapest choice available. However, they are normally used for a limited amount of time (e.g., as test units or wellhead generators) until a better solution can be found, since the absence of reinjection hampers the long term use of geothermal power generation. Back pressure units have a lower efficiency relative to the other technologies mentioned above, which means they generate significantly less power from the same amount of steam. They can, depending on the chemical composition of the fluids and steam, be hazardous to the environment.

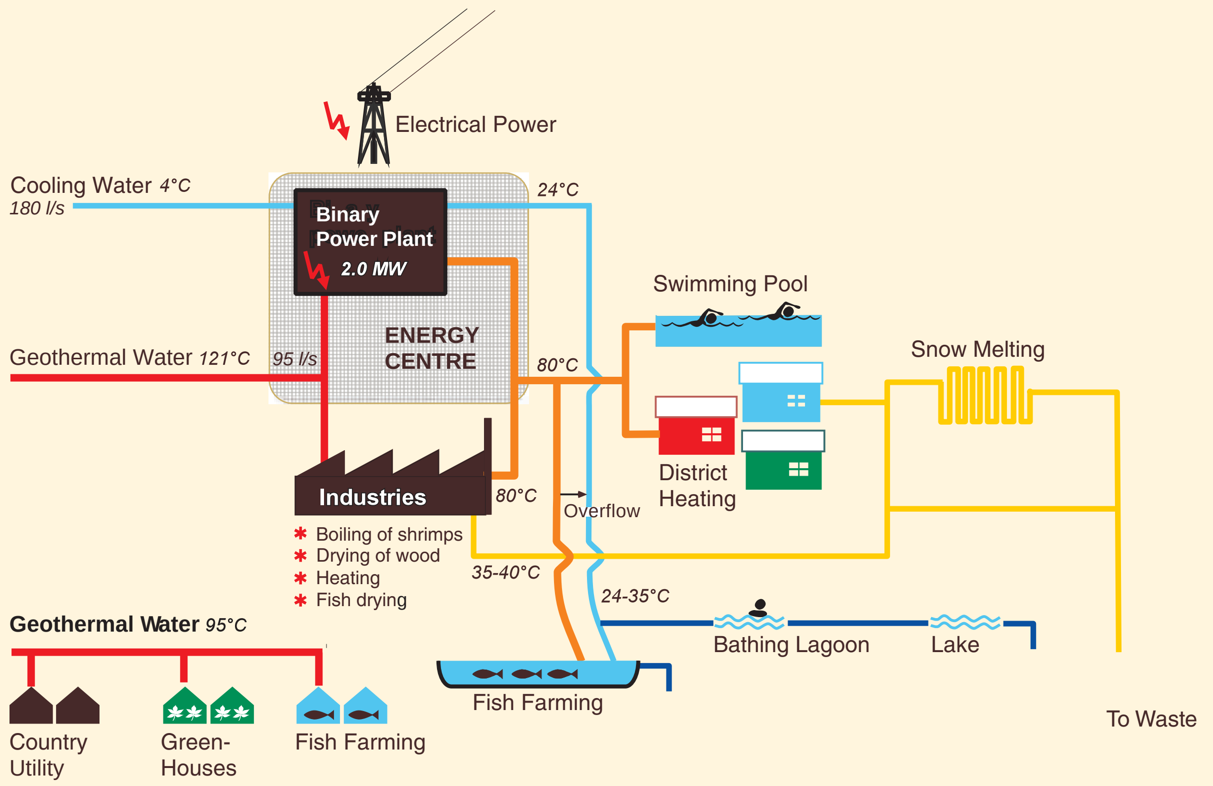
Utilization of Residual Heat from Geothermal Power Plants

Although this handbook focuses primarily on electric power generation, the direct uses of geothermal heat—as well as the possible uses of residual or waste heat from power plants and the use of geothermal fluids for heating, cooling, and mineral extraction—are assessed by developers and policy makers in most geothermal energy producing countries. Once a geothermal power plant is operational, it can also be used in multiple ways to enhance the project's overall economic result. This is referred to as multiple use, cascaded use, or utilization of residual and waste heat.

Figure 1.16 is an idealized diagram showing cascaded use of geothermal energy, based on the example of a small (2 MW) binary power plant in Iceland. The plant is located as far as 18 km from its wells and uses the residual heat of the fluid (after power generation) for nearby industries (e.g., food industry), domestic heating for the entire town, fish farming, and snow melting on streets. As a result, the energy contained in the fluids is almost completely used. Geothermal power plants also can be connected to industries that produce waste heat, such as steel mills or waste incinerators. Their waste heat can be used to enhance the temperature of the geothermal fluid and increase power production.

FIGURE 1.16

Idealized Diagram Showing Multiple Use of Geothermal Energy



Source | ÍSOR (Iceland Geosurvey), 2005, direct communication.

The options for multiple use of energy—as well as the fact that small modular binary units with up to 5 MW capacity are readily available and easy to install and operate—make geothermal power generation a feasible option for smaller installations in remote and even off-grid locations, especially when they replace existing and more costly fossil fuel generation.

In general, the revenue stream from the residual heat use can improve the overall financial viability of both small-size or industrial-scale (over 25 MWe) power projects, with additional revenue coming from the:

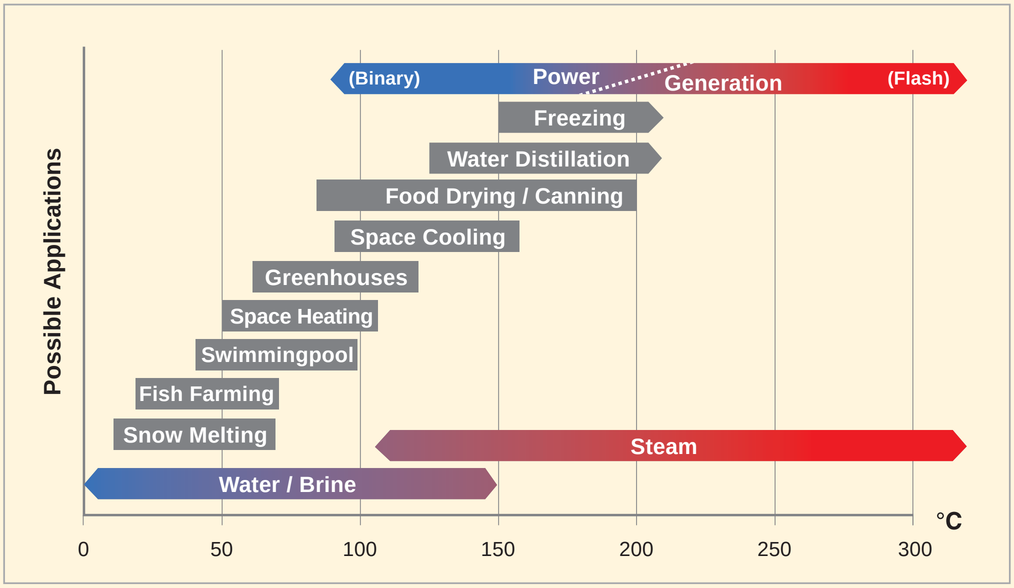
- sale of agricultural products grown in greenhouses (e.g., flowers, plants or vegetables),
- extraction of CO_2 from geothermal fluids for industrial purposes (e.g., the soft drink industry),
- fish or shellfish or other aquaculture products,
- dehydration (drying) of fruits, nuts and other food products,
- desalination of seawater for drinking water,

- use of residual heat for industrial processes (e.g., chemical and biological),
- sale of hot water for district heating or cooling purposes, or
- extraction of valuable minerals and salts from the geothermal fluids (e.g., silica, manganese, zinc, and lithium).

These options are site dependent; some geothermal sites may offer several of these options simultaneously while others may offer none. A more comprehensive overview on how geothermal fluids and steam can be utilized, depending on their temperature range, is given in Figure 1.17.

FIGURE 1.17

Modified Lindal Diagram Showing Applications for Geothermal Fluids



Source | *Authors.*

Coproduction by Extraction from Geothermal Fluids

Coproduction (the production of silica and other marketable products from geothermal brines) could become a viable source of additional revenue for power plant owners. It is also a key technique for improving power plant economics by reducing operation and maintenance costs. The removal of silica may allow additional geothermal energy extraction in bottoming cycles (usually binary power plants using the waste heat from the flash or conventional steam cycle) or additional uses of low-grade heat that are presently prohibited due to scaling problems.

Precipitated silica has a relatively high market value (US$ 1 to 10 per kg) for such uses as waste and odor control, or as an additive in paper, paint, and rubber. Silica removal has the additional benefit of helping to minimize fluid reinjection problems, and, at the same time, opens the door to the extraction of minerals (e.g., zinc, manganese, lithium), all with relatively high market values. The first commercial facility for the recovery of zinc from geothermal brine was built in the Salton Sea geothermal area of southern California in 2000. The facility was designed to produce 30,000 metric tons of 99.99 percent pure zinc annually at a value of approximately US $50 million, while the market value of extracted silica was estimated at US $84 million a year. The plant was unfortunately decommissioned due to depressed zinc prices and some operational difficulties (Bloomquist and Knapp 2002 and updated information from Bloomquist in 2011).

GEOTHERMAL POWER ECONOMICS

Determination of Power Plant Size by Demand Analysis

Two factors strongly determine the highest possible installed capacity, and thereby power generation, of a geothermal power plant: (a) the share of demand for electricity in the country or within the system that can be satisfied from the plant, and (b) the potential of the geothermal reservoir.

The electric load within a country depends on the adequacy of power generation on one hand and the consumption of electricity on the other. The system only functions if generation and demand are the same at all times.

Figure 1.18 presents an example of a country's load curve, in this case with two daily peaks corresponding to additional electricity use for lighting, air-conditioning, or entertainment. Depending on the country, load curves have different shapes, according to the system demand they reflect.

Geothermal power plants are typically not equipped to follow system demand and are usually deployed to provide base load to the system, as shown in Figure 1.18. Other power sources, such as diesel generators and hydropower plants, can adapt more quickly to demand. Along with gas power plants, these generation sources can be used to track the load within the system. Dispatching various power sources depends on whether they can be used for base load or for peaking operations, and on how fast they can adapt to changes in system demand. It is common practice to grant priority dispatch to geothermal power, as well as to most other forms of renewable energy, in order to decrease the use of fossil fuels and to make the water in reservoirs used for hydropower available over a longer period of the year. Therefore, as a general proposition, the combined size of a country's geothermal power plants should not exceed the minimum system demand unless:

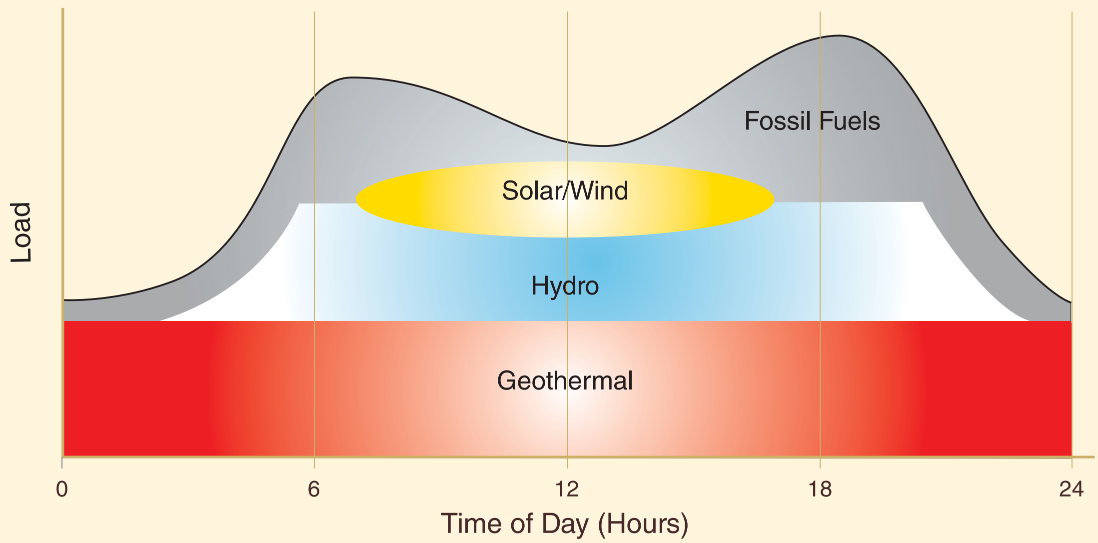
- the excess power generated can be exported through a transmission interconnection to neighboring countries;
- geothermal power plants are equipped with load tracking controls. This is likely to induce additional investments in control valves, heat exchangers, and, in some cases, even turbines and generators, which would of course impact the financial viability of the project. Load tracking is easier to do with medium temperature binary power plants, especially if the production wells are equipped with pumps; or
- a turbine bypass is installed, allowing the steam to be routed past the turbine and through

a gas treatment facility to avoid the potential environmental impacts of a direct release to the atmosphere.

If none of the above options are available, the geothermal plant size should be dictated by the smallest

FIGURE 1.18

Simplified Load Curve with Typical Fuel Sources



Source | Authors.

system demand throughout the entire year. For example, suppose a country's system demand is normally above a given level over a given timeframe (one year), according to data from the power regulator or utility. However, every year during a three months period, the demand happens to fall significantly below that normal level. In this example, geothermal power capacity for such a country should not exceed the capacity that is required to satisfy the demand during the three months period that reflects the lowest point of the load curve. This is the system demand that can always be maintained by the system and therefore installed geothermal capacity should not exceed this level at any time. Other power sources should be deployed to satisfy the remaining demand for electricity.

Besides the level of system demand, the other major factor influencing the size and capacity of a planned geothermal power plant is the reservoir's potential. International best practice is to develop geothermal plants in steps depending on the estimated potential (which is based on scientific exploration) and on the results of test drillings. For high temperature geothermal power projects, common steps are between 30 and 60 MW per power unit (genset) installed. This means that geothermal power projects cannot be regarded as a quick fix for any country's power supply problems, but should rather be part of a long term strategy. Operating the initial unit for some years will provide valuable information about the reservoir's dependable potential and thereby facilitate fact-based planning for future expansions of the power facility.

Respecting the Limits of Sustainability

In cases where the exploration program for a given geothermal field shows very positive results and where electricity demand is sufficient, it is tempting for the developer to assume that it should be possible to build a large power plant in just one step to capture the entire productive capacity of the geothermal field. However, even if reinjection is done as required, oversizing the plant may result in exceeding the productive capacity of the geothermal resource.

BOX 1.2

Lessons to Learn from The Geysers Field in California

In the 1970s, The Geysers field in California was drilled by four independent private companies who failed to properly coordinate exploitation activities. The combined installed capacity of all power plants built during this decade surpassed 2,000 MW. Too many wells were drilled, reservoir pressure dropped precipitously, and still more wells were needed to supply enough steam to the turbines at the required pressure. This led to a severe reduction of power capacity at The Geysers. Subsequently, the steam pressure decline was abated by increasing the reinjection percentage to its maximum and adding sewage water from nearby cities, only to stabilize it at about half of its historic peak.

Source | Calpine 2010.

Exceeding productive capacity may also result from a lack of coordination among the developers of a shared geothermal reservoir.[15] Several projects, the best example being "The Geysers" in California, U.S. (Box 1.2), have faced this problem. In some of those examples of poor coordination, the outcome was partial or total loss of the investment due to loss of the productive capacity of the resource.

Subsequently, geothermal developers have learned to utilize a more judicious approach. To minimize the risks of pressure drops or reservoir depletion, geothermal plant capacity should be expanded in increments of about 30 to 60 MW at a time. If the investment budget allows, several geothermal power projects can be developed in parallel, exploiting different fields. This approach increases the supply faster, more economically, and with less geological risk than does an attempt to capture the entire capacity of a field in one go (as discussed further in Chapter 3).

Investment Cost Estimates

Table 1.6 presents an indicative cost analysis for development of a typical 50 MW greenfield project in a geothermal field with drillings of around 2 km in depth. Power plants of up to 50 MW can often constitute a suitable first step unit, which can be expanded or multiplied at a later stage, or remain as the final unit. Industry practice for well depths is usually between 1.5 and 3 km, with an international average of around 2 km which will be used for the following calculations. The cost figures include all exploration and drilling costs, as well as estimated financing costs for the development of a hydrothermal reservoir for power generation.

[15] The problem is known in economic theory as the "Tragedy of the Commons."

TABLE 1.6

Indicative Costs for Geothermal Development (50 MW ex generator capacity), in US$ Millions

PHASE / ACTIVITY		LOW ESTIMATE	MEDIUM ESTIMATE	HIGH ESTIMATE
1	Preliminary Survey, Permits, Market Analysis[16]	1	2	5
2	Exploration[17]	2	3	4
3	Test Drillings, Well Testing, Reservoir Evaluation[18]	11	18	30
4	Feasibility Study, Project Planning, Funding, Contracts, Insurances, etc.[19]	5	7	10
5	Drillings (20 boreholes)[20]	45	70	100
6	Construction (power plant, cooling, infrastructure, etc.)[21]	65	75	95
	Steam Gathering System and Substation, Connection to Grid (transmission)[22]	10	16	22
7	Start-up and Commissioning[23]	3	5	8
	TOTAL	**142**	**196**	**274**
	In US$ Million per MW Installed	2.8	3.9	5.5

Source | Authors.

Costs of Energy Generated

Investment costs per installed megawatt can vary widely as Table 1.6 indicates, depending on the country, region, geology, infrastructure in place, and difficulty in exploring and drilling the field. The distance to the next transmission grid access point is also an important factor. As geothermal projects usually have a long and stable operation period with a utilization time of several decades, the figures presented in the table above would translate into the following actual levelized cost of energy (LCOE)[24] per kWh generated in several countries (Table 1.7). Only in very rare instances are official figures released by governments or private operators about actual LCOE for generation from geothermal resources. Therefore, in most cases an indicative price range will be provided with a relevant rationale.

[16] Costs for survey depend heavily on size and accessibility of area. Costs for EIA depend on country regulations.

[17] Depending on methods used and accessibility and size of area.

[18] For 3 to 5 drillings with variable depths and diameter, from slim hole to full-size production wells (over 8 inch diameter).

[19] Studies and contracts provided by external suppliers or own company. Conditions and regulations of relevant country.

[20] Depending on depth, diameter, and fluid chemistry, casings and wellhead requirements in terms of pressure and steel material/coating. Also influenced by underground and fractures (drilling difficulty and time).

[22] Depending on distance from plant to transmission grid access point, and on distance between boreholes and power plant.

[23] Standard industrial process. Power plant may need fine tuning for some time and minor adaptations. For high estimate, major changes, repairs and improvements are needed to supply power according to PPA.

[24] The term “Levelized“ refers to average costs discounted over the project life cycle, usually 20 to 30 years, including all costs.

The cost figures in Table 1.7 are similar to those obtained in a 2007 ESMAP study, in which average LCOE was calculated as US$ 0.0427 per kWh for an investment of around US$ 2.6 million per MW installed. A recent United Nations Environment Program (UNEP) report (2009) indicates that in 2008, US$ 2.2 billion was invested in geothermal energy development—the highest among renewable energy technologies and up 149 percent from 2007. According to UNEP, the total of 1.3 GW of new installed capacity was primarily attributed to its competitive levelized cost of energy (US$ 0.044 to 0.102 per kWh), the reliability of geothermal electricity production, the absence of fuel cost and long plant lifetimes.

TABLE 1.7

Observed Indicative Power Generation Costs in 2010

COUNTRY	PROJECT AND / OR SIZE	US$ PER KWh	COMMENTS
Costa Rica	4 projects total 200 MW	US$ 0.04 - 0.05	Figures from ICE[1]
Philippines	Existing total 2,000 MW	US$ 0.04 - 0.055	Privately owned, but mostly built by public companies and then privatized. Own estimate built on utility power purchase price
Indonesia	Total 1,000 MW	US$ 0.045 - 0.07 < US$ 0.097	Estimate built on study[2] Tariff ceiling set by government
Ethiopia	Planned 35 MW plant	US$ 0.05 - 0.08	Estimate
Kenya	Existing 130 MW units Planned 280 MW in 4 units	US$ 0.043 - 0.064 < US$ 0.08	KenGen's Expansion Plan 2008[3] Tariff ceiling set by government, but 10-20% lower according to Kenyan sources[4]
Iceland	500 MW in large units	US$ 0.03 - 0.05	Estimate[5]; Power sold to aluminum companies for contract price
Mexico	960 MW in total	US$ 0.08	Average costs for all units[6]

Notes | [1] P. Moya 2009; [2] World Bank Study 2010; [3] Simiyu; [4] Business Daily 2010; [5] Johannesson 2011; [6] Quijano 2010.

Source | Authors.

It must be noted that financing costs (including interest during construction and the overall cost of capital by which the cash flows are discounted) can affect the geothermal generation costs considerably. The costs and tariff levels included in Table 1.7 generally cover the costs of capital from public sources. In those cases where the developer relies on private sources of financing, tariffs fully covering the costs would tend to be higher. The financing aspects of geothermal development are discussed further in Chapter 3.

Comparison with Other Technologies

As for any other power generation project, developing a geothermal project requires that the resources involved be economically justified. In general, this means that the project becomes part of a least cost development plan, taking into account the alternative resources that a given country can develop within the planning timeframe. These include thermal options based on fossil fuels, such as coal, fuel oils of different grades and prices, and natural gas, as well as renewable resources other than geothermal, such as hydropower, wind, and solar.

The economics of different resources can be compared by taking the different cost characteristics and computing the LCOE which will vary according to investment costs, fuel costs, fixed and variable operation and maintenance costs, useful life span, and the discount rate. Table 1.8 provides the basic parameters of a set of alternative development options that illustrate a range of different possibilities. They include:

- Medium Speed Diesel motors (MSD), which operate typically on Heavy Fuel Oil (HFO), equivalent to FO #6 and provide a full range of capacity factors. Their fuel cost varies in conjunction with the oil price for engine sizes that do not usually exceed 20 MW.
- Steam turbines using HFO or coal. Steam turbines exhibit economies of scale, which normally have sizes in excess of 100 MW. In the case of coal, investment costs vary widely depending on the environmental mitigation equipment required (which will depend on the grade of the coal), as well as on fuel treatment requirements.
- Combustion turbines operating with either gas oil (e.g., FO #4) or natural gas. They may be either simple cycle or combined cycle, in which case there is a steam turbine powered by heat extracted from the exhaust gases of the combustion turbine. Sizes usually do not exceed 150 MW. Modern combustion turbines are designed to operate on heavier fuels.
- Small wind turbines, which are site specific and typically installed to serve as a complement to larger systems. Their capacity factor is typically quite low (approximately 20 to 30 percent).
- Large wind turbines, also site-specific, which are normally installed in favorable sites to provide capacity factors of up to 40 percent.
- Hydropower plants, with costs that may vary widely depending on physical location characteristics and the hydrological regime. Hydropower capacity factors usually range between 40 to 60 percent.

Table 1.9 shows the approximate values for fuel costs as of 2010, based on a reference oil cost of around US $75 per barrel. A comparison of the relative economics of the different alternatives can be performed through screening curves; one such set of curves illustrates the total cost associated with the dispatch of a kilowatt of each type of plant according to the capacity factor. In the case of thermal alternatives, as the capacity factor increases the associated cost increase proportionately to their use of fuel. Renewable energies have a flatter profile, as shown in Table 1.10.

TABLE 1.8

Plant Characteristics*

PLANT	FUEL	CAPACITY	ECONOMIC LIFE	INVESTMENT COST	ANNUALIZED INVESTMENT COST	VARIABLE O&M COST	FIXED O&M COSTS	EFFICIENCY/ HEAT RATE	
		MW	YEARS	US$/kW	US$/kW/Yr	US$/MWh	US$/ kW/Yr	%	BTU/ kWh
MSD	HFO	20	20	1,900	257	7.5	47	43	7,862
Steam Turbine	HFO	200	25	2,500	321	2.1	34	31	11,006
Steam Turbine	Coal	250	25	2,250	289	2.1	34	32	10,663
Combustion Turbine	NG	100	20	730	99	2.4	9.8	28	12,186
Combined Cycle	NG	150	25	1,500	192	1.5	24.5	53	6,438
Combined Cycle	LNG	150	25	1,500	192	1.5	24.5	53	6,438
Combined Cycle	FO #4	150	25	1,500	192	1.5	24.5	53	6,438
Combustion Turbine	FO #4	100	20	800	108	2.5	12	28	12,186
Small Wind Turbine	Wind	0.5	30	2,260	282	4	55		
Large Wind Turbine	Wind	1.5	30	1,700	212	2	35		
Small Hydropower	Hydro	20	40	2,500	304	4	20		
Large Hydropower	Hydro	500	50	2,800	337	1	15		
Geothermal	Steam	50	30	3,000	374	2	35		

**Discount Rate 12%* *Source | Fernando Lecaros.*

In the upper part of Figure 1.19, the steepest curve corresponds to a combustion turbine running on gas oil (FO #4), with a low initial capital cost, but rapidly increasing unit cost due to fuel consumption at higher capacity factors.

The screening curve provides a first approximation towards selecting different types of power plants, particularly when choosing among alternatives that can achieve high capacity factors, which is not the case with intermittent renewable energies, such as wind or run-of-river hydropower. The ideal and most cost-effective combination, theoretically, lies on the lower envelope of the different alternatives as shown on the dotted line in the figure.

TABLE 1.9

Fuel Costs, in US$

FUEL COSTS	VALUE	US$/GJ
Oil $/bbl	74.94	
HFO $/L	0.367	8.79
FO #4 $/L	0.500	12.00
Coal $/ton	118.00	4.07
LNG $/m^3	0.287	8.39
Natural Gas $/MBTU	5.00	4.74

Source | *Fernando Lecaros.*

TABLE 1.10

Screening Curve Data: Total Annual Capital and Operating Costs (US$/kW-year) as a Function of the Capacity Factor

CAPACITY FACTOR	0%	20%	40%	60%	80%	100%
MSD HFO	304	445	586	727	868	1,008
Steam Turbine HFO	355	537	720	902	1,085	1,267
Steam Turbine Coal	323	406	490	574	658	742
Combustion Turbine NG	109	220	330	441	552	663
Combined Cycle NG	217	276	335	394	453	512
Combined Cycle LNG	217	319	422	524	627	729
Combined Cycle FO# 4	217	362	508	653	799	944
Combustion Turbine FO# 4	120	395	670	944	1,219	1,494
Small Wind Turbine	337	344	358			
Large Wind Turbine	247	250	257			
Small Hydropower	324	331	345	366		
Large Hydropower	352	354	358	363		
Geothermal	409	412	419	430	444	461

Source | *Fernando Lecaros.*

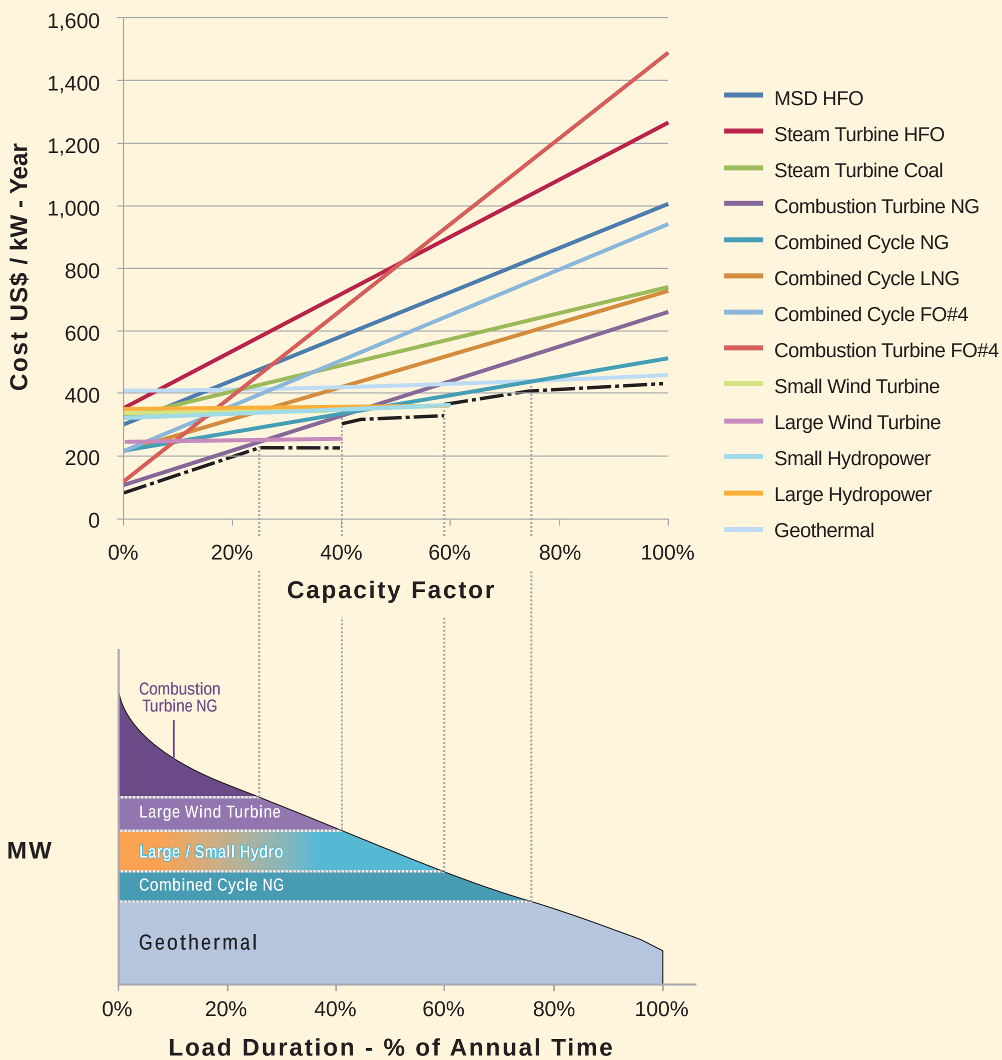
As shown in the lower part of Figure 1.19, the screening curve provides a first approximation of the dispatch of different resources under the load duration curve (LDC).[25] By connecting the starting and ending points of the horizontal dotted line in the upper part of the graph to the LDC in the lower part—which has been done here by vertical dotted lines—the load curve of a given country can show which technologies would be most cost effective in providing the system load over a certain demand period from peak demand on the top to base-load power at the bottom.

[25] The LDC is a normalized representation of the system load curve by which loads are 'stacked' according to how many hours they are present in the system.

The resulting distribution of capacity may not be feasible (e.g., there may not be enough geothermal capacity available to cover the whole generation band assigned to it) whereas there may be excess capacity from other technologies. Detailed production costing and optimization programs are required to tailor plant size to specific conditions to deal with these complexities, but the screening curve approach provides a first approximation of the prioritization of different resources. Following this approach shows how geothermal can be competitive and complement other sources of generation, despite its high upfront cost.

FIGURE 1.19

Screening Curve for Selected Technologies



Notes *Upper part | Total annual capital and operating costs per 1 kW as a function of the capacity factor and its reflection on the LDC* *Lower part | Possible dispatch.*
Source | Magnus Gehringer.

Another option for analyzing the data is to examine the average cost per kilowatt hour for different capacity factors (Table 1.11).

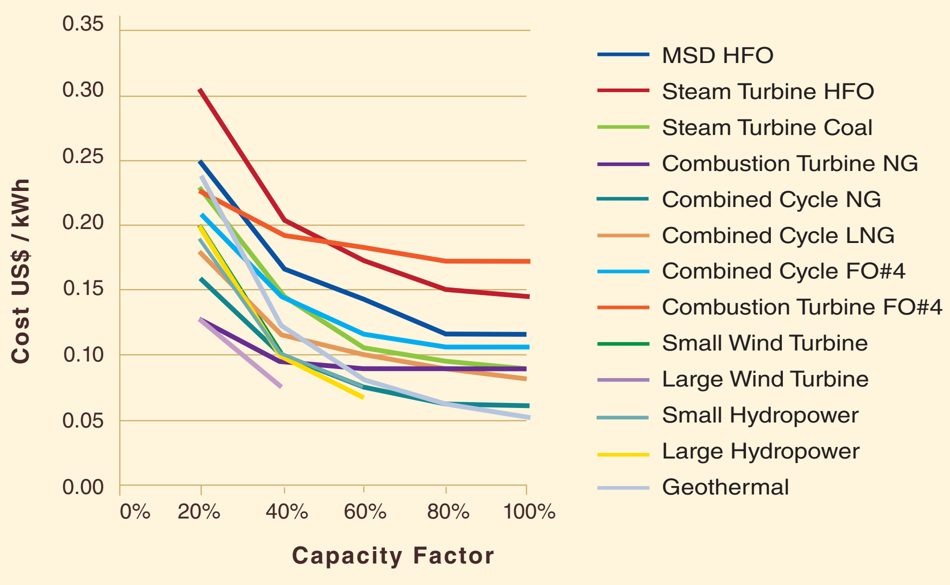
TABLE 1.11
Screening Curve Levelized Cost (US$ per kWh)

CAPACITY FACTOR	0%	20%	40%	60%	80%	100%
MSD HFO	∞	0.25	0.17	0.14	0.12	0.12
Steam Turbine HFO	∞	0.31	0.21	0.17	0.15	0.14
Steam Turbine Coal	∞	0.23	0.14	0.11	0.09	0.08
Combustion Turbine NG	∞	0.13	0.09	0.08	0.08	0.08
Combined Cycle NG	∞	0.16	0.10	0.07	0.06	0.06
Combined Cycle LNG	∞	0.18	0.12	0.10	0.09	0.08
Combined Cycle FO# 4	∞	0.21	0.14	0.12	0.11	0.11
Combustion Turbine FO# 4	∞	0.23	0.19	0.18	0.17	0.17
Small Wind Turbine	∞	0.20	0.10			
Large Wind Turbine	∞	0.14	0.07			
Small Hydropower	∞	0.19	0.10	0.07		
Large Hydropower	∞	0.20	0.10	0.07		
Geothermal	∞	0.24	0.12	0.08	0.06	0.05

Source | Fernando Lecaros.

In Figure 1.19 and the corresponding Table 1.11, geothermal has a high cost for low capacity factors. However, the cost decreases and becomes the lowest cost per kWh when the capacity factor becomes higher than around 80 percent.

FIGURE 1.20
Levelized Costs of Energy (US$/kWh) as a Function of the Capacity Factor



Source | Authors.

Break-even Analysis for Geothermal Costs

The preceding analysis was based on an investment cost of US$ 3,000/kW for geothermal. However, Table 1.6 provides a range of investment cost estimates according to the different development activities of a typical 50 MW geothermal plant. These estimates are between US$ 2.8 and 5.5 million per installed megawatt, which translates to US$ 2,800 to 5,500 per installed kilowatt.

Given this variability of geothermal investment costs, a useful question to ask is: how high can the investment cost of geothermal become before it ceases to be economically competitive? This can be accomplished by comparing geothermal with other base-load technologies, such as steam turbines on HFO or coal, medium-speed diesels on HFO, and eventually large hydropower plants.

Using the method outlined above and based on fuel costs as listed in Table 1.9, economic break-even investment costs for geothermal could be in the range of:

- US$ 8,900 per kW installed, as compared to steam turbines on HFO
- US$ 7,000 per kW as compared to MSD
- US$ 5,200 per kW as compared to steam turbines on coal
- US$ 4,400 per kW as compared to large hydropower with a capacity factor of 60 percent

System Planning Challenges

The previous analyses show how geothermal electricity broadly compares with other power generation options. Determining the actual size and sequence of geothermal power plants to be developed as part of a country's electricity generation expansion plan is usually based on the results of more sophisticated models which take into account different sources of uncertainty. One of the earliest electricity generation expansion optimization models, developed by the International Atomic Energy Agency and known as Wien Automatic System Planning package, takes into account reliability considerations when operating a power system, and is applicable mainly to thermal systems. When the source of uncertainty stems from operating considerations, such as hydropower or wind, additional detailed simulations based on the probability distributions of specific operating factors allow an evaluation of expected operation costs for different configurations of power plants. This is accomplished with detailed simulation programs which are commercially available, such as the Stochastic Dual Dynamic Programming (SDDP) model.[26] In the case of geothermal, the main source of uncertainty lies in the investment cost, mostly reflecting the uncertainty of the exploration and drilling cost. Computer models which take into account this source of uncertainty to quantify the tradeoffs with competing resources have yet to be developed.

Geothermal electricity may entail further additional investment costs for the system compared to other sources of electricity generation. These costs need to be factored in power expansion planning. For example, additional investment in transmission lines may be required since a geothermal power plant cannot be built too far from the source of the fuel supply (geothermal energy). Typically, areas

[26] SDDP is a model used for medium and long term planning of electric power generation and transmission systems.

promising a viable geothermal resource will not coincide with electric load centers. Cities with large populations are not generally built on geological faults that are active enough to support large scale geothermal power plants such as flash plants. This introduces the additional risk of finding geothermal reservoirs of sufficient size to build power plants large enough to justify the cost of transmission lines to the load center.

2

GEOTHERMAL PROJECT DEVELOPMENT PHASES AND RISKS

HIGHLIGHTS

- A geothermal power project can be divided into a series of development phases before the actual operation and maintenance phase commences: preliminary survey; exploration; test drilling; project review and planning; field development; construction; and start-up and commissioning.
- Development of a typical utility size geothermal project will usually take between 5 to 10 years, depending on the country's geological conditions, information available about the resource, institutional and regulatory climate, access to suitable financing, and other factors.
- Risks faced by a grid-connected geothermal power project include: resource risk and the related risk of oversizing the power plant; financing risks due to high upfront cost and long lead time; completion/delay risk; operational risks; off-take risk; price risk; regulatory risk, institutional capacity constraints, and information barriers.
- The upstream phases, and especially the test-drilling phase, are usually seen as the riskiest parts of geothermal project development, reflecting the difficulty of estimating the resource capacity of a geothermal field and the costs associated with its development.
- Balancing the probability of success against the costs of a failure to reach the best expected outcome can be handled by formal techniques such as the use of a decision tree. The technique allows analyzing and adopting choices that maximize the expected value of geothermal development by applying probabilities to various project outcomes.
- Local environmental impacts from geothermal power replacing the use of fossil fuels tend to be positive on balance. However, like any infrastructure development, geothermal power has its own social and environmental impacts and risks that have to be managed. It is also crucial to consult and involve all relevant stakeholders, presenting the trade offs and ways to overcome challenges specific to the project.

DEVELOPMENT PHASES OF A GEOTHERMAL POWER PROJECT

Geothermal projects have seven key development phases before the actual operation and maintenance (O&M) phase commences. According to the schedule in Figure 2.1, it takes approximately seven years to develop a typical full size geothermal project with, for example, a 50 MW turbine as a first step. However, the project development time may vary, depending on the relevant country's geological conditions, information available about the resource, institutional and regulatory climate, access to suitable financing, and other factors.

Each phase of geothermal project development consists of several tasks. After each milestone, the developer—either a project company or a country's institution—will have to decide whether to continue developing the project or not. The first three phases, or milestones, take the developer from early reconnaissance steps to field exploration to test drillings. This first part of the project development (which could be broadly called the exploration stage) either confirms the existence of a geothermal reservoir suitable for power generation or not; it is usually seen as the riskiest part of project development. If the result from the first three phases, including the test drillings, is positive and the geothermal potential is confirmed, Phase 4 is initiated with the actual design of the power project, including the feasibility study, engineering of components, and financial closure. Phases 5 to 7 comprise the development of the project itself, consisting of the drilling of geothermal production wells, construction of pipelines, construction of the power plant, and connection of the power plant to the grid. Figure 2.1 presents the project phases graphically.

Phase 1: Preliminary Survey

The preliminary survey phase includes a first reconnaissance of a geothermal area based on a nationwide or regional study. If no geothermal master plan studies are available, developers usually conduct their own studies based upon available literature and data, or execute their own reconnaissance work to select the areas where they will apply for exploration concessions. Methods include a review of geological ground studies, as well as efforts to document the site through satellite and airborne imaging.

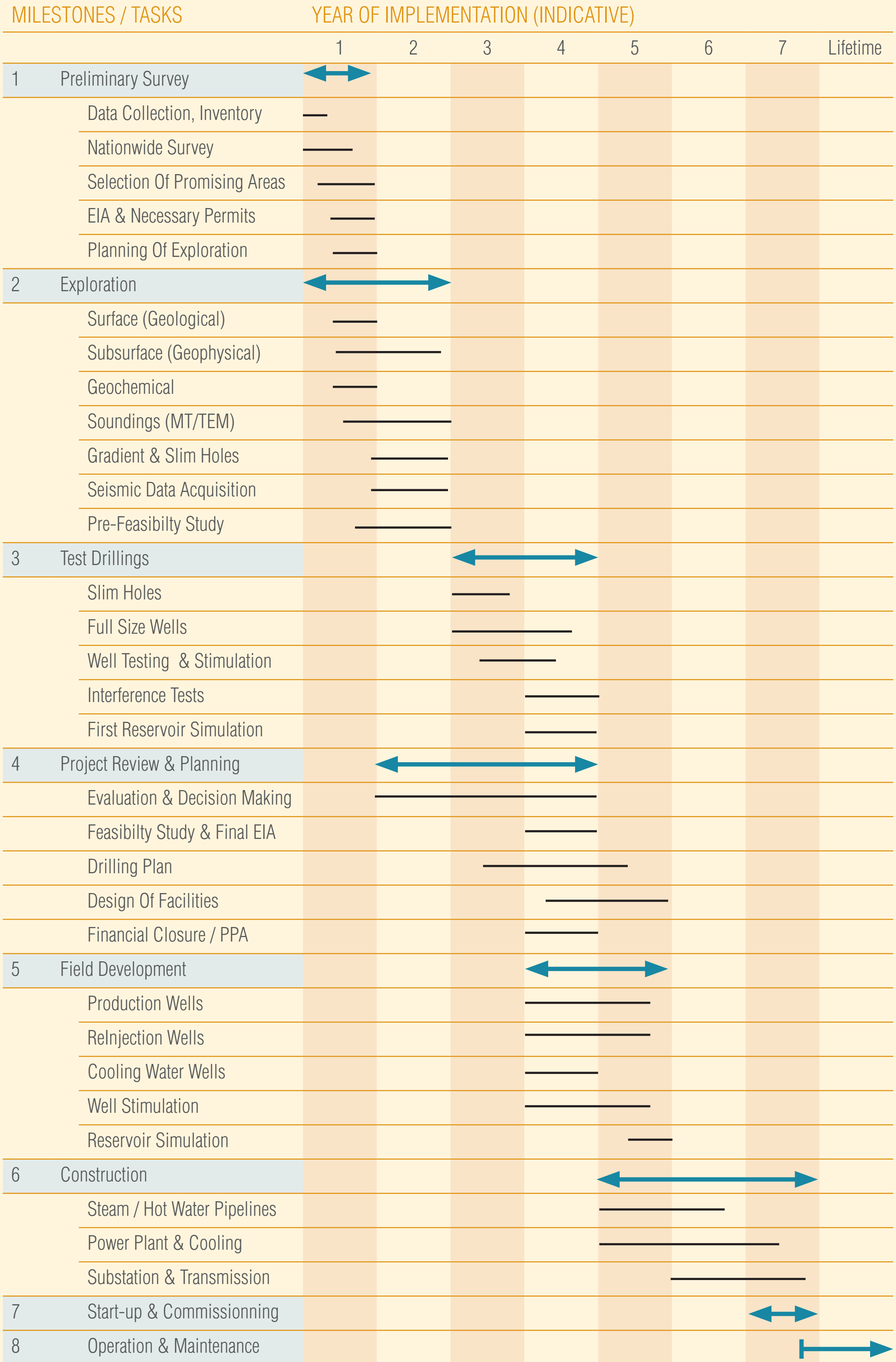
Once the concession is granted or the field is selected, a pre-feasibility study is initiated to explore the likelihood of the existence of a commercial geothermal reservoir and to get a first estimate of its exploitable potential. The pre-feasibility study also touches on aspects such as the characteristics of the country's power market (demand and supply, potential off-takers and customers), transmission and distribution system, availability of basic infrastructure (roads, fresh water supply, communication, etc.), and environmental and social issues. The institutional and regulatory framework of the country is studied to evaluate the conditions for obtaining permits and licenses for project development and operation, and for establishing a Power Purchase Agreement (PPA)[27] with the relevant utility company or other customers.

In order to obtain the rights to explore and develop geothermal resources within a certain area, the project developer (if he or she is not the land owner) must obtain access through lease or concession from the surface and subsurface owners. The regulatory framework and the speed and quality of the regulatory decisions made at this stage can significantly affect the timetable of the project and its development path. Depending on the country, land and mineral water resources can be either publically or privately owned. The developer therefore has to enter into an agreement with the titleholder of these estates, which will normally require a yearly lease fee or royalties upon production. Their impact of these fees on the financial viability of the project should be carefully assessed and calculated.

[27] Several geothermal power projects are operated by separate steam suppliers and power generators. In such a case, an additional steam sales agreement will have to be made. Examples can be found in Indonesia and Philippines.

FIGURE 2.1

Geothermal Project Development for a Unit of Approximately 50 MW



Source | *Authors.*

In addition, it is usually a complex task to secure necessary permits and licenses, especially for water rights and environmental permits. A complete Environmental Impact Assessment (EIA) is usually required for any major power project that also would need to deal with the drilling phase in the case of geothermal; preparing these documents often requires significant amounts of time and capital.

Phase 1 is important to establish the rationale and to assess the need for the project in question and, at the same time, to justify investments needed for the exploration and test drillings (Phases 2 and 3). Costs for this first phase are generally estimated at US$ 0.5 to 1 million. However, this estimate assumes that the basic information on the geology of the area under consideration is already available. In greenfield areas, this can increase to as much as US$ 5 million (Table 1.6). For these reasons, Phase 1 usually takes from several months up to one year to complete.

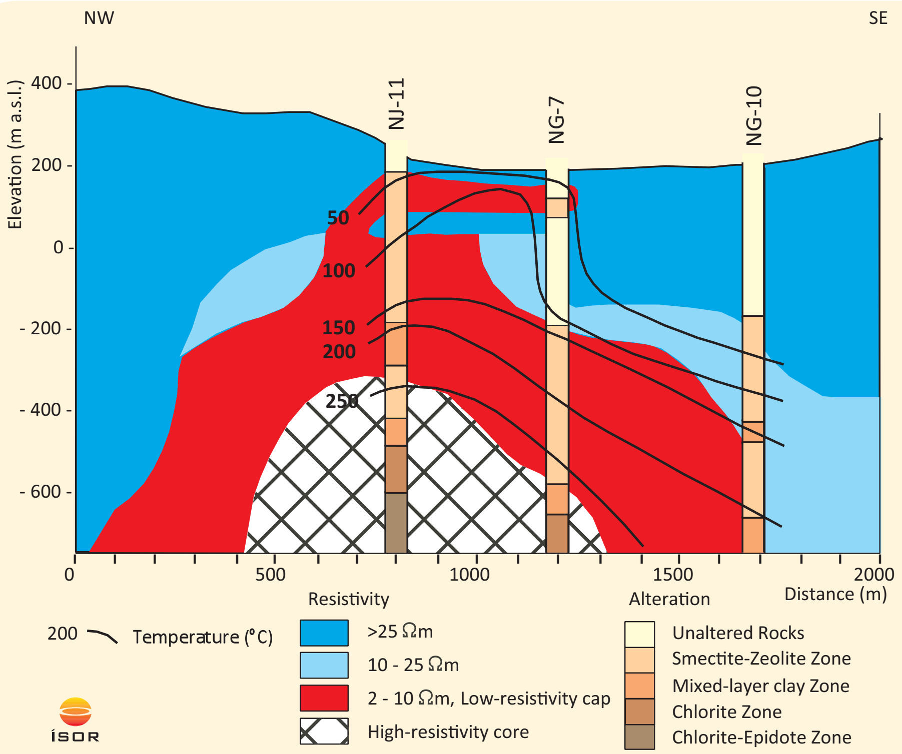
Phase 2: Exploration[28]

The exploration phase consists of surface level surveys to further confirm the preliminary resource assessment. It starts as soon as the project developer is satisfied with the results of Phase 1 and has complied with legal requirements. In total, the second phase can take up to two years, depending on the size and accessibility of the geothermal field and the data already available. In the beginning of this phase, an exploration plan is produced which can include some or all of the following exploration methods:

- **Geochemical Exploration I** Samples are taken from existing hot springs and analyzed. The results allow estimates to be made regarding the temperature of the fluid at the depth of the reservoir and an estimation of the fluid's origin and recharge within the geothermal reservoir, thereby indicating the degree of permeability within the reservoir rock structure.
- **Geological Exploration I** Samples of rocks, sediments, and lava can be taken either from the surface or obtained by core drilling to disclose the type of heat source and to estimate its location and potential.
- **Geophysical Exploration I** Several methods can be used to measure the conductivity or resistivity of subsurface rocks; the Transient Electro Magnetic (TEM) method and the Magneto Telluric (MT) method are most commonly used today. These two methods complement each other since the MT shows results at great depth while the TEM shows results at shallow depth and resolves the telluric shift problem of the MT.
- **Geophysical Exploration with Bouguer gravity measurements complement** MT and TEM measurements by measuring anomalies in the density distribution of subsurface rocks, thereby permitting the identification of large geological structures with boundaries related to tectonic features that in turn may lead to faults and fractures. Results of geophysical exploration, used in combination with geological data, can lead to the location of the heat source and provide targets for the test drillings (exploration drillings).

[28] In this context, the term "exploration phase" refers to the second phase in the detailed breakdown of the project cycle. This usage is distinct from "exploration" in a broad sense, which consists of the first three phases, including the test drilling phase. The latter usage is more common for the oil and gas industry.

FIGURE 2.2
Resistivity Cross Section through a Geothermal Field in Iceland



Source | ICEIDA 2010.

- **Temperature Gradient Holes** are shallow and slim boreholes, usually less than 500 meters deep and less than 6 inches in diameter, drilled to measure the increase in temperature with depth. The standard temperature gradient worldwide is around 30°C for each additional kilometer in depth, resulting in an average temperature of 90°C at a depth of 3 kilometers. If, in a certain area, the temperature gradient were to increase to 90°C/km, this would result in a temperature of 270°C at a depth of 3 kilometers and would be very promising for geothermal power generation, as long as enough steam could be extracted from the reservoir. Gradient holes also allow the collection of additional samples of fluids for chemical analysis. It is common to drill three to five gradient holes as part of the exploration plan for a geothermal greenfield, especially in areas with no signs of recent volcanism.
- **Seismic Exploration,** well known and used in the oil and gas industry, is a geophysical method that uses "waves" from the surface to map subsurface structures like faults and cracks, which are important because they often are conduits for hot steam and fluids. Most drillings for geothermal resources would be targeted to hit at least one subsurface fault; by using directional drilling methods, it is possible to hit more than one

fault and thereby further increase, even multiply, the steam or fluid production of the geothermal well. Seismic exploration is more effective within sedimentary basins than in volcanic areas, where the best hydrothermal resources are found. This is sometimes considered a limitation on the use of seismic exploration for geothermal resources.

At this stage, the pre-feasibility study initiated in early Phase 1 is finalized. Interpretation of old information and results from new surveys are used to develop a preliminary reservoir model, which estimates reservoir properties, such as permeability, flow parameters, temperatures, thickness, and areal extent.

After completing the surface exploration, the first step in evaluating the resource is to carry out a volumetric resource assessment, which can be improved with information gained from the test drillings during Phase 3. For this purpose, probabilistic simulations (e.g., Monte Carlo) are often applied to perform the volumetric assessment. Long term testing of productive exploration wells will define the expected productivity of future wells, as well as yield information on the pressure response (drawdown) of the reservoir to fluid production. The pressure response can be used for lumped parameter modeling of the reservoir to predict the future response of the reservoir during utilization. This is necessary to plan for the next steps in developing the geothermal resource; making the first estimate on potential; and deciding where to focus the work within the exploitation license area. At the conclusion of this stage, a detailed geo-scientific report is developed covering the explored area, including a conceptual model of the geology of the geothermal field. The report should present recommendations as well as preliminary development strategies for the area.[29]

Costs for Phase 2 (i.e., for conducting MT's, TEM's, seismic or drilling gradient holes) depend on the size and accessibility of the geothermal site and the availability of necessary tools and equipment. While minimum exploration costs for a geothermal site would in many cases be US$1 to 2 million, each gradient well could add US$ 0.5 to 1 million to that figure. Since all geothermal fields and projects are different, it is difficult to generalize the required investment costs for Phases 1 and 2.

Phase 3: Test Drilling

This phase is the last one of the exploratory phases. In the beginning of this phase, a drilling program is designed to develop a target to confirm the existence, exact location, and potential of the reservoir. Usually a set of three to five full size geothermal wells[30] are drilled, but, depending on location, accessibility and infrastructure at the geothermal field, it might be prudent to start with slim holes (holes with diameter under 6 inches/15 cm that can be drilled with lighter equipment (drilling rigs) than that used for full size wells (with diameter over 8 inches/20 cm). In this context it is also worth mentioning that drilling plans have to be revised regularly during the drilling activity due to results from well testing. Drilling slim holes for reservoir confirmation, temperature, and chemistry, is becoming more attractive as such wells can be drilled to 1,500 meters at approximately 50 percent of the cost of a similar depth regular well (Johannesson 2011, personal communication).

[29] Based on ÍSOR 2009.

[30] For example, a full size well could be 1.5 to 3.5 km deep and have a bottom hole diameter of 7 to 8 inches. The top (surface) diameter can be over 20 inches.

Drilling full size wells requires mobilizing heavy equipment of several hundred tons (Figure 2.3),[31] transported in many dozen containers. At this stage, no final decision is made as to whether these wells will be used as production or reinjection wells, since the developer cannot predict the future performance of the wells. New wells might have to be "stimulated" after drilling in order to remove any mud or other material that clogs cracks or faults in the rocks. The purpose of stimulation is to increase permeability and volume flow of the geothermal fluids or steam into the borehole. Interference tests between the different boreholes will show if and how the wells are interconnected. This gives scientists a clearer picture of the potential, shape and size of the reservoir in the subsurface, as well as a clearer understanding of the potential for premature cooling of production wells. Directional drilling, a cost intensive technology from the oil and gas industry, can hit multiple fractures in the same well, thereby increasing or even multiplying the well output.

FIGURE 2.3
Mid-size Drilling Rig in the Caribbean

Source | Sigurður Sveinn Jónsson, ÍSOR (Iceland Geosurvey).

[31] Photo of drilling rig Sleipnir from Iceland Drilling Ltd. on borehole WW-03 in Dominica *(ÍSOR (Iceland Geosurvey)*).

Again, the investments related to Phase 3 can be high, but costs are very project specific. Depending on the location and depth of drilling, a slim hole drilling costs between US$ 0.5 and 1.5 million, while a full size well would usually cost between US$ 2 and 6 million. For example, for four full size wells of 2.5 to 3 km deep, including the related scientific work, the investment would be typically between US$ 10 and 25 million. Depending on the location of the geothermal field and the need to build or reinforce access roads, mobilization costs for drilling equipment can be a significant part of the overall cost of this phase, since dozens of heavy full size containers, including fuel and power generators, long steel pipes (casings), drilling mud, and cement have to be transported to the drilling site.

As will be discussed in Chapter 3, funding support from governments to reduce developers' exploratory risks associated with these first three phases is often the only way to ensure private participation in early geothermal project development. Governments that encourage the private sector to develop projects from the start, including the first three project phases, usually consider giving grants, subsidies, or other incentives to private companies. Risk sharing agreements between the public and private sector that are clearly defined before any investment is made can also facilitate the funding of these project phases by sharing costs and limiting the potential financial losses in case the geothermal reservoir is not suitable for power generation.

Phase 4: Project Review and Planning

This phase includes the evaluation of all existing data by the developer, including new data from the exploratory phases. The results from the test drillings will enable the project developer to finish his feasibility study, including all financial calculations; the conceptual engineering for all components to be built; and the drilling program. In this phase, the project developer determines the most economically advantageous project size and the investments necessary.

Costs for the feasibility study will have included all costs from Phases 1 to 3, plus a contingency for all financial, legal, and environmental negotiations, permits, desk-top and engineering work necessary to move the project into the construction phase.

Geothermal is different from other energy generation technologies, such as coal, gas, or hydropower, because it is not possible to do a power production feasibility study until the potential of the geothermal reservoir has been proven by drilling, and because the supply of fuel (geothermal energy) is linked intrinsically to the development of a power plant. The cost- and risk-intensive test drillings can be seen as part of the preparation of the project feasibility study, which explains the general reluctance of private companies to develop geothermal projects from the first phase.

Having completed the financial and technical feasibility study for the power project, the developer usually enters into a PPA[32] with the relevant utility company or other power consumers. The PPA and concession agreement will specify the revenue stream as well as obligations and risk allocation. The completed feasibility study and PPA then allow the developer to approach financiers.

[32] PPAs for geothermal power usually address the same issues as PPAs for other power generation technologies. However, some issues unique to geothermal must be addressed, especially regarding operational risks which would prevent the operator from reaching the output as agreed upon. Issues include, for example, reservoir degradation and costs related to increased maintenance due to geological or chemical reasons, such as make-up wells and force majeure.

FIGURE 2.4
Geothermal Well Head and Silencer

Source | NEA 2011. Orkustofnun, the Icelandic National Energy Agency. Photo of wellheads and silencer at Hellisheiði power plant.

Phase 5: Field Development

Phase 5 marks the beginning of the actual development of the power project and consists of drilling production and reinjection wells, and partially constructing the pipelines to connect the wells to the plant. Depending on the drilling program, one or more drilling rigs are required to drill the production wells necessary to reach the targeted capacity of the power plant. For a utility size geothermal project, a commonly used rule of thumb is that every successful production well will provide enough steam or fluid to produce 5 MW of electrical power in the power plant.[33] However, even in well-explored areas, approximately 10 to 30 percent (on average 20 percent) of all drilled wells turn out to be dry or too weak to utilize. This reduces the actual average output of every drilled well to 4 MW.

In addition to production wells, reinjection wells must be drilled to return the geothermal fluids to the reservoir. Reinjection of geothermal fluids produces pressure support to the reservoir; nevertheless, reinjection must be undertaken in locations where it will not lead to cooling of the geothermal reservoir. This requires knowledge of the underground flow patterns, which is gained through construction of the conceptual and numerical models of the reservoir and from the numerical reservoir analysis. Design of production and reinjection strategies is studied initially through reservoir simulation.

[33] Production capacities of less than 5 MW per well and sometimes capacities as low as 2-3 MW per well can be considered satisfactory in some cases, depending on the project size and other circumstances. However, for utility scale geothermal projects, wells yielding less than 2 MW of power are usually considered unsuccessful.

BOX 2.1

Differences between Drilling for Oil and Geothermal

There are four reasons why drilling and reservoir management in the geothermal sector is different from the oil sector:

1 | **Economy/Markets |** Oil is an internationally traded product, easy to store, transport, and sell. Geothermal steam cannot be sold or priced outside of the local heating and electricity markets—introducing off-take risk because of limited options for selling the product. Furthermore, the integration of geothermal projects into the local grid requires additional infrastructure, permits, and contracts.

2 | **Geology |** Although drilling for hydrocarbons is often carried out at greater depths than geothermal drilling, oil fields are generally in geologically stable environments and can be more easily confirmed by surface exploration technologies. Geothermal fields are often in volcanic and fractured zones and their potential must be confirmed by drilling.

3 | **Fluid or Steam Composition |** Even if a geothermal reservoir is proven to exist, fluid and steam may, in some cases, have a chemical composition that precludes their use for power generation; in contrast, it is usually possible to find ways to process and use oil even if its chemical composition is problematic.

4 | **Reservoir Depletion |** Oil can be pumped until the economics of production fall below a set threshold, or, in the best case, until the reservoir is considered depleted. Geothermal fluids have to be reinjected to avoid pressure drops. Therefore, groundwater flows and reservoir refill systems have to be understood to avoid depletion of a geothermal energy resource. However, an orderly maintained geothermal well can produce steam for decades.

Source | Authors.

The time needed to drill a geothermal well not only depends on a well's depth, but also its geology (rock) and the capability of the drilling rig used. Shallow fracture areas will require extra cementing to fix the well casings (steel pipes) to the surrounding formations to prevent fluid leakage. These operations can cause uncertainty about the total time required for the drilling program. In volcanic environments, drilling a 2,000-meter deep well with a commercial diameter will take 40 to 50 days, on average. The drilling process itself consists of alternating phases of drilling and well casing construction and cementing, until the top of the resource is reached. Once the well penetrates the geothermal reservoir, permeable slotted liners are used to prevent rocks and debris from getting into the wellbore. In addition to casings, materials required for geothermal drilling include drill pipes, drill bits, chemicals to add to the drilling fluid or mud, cement, fuel, tools for directional drilling, wellheads, valves, etc.

The following example explains issues related to costs and investments in this phase. If the project developer plans to develop a power plant with an installed capacity of 50 MW, it may need 13 wells for production. Reinjection might work with half that number, but would depend on the enthalpy and chemical composition of the fluids, which is only known after the wells have been tested. Initially, the project developer would plan to drill a set of 13 production and 7 reinjection wells (altogether 20 wells).

At a cost of US$ 2 to 6 million per well, this would translate into an investment of US$ 40 to 120 million, or from US$ 0.8 to 2.4 million per megawatt installed, with an average of US$ 1.2 to 1.5 million. In most cases, over 50 percent of the total investment for a geothermal power project will be related to exploration and drilling. Since it takes about six weeks to drill a normal 2 km deep well, it would take 30 months to drill the wells for a 50 MW geothermal project with one drilling rig, not considering time for rig mobilization and moving.

In order to speed up the process, it would be necessary to deploy several drilling rigs and to work on the surface pipelines, well heads, and other necessary infrastructure simultaneously. However, in new geothermal areas it might not be appropriate to speed up drilling, especially early in the drilling process. For successful drilling, the location of the next well needs to be based on the results of tests from earlier wells.

Production drilling, as a time-consuming and costly part of any geothermal project, should be based on quality project management and supervision by experienced specialists. Delays during the drilling phase can seriously affect the financial viability of a project, especially when contracts or the PPA contains clauses and deadlines for project completion, commissioning, and delivery of power to the grid.

Phase 6: Construction

This phase comprises installation of the steam gathering system or SAGS (i.e., a system of steam pipelines from the well heads to the power plant and back for the reinjected fluids); the separators; the power plant with the turbine, generator, and the "cold end," which consists of a condenser and needs either air (fan cooling) or water cooling (direct or by cooling tower). After utilization (expansion) of the steam, the cooled geothermal fluids are usually reinjected into the reservoir to be reheated and to maintain the pressure or avoid reservoir depletion. The electricity generated is sent to a substation and from there to the transmission grid.

Figure 2.5 shows the different components of a geothermal power plant and the plant's most important equipment. Starting from the top, there are the geothermal wells, each with an access road and a drilling pad. Some of the wells are releasing steam ("blowing")—possibly due to maintenance work, but all are connected via pipelines to the separator station (in the middle of the picture), where fluids are separated from steam. The pipelines are well insulated to minimize cooling of the fluids and steam over a distance of several kilometers. From the separator, the steam goes to the power plant turbines, while the water, which has the same temperature as the steam, gets reinjected into the reservoir by reinjection wells. The cooling towers are part of the condensing system, which condenses the remaining steam into fluids. The generated power is sent to the transmission grid through the attached substation.

For a 50 MW power plant unit, the costs for the construction phase of project development are, on a turnkey basis, usually in the range of US$ 1 to 2 million per megawatt installed. The cost estimates do not include the transmission line or the substation, which is needed to connect the power plant to the grid, as these costs can vary considerably from installation to installation.

FIGURE 2.5
Krafla 60 MW Geothermal Power Plant in Northeast Iceland

Source | Courtesy of Landsvirkjun.

Phase 7: Start-up and Commissioning

Start-up and commissioning of the power plant is the final phase before the plant starts regular operation. This phase usually involves resolving many technical and contractual issues with the supplier of the plant. The power plant engineering and construction company, often an engineering procurement, and construction (EPC) contractor gets its performance guarantees returned as soon as the plant passes the minimum performance conditions defined in the contract. In many countries, however, the industry standard is to return performance bonds at the end of the warranty period. Providing these guarantees and bonds involves extra costs for the project developer and the EPC contractor. Fine tuning the efficiency of the power plant and all other equipment, including the pressures from the wells, etc., can take several months to complete. Costs for this phase are part of the investments in Phase 6.

Phase 8: Operation and Maintenance

Operation and maintenance can be divided into the O&M for the steam field (wells, pipelines, infrastructure, etc.) and the O&M of the power plant (turbine, generator, cooling system, substation, etc.). Proper maintenance of all facilities is crucial to ensure a high availability factor[34] and capacity

[34] Availability factor is defined as the amount of time that a power plant is able to produce electricity over a certain period, divided by the amount of the time in the period.

factor[35] for the power plant, and to ensure steady steam production from the geothermal wells. The particular plant depicted in Figure 2.5 has been in operation since 1977 and demonstrates a capacity factor of close to 100 percent.

The O&M for the steam field consists of cleaning existing wells, drilling new ones (make-up wells) from time to time to regain lost capacity, and maintaining other equipment in the field. Using the example of a 50 MW power plant unit, estimated costs for these activities are in the range of US$ 1 to 4 million per year, depending on fluid chemistry, geology, the quality of the wells, and other factors.

For the power plant unit, the maintenance costs are often estimated at 1.5 to 2.5 percent of the investment (purchase price) of the power plant. These figures depend heavily on the chemical composition of the geothermal fluids (e.g., their acidity, corrosion, scaling potential, etc.). Using the 50 MW power plant example, this implies that a turnkey 50 MW power plant, costing US$ 100 million, would need annual maintenance of US$ 1.5 to 2.5 million over an expected 30-year lifetime span.

Finally, a fully automated 50 MW geothermal plant would need a staff of approximately 20 well-trained personnel. Estimated operating costs (including taxes, wheeling charges, overhead, etc.) would range between US$ 1 and 4 million per year.

Based on the assumptions above, total O&M costs for a 50 MW power plant in a developing or developed country would be in the range of US$ 3.5 to 10.5 million per year. These costs can be translated into US$ 0.009 to 0.027 per generated kilowatt hour, based on a 90 percent capacity factor.[36]

ENVIRONMENTAL ISSUES

Maintaining the natural environment and the integrity of underlying ecosystems is an important consideration for any significant development project; effective safeguards need to be in place to protect the environment and communities living in the area. The fundamental concepts of environmental and social sustainability are now widely recognized by policymakers, development institutions, and society at large. International financial institutions, such as the World Bank Group (WBG), have developed environmental and social safeguard policies to ensure the sustainability of projects they support (Annex 1). Similar guidelines are increasingly followed on a voluntary basis by the private sector.[37] Guidelines specific to geothermal power were issued in a noteworthy 2007 document entitled “Environmental, Health and Safety Guidelines for Geothermal Power Generation” (IFC/World Bank 2007).

[35] Capacity factor is defined as the ratio of the actual output of a power plant over a period of time and its output if it had operated at full nameplate capacity the entire time.

[36] In some cases and locations, environmental management costs might have to be added to these figures, for example, when NCGs gases like H_2S appear in very high concentrations.

[37] An example of such voluntary commitment is the launch in 2003 of The Equator Principles (EPs) by private sector banks led by Citigroup, ABN AMRO, Barclays, and WestLB. Financial Institutions adhering to the EPs commit to not providing loans to projects where the borrower will not or is unable to comply with their respective social and environmental policies and procedures that implement the EPs.

BOX 2.2

The Importance of Quality O&M

Operation and maintenance costs are an important factor in any power generation project. However, the importance of this cost component is particularly high for base-load units, including geothermal power plants, since they are intended to be run at close to full capacity as much of the time as possible. Plant operation costs and on-line performance are under increasing scrutiny by purchasing utilities, direct electrical service customers, and financiers. Because investors and financiers are usually more conservative than developers, an experienced, well known company able to provide O&M appeals to bankers, and this appeal then can translate directly into slightly lower financing costs, a major consideration for any geothermal power project. It is important that the O&M provider or in-house O&M staff be retained at an early stage in the project development process in order to provide input into power plant design, to participate in plant construction and start-up, and to conduct system checks. The contractor or plant staff should also be capable of and required to perform an ex-post analysis of all significant events within the system, including root cause analyses for future planning.

The increase in partnerships to develop projects also highlights another O&M trend: affiliates of financiers and developers are often highly competent facility operators. A vested interest in plant performance provides a motivating influence on the O&M provider. Such motivation, in return, provides security to financiers. Other incentives for peak performance also exist. A bonus for good operation, tied to a penalty for failing to meet minimum performance requirements, helps ensure optimum performance, guarantees the achievement of output to match contractual requirements, and generates maximum revenue and profit. Good O&M goes beyond maximizing current profits and can lead to an efficient use of the reservoir, prolonging its life span and assuring steam supply. Experienced developers also know that a good performance record will be critical to obtaining both future sales agreements and financing at attractive rates for future plants.

Source | Bloomquist 2002.

As Figure 2.6 illustrates, CO_2 emissions from geothermal power generation, while not exactly zero, are far lower than those produced by power generation based on burning fossil fuels.[38] Data from 85 geothermal plants (operating capacity 6,648 MWe) in 11 countries, representing 85 percent of global geothermal capacity in 2001, indicate a weighted average of CO_2 emissions of 122 g/kWh. In the United States, the largest producer of geothermal energy in the world, CO_2 emissions were reported at 91 g/kWh (Fridleifsson et al. 2008).[39]

Local environmental impacts from geothermal power replacing the use of fossil fuels also tend to be positive on balance—due to avoided impacts of fuel combustion on air quality, the hazards of fuel transportation and handling, etc. Nevertheless, like any infrastructure development, geothermal power has its own environmental impacts and risks that have to be assessed, mitigated, and managed. The need for a careful assessment and mitigation of all significant impacts from a geothermal power project is often underscored by a plant's location in an environmentally sensitive area, which is not unusual

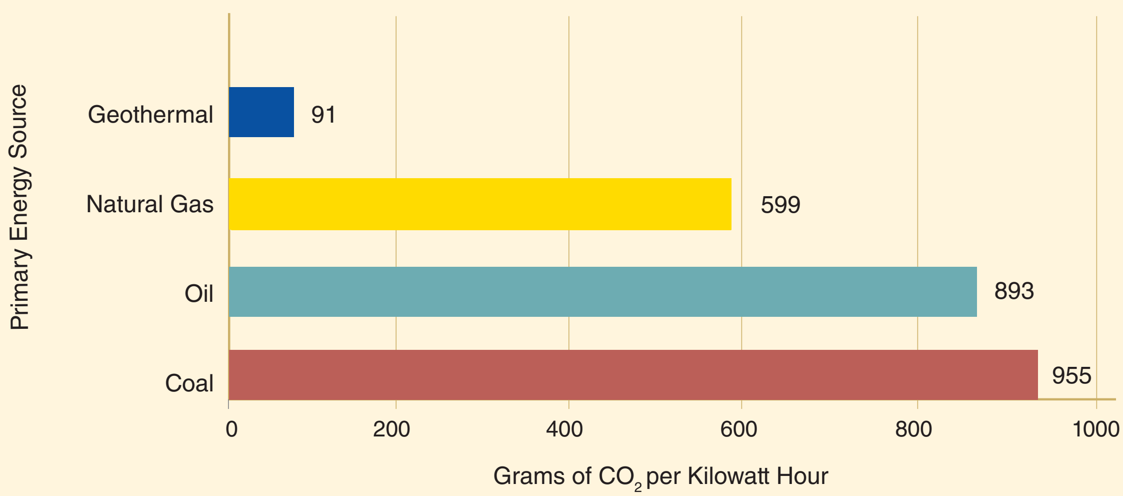
[38] Geothermal fluids or steam in some locations can contain high amounts of natural CO_2 (Johannesson 2011). However, the gas can usually be reinjected or captured and used for industrial purposes.

[39] Based on Bloomfield et al. 2003.

for greenfield geothermal development. However, the impacts from a geothermal power development project are usually highly localized and site specific and few, if any, of them are irreversible. In most cases, mitigation measures can be readily designed and implemented.

FIGURE 2.6

CO_2 Emissions by Primary Energy Source in United States



Source | Fridleifsson et al. 2008.

The first perceptible effects on the environment come from drilling and related infrastructure. The magnitude of these risks depends on whether the wells being drilled are shallow wells for measuring the geothermal gradient in the study phase and whether they are exploratory or production wells. However, in all cases, solid waste generated during well drilling, such as drilling mud and cuttings, and other solid waste needs to be disposed of in an environmentally responsible manner; risk of ground water aquifer contamination during well drilling needs to be controlled; and risk of a steam blowout or of geothermal water rising to the surface and spreading during well drilling needs to be minimized.

The installation of a drilling rig and all the accessory equipment entails the construction of access roads and a drilling pad and the management of drilling inputs (e.g., mud and water). Specific investment to ensure appropriate casing and cementing of drilled holes is necessary to avoid aquifer contamination, including after a well is abandoned. Ground water should not be contaminated with geothermal reservoir fluids.

Installation of the pipelines that will transport the geothermal fluids and construction of the power plant can also disrupt natural habitats and the surface morphology. Some of these pipelines can be buried to reduce environmental disturbances.

Environmental impacts can also arise during plant operation. Geothermal fluids (steam or hot water) usually contain gases, such as CO_2, H_2S, ammonia (NH_3), methane (CH_4), and trace amounts of other gases, which can contribute to global warming, acid rain or noxious smell if released into the atmosphere. They can also contain trace amounts of toxic dissolved chemicals whose concentrations usually increase with temperature, and which can also cause damage if released into the environment. A number of proven technologies, often developed for other types of power generation or other industries, are available on the market to control, filter, or chemically modify the emissions streams from geothermal plant operation.

Geothermal power plant condensers can operate on direct (river or ocean), wet (cooling tower), or dry cooling, depending on the availability of water, the power plant technology used and the size and altitude of the plant. Criteria for choosing the cooling equipment are largely the same as for any other thermal power generation technology, since the design of all these cooling systems is based on the wet-bulb temperature[40] of the actual site.

Amongst water-cooled power plants, geothermal plants tend to use less water per unit of power produced than other thermal solutions; water-cooled geothermal plants use only about 20 liters of freshwater per megawatt hour generated, while binary air-cooled plants use no freshwater. This compares, for instance, with over 3,000 liters per MWh for nuclear plants, over 2,500 liters per MWh for coal plants (World Nuclear Association), and 1,400 liters per MWh for natural gas facilities (Kagel, Bates, and Gawell 2007). In practice, however, the consumption of water for wet cooling purposes per generated unit of power depends on multiple factors that affect the overall efficiency of the power generation process.

Large water requirements can also lead to conflicts with other competing uses when water is scarce. In addition, waste water from cooling towers has a higher temperature than ambient water, therefore constituting a potential thermal pollutant when discharged to nearby streams or lakes. This can be mitigated by an environmental management plan that sets authorized discharge and temperature levels.

Discharge of waste fluids is a potential source of chemical pollution. After having passed the turbine, geothermal fluids with high concentrations of chemicals, such as sodium chloride ($NaCl$), boron (B), fluoride (Fl), or heavy metals such as mercury (Hg) and arsenic (As), should either be treated or reinjected into the reservoir. Fluids coming from low to medium temperature geothermal fields, as used in most direct-use applications, generally contain low levels of chemicals.

The withdrawal and/or reinjection of geothermal fluids may cause ground subsidence at the surface. In certain areas, this may trigger or increase the frequency of micro seismic events, which are imperceptible and can only be detected by means of instrumentation. No major seismic events induced by the exploitation of geothermal fluids have been observed so far. The few incidents that induced perceptible earthquakes were linked to the "fracking" process (the creation of an artificial underground reservoir by induction of highly pressured cold water) as part of EGS projects (see the section on Classification of Geothermal Systems for more information on EGS).

The noise associated with operating geothermal plants could be a problem in populated areas near where the plant in question generates electricity. During the production phase, there is high-pitched

[40] Wet-bulb temperature is, simply put, the temperature one feels when one's skin is wet and is exposed to moving air. It is an indication of the amount of moisture in the air.

noise from the steam travelling through pipelines and from the occasional vent discharge as well as noise from the cooling towers. These issues can be mitigated by determining the maximum decibel levels and investing in appropriate mitigation measures, such as sound barriers or other insulation.

Public Consultation and Communication

While geothermal power is an attractive energy alternative, it faces many challenges which may be viewed differently by each stakeholder. In some instances, lack of public awareness about different geothermal technologies can cause confusion. For instance, since two 5-km deep geothermal drillings for an EGS project induced a minor earthquake in Basel in 2007, public concerns about the impacts of geothermal drilling have been voiced in Germany and Switzerland. In the heat of the debate, the public did not distinguish between hydrothermal technology and EGS, and therefore incorrectly attributed the risk of seismic disturbances to geothermal development in general.

The objective of engaging stakeholders is to identify, raise, and discuss solutions to all environmental and social issues that might affect local communities. The target audiences should include representatives of the affected community and land-owners, government officials, geothermal industry and related industry interests (e.g., mining, oil, and gas), financial institutions, law firms, nongovernmental organizations (NGOs) and community groups.

For projects supported by international financial institutions, public consultation is required, and the project sponsor initiates such consultations as early as possible. In the process of consultations, project-affected groups and local NGOs are involved and their views about the project's environmental and social aspects are taken into account. The environmental and social safeguard policies of the World Bank Group, for example, require that for projects with major environmental impacts (Category A projects), the borrower consults these groups at least twice: (a) before the terms of reference for the environmental assessment (EA) are finalized; and (b) once a draft EA report is prepared. In addition, the borrower consults with such groups as necessary throughout the project implementation to address EA-related issues that affect them.

GEOTHERMAL PROJECT RISKS

There are several risk factors that affect investors' appetite for risk in geothermal projects and hence the availability and cost of commercial capital for such projects. Many of the risk factors are the same as those faced by any grid-connected power generation project, such as completion and delay risk, off-take risk, market demand or price risk, operational risk, and regulatory risk. Additionally, there are two major risks that distinguish geothermal from most other power generation technologies.

The first is the resource or exploration risk that reflects the difficulty of estimating the resource capacity of a geothermal field and the costs associated with addressing this uncertainty. The nature of operational risks faced by a geothermal project is also affected by resource risks.

A second major risk more relevant for geothermal than most other power generation options is the financing risk due to the long lead time (time lag) between the initial investment and the start of revenues. The risk of the long lead time is exacerbated by the cost profile typical of geothermal projects with a high up-front capital cost (followed by relatively lower cost O&M).

Financing risks and resource risks are closely interlinked. For example, risk premiums required by the financiers will be higher for greenfield projects where the resource risk is the highest, rather than in brownfield areas where some development has already taken place and therefore the anticipated lead time is shorter and revenues more certain.

These risks are described in more detail below, starting with the resource risk specific to geothermal projects.

Resource or Exploration Risk

Modern surface exploration technology has progressed considerably, but even today it cannot predict either the exact depth of a reservoir or the exact steam output from drilled wells. Accurate values are not obtained until test wells and, finally, production wells are drilled. In this respect, the exploration challenges of geothermal energy development are similar to those found in the oil and gas industry where exploration risk is also very high.[41] In the case of oil and gas projects, however, the potential returns on investment are usually high enough to attract private investors willing to absorb the exploration risk, and oil and gas companies employ a portfolio approach to mitigate the risk (Box 2.3). In contrast, in geothermal development, the extent of the potential returns is usually more limited for several reasons, including the fact that electricity is typically sold at a regulated price and that the development of the geothermal field needs to be done using an incremental/stepwise approach, as mentioned earlier and further described in Chapter 3. The returns are also more distant than in the case of oil and gas, as revenue flows will start only after construction of the power plant.

The economics of a geothermal development project depends both on the productivity of the geothermal resource and on the degree of success in tapping into the resource per dollar invested. The amount of power extracted from a geothermal field is primarily a function of the number of wells drilled and the production capacity of each, which also depends on the size and permeability of the underlying reservoir. The production capacity of a well is largely determined by the flow rate and temperature of geothermal fluids.[42]

Results of drilling in a number of high temperature geothermal fields around the world have shown that the output per well among wells of the same depth can vary widely (histogram in Figure 2.7). While the average output of wells in any particular geothermal field becomes fairly constant after passing through a certain "learning period" when knowledge is gained about the reservoir (Stefansson 2002), the learning process itself is costly. This is because many of the wells drilled in the initial phase will most likely be less productive (if not completely "dry") than the eventual "steady state" average for the field. In Indonesia, for example, most of the geothermal wells that are in operation produce between 4 to 7 MW, on average. With additional reinjection wells, a total of 16 to 20 wells would have to be drilled, on average, for a 50 MW power project.

[41] The average exploration success rate in the oil industry worldwide is approximately 33%, or one in three wells (Tordo, Johnston, and Johnston 2010).

[42] Additional parameters affecting the value of the resource and the cost of its development are: (i) sustainability of the reservoir for power generation (which in turn depends on reinjection and natural recharge); and (ii) fluid chemistry (high mineral contents can make it complicated and costly to utilize the fluids).

BOX 2.3

The Oil Industry: Who Carries the Exploration Risk?

Risk management is an important feature of the oil industry. Companies hedge against risk by investing in a diverse portfolio of projects, often in several countries, and by involving partners. Countries rarely have the same ability to diversify their petroleum investments as large companies do. It is therefore not surprising that governments, even when they participate in commercial activities through a national oil company, seldom choose to bear the risks of direct exploration. Usually, governments hedge against exploration risk by transferring part of it to investors through contract and fiscal system design. Normally, the investors bear the risk and cost of exploration (and development as the case may be) and the government's or national oil company's share of the cost is paid out from production according to specifications of the petroleum contract. If no commercial discovery occurs, the cost of exploration is borne solely by the investors.

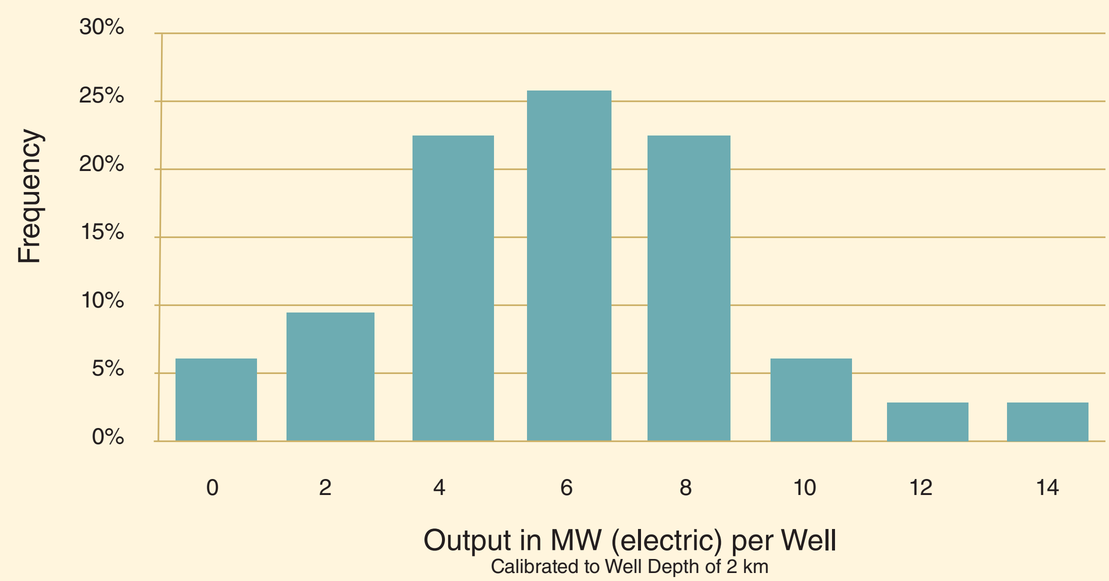
Source | Tordo, Johnston, and Johnston 2010.

The other important factor subject to uncertainty is the depth to which wells need to be drilled to tap into the reservoir. For example, the difference between drilling to a depth of 2.5 km instead of 2 km for full size wells may easily translate into an additional cost in excess of US$ 1 million per well.[43] It is also important to note that the unit cost per meter drilled will likely increase with increased depth.

FIGURE 2.7

Histogram of Geothermal Well Output

Based on a sample of 91 High-Temperature Geothermal Fields in the World



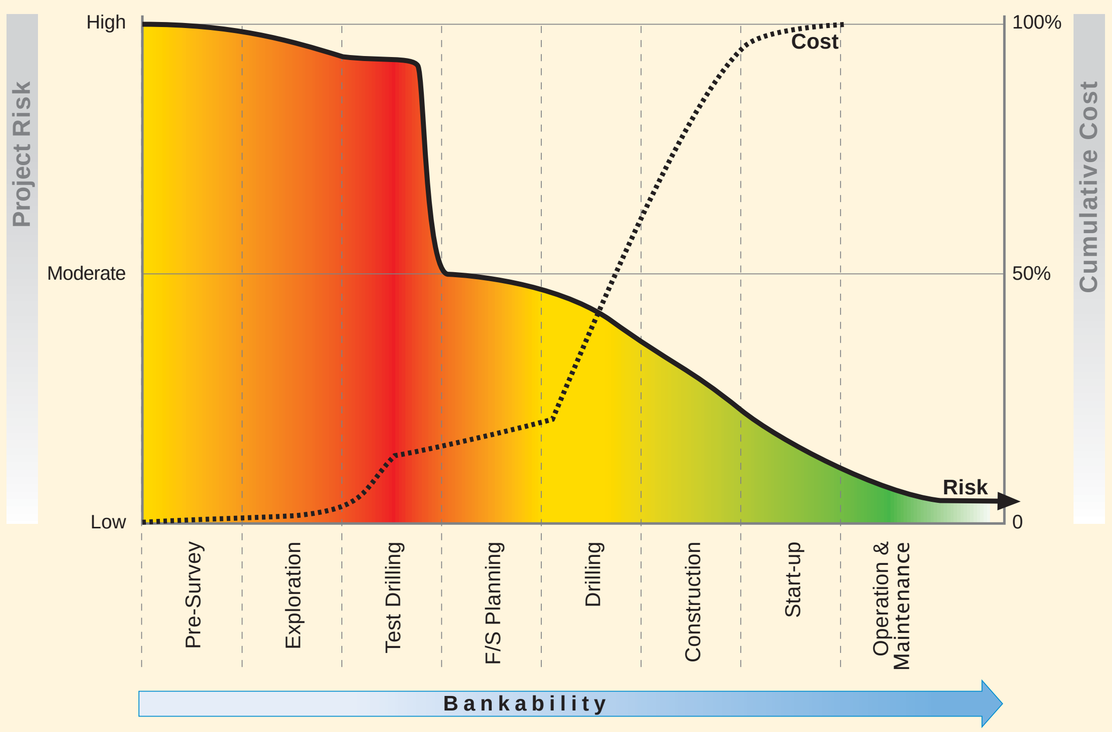
Source | Adapted from Stefansson 2002.

[43] In this handbook, the cost per meter drilled is assumed to be in the range of US$ 1,000 to 3,000. A useful calculation from another source is based on US$ 1,500 to $2,500 per meter (as of 2009), inclusive of the cost of the drilling rig movement between well pads, but exclusive of initial mobilization charges. Assuming mobilization of the rig to the field to cost from US$ 250,000 to 500,000, an initial 3-well exploratory program for a typical depth of 1.5 to 3 km may cost between US$ 7 and 24 million (PPIAF 2010).

Figure 2.8 illustrates the relative magnitude of risks and costs incurred as a geothermal project goes through its development phases. With each successive stage, the cumulative costs keep rising, but a greater understanding of the field characteristics is reached, reducing the risk. The breakthrough in risk reduction typically comes with confirming the resource through a few test drillings. Even then, however, the eventual production cost of electricity (and thus the expected profitability/rate of return) is only an estimate, and its range may still be relatively wide.

FIGURE 2.8

Geothermal Project Risk and Cumulative Investment Cost



Source | *Authors.*

The bankability of a geothermal development project (defined as the ability to attract financing from commercial sources) will increase gradually as long as each successive development phase brings more positive results and reduces uncertainty. However, resolving that uncertainty comes at a price. The test drilling phase should once again be mentioned as a major hurdle to clear. With each well costing a few million dollars, this phase is much more capital intensive than the previous phases, while still fraught with uncertainty. This is when the developer has to make significant investments, without knowing whether the geothermal resource has enough potential to recover the costs. Obtaining debt financing or investment capital in such conditions is not an easy task. Even if financiers are found, they will most likely require a high risk premium on the cost of capital or look for ways to either mitigate or share the remaining risks. Options for overcoming the financing hurdle resulting from the resource risk are discussed in Chapter 3.

Formal techniques such as the use of a decision tree can be used to balance the probability of success against the cost of failure to reach the best expected outcome. A potential project developer is essentially faced with three choices: go ahead immediately with production drilling and risk project failure; undertake test drilling at a certain cost but possibly reduce the risk of project failure through the knowledge gained; or, decide that the prospect is not sufficiently attractive to make it worthwhile risking money even for testing. Annex 2 provides an illustration of the decision tree approach for a simplified set of data.

Certain interactions between resource risks and market risks should also be considered. In recent years, the cost of drilling wells has had periods of sharp increase due to rising prices in commodities such as steel. Also, the geothermal sector can experience a shortage of drilling rigs due to competition with the oil and gas industry for the same equipment (World Bank/GEF 2008).

Risk of Oversizing the Power Plant

Commitment of investment resources to a geological resource of uncertain production capacity is always risky: the results will be suboptimal when a geothermal power plant is either too large or too small in relation to the underlying geothermal reservoir. This could be considered part of the resource risk discussed earlier. The risk of oversizing the power plant needs to be specially mentioned for two reasons. First, oversizing the power plant magnifies the resource risk by concentrating investment resources in a given location instead of spreading it by building smaller plants in several geologically independent fields. Second, excessive plant capacity in relation to the productive capacity of the underlying geothermal field can cause extraction rates that are unsustainable. Pressure drops or even reservoir depletion may result. The best way to mitigate this risk, as discussed in Chapter 3, is to limit the development in a single geothermal reservoir to increments of about 50 MW sequentially, adding subsequent increments as data about the resource are collected over time rather than immediately developing a single, large power plant. To accelerate the build-up of the overall geothermal development program in the country or region, developing multiple independent reservoirs in parallel is recommended.

Financing Risks due to High Upfront Cost and Long Lead Time

Geothermal projects involve a greater commitment of capital upfront than most other power generation projects. While relatively high capital costs (and relatively low operating costs) are typical for all renewable energy projects, geothermal projects have the additional capital expense associated with the upstream development of steam fields. Unlike coal or gas supplies that are purchased over the project's lifetime, the upstream development of a geothermal steam field is equivalent to purchasing the fuel needed for the life of the project upfront. In addition, much like large hydropower projects, geothermal projects have relatively long lead times from the start of exploration to power plant commissioning and the first revenues.

Both these factors—high upfront cost and long lead time—can have a negative impact on the cost of capital. Debt financing may not be available during the early phases of the project, increasing the need to rely on more costly equity capital. Even when both debt and equity are available, the high capital requirement and the long lead time will drive up the costs. Commercial debt suppliers (banks) may require a higher credit risk premium to account for the higher risk due to the relatively large amount of debt induced by the high capital requirement. For their part, as repayment of debt usually has priority over cash flows to equity, suppliers of equity will require a higher premium for the delayed and hence more uncertain payoff on their capital.

Completion or Delay Risk

Delays or disruptions in the completion of any infrastructure project result in a reduced discounted value of the project's revenues. For geothermal projects, the uncertainty about the time needed to complete the drilling program for both production and reinjection wells is a major factor affecting the level of risk taken by the financiers. Consequently, both debt and equity investors require a greater return on capital to offset the risks in a geothermal project.

Operational Risks

In addition to risks typical for any power plant, such as equipment breakdowns, a geothermal facility faces risks during the operational phase that are unique to the geothermal sector. These risks are mostly related to steam field operation and maintenance. In areas where wells have to be worked over frequently and many make-up wells have to be drilled (for example due to heavy scaling from silica saturation or corrosion), the costs of these activities can significantly affect the O&M costs and the overall power generation costs.

In addition, similar to the case of oversizing the power plant, improper steam field operation practices can lead to pressure drops and—in extreme cases—depletion of the geothermal reservoir.

Off-take Risk and Price Risk

Off-take risk encompasses the risk of failure by the buyer to take power due to reasons concerning dispatch, transmission congestion, or transmission line failure and the risk that the off-taker may be unable to make agreed payments in a timely fashion. These risks should not be higher for geothermal generation than for other types of power generation: the dispatch risk may, in fact, be lower if geothermal energy enjoys the dispatch privileges often granted to other renewable energies. Payment risk can be addressed by government or international financial institution (IFI) guarantee approaches.

Price risk is the risk of less-than-expected revenue resulting from lower-than-expected off-take prices. This is a serious risk in a situation in which some—or all—of the off-take is at market prices (as opposed to fixed prices under a PPA or a feed-in regime), or in a situation in which the developer has to negotiate his contract price with the off-taker or auction manager.

Regulatory Risk, Institutional Capacity Constraints, and Information Barriers

Regulatory risk is a general term for all risks resulting from a government's holding of discretionary power over factors affecting the project developer's (or investor's) commercial success. Policies related to issues such as pricing and taxation, natural resource (geothermal) use, procurement procedures, environmental concerns and land usage permitting can all affect the eventual outcome. Therefore, clarity and certainty in relation to regulatory risk is an important factor that informs investor decisions.

Capacity constraints on the part of public institutions often constitute a deterrent to private investment in geothermal energy development. In addition to providing a clear and sound regulatory framework, it is important that the public institutions responsible for planning and managing the development of the sector and for engaging private developers are sufficiently capable and seen as credible by investors.

An example in which government institutions need to be seen as capable and credible would be the offering of geothermal concessions for private development, which often takes place through a public procurement or tender process. In such cases, it is critical that good quality information regarding the development (such as surface level surveys, pre-feasibility studies, etc.) is provided to bidders and potential investors. Moreover, the ability to structure a transaction to be "bankable" to developers is essential if the tenders are to lead to financial closure and the development of geothermal resources.

Indonesia provides an example in which, due to limited domestic capacity, poorly executed transactions have led to many concessions being tendered but almost none of them achieving financial closure. Such shortcomings, among others, have contributed to the prolonged stagnation of Indonesia's geothermal development. As a result, only a handful of existing geothermal operations (brownfields) in Indonesia have expanded production over the past decade, while none of the newly tendered, private, greenfield concessions that carry greater risks have been developed. Box 2.4 illustrates this in more detail.

Allocation of concession rights to multiple developers within the same geothermal field creates additional challenges. The allocation of withdrawal quotas for a natural resource of this kind is almost as difficult as for classic "open access" resources (such as ocean fish), due to the uncertain quantity or capacity of the resource. From the perspective of the owner of the resource (e.g., the state), there is a risk of resource degradation or even depletion due to overexploitation. From the developer's perspective, the risk is that the owner may fail to safeguard the resource from overexploitation by others (or by the owner itself) or to secure the exclusivity of the developer's right to his contractually allocated share of the resource. Other challenges in managing the concession rights of multiple developers within the same field include the prevention of negative externalities from reinjection, which may happen if reinjected fluids from one developer cool down the production wells of another.

Other Risks

Besides the risks specific to geothermal or any other grid-connected power generation there are other, market-wide risks that a geothermal project investor should also keep in mind. These include the foreign exchange risk, interest rate risk, and commodity price risk.

BOX 2.4

Indonesia's Limited Success in Tendering Geothermal Concessions

In 2003, the Government of Indonesia issued Geothermal Law No. 27/2003, which required all new geothermal concessions to be competitively tendered for development. To be consistent with the country's law on decentralization, the authority to carry out most geothermal tenders rested with the local or provincial governments.

However, most subnational institutions lacked the capacity and experience to carry out multimillion dollar international tenders. Equally important, many public institutions faced capacity constraints in planning and managing geothermal developments. The result was a number of poorly structured geothermal development opportunities being tendered and none achieving financial closure.

With a lack of preliminary information regarding the field and the credibility of the information offered being questioned (despite Indonesia having a vast database of mapped geothermal fields and related information), many top geothermal developers did not participate in the tenders. Those that did participate proceeded to renegotiate the terms after the concession was awarded. Since the tenders did not include a "bankable" PPA with Perusahaan Listrik Negara (PLN), the national power company and primary off-taker, the financial prospects of the offer were undermined. If Indonesia is to carry out successful, competitive concession tenders to develop its geothermal resources, it will be necessary to strengthen the capacity of Indonesia's public institutions to plan and manage geothermal developments, to clarify the policy and regulatory frameworks to eliminate several key barriers to investments, and to structure bankable transactions.

Source | Migara Jayawardena and Authors, based on Ibrahim and Artono (2010).

The disruption caused by these macroeconomic risks to any infrastructure project investment may be profound. The impact of macroeconomic risks on geothermal project investments was illustrated by the experience of Indonesia following the Asian crisis of 1997 (Box 2.5).

BOX 2.5

Indonesia's Currency Devaluation Triggered Renegotiation of PPAs in the 1990s

The 1997 Asian financial crisis resulted in an unprecedented devaluation of Indonesia's national currency, making dollar-denominated PPAs unaffordable for the state-owned power utility. The government was compelled to suspend and renegotiate the PPA contracts. These renegotiations took years to complete and resulted in electricity prices almost 50 percent below pre-crisis contracts—an average of US$ 0.0452/kWh.

These lower prices created a disincentive for future developers. The geothermal industry practically ground to a halt, and no greenfield geothermal projects have come on-line since 1997. In an effort to rejuvenate the geothermal industry, the Indonesian government is now considering schemes to provide more incentives by purchasing geothermal power at higher prices.

Source | Migara Jayawardena and Authors, based on Schlumberger Business Consulting 2009.

3

KEY ELEMENTS OF SUCESSFULL GEOTHERMAL ENERGY DELEOPMENT

HIGHLIGHTS

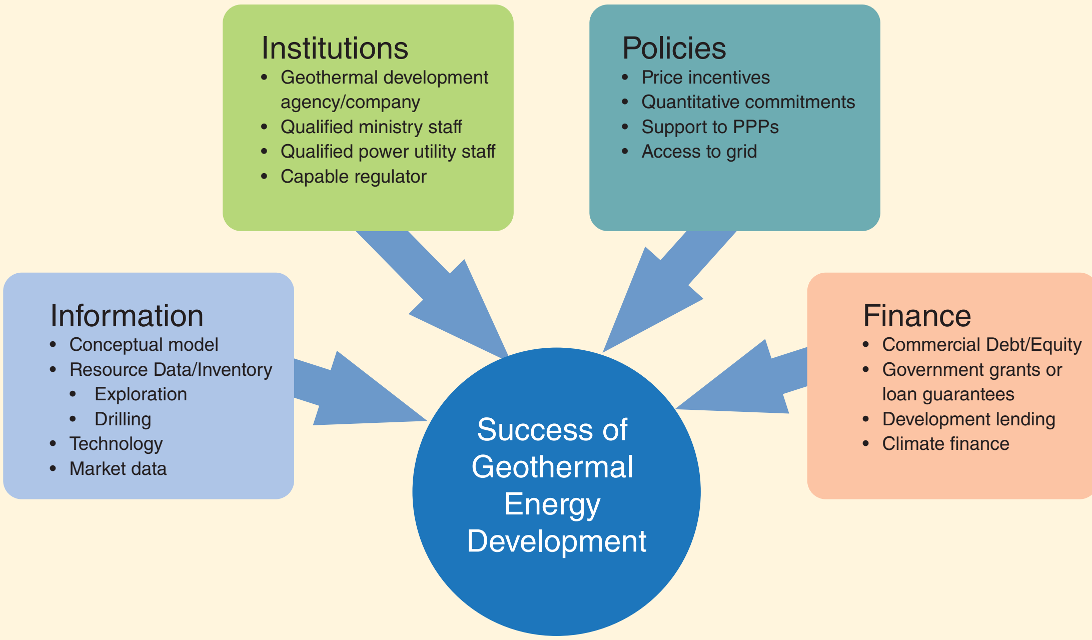
- Besides the basic prerequisite of a promising geothermal resource potential, the other key elements supporting a successful geothermal development effort are: availability of sufficiently accurate geothermal resource data and other relevant information; effective and dedicated institutions; supportive policies and regulations; and access of the project developer to suitable financing, including both commercial and concessional finance.
- Institutional requirements include the need for a country to have a dedicated national geothermal exploration and development organization (or company) capable of managing large-scale infrastructure projects consistent with international and industry standards.
- Granting geothermal exploration and development rights should be based on the principles of: a clear legal and regulatory framework; well-defined institutional responsibilities; and transparent and non-discriminatory procedures, including adequate measures for controlling speculative practices.
- Governments around the world use a wide range of instruments to support the deployment of renewable electricity, including FITs or quota obligations such as renewable portfolio standards (RPSs).
- There are only a few examples of FIT schemes being applied to geothermal power, with most in continental Europe. Africa and Asia have seen budding interest in using FITs for geothermal, but the efforts have resulted in policies setting a ceiling price instead of a FIT in some cases (e.g., Indonesia).
- As alternatives to FIT or RPS, governments may choose to support public-private partnerships (PPPs) involving build-operate-transfer (BOT) or similar contracts to jump-start geothermal development programs. The public sector taking the geothermal resource risk has been key to making such schemes work (Philippines, Mexico).
- After proving the commercial viability of its geothermal sector through a series of successful PPP contracts with the government taking the resource risk, the country may consider transitioning to models that increasingly rely on the private developer to accept and manage the resource risk. However, the developer or investor in this case will require a compensation for the increased risk through a higher off-take price of electricity or through other contractual means. Many countries have preferred to directly fund the risky upstream phases due to this trade off.
- Exposure to resource risk can be mitigated through the application of portfolio management concepts that allow for diversification across a sufficiently large number of prospective development fields, including insurance schemes. International development agencies and other donors have a key role to play by providing capital to set up concessional financing facilities to mitigate geothermal resource risk, as well as by offering technical support that can help overcome institutional capacity constraints.
- Possible designs for a donor-supported geothermal development facility include: (a) a direct capital subsidy or grant facility; (b) a loan (on-lending) facility; and (c) a risk guarantee or insurance facility. Any of these designs can reduce the private investors' risks and thus reduce the risk premiums for the return on equity and the overall cost of capital, opening up new opportunities for scaling up geothermal power.

Geothermal power offers a number of attractive benefits that any country endowed with geothermal resource potential should seek to utilize. At the same time, as indicated by the risks and barriers discussed in the previous chapter, geothermal energy development is a challenging undertaking. The following discussion provides guidance on how the inherent risks and challenges of geothermal development can be addressed. The existence of exploitable geothermal potential in the country, while absolutely and obviously essential, is only a prerequisite.

Besides the basic prerequisite of a promising geothermal resource potential, the other key elements supporting a successful geothermal development effort are: (a) availability of sufficiently accurate geothermal resource data and other relevant information; (b) effective and dedicated institutions; (c) supportive policies and regulations; and (d) access by the project developer to suitable financing, including both commercial and concessional finance (Figure 3.1).

FIGURE 3.1

Key Elements of Successful Geothermal Energy Development



Source | *Authors.*

Each of these four elements represents a factor that directly affects the outcome of a geothermal development project or program. From an investor's standpoint, the strength of each of the factors works to increase the expected return or reduce risk. From the perspective of a country and its government, these factors may determine the level of investment in geothermal energy or, indeed, whether or not such investments will happen at all.

RESOURCE INFORMATION

The previous chapter showed that a geothermal project's risks are highest in the initial stages, when available resource information is scarce. The risk gradually decreases as the resource information base strengthens in the process of exploration and development. The country's government has an important role to play in making geothermal resource information available to potential developers and investors. At a minimum, the government should keep public records on such geothermal information as seismic data (events, fractures, etc.) and deep drilling data (temperature, pressure, faults, permeability). Information on groundwater resources is also essential to geothermal development as groundwater should not be contaminated with geothermal reservoir fluids and, among other uses, is a potential source of cooling water for the power plants.

These types of data are crucial for potential developers and investors. However, credible interpretation of such data can only be done by experts in geology, geophysics, and other relevant disciplines. In order to make this first layer of information interpretable for a developer considering exploratory drillings, a reliable conceptual model of the entire underlying geothermal system (or, at a minimum, the field or reservoir under development) has to be available. Such a model allows a better understanding of possible reservoir locations and their size and recharge conditions, as well as the location of relatively shallow ground water supply reservoirs. The government should make every effort to acquire the best geological and geophysical expertise available to obtain and correctly interpret such information.

As discussed in Chapter 2, the exploration and test drilling phases provide crucial data which must be updated as results from production drillings become available. Annex 2 illustrates the process and value of information obtained through test drillings.

It should also be noted that the owner of the resource may have an inherent interest in introducing a positive bias in the information about the resource. The possibility of independent verification of geothermal resource information is therefore highly desirable from a potential investor's point of view, and can benefit the geothermal development market as a whole.

INSTITUTIONS

The second key element in successful geothermal energy development is the strength of institutions and their structural organization with respect to geothermal energy development. The legal framework for geothermal resource use—starting with the definition of property rights—is the foundation for the strength and organization of all institutions dealing with the resource. In most countries, natural resources, including geothermal energy, belong to the state (at national or subnational levels), with a provision to this effect often included in the constitution.[44] While the right of ownership rests with the state, various forms of private sector participation in the exploration, development, and exploitation of geothermal resources have evolved in many countries.

[44] There are relatively few countries where the owner of the land holds the title for the subsurface resources.

The treatment of geothermal resources within the legal framework varies substantially from country to country. Indonesia, for example, has introduced a special geothermal law as a piece of primary legislation, recognizing the unique characteristics of geothermal energy and its prominent role in the national economy. The existence of a self-standing geothermal law, however, is not essential. In many countries, geothermal resources are subject to general mineral extraction or mining laws governing access to land, and exploration and development licensing. Separate legislation often governs environmental and water use permitting procedures. Renewable energy legislation also plays a strong role in supporting geothermal development in many countries.

Various aspects of geothermal energy development often involve regulation by one or more government agencies, whose actions need to be well coordinated to avoid imposing too many regulatory hurdles that can discourage investors. For example, obtaining multiple permits or licenses for the same project may cause delays detrimental to private sector interest.

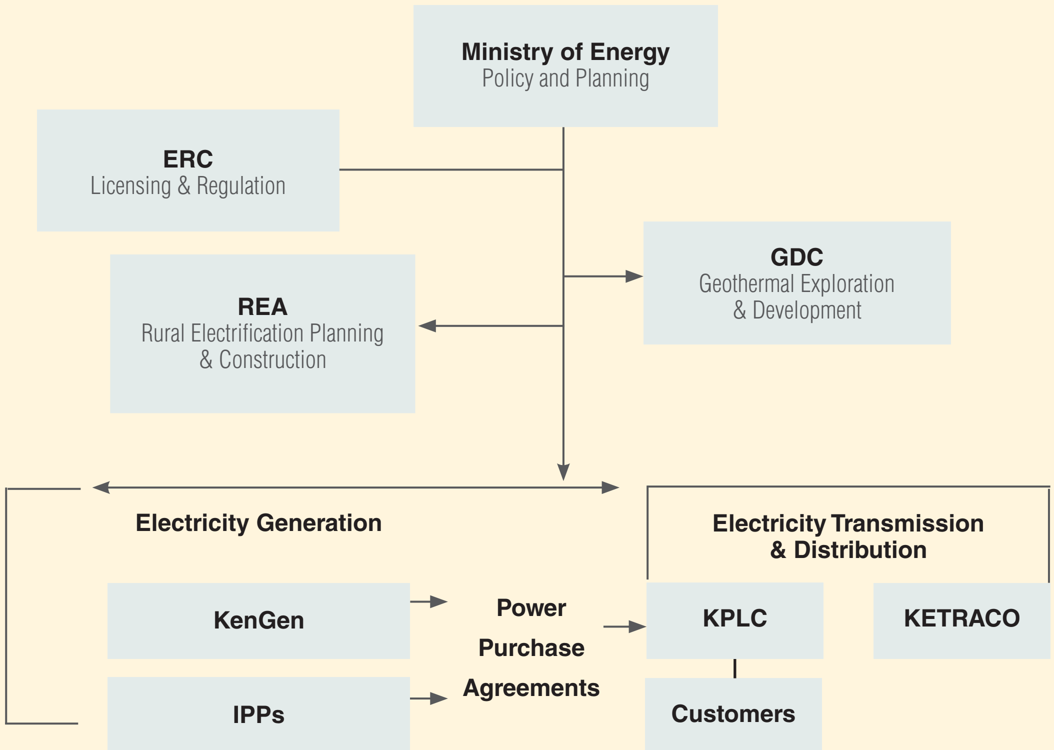
The government should be able to develop strategies, plans, targets, and policies for geothermal energy. Geothermal resources need to be properly delineated and characterized before they can be counted on in the country's power system planning. Thus, the government's role in this area starts with setting up and maintaining services to generate and continuously enhance geothermal resource knowledge, and such knowledge should be industry-oriented rather than just academic. This means institutional capability is needed to properly plan geothermal development and to sufficiently engage suitable developers.

The experience of successful countries points to the need for a country to have: (a) a dedicated national geothermal exploration and development organization or company capable of managing large-scale infrastructure projects consistent with international and industry standards; (b) a committed and adequately staffed ministry or similar department of government in charge of the energy sector, whose functions include explicit planning for geothermal energy development; (c) a similarly adequately staffed and committed national power utility; and (d) a capable regulator—especially in the context of a liberalized electricity market—whose functions include the enforcement of the country's renewable energy policies and balancing the interests of generators and consumers.

When the entire supply chain of geothermal electricity is considered, the institutional landscape for geothermal power generation can be relatively complex, especially in the context of a liberalized power sector (e.g., the Philippines) or in a country which is on a path to electricity sector reform. The example of Kenya's institutional framework for the energy sector (Figure 3.2) illustrates the place of the national geothermal exploration and development company within the power sector of a country where the market for geothermal energy includes both the national power generation utility (KenGen) and independent power producers (IPPs). The geothermal exploration and development company, Geothermal Development Corporation (GDC), confirms the viability of potential geothermal resources through a program of technical studies and exploratory drillings, and offers geothermal resources to potential power developers through competitive tendering. This includes selling steam to both IPPs and KenGen for electricity generation (World Bank 2010a).

FIGURE 3.2

Institutional Framework of Kenya's Energy Sector



KEY I ERC = Energy Regulatory Commission; GDC = Geothermal Development Company; IPPs = Independent Power Producers; KenGen = Kenya Electricity Generating Company; KETRACO = Kenya Electricity Transmission Company; KPLC = Kenya Power and Lighting Company; REA = Rural Electrification Authority.

Source | World Bank 2010a.

In some cases, regional or subnational level institutions play a distinct and important role in geothermal energy development. The African Rift Valley, where cross-border interconnections and synergies are of paramount importance, is one example. Indonesia, on the other hand, is an example of a country in which the geothermal exploration and development process has been substantially decentralized to subnational (district and provincial) authorities, highlighting the importance of transparent regulation and institutional strengthening at the local level.

Finally, as with other extractive industries, the government and civil society should seek to enhance the governance standards applied to companies involved in the geothermal sector. In many resource-rich countries, the quality of governance is viewed as a key factor influencing the ability of countries to use revenues from their extractive industries for development. Geothermal resources are no exception in this regard.

Regulation of Land Rights and Permits[45]

Conditions of access to land are a central prerequisite determining the efficiency of a policy to promote geothermal resource development. The government should therefore ensure that such conditions are in place and aligned with the best practices observed around the world, encompassing both good governance principles and adequate measures for controlling speculative practices.

Geothermal resources are widely governed by the mining code, since many countries still lack specific laws and regulations for the sector. The legal basis for exploration of these resources is often found in a country's constitution, with sector laws approved at the parliamentary level and more specific issues covered by regulations or decrees. As with any land-related development policy and strategy, the success of geothermal sector development will depend greatly on the integrity of access to, maintenance of, and transfer of rights to geothermal resources.

Geothermal exploration and exploitation rights in particular areas are granted by governments or regulators by means of concessions, leases, licenses and agreements. Granting of these rights should be based on the following three principles: (a) a clear legal and regulatory framework, (b) well-defined institutional responsibilities, and (c) transparent and non-discriminatory procedures.

Principles Governing Geothermal Rights Management

The core principles that govern mining operations in many countries, and which also are applicable to the exploration and exploitation of geothermal resources, are:

- Resources belong to the state (or, in rare cases, to the surface land owner).
- The right to explore and exploit the resources may be temporarily transferred to an individual or a corporate entity through a written document, normally called a license or lease.
- The rights granted through such a license or lease are independent from surface or land ownership rights.
- The granted license or lease usually does not provide for visible physical boundaries (such as fencing); instead, the area is usually delimited by geographic references or coordinates.
- The holders of the granted license or lease must fulfill pre-established conditions to maintain their rights over the area.
- When the validity of the granted license or lease ends, the rights return to the state (or to the surface land owner).

Some basic principles should also govern the ownership rights to geothermal resources, which must always be granted in a transparent, objective, competitive, and non-discriminatory way. Those principles are:

- **Security of Tenure |** This refers to the security of title, the right to transfer the title to any eligible third party, and the right to mortgage the title to raise money; as well as to the transformation of exploration licenses into exploitation licenses once the presence of economic resources has been confirmed.

[45] This section is largely based on Girones, Pugachevsky, and Walser 2009.

- **Security of Title |** Licenses and geothermal rights should not be revoked or suspended except under specific circumstances clearly established in the legal framework.
- **Auctions or Tenders |** A country's legal framework may include provisions to allow for auctioning of specific rights when geological knowledge about a specific geothermal reservoir is strong, either due to the government's own exploration campaign or through other activities. Otherwise, the cost of the auctioning process exceeds its benefits given the risks.

Legally ensuring the security of tenure is fundamental since it would otherwise be difficult to attract investors to geothermal exploration. If there is a risk that the discoverer of the resources will not be granted exploitation rights when in compliance with certain predefined technical and economic conditions, the recovery of his capital investment will be jeopardized. It is also important to ensure that exploitation and exploration rights are given for a sufficiently long period of time and that they can be renewed as appropriate, based on compliance with pre-established conditions.

Security of title/tenure, however, does not mean the license for the developer to allow the resource to idle. The pre-established conditions noted above should include all the necessary requirements for the developer to put the resource to productive use within a reasonable time frame. This means that: (a) the conditions for granting the geothermal concession rights should be sufficiently rigorous with regard to the timetable for exploration and development to make sure that developers expand/develop the field where they have concessions; and (b) the government should include sufficient exit clauses that enable it to claw back the fields and reissue them if the developers are unable to expand development (at least with respect to greenfield areas).

Granting of geothermal rights is usually independent of water rights. This implies that, if the use of the geothermal resource requires the evaporation or consumption of water, specific rights may have to be obtained from a different government agency. Additional permits will also be required for the construction and operation of electrical generation facilities, direct-use steam plants, and related facility and well field operations.

Measures for Controlling Speculative Practices

By setting the framework for granting licenses to private investors, the government can profoundly affect the market structure, either setting the stage for productive competition or, in some cases, for unproductive speculative behavior. In the mining industry, a useful distinction is sometimes made between active and passive speculation. Active speculation, which seeks to promote the property and increase its selling value by undertaking reconnaissance or exploration activities, can play an essential role in the development of the geothermal sector. In contrast, passive speculation, where no activity is developed inside a specific license that remains totally dormant, can stall development of the sector. Governments limit passive speculation by exploration licensees through the application of escalating fees, mandatory relinquishment requirements (periodic obligation to reduce the surface area of the exploration licenses), and minimum investment requirements and work obligations, among other provisions.

Governmental institutions granting concessions for geothermal exploration must keep in mind that private geothermal power companies seeking to develop geothermal power projects worldwide may try to accumulate as many concessions as possible and develop them simultaneously, a practice well known in the mining industry. It is essential for authorities to establish procedures for evaluating both the intent and capacity of an applicant for geothermal exploration and development to successfully implement the activity. At a minimum, the authorities should check the applicants' in-house experience, track record in the field of geothermal energy, and capital assets. The findings should be used to evaluate each company's ability to actually develop projects on the ground as well as its intentions and future strategies.

The government should ensure that the implementation of the principles governing the provision of geothermal access rights and of the measures to control speculative practices is as efficient as possible. To do so, the government will need to clarify whether geothermal access rights require special treatment. Such treatment might include setting up a legal framework specific to geothermal exploration or the establishment of a special one-stop shop within the government which might help avoid unnecessary delays linked to multiple agencies governing access to various elements of geothermal rights.

Role of Core Geothermal Development Organization

In a country aspiring to scale up geothermal resource development, the government needs to set up an appropriate institutional structure. The experience of countries that have been successful in developing geothermal resources highlights the importance of a national champion or a dedicated core agency in charge of geothermal exploration and development. This can be a government agency or, preferably, a state-owned company with the requisite industrial capabilities. The company in charge of geothermal exploration may not necessarily have geothermal energy as its sole focus. The Philippines offers an example of an effective model based on leadership by a state-owned oil company (PNOC EDC). The example of Mexico points to the possibility of a similarly effective leadership by an integrated state power company (CFE) in geothermal development. Examples of state-owned companies with a specific focus on geothermal energy are the Geothermal Development Company (GDC) of Kenya and Pertamina Geothermal Energy Corporation (PGE) in Indonesia.[46]

In the Philippines, the central role in geothermal development for many years belonged to a subsidiary of the Philippine National Oil Corporation, called Energy Development Corporation (PNOC EDC) until its privatization in 2007. The latter company, now called just EDC, is in charge of PNOC EDC's former operations in the Philippines' increasingly liberalized electricity market. PNOC EDC has a long history and has been studied as an example of a national champion company with impressive results achieved over the years (Box 3.1).

[46] Among the developed countries that have added substantial geothermal power capacity in recent decades, Iceland stands out. In the case of Iceland, the leadership role as a developer has been shared by the state power company and the private drilling companies, while the leadership in research and exploration has belonged to the National Energy Authority and, since 2003, the government-owned institution named the Iceland GeoSurvey (Islenskar Orkurannsoknir) or ÍSOR.

BOX 3.1

The Philippines' PNOC EDC as an Early Example of a Core Geothermal Development Company

In 1976, the Philippine government, through the Philippine National Oil Company (PNOC), created the subsidiary company, PNOC Energy Development Corporation (PNOC EDC), to take over the exploration and development functions of the national power utility National Power Corporation (NPC) in the Tongonan and Palinpinon geothermal fields. NPC was still responsible for power generation and would remain the buyer of geothermal steam.

PNOC EDC became the government's arm in implementing the exploration and development of a number of geothermal fields in the country. Many areas were explored and drilled with very satisfactory results which led to eventual development and production of over 700 MW of geothermal power, much of it in partnership with private sector investors.

In 2007, the company itself was privatized and became independent of PNOC, now operating under the name of EDC.

Source | Dolor 2006

A wholly government owned and controlled corporation, PNOC EDC's experience in financing of geothermal exploration and development projects made it an appropriate counterpart for ODA. Over the years, PNOC EDC received a number of loans from the World Bank and the Japan Bank for International Cooperation to finance geothermal projects.

In Indonesia in the 1970s, the national oil company Pertamina took the lead on geothermal exploration and was the government arm for leveraging multinational company and donor funds for geothermal investments. The strong public sector role in geothermal development was reinforced by the creation of Pertamina Geothermal Energy (PGE) as the core state-owned geothermal entity. PGE was established in 2006 as a wholly owned subsidiary of Pertamina to take over all aspects of the geothermal business from the parent company. Currently, PGE is Indonesia's leading public sector geothermal developer. PGE operates 272 MW of geothermal capacity, and has developed a strategy in line with the Indonesian government's second Fast-Track Program to expand its geothermal production capacity by four fold, with an addition of 1,050 MW by 2015. PGE's functions include constructing and developing geothermal investments under the oversight of Pertamina; operating steamfields and power plants that Pertamina owns; and managing Joint Operation Contracts (JOCs) through which it oversees the revenues from Perusahaan Listrik Negara (PLN) for existing private geothermal developers (World Bank 2011).

In Kenya, the Geothermal Development Company (GDC) was established in 2008 to take primary responsibility for the exploration and development of geothermal resources. Specifically, GDC undertakes integrated development of geothermal resources through initial exploration, drilling, resource assessment and promotion of direct utilization of geothermal energy. By undertaking the initial project phases, GDC absorbs the exploration and early development risks, opening up opportunities for both public and private participation in subsequent phases (CIF 2011b).

In Mexico, geothermal exploration initially pioneered by the Comisión de Energía Geotérmica (CEG) in the 1950s was taken over by the national power utility CFE in late 1960s. Since the 1970s, geothermal development has grown from a single 37.5 MW power plant to a total installed capacity of more than 950 MW—a 25-fold increase, bringing Mexico into third place for geothermal power production, behind only the United States and the Philippines (Quijano-León, Luis, and Gutiérrez-Negrín 2003).

Overcoming Institutional Capacity Constraints

Although geothermal resources have been used for electricity production for more than a century, technical and institutional capacity to implement such projects is still lacking in a number of countries, many of which have some of the best geothermal resources on the planet. The low implementation capacity manifests itself in lack of supporting policies and institutions, which are further weakened by the lack of adequate resource information and insufficient exploration activity. To be an effective counterpart for the private sector and the IFIs, the government has to formulate strategies and strengthen its agencies to advance its geothermal development objectives.

The international community extends technical assistance (TA) to developing countries through a number of different avenues. Much of the technical assistance for geothermal development is associated with multilateral and bilateral development assistance (Box 3.2).

BOX 3.2

Multilateral and Bilateral Development Assistance for Geothermal Energy

Multilateral bank funding has a major presence in geothermal development as more and more projects are in developing countries; since 2005, US$ 3.8 billion or 57 percent of all geothermal project funding has been released in developing countries. Multilateral banks such as the Inter-American Development Bank, the European Investment Bank and the International Bank for Reconstruction and Development rank high in the top 15 debt providers for financing geothermal development. The German government-owned development banking group KfW, the French Development Agency (AFD), and the Japan International Cooperation Agency are some major bilateral organizations that are funding geothermal development worldwide. Lending operations of these institutions typically have technical assistance components associated with them.

Source | Authors and IEA 2011b.

Grants from the GEF available through the World Bank Group, the United Nations Development Progam (UNDP), and UNEP have long been a major source of technical assistance for geothermal energy. Climate Investment Funds (CIF) have recently become a significant source of concessional financing for investments in renewable energy, including geothermal power.

Apart from TA associated with lending, the World Bank's Energy Sector Management Assistance Program (ESMAP) has been providing funds for training and technical assistance to support countries to develop plans to diversify their energy supply and switch to zero and low carbon technology options, including geothermal.

The scope of technical assistance mobilized by these international institutions ranges from relatively routine and location-specific project preparation work (see Figure 3.3 for a sample list of activities undertaken in several countries by an experienced consulting firm from Iceland) to high-level policy advice to governments, regulators, and utilities.

Encouraging evidence of the effectiveness of such assistance comes from the Philippines. Over the years, the national geothermal development company PNOC EDC developed its expertise in exploration and resource evaluation techniques by learning from other geothermal producing countries, including New Zealand, Japan, Iceland, Italy, and the United States. This has helped build confidence in PNOC EDC's technical capability, and the company developed a series of geothermal projects financed by loans from the World Bank. The company acquired necessary expertise and technology in exploration, resource assessment, well drilling, reservoir management and steam production, as well as expertise in environmental management, impact assessment and risk mitigation from those advanced countries. The sector loans provided by the World Bank for the exploration and delineation of prospective geothermal areas gave the necessary boost for the Philippine government's geothermal development program (Dolor 2006).

The Kenyan example is noteworthy in terms of TA for training and building an information base. The country has made considerable investments in its human resources over the years. This has included participation by key state-owned companies in short training courses given by the Geothermal Training Program of the Iceland-based United Nations University (UNU-GTP). The first course was held jointly by UNU-GTP and KenGen in 2005 and it has been held annually thereafter. UNU-GTP, KenGen, and now GDC are discussing modalities for making the short course a permanent school for the whole Eastern African Rift Valley region. Under the GEF-supported regional African Rift Geothermal Development (ARGeo) Program, UNEP is supporting the Rift Valley countries in the critical task of building up the information base on the countries' geothermal resources. Supported by the regional network of geothermal agencies, a package of technical assistance and finance will be provided to bring the proposals to the pre-feasibility stage, and before exploration drilling. This will include surface exploration to confirm the potential of priority prospects in each country and will address the barriers related to resource confirmation (Mwangi 2010).

Some common areas of policy and regulatory support from international assistance in countries with significant geothermal development prospects can be classified as follows:

- The choice of policy instruments for supporting geothermal energy in the context of the country and its electricity sector.
- Pricing and cost recovery mechanisms for countries where geothermal energy is not the least cost option when environmental externalities are excluded.
- Application of available climate finance instruments to monetize GHG-related global externalities.

FIGURE 3.3

Selected Geothermal Project TA Activities Implemented by a Consulting Firm in Developing Countries

Selected Projects Worldwide	Reconaissance and preliminary exploration	Advanced exploration geophysics	Advanced exploration, detailed mapping	Advanced exploration, geochemistry	Site selection, wells	Drilling, engineering and management	Well logging	Well testing	Resource assessment	Direct use	Envir. assessment, impact and monitoring	Contract development and administration	Reservoir monitoring, management and QC	Technology transfer and capacity building	
AFRICA															
Kenya	■	■	■	■	■	■	■	■	■		■	■	■	■	1975-2011
Djibouti	■	■	■	■										■	1990-2008
Uganda	■	■	■	■	■				■					■	1995-2010
Rwanda	■													■	2009-2011
Eritrea	■	■	■	■					■					■	2008-2009
Ethiopia	■		■	■										■	2011
AMERICAS															
Nicaragua	■		■										■	■	2004-2011
El Salvador	■			■		■								■	1968-2011
Chile	■	■	■	■	■	■	■	■	■						2009-ongoing
Argentina	■														2007-2008
Costa Rica	■			■										■	1995-2002
ASIA															
Indonesia														■	2006-2010
Turkey	■	■	■	■	■	■	■	■	■				■	■	2008-2011
Iran	■					■	■	■						■	2005-2007
India	■														2011
Oman	■														2010
CARRIBEAN ISLANDS															
Guadeloupe					■	■	■	■	■				■	■	1996-2011
Nevis	■										■			■	2011
Dominica					■	■	■	■	■		■		■	■	2010-ongoing
UNU-GTP														■	1979-ongoing

Source | *ÍSOR 2011.*

- Modalities for risk mitigation instruments to address resource risk.
- Improvements to the tender process for granting exploration and development rights for geothermal energy resources.
- Guidelines on the scope and quality of information to be included in tender documents or requests for bids.
- Private sector participation and PPP models suitable for geothermal energy investments.
- Local manufacturing development opportunities for geothermal exploration and power generation equipment.

To summarize, a number of donor-supported TA programs are currently available to help developing countries strengthen their technical and institutional capacity to develop and scale up geothermal energy utilization.

BOX 3.3

World Bank Assistance to Scale-up Geothermal Energy in Indonesia

In Indonesia, the World Bank is helping strengthen the institutional capacity to scale-up geothermal development. A grant from the Global Environmental Facility (GEF) is assisting the Ministry of Energy and Mineral Resources' dedicated Directorate for Geothermal to undertake a number of reforms, including: (a) development of a pricing and compensation mechanism for covering incremental cost and risks of geothermal development; (b) design of a credible tender process for bidding out new geothermal concessions; (c) identification of ways in which to best allocate geothermal resource risks; (d) undertaking the necessary reviews and revisions to existing regulatory framework for geothermal energy; and (e) clarification of environmental and social safeguards.

These reforms are necessary if Indonesia is to successfully achieve its globally unprecedented scale-up of about 4,000 MW of geothermal generation capacity under its accelerated program for expanding power generation capacity. Pertamina Geothermal Energy (PGE) is responsible for about a quarter of this target, and plans to expand its geothermal installed capacity from 272 MW at present to over 1,300 MW by 2015. The financing required for such a scale-up is estimated at about US$ 2 billion or higher and will also challenge the institutional capabilities of PGE to successfully implement a vast program. The World Bank, which is financing about 150 MW of the capacity expansion, facilitated a grant of about US$ 42.5 million from the government of the Netherlands to PGE during the preparation of the project. The objective of the grant was to augment existing expertise in PGE; prepare the project to meet industry and international standards; and strengthen the overall capacity of the company. Given the positive impact of this effort, an additional grant of about US$ 7 million was included as co-financing from the Government of New Zealand to enhance the institutional impact of the technical assistance to effect PGE's entire investment program of over 1,000 MW.

Source | World Bank 2011.

POLICIES

Thirdly, supportive policies for attracting private investors are required for successful geothermal development. This is especially true if a country decides to move beyond a project-by-project approach to one that creates the right environment for investments in a scaled-up, nationwide effort to deploy geothermal power. While project-specific measures, such as individual power purchase agreements, may suffice to kick-start geothermal development in a country, nationwide approaches are more suitable in countries trying to meet significant quantitative targets for geothermal energy or pursuing expansion of their existing geothermal industry.

Ideally, the supportive policy environment should extend to all phases of the geothermal energy supply chain and include removal of barriers for off-take of geothermal energy by the grid operator and mechanisms for incremental cost recovery (if any) from the rate-payers (end users of electricity). Governments around the world have used price incentives (e.g., FITs), quantitative targets (quotas, etc.), priority dispatch, and other regulatory measures to support renewable energy, including geothermal. In addition to these measures, and arguably as a matter of even higher priority, governments can increase the cost-effectiveness of all renewable energy support by reducing fossil fuel subsidies.

At the same time, in considering their policy options, developing countries should be aware of the costs of instituting and maintaining nationwide incentives for geothermal and other renewable energy development. A FIT has a cost, either covered by the final consumers or public finances. In either case, a sustainable, fair approach is needed to cover any extra price for clean energy in recognition of its domestic and global benefits.

Policy interaction and sequencing is another important consideration if incentives to deploy any renewable energy (including geothermal) are to be effective. In addition to the incentives themselves, the existence of specific legal and regulatory provisions addressing the issues of land use, resource use, and allocation of rights need to be in place to avoid frustrating bottlenecks in renewable energy development (Azuela and Barroso 2011).

National Policy Instruments to Support Geothermal Power Generation

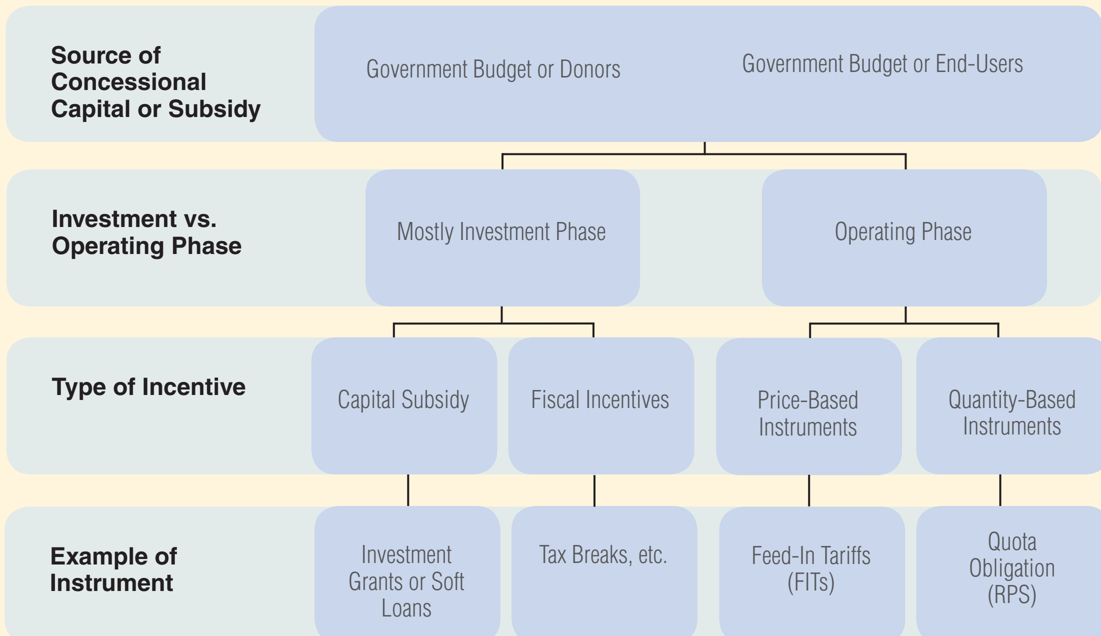
Geothermal power generation incentives

Governments in many countries use a wide range of policy and regulatory instruments to support the deployment of renewable electricity (Figure 3.4).

These can be broadly divided into two categories: investment support (capital grants, soft loans, tax exemptions/reductions on the purchase of goods) and operating support (price subsidies, quota obligations combined with tradable green certificates, and tax exemptions/reductions on the production of electricity). Operating support has the advantage of more directly influencing the ultimate outcome—renewable electricity delivered to the grid—by rewarding actual power production, not just installation. Investment support, such as subsidized capital and fiscal incentives, can play an

FIGURE 3.4

Policy and Regulatory Instruments Supporting Deployment of Renewable Electricity



Source | *Authors.*

important role during the initial stage of market introduction when necessary funds are still limited. For geothermal energy projects, investment support instruments are particularly important as they help directly address upfront barriers such as exploration risk and high investment costs.

Instruments providing operating support can be divided into quantity-based and price-based instruments. In a quantity-based scheme such as a renewable portfolio standards (RPS) policy, the quantity target (or obligation) is a decision set by policy, while the price is set by market forces. In a price-based scheme such as FIT, the market determines the quantity supplied at the price set by policy. Economic theory suggests that, under ideal conditions, quantity-based instruments and price-based instruments have the same economic efficiency (IEA 2008).

Most renewable energy sources receive public support in several different forms. Countries with strong renewable energy development agendas have introduced either FITs or quota obligations, such as RPS as their core policy, with other forms of support as supplements. RPS is sometimes combined with a system of tradable green certificates (TGC) by which the party obligated to meet the renewable energy quota can prove compliance. Both FIT and RPS policies require a strong, long-term commitment from the government and an elaborate legislative framework. Mandatory off-take of renewable energy by the power utility is a key element of both FIT and RPS regimes. The incremental cost for the utility that is due to the cost difference between renewable and conventional energy has to be absorbed either by the rate-payers or the government/tax-payers. The payoff comes in the form of increased capital inflow to the country's renewable energy sector. For renewable energy projects in which the main barrier is one of incremental cost, investors tend to find FIT-supported projects particularly attractive, since the tariff levels are usually set with the objective of guaranteeing attractive returns on investor's equity. Theoretical advantages of RPS and TGC schemes include the introduction of fewer pricing distortions than with FIT schemes.

Geothermal power stands out as a special case among renewable energy sources, and the scope of application of the policy instruments discussed here needs to be carefully considered in the specific context of the country at hand. There are only a few examples of FIT schemes successfully catalyzing the start of geothermal exploitation in a country, with most of the examples found in continental Europe. Outside of Europe, Africa and Asia have seen budding interest in using feed-in tariffs for geothermal power (Gipe 2011). The noteworthy example of Kenya is considered below. Quota obligation systems or RPS combined with TGC have been applied to geothermal power in the USA, Italy, and Japan (IEA 2008). In the developing world, the Philippines has recently introduced provisions for RPS in its legislation covering geothermal, among other forms of renewable energy.

In Kenya, the most significant measure to promote private or community supply companies has been the Feed-In-Tariffs Policy on geothermal, solar, wind, biomass, and small hydropower of January 2010. The stated objectives of the Kenyan FIT system are to: facilitate resource mobilization by providing investment security and market stability for investors in electricity generation from Renewable Energy Sources; reduce transaction and administrative costs and delays by eliminating the conventional bidding processes; and encourage private investors to operate their power plants prudently and efficiently so as to maximize returns (GoK 2010).

BOX 3.4

Kenya's Geothermal Feed-In-Tariff

- The Kenyan feed-in-tariff for geothermal power is defined as a fixed tariff not exceeding US$ 0.085 per kilowatt-hour of electrical energy supplied in bulk to the grid operator at the interconnection point.
- This tariff will apply for 20 years from the date of the first commissioning of the geothermal power plant.
- This tariff applies to the first 500 MW of geothermal power capacity developed in the country under this tariff policy.
- The tariffs applies to individual geothermal power plants whose effective generation capacity does not exceed 70 MW.

Source | Ministry of Energy, Government of Kenya 2010.

Indonesia has taken a different approach, as set out in the MEMR Regulation No. 32/20099, which became effective in December 2009. Under the regulation, the price ceiling for geothermal power has been set at US$ 0.097/kWh. A price ceiling is not a FIT, and does not guarantee any particular price for the electricity. The actual price to be included in the PPA is determined through bidding in a tender. The key determinant of the bidder's success in the tender process is the power price submitted, and the final price can be well below the ceiling price.[47] This approach has its pros and cons. On one hand, it can make the process more competitive and potentially reduce the overall cost of the incentive system. On the other hand, potential investors in renewable energy generation tend to see such schemes as much less attractive, since the price ceiling does not protect them from pricing risk.

The market structure and the context of the country's electricity sector reform influences the choice of renewable energy support instruments as well. In most developing country contexts, conditions for RPS and TGC would not be ideal due to lack of competition in generation. Thus, while the government can assign quotas for geothermal energy, the main driver of economic efficiency in meeting the quota obligation would be lost. In the case of Indonesia, for example, until or unless private developers are allowed to contract directly with the off-taker, the national power utility, PLN, would be buying all geothermal energy from PGE, the national geothermal development company.

In the Philippines, the Renewable Energy Bill was signed into law in late 2008. It went into effect in July 2009, providing legal definitions and financial incentives to further develop all renewable sources of power, including geothermal. Even though provisions in the law for FITs exclude geothermal energy, the law includes a range of other incentives that are intended to encourage geothermal energy development. These additional provisions extend to all renewable energies, including geothermal power development and generation. The provisions include establishing RPS for utilities, promoting transmission access, and offering a range of tax and investment incentives (Ogena et al. 2010). Additional incentives are listed in Box 3.5. Foreign investors are encouraged by the provision in the law that explicitly allows foreign-owned companies to participate in geothermal energy exploration and development.[48]

Overall, it can be observed that FITs are not used as much for geothermal as for other renewables. While this may change in the future, possible explanations for limited application of FIT schemes to geothermal energy can be found in the following line of reasoning.

A feed-in tariff is designed to address an incremental cost that arises when renewable energy is more expensive than conventional generation. Developers can use the promise of a reliable incremental revenue stream to strengthen their case in raising the initial financing. However, this is only helpful insofar as investors and/or lenders have confidence in the capacity of the proposed project to reach the revenue generating stage. In the case of geothermal, incremental cost is not the only issue—and for some projects may not be an issue at all. Instead, the large uncertainty regarding the resource early in the project cycle is a major obstacle for financing, and a FIT approach does not specifically target this barrier. However, if the resource exploration is undertaken by the government, there may well not be a need for additional subsidies later on; with the resource risk in part or completely removed from the equation, geothermal can be very competitive—i.e., there may not be an incremental cost.

[47] A recent Indonesian PPA to be negotiated was for the 330 MW Sarulla geothermal power plant in North Sumatra, with a levelized price of US$ 0.0697, with the initial price to be higher than in later years (Norton Rose 2010).

[48] For other renewable technologies, 60% Filipino ownership in the company is required.

BOX 3.5

Philippine Incentives for Renewable Energy under the Renewable Energy Act of 2008

The Renewable Energy Act provides fiscal and non-fiscal incentives for Renewable Energy investors and mechanisms to help ensure a market for renewable energy, including:

- An income tax holiday (ITH) for the first 7 years of commercial operation
- Duty-free importation of Renewable Energy machinery, equipment, and materials
- Special realty tax rates on equipment and machinery
- Net operating loss carry-over
- Corporate tax rate of 10% after 7 years of ITH
- Accelerated depreciation (as an alternative to ITH)
- Zero value-added tax
- Tax exemption of carbon credits
- Tax credit on domestic capital equipment and services
- Tax exemptions to manufacturers of Renewable Energy equipment
- Financial assistance through the Development Bank of the Philippines and other suppliers of preferential capital

Source | Peñarroyo 2010.

In those cases where an incremental cost is still an issue after the resource is confirmed, a FIT for geothermal power can be an appropriate policy choice. However, the introduction of a FIT policy should be done with consideration of the impact on every link down the supply chain. When utilities are obliged to off-take electricity generated from renewable/geothermal resources that can financially cost more than other available alternatives, then “someone has to pay” for these incremental costs. International experience suggests that these additional costs are either passed through to consumers or covered through government outlays or fiscal incentives. Increasingly, carbon off-set trading is also utilized by developers to enhance their revenues and bridge some of the incremental costs.

Public-Private Partnerships

A public-private partnership (PPP) is a general term for a financing scheme that integrates commitment of resources from both public and private participants to implement an investment project or program, usually in infrastructure. In geothermal power development, a PPP can be especially effective if it covers all major project phases including test drillings, field development, and power plant construction. This allows for a tailor-made arrangement in which the public sector concentrates its contribution of resources in the riskier upstream phases, while the private sector partner finances the bulk of the capital costs in the more mature phases.

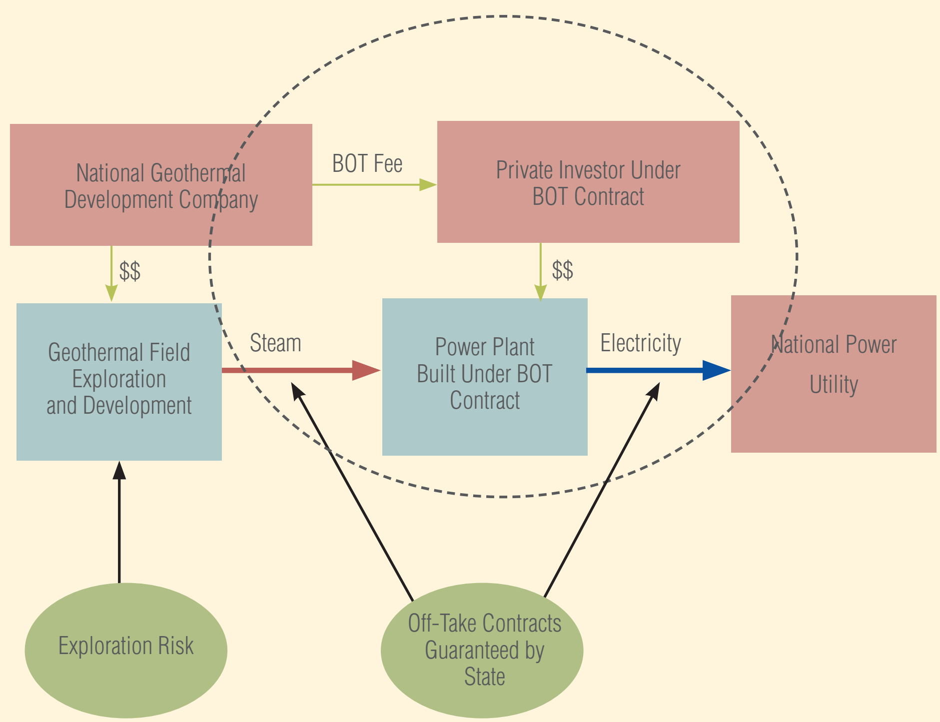
A PPP in the power generation sector is typically formed to build a certain amount of power capacity or an individual project. In a PPP, the costs and risks are carefully considered and allocated to the participating public and private entities. Obligations, benefits and risk allocations are set out in the power purchase agreement (PPA) and concession agreement. In a typical PPP for power generation, private investors build a power generation plant and contract to sell the electricity generated to a publicly owned power utility. The public authority assumes the demand risk and makes a minimum payment for availability (or capacity) of the power plant, whether or not its output is required. A further payment is made for usage, to cover the cost of fuel for the plant.

To further describe the type of contract involved in a PPP, terms such as BOT (build, operate, and transfer) or DBFO (design, build, finance, and operate) are often used (World Bank 2009). When the infrastructure asset is not returned to the public sector, it is sometimes referred to as a build, own, and operate (BOO) contract.

Examples of Successful Geothermal PPP Implementation

FIGURE 3.5

The Philippine BOT Model: Private Investor Insulated from Exploration Risk and Off-Take Risk



Source | Authors based on Dolor 2006.

The Philippine BOT model. The Philippines is notable for its successful application of one particular form of PPP—that based on BOT contracts with private investors in geothermal power.

Indeed, BOT contracts are the main form of PPP that has contributed to the development and commissioning of more than 700 MW of geothermal power generation capacity. This has contributed substantially to bringing the Philippines into the second place (after the United States) in terms of installed geothermal capacity.

The first application of BOT-based geothermal PPP in the Philippines is attributed to the World-Bank supported Leyte-Cebu Geothermal Power Project, where the construction of about 200 MW of geothermal power plants was to be implemented by a private firm through a BOT contract with PNOC EDC, the publicly owned national geothermal development company. For this component, PNOC EDC followed the BOT model which has come to be regarded as a typical private sector participation format (Figure 3.5).

Under this BOT format, PNOC EDC performs the exploration and development of the geothermal field. For its part, the power plant contractor designs, supplies, installs and commissions the plant for a pre-determined cooperation period of 10 years. During the cooperation period, PNOC EDC pays for the plant through an energy conversion tariff (essentially a BOT fee) which covers operating costs, and provides for capital recovery and return on capital. Plant ownership is transferred and handed over to PNOC EDC at the end of the cooperation period. Finding commercial funding for the private BOT contractors was not a problem because the exploration (geothermal resource) risk and the off-take risk were clearly borne by the state through PNOC EDC and National Power Corporation (NPC), the national power utility. Furthermore, payments to the BOT contractor were backed by a government undertaking in case of default by PNOC EDC or NPC (Dolor 2006).

The Mexican OPF model. The experience of Mexico points to the effectiveness of a somewhat different PPP scheme called OPF (Obra Publica Financiada). Similar to the Philippine model and the BOT model used for some projects in Mexico itself, the state power company CFE has the mandate for geothermal exploration and development. However, unlike the BOT model where the private participant constructs and operates the power plant for a number of years, the OPF model involves the private participant only until it constructs and commissions the power plant, which is to be owned and operated by Federal Commission for Energy (CFE).

Specifically, CFE develops the steam field, completes the pre-design of all the necessary components of the power plant (including the plant itself and associated transmission connections), obtains necessary permits, and then puts the project out for public bidding. The winning private contractor finances and carries out the detailed design and construction of the project and then transfers the completed project to CFE for operation and maintenance. The CFE pays the contractor the total amount of the contract after the transfer and resorts to private or public financing institutions for long-term financing to pay the contractor. The risk for the private sector is limited to short-term financing over the construction and commissioning period and to guarantees for the equipment. It does not include any risks related to geothermal reservoir or drillings.

Under this scheme, CFE has more control over specific technology choices (by virtue of its leading role in the pre-design phase and the public tender) and over the credit arrangements for the construction of the power plant. CFE takes full responsibility for the resource risk and allows the private sector to compete for a turnkey (engineering, procurement, and construction or EPC) contract, where the private company's risk is short term (construction period only). The aim is to combine the technological capabilities of the private sector with the public sector's credit resource (World Bank 2004).

Geothermal Risk Insurance

National geothermal development agencies or companies should identify available insurance schemes and carefully consider their costs and benefits. Public insurance schemes for geothermal wells have been tried on national levels, notably in Iceland (Box 3.6) and Germany. In recent years, private insurance companies have started to show increasing interest in participation in such schemes as well (Schultz et al. 2010), with private sector insurance involved in projects in Germany since about 2006.

BOX 3.6

Iceland's Public Insurance for Geothermal Risk

In the 1960s, Iceland introduced a pioneering public insurance scheme for geological and financial risks related to geothermal drillings. The National Energy Fund (NEF) was created by the government to provide such insurance. Once a drilling plan was approved by NEF, the Fund would reimburse up to 80 percent of the actual costs of unsuccessful drillings. NEF was replenished on a regular basis and, later on, included grant support for geothermal development, mainly for exploratory activities.

The role of the insurance from NEF was especially critical in the first three decades of geothermal development in the country. As the Icelandic industry became more experienced, with fewer failures in drillings and dry boreholes, the Fund became less important for the development of new projects. It is worth noting that to date all power generation in Iceland has been developed by public companies and utilities.

Source | Authors.

Further Options for Enhanced Private Sector Role

After proving the commercial viability of its geothermal sector through a series of successful PPP contracts with the government taking the resource risk, the country may consider transitioning to models that allocate more of this risk to the private developer. Two basic options can be considered: (a) inviting proposals from private companies to develop new geothermal sites through concessions or PPPs in which more of the resource risk is taken by the private investor/developer[49]; and (b) introducing attractive off-take prices through a FIT policy (or setting quantitative targets through RPS), while phasing out public support in the upstream phases.

The first approach (inviting bids for concessions to explore new sites at private investor's risk) has

[49] Depending on the contractual structure of the PPP/concession, the ownership in the assets may either revert to the public sector or remain private in the case of BOO or "pure IPP."

been difficult to implement in international practice without first going through the initial development of the industry based on public support for exploration. The example of Indonesia has shown that private investors are reluctant to take on the exploration risk even when they already hold the right (concession) in a relatively well known geothermal field, let alone taking such risk in a greenfield area (Box 3.7). Understandably, the developer/investor in a riskier area requires compensation for the extra risk through a higher off-take price of electricity or through other means of remuneration. Many countries have preferred to directly fund the risky upstream phases due to this trade-off. Indeed, the developing countries actively involving the private sector in geothermal development today (e.g., the Philippines) have previously deployed large volumes of public funding and official development assistance to finance geothermal resource exploration.

BOX 3.7

Indonesia's Concession Holders Reluctant to Expand Capacity

The example of Indonesia shows that even in those cases where private developers are already holding concessions in a large number of geothermal development areas, private investments in building and expanding new geothermal power capacity may be slow in coming (CIF 2010). Presently, there is nearly 1,000 MW of unexploited geothermal power potential under private control and over 3,000 MW with state-owned enterprises. About half of these resources are in geothermal fields which are currently producing electricity (brownfields) or with confirmed reserves (quasi-brownfields) and are well placed for further expansion (World Bank/GEF 2008).

Brownfield developers would be better equipped to proceed with investments if sufficiently attractive feed-in tariff policies were introduced in the country.

Source | Authors.

The second approach—a national policy commitment to support geothermal power generation, such as FIT, while phasing out public support in the upstream phases—has a chance of success if: (a) geothermal exploration and resource confirmation resulting from prior public support is well advanced in many areas of the country, so there is substantial scope for immediate brownfield rather than greenfield development; (b) the companies expected to respond are financially able to take the residual exploration risk—including, if necessary, through balance sheet financing rather than seeking loans; and (c) the off-take tariff or FIT is sufficient to compensate the developer for the incremental cost relative to lower cost generation alternatives, if any.

Increasing private participation in the sector can also be accomplished by privatization of the national geothermal development company and its assets. However, this does not necessarily lead to further geothermal development by the in-coming private sector entities. Such privatization, therefore, needs to come with explicit commitment of the investor to further geothermal development.

Privatization of geothermal facilities built by the public sector is the route taken by the Philippines in 2007, when it privatized PNOC EDC (now called EDC). As a private company, EDC and its subsidiaries have been actively acquiring state-owned geothermal power generation assets (see Pilipinasenergy

2009 and Danapal 2011). This approach is a sure way to increase private sector participation in the sector and raise some capital for the state budget, but the benefits for continued geothermal development are yet to be demonstrated. In fact, there has been a noticeable slowdown in greenfield geothermal development in the Philippines since privatization (World Bank/PPIAF 2010). It is hoped that the newly announced projects by EDC and Chevron will restart the momentum in the Philippines (Chevron 2011; Danapal 2011).

BOX 3.8

Chevron's Investment in a New Greenfield Geothermal Project in the Philippines

Chevron holds a 90 percent-owned and operated interest in the Kalinga geothermal prospect area in northern Luzon, which is under a 25-year renewable-energy service contract with the Philippine government. The project could add 100 MW of capacity to Chevron's geothermal portfolio, which is in the early phase of geological and geophysical assessment.

Source | Chevron 2011.

FINANCE

A Case for Public Support

A country may decide to develop its geothermal resources for a range of reasons: geothermal may represent the least cost generation expansion, or the government may place significant value on the environmental and other benefits associated with domestic renewable energy. Arguments for public support for renewable energy based on the associated environmental and other benefits, which are used by many governments globally to justify public financial support for renewable energy, apply equally to geothermal. As discussed in previous sections, additional justification for public support specifically for geothermal power generation is primarily centered on the challenges of financing the early-stage resource exploration, and the difficulty of financing such projects by the private sector alone, given the resource risk, high upfront costs, and long lead times.

The extent of difficulty in raising private capital for a geothermal power project depends on the project implementation structure. When all phases of a geothermal power project are implemented by the same developer, building a geothermal power plant is vertically integrated with a steam mining operation upstream. Such a project offers an unusual risk-reward profile, quite different from both conventional thermal power and from other renewable energies. Unlike conventional thermal power generators, which buy fuel from suppliers operating in a well established and highly liquid fuel market, geothermal power generators typically have to supply their own geothermal "fuel" for themselves, with all the costs and risks that this entails.

Even after a series of successful geothermal drillings, the expected revenue from selling electricity is still uncertain and relatively distant in the future, while major capital outlays continue to be required.

This is because further wells are needed to confirm the resource size and output and to gather sufficient geothermal flow to run a power plant. Then the plant must be constructed and commissioned before the first revenue finally comes. This contrasts with an oil and gas extraction operation, for example, which the private sector is more ready to finance, as the revenues typically come fairly soon and the expected profit margins can be much higher.

Clearly, it is mostly the upstream phases of resource exploration and development that make a vertically integrated geothermal power project difficult to finance, but financing these upstream phases separately may be even more problematic. For example, the development of geothermal steam fields as a self-standing operation may be considered creditworthy only if the off-take of the steam by a reliable buyer is secured. However, the choice of buyers of steam will usually be very limited, weakening the steam seller's prospects for guaranteed off-take and its overall bargaining position vis-à-vis the buyer.[50]

Once the steam field is substantially developed, the remaining electricity generation part of a geothermal project is more likely to attract private investors. However, there is a possibility that public financing will still be required, especially in the case of a project that is large compared to the existing power sector, such as the Olkaria IV project in Kenya (Box 3.9). Similar to other capital-intensive projects (such as large hydropower), this case shows that the risk of a geothermal power generation project may easily exceed the "risk budget" of any single private investor, making public financing solutions more appropriate, even when the risks of the steam extraction phase are resolved.

BOX 3.9

The Public-Private Choices in the World Bank Supported Kenya Electricity Expansion Project

With an appraisal document dated May 2010, the Olkaria IV geothermal project is a recent World Bank supported energy project in Kenya. The first and largest component of the project is the expansion of geothermal power generation capacity at two fields in the Olkaria volcanic complex. In designing the project, the Bank and the Government considered and rejected the alternative of private rather than public sector financing for development of the Olkaria I and IV geothermal fields. In the case of Olkaria IV, the Government of Kenya and the Bank considered having GDC develop geothermal resources and then offering proven steam resources to the private sector for development on a competitive basis. The government and the Bank rejected this alternative design because the large size of the Olkaria IV part of the project (costing about US$ 0.5 billion) made it extremely risky for the private sector, and because the government was not prepared to provide the guarantees that the private sector would demand to develop Olkaria IV.

Source | World Bank 2010a.

However, apart from cases of exceptionally large project size as in the Olkaria example, the chance of a private solution is much better for the power generation part of the project than for its upstream

50 In Indonesia, very little geothermal steam development has happened since the 1990s as many private owners who have been granted concessions continue to perceive the likely payoff from steam development as too limited for the risk involved (Ibrahim and Artono 2010). In those cases where geothermal steam development has become commercially viable (e.g., the Philippines), large volumes of official development assistance combined with government guarantees were initially required for exploration and reservoir delineation (Dolor 2006).

phases. Once the resource parameters are established and deemed sufficiently attractive, a geothermal investment resembles a typical power generation investment with a high upfront capital cost followed by long-term, steady cash flows and relatively little operating risk.

A properly developed geothermal project has the potential to generate base-load renewable energy for over 30 years, promising a return that may be attractive to a private investor with a long term horizon. Beyond addressing the resource risk, the case for public support is reduced to the role of government in providing the supportive policy and regulatory environment. This role need not involve explicit commitment of public funding. However, the government still has a vital role as a guarantor of the appropriate pricing and contracting mechanisms, including putting in place mechanisms that provide the private sector with the comfort that the off-take obligations would be honored by the buyer.

Financing Options for Different Project Phases

As the previous discussion indicates, mobilizing capital for geothermal development projects from commercial sources is more complicated than for conventional power and for most other renewable energy technologies. This is especially true for early stages of project development—particularly the test and initial production drilling,[51] when the risk is still high and the costs involved run into millions of dollars. However, the conditions for financing are rather different at various phases of the project, each phase calling for a different menu of financing options. Table 3.1 summarizes these options, breaking the geothermal development process into three distinct stages: (a) early stage (high risk); (b) middle stage (medium risk); and (c) late stage (low risk).

Early Stage | Test Drilling and Initial Production Drilling. In the early stage, the greatest obstacle to closing a deal with commercial financiers is the exploration risk, which is considered to be high and difficult to price. Commercial debt will typically not be available at this stage. Major geothermal development companies may consider the early development costs acceptable and may choose to finance test drilling and initial production drilling from their balance sheets. Similarly, major publicly-listed companies with established access to capital markets may be able to issue public equity to finance early stage development, but this is rarely done in practice. Private equity investors may be willing to contribute their capital, but will require a very high risk premium in return. Public sector contribution, through direct funding, loan guarantees, or other incentive mechanisms, has been used in many countries with geothermal developments. Donor, development agency and IFI sources may also be available.

Middle Stage | Resource Confirmation, Field Development, and Completion of Production Drilling. After seeing successful results from test drillings and initial production drillings, suppliers of debt financing will increasingly view the project as capable of supporting a short- to medium-term debt obligation. Construction debt, sometimes convertible to longer term debt, is by far the most widely employed source of financing for the completion of the drilling program (and often the power plant), usually through a loan with a maturity of two to three years, according to Bloomberg New Energy Finance. In developed markets, such as the United States, spreads over LIBOR have recently been about 325 to 400 basis points (3.25 to 4 percent) for such loans (BNEF 2011). However, the remaining

[51] Surface studies may be as low as US$ 200 thousand so financing for them may be reasonably straightforward.

risks will still deter pure project finance solutions in many cases, making the balance sheet strength of the developer an important consideration. Therefore, access to commercial debt will still be mostly unavailable except to large developers. Public sector support mechanisms, including loan guarantees by government and long-term debt from IFIs, may be helpful in extending the tenor and improving the terms of debt and in some cases may be a critical factor in mobilizing commercial lending.

Late Stage | Power Plant. Once the resource has been well-established, the risks can be finally considered roughly comparable to other thermal generation investments. At this stage, the construction of the power plant and associated infrastructure can be financed through a construction debt facility or term debt, combined with a partial risk guarantee from IFIs, as appropriate. Term debt is employed upon project commissioning to refinance any existing debt and to establish a long-term financing structure. Provided that adequate cash flow from electricity sales is guaranteed through a long-term PPA, long-term debt may be available.

TABLE 3.1

Financing Options for Different Stages of a Geothermal Development Project

PROJECT DEVELOPMENT STAGE	EARLY STAGE: Surface Exploration, Test Drilling, Initial Production Drilling	MIDDLE STAGE: Resource Confirmation, Field Development, Complete Production Drilling	LATE STAGE: Power Plant Engineering, Construction, and Commissioning
Risk of Project Failure	High	Medium	Low
Typical Financing Sources	• Balance sheet financing by a large developer • Private equity (project finance) possible but with high risk premium • Government incentives (capital cost sharing, soft loan or guarantee) • Concessional funds from international donors	• Balance sheet financing, corporate debt or bonds issued by a large developer • Public equity issuance • Construction (short-term) debt • Loan guarantee by government • Long-term debt or guarantees from IFIs • Export credit agency financing	• Construction debt • Long-term debt from commercial sources • Long-term debt from IFIs • Partial risk guarantee or partial credit guarantee instruments to attract or improve tenor and terms of commercial debt • Export credit agency financing

Source | *Authors.*

Reliance solely on commercial capital for geothermal development is rarely a viable option even in developed country markets. Although direct capital subsidies are rarely used in those markets, incentives such as loan guarantees and investment tax credits are often granted by government to geothermal developers. In developing countries, where the challenges involved in attracting private capital to geothermal projects are often greater, the commitment of the public sector—including the country government, international donors, and financial institutions—to contribute financial support is likely to be an essential element of success in mobilizing capital. Since the financial crisis of late 2008, development banks have provided 53 percent of total geothermal project financing. The financing provided by development banks was a major factor in bringing geothermal project financing to a record-high level of US$ 1.9 billion invested in 2010 (BNEF 2011).

Development and Financing Models Used Internationally

International experience shows that there has been no single model for development of geothermal resources. Even within a single country, various development models have been adopted, either consecutively nationwide, or at the same time in different fields (World Bank/PPIAF 2010).

Figure 3.6 shows eight different models that have been utilized in the international practice of geothermal power development. As the figure shows, the upstream phases of geothermal project development rely heavily on public sector investments, while private developers tend to enter the project at more mature phases. The project development cycle (and sometimes the broader geothermal market structure) may be vertically integrated or separated (unbundled) into different phases of the supply chain.

In an unbundled structure, more than one public entity or more than one private developer may be involved in the same project at various stages. It should be noted that the involvement of the private developer can take a number of different forms. For example, a BOT scheme may be used (the model historically used in the Philippines before privatization of PNOC EDC), or the role of the private sector may be limited to constructing the power plant to be owned and operated by the public utility (the Mexican OPF model).

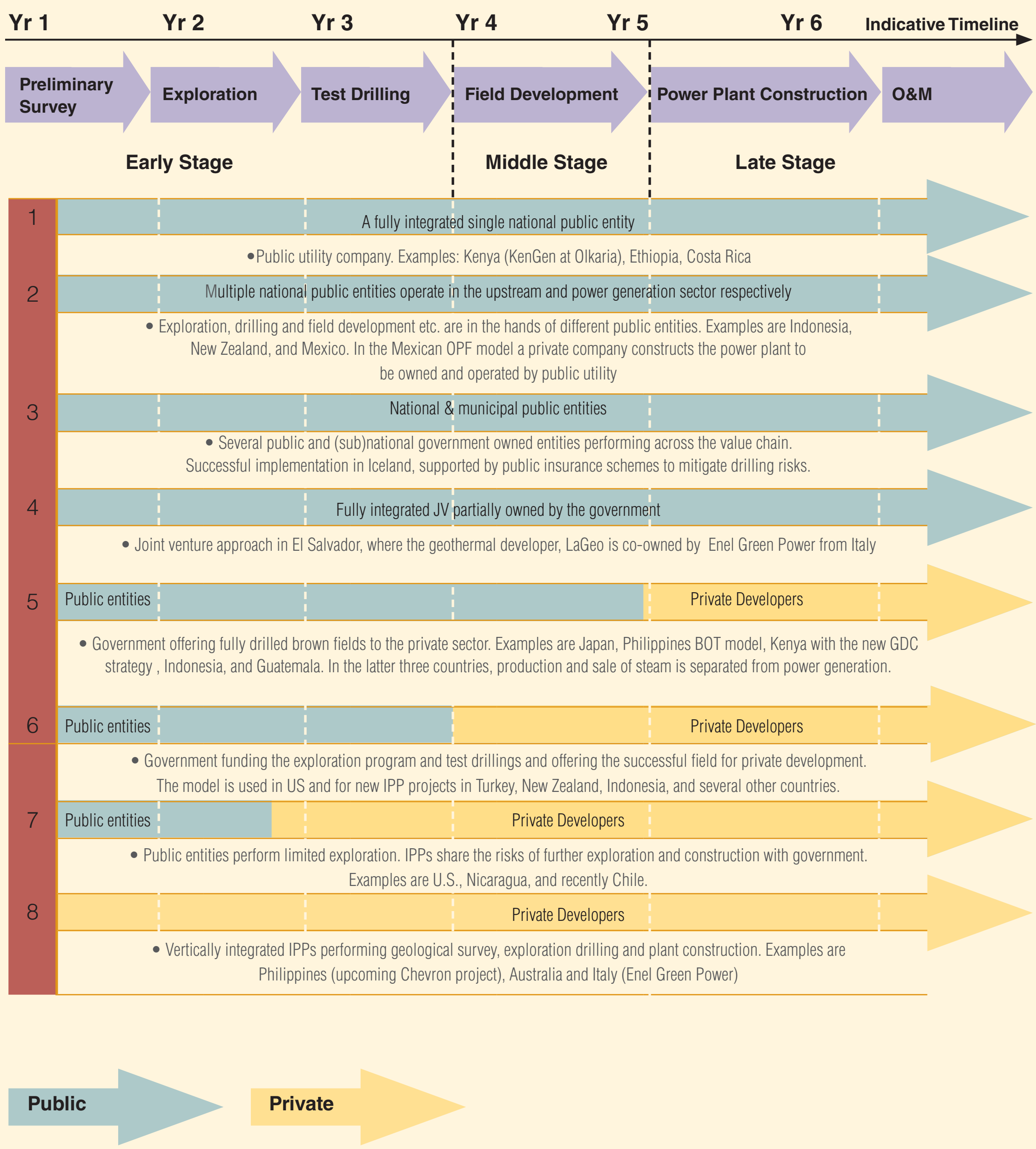
The financing structures and the corresponding risk allocations can vary widely. On one extreme is Model 1, where a single national entity performs all functions, including exploration, drilling, wellfield development, power plant design and construction, and operation of the wellfield and power plant. This is financed either by the national government and state-owned utility, or by government in conjunction with grants from donor nations and loans from international lenders. In this model, risk is borne almost entirely by the national government, through its treasury or by sovereign guarantees of loans. The burden on the public finances is reduced only by revenues earned from sale of electricity and by grants from donor nations if available.

The other possible extreme is Model 8, exemplified by the case of the fully private development led by the international oil company Chevron in the Philippines (Chevron 2011). Chevron has agreed to fund the project using hydrocarbon revenue and takes the full risks from exploration to power generation. Similar private developments can be found in Australia and in Italy where Enel Green Power develops the project.

However, most private investors shy away from taking the full resource risks in geothermal projects. Thus, Model 7 is a more typical case for a privately led development. In this model, government entities perform limited exploration, the data being in the public domain and accessible by developers. Then both public and private companies independently and competitively continue to explore, drill wells, and, if successful, build and operate power plants, selling electricity either within a service district or competitively into a national grid at market price. Revenues are expected to cover all

FIGURE 3.6

Models of Geothermal Power Development in International Practice



Source | *Authors.*

expenses and yield a profit. Risk is borne separately by the private companies and the government entities, the latter being supported by the national treasury.

In addition, a fairly broad spectrum of structures has been found between Models 2 and 6. Sometimes, more than one state-owned company or more than one level of government is involved in the provision of funds for geothermal development, while the private sector plays a limited role. In other cases, PPP structures are utilized in which the private participant plays an active role, as in Models 4 through 7.

As can be seen, apart from Model 8, public funding has an important role to play in all cases, and it usually comes either as direct support to investments or through loan guarantees. A loan guarantee covers the risk of default on the loan. Insurance or guarantee schemes specifically covering resource risk for the private sector are rare. Although there is increasing interest in employing such schemes, their introduction will most likely require a substantial amount of support from donors and IFIs, at least initially. Today, state-supported geothermal drilling insurance exists mostly in Iceland. In the United States, a scheme of reservoir insurance has been tried but did not take off commercially due to steep cost of premiums—equal to between 2 and 5 percent per annum of the face value of the policy (World Bank/PPIAF 2010).

From a government perspective, two key decisions have to be taken when choosing an approach to financing geothermal development. One is the level of participation by the private sector and the other is the level of vertical integration of geothermal development phases.

Figure 3.7 maps the development models used historically in various countries when making these two decisions. The far left and far right extremes on the horizontal axis represent fully public and fully private development, respectively. On the vertical axis, the top side represents a fully vertically integrated business model, whereas the bottom side represents an unbundled value chain with different players in the upstream and power generation business.

The countries on top left of Figure 3.7 have chosen a vertically integrated, public sector led approach. In these countries, a national champion undertakes the geothermal development activities all along the value chain, from early upstream exploration to power plant construction and operation. The countries in the bottom left area have several public entities participating in the value chain at different stages.

The governments of the countries on the right have taken a much less proactive stance, relying to a large extent on the private sector. On the top right, one private entity undertakes the activities across the value chain. Large international corporations such as Enel and Chevron can lead such development, taking significant resource risk. One example is the public-private LaGeo joint venture in El Salvador, in which Enel Green Power is the private investor.[52] In the case of the Chevron project in the Philippines, an oil company with a strong balance sheet funds the entire project development cycle.[53]

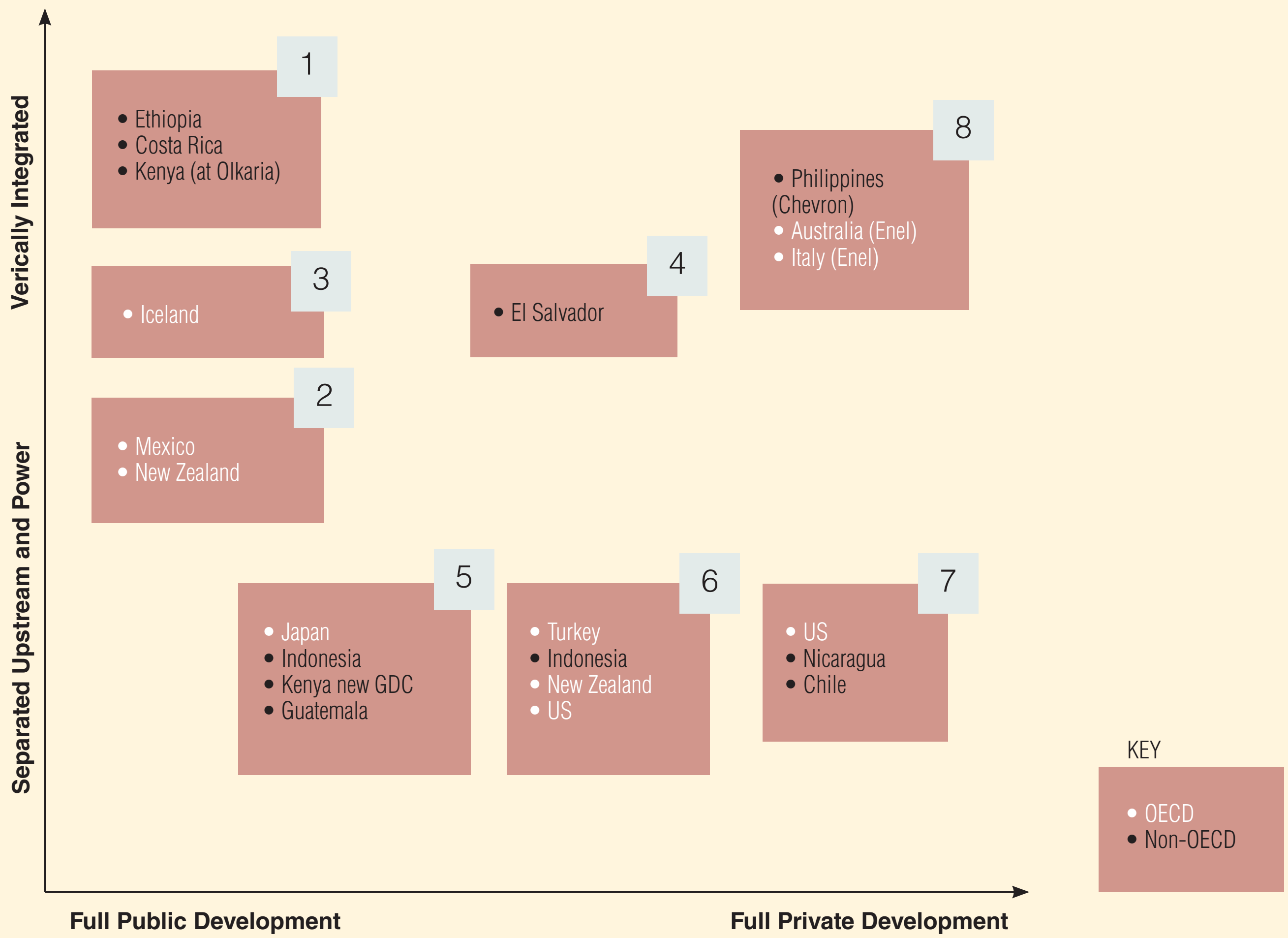
[52] Enel Green Power is the World's largest renewable energy company (around 6,500 MW installed capacity in 2011), strengthened by being owned by the Italian public utility Enel (Enel Green Power 2011).

[53] The potential motivations for oil companies to undertake geothermal development projects include the diversification benefits for their portfolio, synergies with the core business, and new relationships established with the country. From the oil company perspective, these benefits may outweigh the significant upstream risks of geothermal development.

On the bottom right, the private sector has a strong role in various phases of an unbundled geothermal supply chain. These countries are successful in introducing private investors into geothermal business in various stages of development. Possible explanations to this apparent success include the following. First, many of these countries have gone through electric power market reforms including privatizations, so parts of the value chain are operated by private companies already. Second, the relatively low country risks coupled with sufficiently high expected returns make it feasible for

FIGURE 3.7

Two-Dimensional Framework of Supply Integration vs. Unbundling and Public vs. Private Financing of Geothermal Power Projects in International Experience



Source | Authors.

the private sector to invest. Third, the supportive national or local policies for renewable energy development also help attract private investors. Government programs exist in these countries offering support in various forms, which may include tax deductions, tax credits, accelerated depreciation schedules, cost sharing, or loan guarantees. It may also be noted that the countries in this group are mostly middle- and high-income countries, or countries with well understood geothermal resources and an established track record in developing them.

Reaching for High Returns on Equity

While an operating geothermal power facility promises a steady and long-lasting revenue stream making it an attractive investment opportunity in the long run, the risks discussed above make financing more complicated and certainly put upward pressure on the cost of capital, particularly at the early stages. This is true for both debt and equity, and the role of the latter needs to be especially emphasized. While debt financing typically covers the greater part of the capital requirements (commonly 60 to 70 percent of the total project cost), lenders usually require that a significant amount of equity be invested in the project as well. In fact, equity may be the only source of capital in the initial phases of the project apart from possible grant support from government or international aid.

When financing geothermal projects, private equity investors are likely to require relatively high rates of return on their invested capital. For an equity investor entering at an early stage, required return on equity of 20 to 30 percent per year is not unusual (BNEF 2011). The resource risk makes the greatest contribution to the high risk premium. The long and uncertain completion time is often next in significance while other factors discussed above (including regulatory risk) contribute as well. In addition, from an equity investor's perspective, risk factors should include not only those affecting the return on the project as a whole, but also the risks associated with the financing structure (leverage). For example, return on equity is sensitive to changes in the terms of the debt financing, such as the interest rate, maturity period, grace period (if applicable), and debt-to-equity ratio.

It is also important to note that the long lead time for geothermal projects (with the first revenues coming only in Year 6 or even later) can greatly increase the difference in results based on the levelized cost that assumes relatively low cost of capital coming largely from public sources (with LCOE looking rather attractive at about $US 0.04 to 0.10/kWh), versus the tariff level required to reach the targets for financial return on equity. Based on a hurdle rate of, for example, 25 percent for return on equity, a geothermal project will tend to require, at least initially, tariff levels well in excess of the levelized cost, even if debt financing is available on relatively favorable terms.

One of the options to bring return on equity above the threshold rate required by the private investor is for the government (or international donors) to pay for, or at least subsidize, the costs of the initial project development—including exploratory drilling, if possible. The following illustrative example shows the impact of a government commitment to absorb 50 percent of the costs during the first three years of the project including test drillings. The methodology of the underlying financial model is given in Annex 3, along with the summary spreadsheets and sensitivity analysis for key variables.

Example

The government is interested in adding a new (greenfield) 50 MW base-load geothermal plant to the grid and is trying to encourage private investment in the project. It starts by considering the case in which no upfront grant support is provided to the private investor, but the guaranteed off-take tariff is set at a level sufficient to meet the private investor's required rate of return on equity.

Base Case | No grants (or capital subsidy) support is provided by the government. Without assured support from the government or international donors in the early stages of a geothermal project, a private equity investor may perceive the risk to be high and require an accordingly high return on equity. The example considered here assumes the required rate of return on equity to be 25 percent (Table 3.2). However, this level of return on equity proves difficult to achieve. When all costs required to confirm the resource are included, the capital cost incurred throughout the first six years are about US$ 3.9 million per MW; and the plant commissioning and the first revenues are expected only in Year 6. As a result, the net present value (NPV) of the Base Case comes out negative, even with a wholesale tariff as high as US$ 0.12 per kWh and a bank loan at 6 percent secured for 25 years.[54]

TABLE 3.2
Case without Public Support

PARAMETER	VALUE
Total Investment Cost of Project	US$ 196,000,000
Investment Cost per Megawatt	US$ 3,920,000 / MW
Required Return on Equity	25%
Interest Rate of the Loan	6%
Equity Share in Capex (from Year 2 on)	30%
Tax Rate	20%
Capacity Factor	90%
O&M, including Labor	US$ 10,192,000 / yr
Levelized Cost of Energy	US$ 0.05 / kWh
Tariff	US$ 0.12 / kWh
Return on Equity	24.5%
NPV	US$ -740,354

Source | Authors.

Given the negative NPV in the Base Case, the government considers a different approach.

[54] It is also assumed that no interest or principal is due until the project starts to generate revenues.

Government Support Case | The government provides grants (or capital subsidies) covering 50 percent of the project's investment costs in Years 1 through 3, and stops the grant support only when exploratory drilling reaches a positive result. Given that the initial phases prior to exploratory drilling are relatively low-cost surface surveys, the first three years of the project are high on risk but not so high on costs. The amount of the total grant contribution is US$ 14 million. Still, the grant support substantially increases the return on the private investor's equity, bringing it above the required return of 25 percent.

Under new circumstances, the project passes the positive NPV test (Table 3.3).

TABLE 3.3
Case with Public Support

PARAMETER	VALUE
Total Investment Cost of Project	US$ 196,000,000
Investment Cost per Megawatt	US$ 3,920,000 / MW
Government Grant Undiscounted Value [55]	US$ 14,000,000
Required Return on Equity	25%
Interest Rate of the Loan	6%
Equity Share in Capex (from Year 2 on)	30%
Tax Rate	20%
Capacity Factor	90%
O&M, including Labor	US$ 10,192,000 / yr
Levelized Cost of Energy	US$ 0.05 / kWh
Tariff	US$ 0.12 / kWh
Return on Equity	27.8%
NPV	US$ 3,539,420

Source | Authors.

From the government's perspective, a grant of US$ 14 million or less to leverage a US$ 196 million project may be a contribution well worth considering, if this leads to affordable, reliable power supply.

It should be noted that, in addition to improving the rate of return on equity, government support during the crucial first stages of project development may reduce the private investor's perception of risk and thus lower the hurdle rate of return on equity. The reduced cost of capital may in turn bring the required tariff down. For example, applying a 20 percent hurdle rate for the return on equity in the Government Support Case instead of the rate of 25 percent used in the Base Case renders the tariff of US$ 0.12 per kWh unnecessarily high. A tariff of US$ 0.10 per kWh, which results in a 21 percent rate of return on equity, may be sufficient for the private investor, whose NPV remains positive.

[55] The present value of the grant would be lower since the grant is disbursed over a period of three years.

The impact of the reduction in the cost of equity leading to a reduction of the tariff by 2 cents per kWh can be illustrated by calculating the present value of the reduction in the tariff over the project life. If, for example, instead of providing grant support in the early years of the project, the government chose to subsidize the tariff for geothermal energy once the plant was in operation, it would be committing to a greater expenditure of public money than the value of the grant noted above. Over the plant operation period of 25 years (assuming that a flat tariff[56] is contractually secured for the same period), the difference of 2 cents per kWh translates into an additional public funding commitment of US$ 46.9 million (present value discounted at the weighted average cost of capital applied to the project).

Scope for a Portfolio Approach

Minimizing Resource Risk Exposure

Mitigation of risk through diversification is a strategy well known in industry practice. Extractive industries, such as oil and gas, find it important to spread the resource risk across a sufficiently large number of prospective development fields or "prospects." Similarly, a geothermal exploration and development company can benefit from a sound diversification strategy in its investments across geothermal fields.

A strategy for minimizing resource risk exposure could consist of the following approaches:

1 | **Portfolio exploration**, in which the country to some extent explores and evaluates multiple geothermal fields, thereby increasing the probability of finding at least one viable site and reducing the chance of overlooking significant development opportunities;

2 | **Parallel development** of the fields selected from the portfolio to reduce time and costs, and

3 | **Stepwise expansion**, reducing the risk of reservoir depletion and pressure drops by developing a geothermal power project in cautiously sized increments/steps, determined by reservoir data.

Geothermal exploration in its initial phases—i.e., surface exploration to identify potential geothermal opportunities—should include all or most of the identifiable geothermal reservoirs in the country/region. This principle is most obviously applicable to all the project development phases prior to drilling, and may well be applicable to the test drilling phase. The inclusion of test drillings will require a commitment of a substantial amount of resources, particularly when the commitment is to undertake drillings in several locations in parallel. Therefore, the selection of fields to drill should always be informed—and generally narrowed down—by the results of surface exploration.

Unlike the oil and gas industry that serves the global market, demand for geothermal power is limited by a specific country's/region's minimum system demand (base load). This means that the entire demand for geothermal power may be met by a relatively small number of productive fields.

[56] The assumption of a flat (constant) tariff for the entire operating period of the plant is made for the sake of illustrative simplicity. In the actual practice of projects with a long economic life, such as geothermal or hydropower, the initial tariff is often reduced over time. The repayment of loans, in particular, allows reducing the tariff over time and still maintaining a sufficient cash flow to generate adequate return to investors.

After the initial effort to consider as many reservoirs as possible, progress in geothermal exploration may enable better targeting of the relatively small number of the most productive or promising areas. Indeed, there are some examples from the World Bank practice of how the initial drilling results can inform decisions to redirect the resources of the next phase of the project to the most promising fields (Box 3.10).

BOX 3.10

World Bank Experience: Shifting Resources to the Most Productive Geothermal Resources in the Philippines

Two major investment lending projects supported geothermal power development on the Philippine islands of Luzon and Leyte in the 1990s. In the case of Luzon, PNOC-EDC, the company in charge of the geothermal components of the projects, tended to be overly optimistic, both in planning for the number of wells to be drilled at geothermal sites and in estimating the power capacity from the geothermal steam these were to provide. The original program had to be revised drastically downwards midway through the project cycle and the geographical focus had to be shifted to Leyte, which proved a fruitful move.

Source | World Bank 1996.

In principle, a few large installations (or even just one) built in the right location(s) may end up being superior to many installations built in different locations. However, given the inherent uncertainty of geothermal resource exploration, there are several factors that need to be considered in striking the balance between concentrated and distributed strategies to plant capacity allocation.

A country endowed with geothermal resources will typically have several potentially exploitable geothermal fields (or reservoirs), making the following questions relevant.

If the country decides to allocate a certain budget to geothermal power development over the next few years, it will need to decide whether it should:

- allocate the budget entirely (or mostly) to one field that appears the most promising;
- allocate the budget across all known fields (e.g., in proportion to their estimated steam generation capacity) and proceed with the project development phases in all fields in parallel; or
- try to use a combination of the two options, for example, develop all fields in parallel until their relative merits become clearer, and then shift the resources to the most productive or promising fields.

The first option does have certain advantages (such as economies of scale) and may be preferable in some cases (for example, if the country has reliable information that suggests that it has only one exploitable geothermal field or that one particular field is far superior to the others). However, absent such exceptional circumstances, this approach will suffer from a number of shortcomings. First, allocating all the available capital to one field may unreasonably concentrate the resource risk.

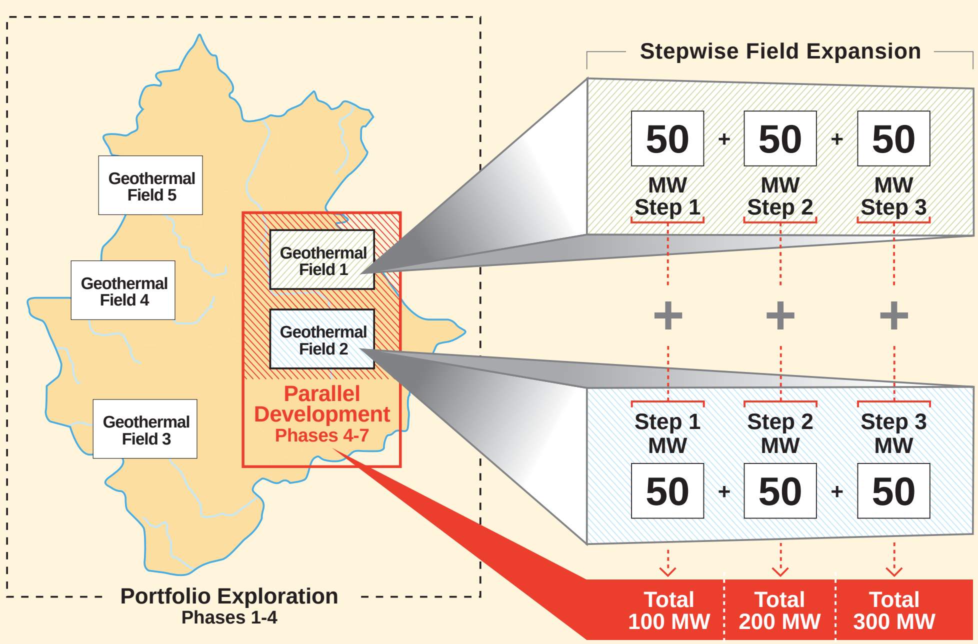
Second, this approach can lead to oversizing the plant capacity in relation to the production capacity of the field. Third, and partly as a result of efforts to determine the optimal size of the plant in relation to the field, this approach tends to increase the period of time between the investment in drilling and the start of production. This is because many wells must be drilled and tested early on to minimize the estimation risk of the generating capacity of the geothermal field (Stefansson 2002).

The second option, in which several fields are developed more or less in parallel but the initial plant size is relatively small in relation to the potential of the field, should be preferable to the first option in most cases. In a simple case of five geothermal fields available in a country, of which two are selected for further development, the approach is illustrated by the schematic in Figure 3.8.

In this schematic, the project development process leading to production drilling in each of the two selected geothermal fields has the objective of installing a plant capacity of 50 MW, well below the 150 MW estimated production capacity of the field. This dramatically reduces both the number of production wells to drill per field and the time it takes to reach the targeted production capacity. Furthermore, this greatly reduces the risk of pushing the geothermal field beyond its natural limits of sustainability.

FIGURE 3.8

Parallel Development of Two or More Geothermal Fields Reduces Resource Risk



Source | *Authors.*

Of course, parallel development could be extended to additional geothermal fields in the country based on the same principle. One 50 MW plant built in each of three geothermal fields, for example, could make 150 MW of geothermal power available to the country's power system within the period of time it takes to install a 50 MW project in just one field.

In contrast, committing the entire geothermal development budget of the country to a 150 MW plant built in a single geothermal field would be a riskier proposition and could take more time for reasons mentioned earlier.

BOX 3.11

Experience from Application of the Stepwise Expansion in Kenya

The Kenyan Olkaria geothermal power project is an example of stepwise development. The field is located in Kenya's Rift Valley, about 120 km from Nairobi. The first power plant, Olkaria I, was commissioned in 1981 with a capacity of 15 MW, then enlarged to 45 MW. The Olkaria II plant followed in the 1990´s with two 35 MW generators; it was enlarged in 2009 by another 35 MW. An IPP generates 12 MW at the Olkaria III site with a binary bottoming cycle. KenGen, the generating company, has plans to enlarge the Olkaria field from 170 MW to over 400 MW in the coming years, by deploying 4 new 70 MW power plants. Parallel to these activities, at least two other fields are expected to provide several hundred megawatts each.

Source | Magnus Gehringer based on Mwangi 2005.

FIGURE 3.9

Olkaria Power Plant, Kenya

Source | Magnus Gehringer.

The parallel development approach will initially result in only partial utilization of each field's productive capacity. Subsequently, additional plant capacity may be added so the degree of utilization of each field's productive capacity will increase over time. The 50 MW plants in our example would be only the first step for each respective geothermal field. As the demand for electric power in the country grows, so does the need for additional capacity, including geothermal. Subsequent increments of geothermal power capacity will then be built—this time, taking advantage of the much better information about the resource, based on several years of operational data from the "first-step" plant in each field.

As mentioned earlier, there is a middle ground between an all-out effort to develop the country's most promising field and developing several fields in parallel. For example, all fields could be developed in parallel until their relative merits become clearer, and then resources shifted to the most productive or promising field(s). Which phase in the project development cycle produces the needed information to justify the shift depends on the particular circumstances of the country. In most cases, completion of the test drilling phase should be sufficient to make the decision. However, there will always be a trade-off between allocation of capital to the resources that appear the most promising at the time and hedging the future uncertainty through the diversification of resource risks across geothermal fields.

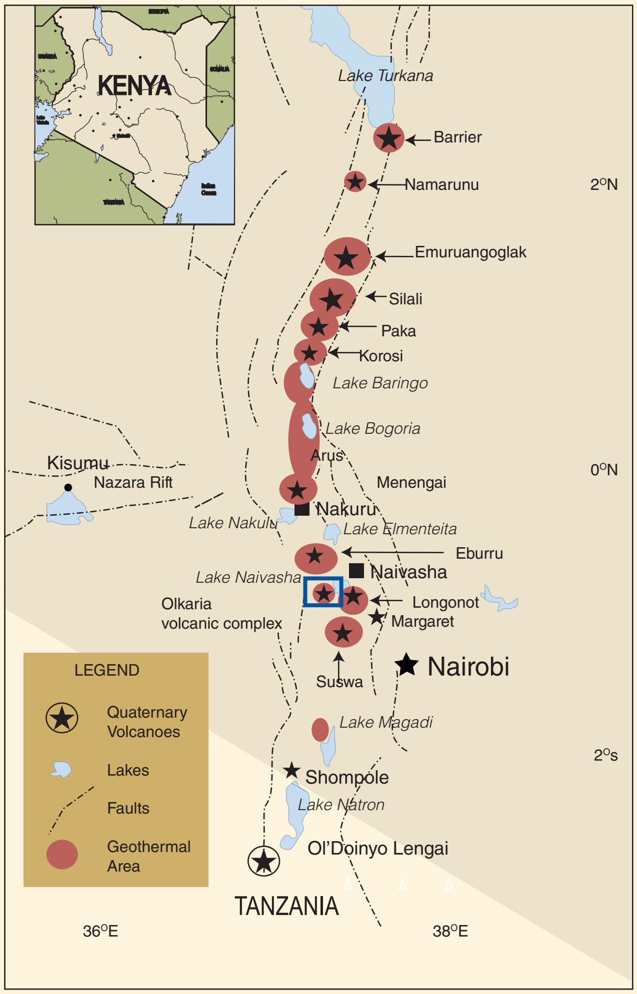
Notable Country Cases

Countries with extensive inventories of identified geothermal fields will stand to benefit most from the application of portfolio management concepts, such as benefits from diversification, reducing the overall risk of developing the geothermal resources in the country. The country's geothermal development company could, for example, have an investment portfolio consisting of multiple projects to develop geothermal fields and construct the first geothermal power plant in each (or some) of them. Provided that the probabilities of successfully tapping into a commercially viable geothermal resource are independent across the geothermal areas included in the portfolio (that is, the probabilities have little or no correlation), disappointing drilling results in some areas would tend to be offset by superior results in others. As a result, the portfolio in aggregate may be financially sustainable even if some of its individual projects fail.

Examples of countries which may enjoy potentially significant benefits from a portfolio approach are not hard to find. Kenya is one of them. At Naivasha, north-west of Nairobi, installed geothermal generation capacity was 198 MW in April 2010, putting Kenya among the top 10 nations with developed geothermal resources developed for power production. However, there are many additional sites in the Rift Valley (Figure 3.10) where exploratory drilling can be carried out. A group of international consultants retained by KenGen has determined that the Menengai and Longonot geothermal prospects are ready for drilling exploratory wells, with the aim of confirming commercial resources at each site. On the basis of surface exploration and field modeling in about 13 sites, it is reasonable to expect reserves of several hundred megawatts at each of these fields (World Bank 2010a).

Indonesia, as the country possessing the world's richest geothermal potential and where the geothermal exploration and development activities are decentralized to districts and provinces, has an even greater scope for applying a portfolio approach. The government of Indonesia has identified

FIGURE 3.10
Location of Geothermal Resources in Kenya



Source | *World Bank 2010a.*

around 250 working areas (geothermal fields) and about 50 projects (for a total of 9,076 MW) that are ready for detailed exploration or exploitation (CIF 2010). Indonesia's geothermal resources are diverse, in terms of the size and quality of a particular reservoir, as well as in the available knowledge about the characteristics of a given prospect (Castlerock Consulting 2011).

In addition to exploration risks, operational risks can also be reduced by utilizing a portfolio approach during the operation and maintenance phase. Plant output will continue to vary depending on the performance of the production wells and other factors.[57] As a result, poor operating results of one plant may be at least partially offset by the superior performance of another.

Outlook for Private Insurance

The availability of large portfolios of geothermal projects offers fertile ground for insurance schemes. Risk management through diversification is the foundation of the insurance industry. A stronger private sector role could be achieved through increasing involvement of private insurance companies in the provision of geothermal exploration guarantee/insurance schemes. Initially, including some element of public sources of subsidized capital (grants from governments, donors, or climate finance) would reduce the cost of coverage. This is how the GeoFund program supported by GEF initially operated in the World Bank client countries of Europe and Central Asia region. However, it is hoped that the insurance industry and private equity investors will fill this market niche in the future.

The geothermal industry seems to be in greater need of such insurance instruments than the oil and gas industry in which private investors absorb the exploration risk. The entry of the insurance industry into the sector, which is already happening in advanced markets, is likely to expand into the more geologically promising locations in the developing world once a critical mass of hard data is accumulated about the level of risk involved. The International Finance Corporation (IFC) in Turkey is helping to move this process forward by building a large database of drilling results available from the geothermal industry. The Geothermal Well Productivity Insurance (GWPI) facility for Turkey may be the first example of an international insurance company covering geothermal resource risk outside of continental Europe. The scheme involves local insurance companies providing the immediate coverage and the international insurance company providing reinsurance.

Small Geothermal Systems

The special case of small distributed geothermal power generation refers to the experience of rural power development in Latin America, the Caribbean, and the Philippines, among others.

The decision in favor of distributed geothermal generation may be made due either to scattered resource availability or fragmented demand centers.

Small geothermal power projects (0.5 to 5 MW per installation) could be an attractive solution for island states with limited demand, since geothermal provides reliable base-load power. For the peak demand within a given power system, geothermal energy can be successfully combined with other renewable energies like solar, wind, and hydropower, or most fossil fuel technologies. Geothermal can improve living conditions on remote islands by providing cheaper domestic energy while reducing dependency on fossil fuels.

An exploration plan for small geothermal plant sites should pool exploration risks across many small projects and identify a group of projects that will be logistically viable when bundled. Small projects cannot afford high drilling costs on the order of millions of dollars per well, which are typical for large projects. Drilling slim holes for exploration and production or using smaller, more portable drill rigs are promising methods to reduce costs in such locations (Vimmerstedt 1998).

[57] Under the World Bank supported Leyte-Luzon Geothermal Project, as a result of declining capacity of the production wells of the Mahanagdong field (primarily due to clogging), the output of the 120-MW plant declined to 72 MW. PNOC-EDC managed to increase the output through scale drillout (cleaning of wells), acidizing, drilling of additional wells and deposition inhibition techniques and the plant has been operated above 100 MW. In order to avoid similar problems in the future, it was decided to build a steamline interconnection system from Mahanagdong to other fields where surplus steam was available (World Bank 2000).

Role of Donors, IFIs, and Climate Finance

It should be clear from the previous discussion that scaling up geothermal power development requires active participation from both the public and private sector. In developing countries, however, despite some encouraging examples, such as the recent project by Chevron in the Philippines, the LaGeo venture in El Salvador, and the projects guaranteed by the Multilateral Investment Guarantee Facility (MIGA) in Kenya (Box 3.12 on the recent investment by Ormat), private sector investment in major geothermal projects in the developing world has been limited thus far.

BOX 3.12

Kenya: Equity Investment by Ormat Holding Corp. (Supported by MIGA)

In 2008, MIGA issued a guarantee of US$ 88.3 million to Ormat Holding Corp., a Cayman Islands-registered subsidiary of Ormat Technologies, Inc., for its US$ 98.1 million equity investment in OrPower 4, Inc. in the Republic of Kenya. The coverage is for up to 15 years and covers the risks of war and civil disturbance, transfer restriction, and expropriation.

The project consists of the design, construction, management, and operation of a base-load geothermal power plant with a combined capacity of 48 MW on a BOT basis in the Rift Valley's Olkaria geothermal fields, 50 km northwest of Nairobi. Electricity generated by the plant will be sold under a 20-year power purchase agreement with the national power transmission and distribution utility in the country—the Kenya Power & Lighting Company Limited.

Source | World Bank 2010a.

International development banks and other donor agencies have a very important role to play in catalyzing investment in the sector. The Philippines offers a telling example of the powerful impact of development assistance in building up the geothermal sector in a developing country. In the 1970s, the Philippine government put PNOC EDC, a subsidiary of the national oil company PNOC, in charge of geothermal exploration in several geothermal fields. However, because of limited financial resources, financing the exploration, development and commissioning of the geothermal projects of PNOC EDC was a great challenge initially. With initial capitalization and advances from PNOC, the mother company, PNOC EDC was able to carry out its mandate to explore, develop, and put into production the country's geothermal resources. The major advantage that the company enjoyed was its ability to access loans from IFIs that were guaranteed by the government (Box 3.13). Similarly, development financing enhanced the viability of geothermal power plant construction projects implemented by private investors under BOT contracts and by the national electric power utility, NPC.

Climate Finance (including CIF and carbon finance) has a key role to play in supporting geothermal energy development. Carbon finance mechanisms initially established under the Kyoto Protocol of the United Nations Framework Convention on Climate Change (UNFCCC) remain available, whereby geothermal projects can benefit from supplemental cash flows due to GHG emission savings (Annex 4). However, the cash from carbon credits is typically not available upfront and there are uncertainties surrounding the future market structure when the current Kyoto Protocol commitment period ends

BOX 3.13

Development Assistance and the Philippine Geothermal Success Story

The Philippines has a total installed geothermal power capacity of 1,904 MW and now ranks second in the world next to the United States. An aggressive geothermal exploration and development program was formulated following the energy crisis of the 1970s and was carried out by Philippine Geothermal Inc. (PGI), a private company now with 756 MW of steam field capacity, and PNOC EDC, a government owned and controlled corporation now operating 1,149 MW. PNOC EDC implemented its geothermal activities with long-term loans on affordable terms from the World Bank and the Japan Bank for International Cooperation (JBIC). To help the energy sector develop the country's geothermal resource potential, the World Bank financed exploration drilling and delineation of several areas through sector loans. After establishing technical and financial feasibility, subsequent World Bank project loans financed the development and commissioning of 777 MW of geothermal fields and power plants. The JBIC helped finance 305 MW, also through project loans.

Source | Dolor 2006.

in 2012. The concessional nature of capital supplied by climate finance vehicles, such as CTF and SREP,[58] coupled with the involvement of major international development organizations, such as MDBs, creates unique opportunities for transferring knowledge and leveraging capital from multiple sources to support low carbon investments.

Kenya, one of the six pilot countries selected to benefit from the Scaling-Up Renewable Energy Program (SREP) in Low Income Countries funding, proposes to use concessional financing at the production drilling phase, which will pave the way for non-concessional or commercial financing in subsequent stages of the proposed Menengai 400 MW geothermal project (Table 3.4).

TABLE 3.4

Proposed Sequencing of Funding Sources under the SREP Investment Plan in Kenya

	DEVELOPMENT STAGE	FUNDING AGENCY
1	Detailed Studies	Geothermal Development Company (GDC) Government of Kenya (GoK)
2	Exploration Drilling	GDC and GoK
3	Appraisal Drilling	GDC and GoK
4	Feasibility Studies	World Bank
5	Production Drilling	African Development Bank (AfDB), French Development Agency, and SREP
6	Steam Field Development	World Bank
7	Power Plant	IFC, Private Sector, and AfDB
8	Transmission / Substation	World Bank

Source | CIF 2011b.

[58] SREP operates under the Strategic Climate Fund (SCF) that supports programs with potential for scaled-up, transformational action aimed at a specific climate change challenge. SCF is part of the Climate Investment Funds (CIF), which promote international cooperation on climate change and support developing countries as they move toward climate resilient development that minimizes GHG emissions and adapt to climate change.

In the case of Indonesia, IFIs are bringing together a comprehensive package of support to accelerate geothermal development. The World Bank Group and the Asian Development Bank are mobilizing financing from their own resources, as well as the Clean Technology Fund, to immediately help scale-up investments in the sector. There is also cooperation on carbon off-set financing. The World Bank is assisting the Government of Indonesia to improve its policy and regulatory framework to enhance the investment climate for geothermal development on a sustained basis. This support is through a GEF grant and development policy lending. The World Bank and IFC are also providing advisory services in order to carry out credible and competitively tendered geothermal concessions so that private interest can be maximized. The specific activities and multiple funding sources are brought together to form a comprehensive support package that will provide the necessary short-term boost while at the same time facilitate the sustained development of the geothermal sector in Indonesia, with the ultimate goal of transforming the sector (CIF 2010). Figure 3.11 illustrates the various support activities that comprise the comprehensive support program by the IFIs.

FIGURE 3.11

Blending Various Financing Sources to Scale-Up Geothermal Development in Indonesia

GEF	POLICY-BASED LENDING	IBRD/ADB/IFC INVESTMENT LENDING	CTF	CARBON FINANCING/CDM	IFC ADVISORY SERVICES
GEOTHERMAL SECTOR REFORM PROJECT	POLICY-BASED LENDING	GEOTHERMAL POWER GENERATION PROJECTS	INDONESIA CTF IP GEOTHERMAL	CARBON FINANCING/CDM	GEOTHERMAL SECTOR ADVISORY SERVICE
• Enhance policy framework incl. pricing policies & risk mitigation • Transactions to develop brownfield & greenfield projects for private financing •Long-term domestic capacity building	• Climate change development policy loan series • Infrastructure development policy loan series	• Provide long-term financing for public sector projects • Mobilize financing for private geothermal developers	• Provide concessional financing to buy down incremental costs & cover associated risks, for projects that mitigate climate change impact	• Technical Assistance to MEMR to help secure greater levels of carbon revenues for geothermal development • Individual carbon finance transactions	• Transaction advisory service support for geothermal tenders

Source | *World Bank 2011.*

Some Guidance on Concessional Financing Facilities

General Principles Emerging from Past Experience

Participation of international agencies can substantially reduce the cost of capital available to projects. Some of the capital may even come in the form of grants. This opens the door to a variety of opportunities for setting up financial facilities (funds) customized to address specific needs.

Since resource exploration risk is a major barrier to geothermal energy development, in recent years considerable efforts and resources have gone into attempts to set up funds using concessional financing to mitigate this risk for investors.

Two significant programs supporting the development of such funds have been undertaken under the auspices of the World Bank. In both cases, GEF has been the main source of concessional capital. The experience from designing and operating geothermal funds in Europe and Central Asia, as well as more recent experience in Africa has helped the international community learn some valuable lessons and develop a better understanding of the available options (Box 3.14).

BOX 3.14

Two Donor Supported Geothermal Development Programs

Donor supported geothermal development facilities established in the past under the auspices of the World Bank with GEF support have included the GeoFund in ECA and ARGeo in Africa.

The ECA GeoFund was initiated in the early 2000s but took a few years to become operational. The overall ECA GeoFund Program capitalization from the GEF as approved by the World Bank in 2006 was US$ 25 million. The first phase of the GeoFund included two subprojects: (a) a grant of US$ 810,000 to the International Geothermal Association for Regional Technical Assistance (TA) activities and (b) a Geological Risk Insurance (GRI) Grant of US$ 3.72 million to MOL, the Hungarian integrated oil and gas company group. In the second phase, US$ 1.5 million was allocated for TA in Armenia, and US$ 10 million was allocated to the IFC for geothermal development projects involving the private sector in Turkey. The remaining US$ 9.5 million was returned to GEF, as no additional subprojects were envisaged and because the GEF administrative budget was exhausted (World Bank 2010b). The current follow-up project by the IFC in Turkey builds on the GeoFund experience, utilizing the valid concept of GRI developed under the GeoFund to attract private investment.

African Rift Geothermal Development (ARGeo) Program was initiated in 2003 and had many common features with the ECA GeoFund. Its capital consisted of US$ 11 million for risk mitigation and US$ 6.75 million for TA components. Six countries—Ethiopia, Eritrea, Djibouti, Kenya, Uganda, and Tanzania—were eligible to receive support from the program, implemented by UNEP and the World Bank. According to the original plan, the project was to start in 2005 and operate for 10 years. However, the project's risk mitigation facility was never made effective, and the UNEP-executed TA component was only approved in late 2009.

Source | Mwangi 2010 and Authors.

Key lessons and guiding principles underlying the design of a successful global / regional / MDB facility to support geothermal development have emerged from this experience. They can be summarized as follows:

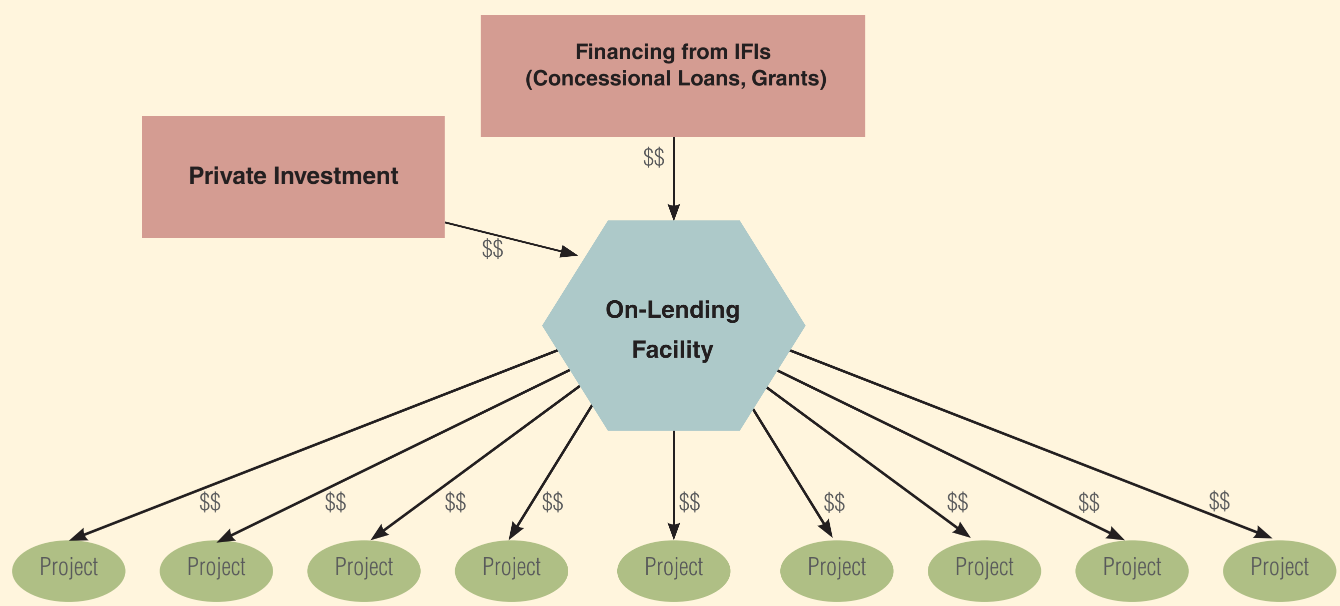
- To be successful, a donor-supported geothermal development facility needs to be well staffed and professionally managed. The expertise available within the facility should allow for proactive identification and development of a suitable investment project portfolio, its investment risk assessment, financial packaging, and the implementation of relevant tendering procedures for bidding the projects out to the market.
- The facility needs to be adequately funded, including the critical mass of concessional capital sufficient to attract cofinancing from the market at large—including private sector debt and equity—in amounts sufficient for full-scale geothermal project preparation and implementation.
- Concessional financing should be directed at phases in the geothermal development cycle when such financing has the most impact in reducing risk for investors and thus increasing the bankability of a geothermal project. In the development phases of a typical mid-size geothermal power generation project, the early phases of project preparation, including test drilling phase, will usually be the most suitable phases for a targeted application of concessional funds.
- Success during the test drilling phase is the key to bridging the crucial gap between the early start-up phases that are unlikely to attract debt financing and the more mature phases of the project, when the financiers begin to see the project as increasingly bankable. During the start-up phases, relatively little capital is required, but the risk is unacceptably high for most investors. During mature phases, the project is seen as increasingly bankable without further concessional finance.
- The geographic scope of the project portfolio should cover an area(s) containing well established and highly productive/promising geothermal reservoirs, principally those suitable for electricity generation. To reduce the concentration of risk, the area(s) should also be sufficiently wide to allow for a diverse portfolio of geothermal project locations.
- Notwithstanding the benefits expected from risk diversification, each individual project proposal presented to the facility has to meet investment risk evaluation criteria on its own merits, including geothermal resource risk assessment, creditworthiness assessment of the developer or other project sponsors, and assessment of regulatory and other relevant risks.
- To align the incentives of the developer and its sponsors with those of the facility, minimum requirements for equity contribution from the developer or sponsor need to be set in advance.
- In the case of a guarantee or insurance facility, the compensation should be limited to losses directly due to the risk that the facility intends to address (e.g., resource risk) within the criteria specified in advance and in amounts that will generally not be the full amount of the developer's losses. The guarantee fee (insurance premium) should be set to recover the costs to the facility occurring over the long term on a portfolio-wide basis.

Facility Design Options

In a donor-supported geothermal development facility, concessional finance instruments may be utilized through a number of possible designs. For example, to address the risks of the geothermal exploration/test drilling phase in a developing country, the following structures may be used.

A direct capital subsidy facility to cost-share the drilling costs of project developers. This option calls for cost sharing between the developer and the government. The cost sharing arrangement could cover a predefined maximum number of wells (up to five, for example). In return for this cost sharing, the government will receive all resource data the developer collects and will own the wells drilled if the developer abandons the project. This approach is relatively expensive but would be reasonably easy to administer and should be attractive to developers. An illustrative financial return calculation included earlier in this chapter (with details in Annex 3) shows that a 50 MW geothermal plant costing US$ 196 million may require a capital subsidy of about US$ 14 million, if the government absorbs 50 percent of the costs during the first three years of the project, including test drillings. On a country-wide scale, the approach has been proposed as one of the options for Indonesia, with the maximum cost for the government estimated at US$ 500 million (World Bank/PPIAF 2010).

FIGURE 3.12
An On-Lending Facility for a Portfolio of Geothermal Projects



Source | Authors' adaptation of a diagram presented in the 2008 Geothermal Technologies Market Report (US DOE 2009).

On-lending facility. On-lending schemes are common for IFI-supported operations with multiple sub-borrowers. In the stylized schematic of Figure 3.12, the on-lending facility borrowing concessional funds from the IFIs could be a development bank or similar entity with portfolio management expertise. The on-lending facility would establish a pool of investment funds from the IFIs and private investors. The blended cost of capital available to sub-borrowers (geothermal projects or prospects) from this facility would be significantly lower than the cost of capital to support this activity obtained solely from private debt and equity markets. Investments would be made under a determined set of criteria, designed to limit loss exposure within single projects, geographies, and activity types. The goal of the structure would be to reduce the concentration of risk by ensuring as broad a portfolio of geothermal development investments as possible.[59]

Guarantee or insurance facility. Such a facility may be set up to provide insurance against a drilled well being unusable for electric power generation. In the case of failure to achieve the expected drilling result, a compensation amount is paid out of the fund based on the terms of the insurance agreement. The agreement may define the geological parameters (temperature, flow rate, fluid chemistry, etc.) upon which the success or failure of the drilling activities are to be measured in a quantifiable manner and upon which the amount of compensation will be determined. It should be noted that the insurance instrument described here will only cover resource risk, not operational drilling, or other risks. Also, unlike a guarantee facility that could be required for the on-lending facility described earlier, it is directly focused on the most relevant risk exposures, such as test drilling, rather than on broader risks, such as general creditworthiness of sub-borrowers.

In order to limit the risk to the guarantee/insurance facility, project applicants would be required to provide sufficient data and analytical reports regarding the geothermal prospect in a full project proposal to allow for a detailed evaluation of the prospect (IFC 2011).

As an extension of this concept, the same guarantee or insurance scheme may be applied to a portfolio of geothermal projects. For example, a portfolio of an agreed number of first exploration wells drilled by the national geothermal agency or company would be insured against underperformance according to the defined geological parameters. The criterion for triggering the insurance cover would be the performance of the whole portfolio against a benchmark, which may be defined as a notional portfolio sufficient to service the debt. If the portfolio performs below that level, the guarantee or insurance fund would be called upon to top up revenues to the minimum level required for debt service. However, the fund would only cover the “first loss” up to a fixed percentage of the portfolio value. Beyond that, the national geothermal agency or company would have to cover any additional losses. The portfolio approach has the advantage that the guarantee does not need to be called upon if dry wells are compensated for by highly productive wells. The other advantage of this approach is that the insurance cost/premium per project does not have to be very high. As an increasing number of projects and prospects achieve bankability, the geothermal agency or company will decide whether or not to continue to purchase the cover (CIF 2011a).

[59] In this description, the authors have adapted certain features of a proposed DOE-supported facility described in recent reports on geothermal risk mitigation in the United States (Deloitte 2008).

ANNEX 1

THE WORLD BANK SAFEGUARD POLICIES APPLICABLE TO GEOTHERMAL PROJECTS

The World Bank's environmental and social safeguard policies are often regarded as the most comprehensive set of policies established for lending institutions to ensure that investment projects do not harm the environment or social well-being of people in the project area. The WBG currently has eight environmental and social safeguard policies for investment lending: OP/BP 4.01 on environmental assessment, OP/BP 4.04 on natural habitats, OP/BP 4.09 on pest management, OP/BP 4.10 on indigenous peoples, OP/BP 4.11 on physical cultural resources, OP/BP 4.12 on involuntary resettlement, OP/BP 4.36 on forests and OP/BP 4.37 on dam safety.

Depending on the nature of the project, one or more of these policies are usually triggered —that is, policy requirements have to be addressed through specific actions and documentation must be developed as part of project appraisal. For geothermal power projects, the OP/BP 4.01 on environmental assessment is particularly relevant, and some of the other seven policies may also apply.

OP/BP 4.01 requires screening (categorizing) projects into one of four environmental categories denoted as A, B, C, or FI, which determine the scope and depth of environmental assessment (EA). Category A is reserved for projects that are likely to have significant adverse environmental impacts that are sensitive,[i] diverse, or unprecedented. A proposed project is classified as Category B if its potential adverse environmental impacts on human populations or environmentally important areas—including wetlands, forests, grasslands, and other natural habitats--are less adverse than those of Category A projects. These impacts from Category B projects are site-specific; few if any of them are irreversible; and in most cases mitigation measures can be designed more readily than for Category A projects. A proposed project is classified as Category C if it is likely to have minimal or no adverse environmental impacts. A proposed project is classified as Category FI if it involves investment of WBG funds through a financial intermediary (FI), in subprojects that may result in adverse environmental impacts. For an FI project, screening subprojects may ultimately lead to assigning the subprojects categories similar to A, B, and C for projects.

The application of OP/BP 4.01 to geothermal power projects and the resulting scope of the EA will inevitably vary from project to project. Category B environmental assessment is usually the most appropriate for the majority of moderately sized geothermal development projects. Category A may be triggered in some complicated cases—for example, due to factors such as the presence of sensitive ecosystems in close proximity to the project site, a very large scale of the geothermal installation (e.g., several hundred megawatts), unfavorable chemical composition of the geothermal fluid (e.g., high content of H_2S), or unstable geology causing concerns about land subsidence or induced seismicity.

[i] A potential impact is considered "sensitive" if it may be irreversible (e.g., lead to loss of a major natural habitat) or raise issues covered by OP 4.04, Natural Habitats (http://go.worldbank.org/PS1EF2UHY0); OP/BP 4.10, Indigenous Peoples (http://go.worldbank.org/UBJJIRUDP0); OP/BP 4.11 (http://go.worldbank.org/IHM9G1FOO0), Physical Cultural Resources or OP 4.12, Involuntary Resettlement (http://go.worldbank.org/GM0OEIY580).

The EA for a Category A project requires a careful analysis of alternatives with respect to selection of the project site, scale, choice of technology, etc. Extensive consultation with the affected groups of people is required at key stages of EA preparation. The EA report, sometimes consisting of several volumes, is written by specialists who must be independent from the project developer. A detailed environmental management plan (EMP) is also required, covering all significant environmental impacts and risks expected to result from the project (during both construction and operation, and in certain cases decommissioning) and specific measures to mitigate them. A program of institutional strengthening for the local staff involved in the implementation of the project also will be typically proposed in the EMP. Costs and budgets for mitigation and institutional strengthening measures have to be specified. Finally, a monitoring plan is also included as part of the EMP. The monitoring plan specifies the indicators to be monitored in order to ensure that the project is operating within the limits of environmental sustainability.

For Category B projects, the scope of the EA is typically narrower than for Category A projects, and the EMP rather than an EA report may be the main document resulting from the EA. Public consultation is still required but may be less extensive than for Category A projects.[ii] However, the EA for a Category B project still requires considerable effort and resources. The indicative list below gives an idea about the nature of some of the impacts and risks that may be covered in an EMP for a Category B geothermal project.

- Solid waste generated during well drilling (drilling mud and cuttings) and other solid waste
- Risk of contamination of ground water aquifers during well drilling
- Risk of intrusion of geothermal steam or water onto the surface during well drilling (blowout)
- Risk of accidental discharge of waters to rivers or onto land surface during production tests of wells
- Interruption of traffic during pipeline construction
- Damage to soil and road surfaces during construction works for pipelines, power plant, and other structures
- Damage to or removal of trees caused by pipe laying, power line construction, and building construction works
- Risk of destabilization of geological formations caused by well drilling
- Risk of causing damage to environmentally sensitive areas on the ground
- Noise and dust from the construction sites
- Risk of intrusion of geothermal steam or water onto the surface during operation as a result of a rupture at the well head or in the steam gathering system

[ii] For all Category A and B projects proposed for WBG financing, the borrower consults project-affected groups and local nongovernmental organizations (NGOs) about the project's environmental aspects and takes their views into account. For Category A projects, the borrower consults these groups at least twice: (a) shortly after environmental screening and before the terms of reference for the EA are finalized; and (b) once a draft EA report is prepared. In addition, the borrower consults with such groups throughout project implementation as necessary to address EA-related issues that affect them.

- Impacts on soil and groundwater aquifers from possible pipeline leakages
- Risk of failure of reinjection equipment
- Noise pollution from the operation of the power plant and cooling towers

As noted above, the EMP needs to describe the mitigation measures for each of these impacts or risks and detail a monitoring plan.

For Category C projects, no further EA action is required beyond the screening process that assigns the category. However, assigning Category C to a geothermal power project is very unlikely to be appropriate, except for those cases in which the project does not involve any physical installation or construction activity and consists only of technical assistance.

Key documents such as EA reports, EMPs, and minutes of public consultation become a matter of public record and are available from the WBG's InfoShop.[iii] The EMP is also often referenced in the legal documents for the lending operation (e.g., loan agreement), which makes the borrower's commitment to the EMP legally binding. More complete information about the WBG's environmental and social safeguard policies is available on-line at the permanent URL site http://go.worldbank.org/WTA1ODE7T0.

[iii] World Bank InfoShop's mailing address is 1818 H Street NW MSN J1-100 Washington DC 20433, USA.

ANNEX 2

THE VALUE OF INFORMATION FROM EXPLORATORY DRILLING

Introduction

Resource risk is a major factor in the economic evaluation of a potential geothermal power project. The possibility that investment could be committed to its construction only to find that there was an inadequate resource supply to feed the power plant has to be borne in mind when undertaking the analysis of the project's potential benefits. The decision taker has to balance the probability that production drilling will be successful, leading to economic gains from the construction of the geothermal plant, against the probability that the drilling will fail. In the latter case costs will have been incurred and yet no economic benefit will ensue. If the probability of success is thought to be too low it may not be worth taking this risk and starting the investment program.

However, exploratory drilling or other tests may be able to give a better picture of the probability that adequate resource is available. Such a test would have some cost, but much less than that of investment committed to full scale production. The problem for the decision maker is to decide when it would be worthwhile incurring the costs of the test; when it would not be worth doing so but could still be worth proceeding directly to investment in the project; and when it would not be worthwhile to take any action.

The benefits of a viable geothermal plant can be measured by the reduction in the net present value of the generation expansion plan (capital expenditure, operational expenditure, and fuel) made possible by its inclusion. It is the probability of this cost reduction versus the probability of no cost reduction and wasted investment costs of an unsuccessful geothermal project that have to be weighed against each other and against the cost of the test. Tools for analyzing such choices have been developed for exploration in extractive industries. A basic case is illustrated below to provide an introduction to this approach.

"The Wildcatter Problem"— When to Test and When to Invest

The "wildcatter problem" that analyzes this set-up was formulated by Howard Raiffa (1968), using drilling for oil as an example. The principles he developed can equally be applied to exploration for geothermal resources. In this model, the wildcatter is assumed to have made a prior probability assessment which determined that production drilling would be successful (there is a viable resource). A test is also available (seismic or exploratory drilling) at a known cost that will provide certain information about the presence or absence of a viable resource.[iv] A central concept is that of adopting the combination of choices that would appear, based on current knowledge, to give the maximum expected value of the outcome—that is, to maximize the average benefits of the decision by weighting different possible outcomes of that decision by the probabilities of those outcomes.

[iv] This is the case of "perfect information". The more complex case of "imperfect information", where the test increases information about the probability of a viable resource, but does not confer certainty, is also able to be analyzed by similar methods to that described below.

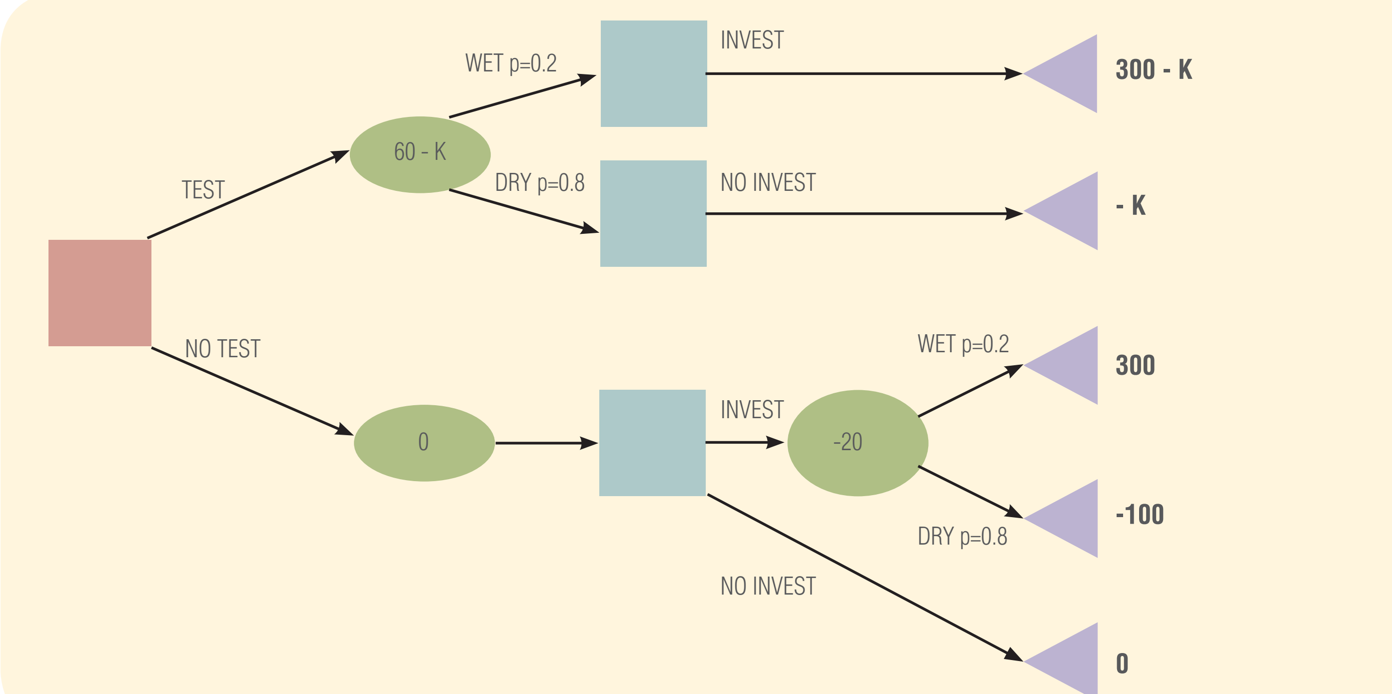
The approach is demonstrated with some purely illustrative numbers. The net benefits of successful drilling for geothermal are 300 (reduction in costs of the expansion plan); the cost of investment in a geothermal plant is 100; and the prior probability, before carrying out the test, of finding viable resource is 0.2 (the wildcatter believes that there is a 20 percent chance of being successful). The cost of the test that will demonstrate with certainty the presence or absence of a viable amount of the resource is denoted as K.

The problem is solved with the aid of a decision tree that lays out the various options open to the wildcatter and, for each option, the possible outcomes and the prior assessment of the probabilities of those outcomes. The first option on the tree is whether to test or not. The test is assumed to provide perfect information so that a "success" would guarantee that production drilling will find adequate resources for the generation project—as a result, investment can go ahead. A failure on the test would indicate that adequate resources do not exist and so no investment should take place.

If, instead, the first decision was not to undertake the test, a second decision on whether to go ahead with the project would still be required. A decision to go ahead could lead to a success with its attendant benefits, while a failure would have incurred the investment costs but no benefits. The final alternative would be not to test and not to invest (the base case against which other cases can be judged).

ANNEX 2, FIGURE 1

Decision Tree for Testing and Investing



Source | *Robert Bacon.*

Such a tree is shown in Annex 2, Figure 1. A square node indicates a decision (test or not), a circular node indicates a probabilistic outcome (wet well or dry well), and a triangular node indicates the net benefits of that particular outcome. The decision maker chooses the path through the tree that provides the maximum expected benefit.

The first path through the tree is one in which the test is undertaken. If a wet hole is found (assessed at probability 0.2) then investment would take place because of the certainty about the resource—the net benefit would be 300 - K (the net benefit of the project less the cost of the test). If a dry hole is found (probability 0.8) no investment would take place because of certainty that a viable resource is not present—the net benefit would be -K (the cost of the test). Taking the expected value of these outcomes (the weighted average) leads to a value of 60 - K. Provided the cost of the test is less than 60, the outcome of testing and then investing or not, according to the test results, yields a positive expected return.[v]

The second path through the tree involves first the decision not to test and subsequently the decision to invest. This has two possible outcomes—a wet hole (probability 0.2) with net benefit of 300 (no cost of testing) and a dry hole (probability of 0.8) with a net benefit of -100 (wasted investment costs). The expected net benefit (weighted average) would be -20. Drilling without testing first would, with the assumed probability of success, lose money on average. The difference from the case with testing is that investing when there will be a dry hole could have been avoided by following the indications of the test results.

The third path through the tree would be the decision not to test and not to invest. The expected net benefit would be zero—no costs but no geothermal plant. If testing is not done, it is better not to invest than to invest, since the third path has a better expected outcome than the second path. However, provided the cost of the test is less than 60, it is best to follow the first path—test, then invest or not according to the results.

This example makes it clear that the values of the prior probability of a viable resource being found and the cost of the test are crucial to the decision taken. Decisions that maximize the expected net economic benefit for different values of these parameters are shown in Annex 2, Table 1. Lower costs for a test make it more likely that it will be optimal to test before investing, while higher prior probabilities of well success make it less likely that a test will be needed before investing. A high test cost and a low probability of success leads to the decision to neither test nor invest.

The cost of the test is known from general geophysical experience, adjusted to local conditions. Drilling an exploration well is a clearly defined activity and the cost should be calculable within a narrow margin. However, making a prior assessment of the probability that a viable resource will be found is more difficult and depends, in large part, on whether any prior drilling has taken place in the area. Bickel, Smith and Meyer (2008) discuss some aspects of arriving at an assessment of this probability. Annex 2, Box 1 indicates that globally the probability of well success (proportion of wells drilled that have found viable resources) is substantial, and that the probability of a well success tends to increase with the number of wells already drilled in a field as drillers learn about the characteristics of the field from previous trials.

[v] In practice it is likely that a program of several exploratory wells would be drilled, and that certainty would be equated with a given number (for example, at least two out of four) indicating the presence of a viable resource.

ANNEX 2, TABLE 1

Optimal Decisions for Different Test Costs and Well Success Probabilities

PROBABILITY OF SUCCESS	COST OF TEST	OPTIMAL DECISION	NET ECONOMIC BENEFIT
0.2	50	Test	10
0.6	50	No test, invest	140
0.2	65	No test, no invest	0
0.6	30	Test	150
0.2	30	Test	30

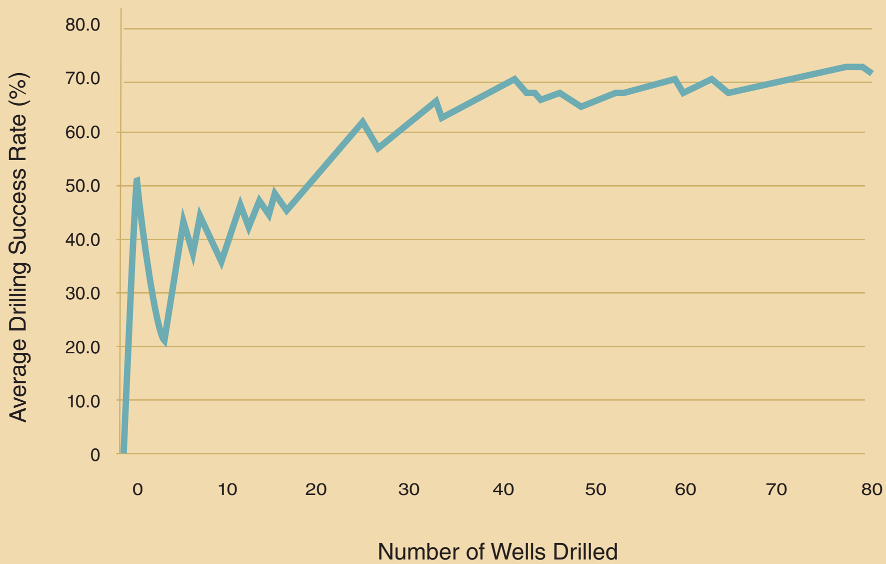
Source | *Robert Bacon.*

ANNEX 2, BOX 1

Drilling Success Rate for Geothermal Wells

Sanyal and Morrow (2012) estimated that at least 4,000 geothermal wells have been drilled to date globally. They had sufficient information to analyze 2,528 geothermal wells in 52 fields in 14 countries and found that the mean success rate was 68 percent. Analysis of results for individual fields showed that the mean success rate stabilized fairly quickly after broad fluctuations for the first few trials. For example, in the Kamojang field in Indonesia, where a large number of wells have been drilled, the success rate settled down after 5 or 6 wells and then slowly rose to an asymptotic value around 70 percent as shown below in a figure taken from a study by Geothermex prepared for the World Bank in 2010.

Average Drilling Success Rate vs. Number of Wells Drilled in Kamojang Field, Indonesia



Source | *World Bank/PPIAF, 2010.*

Sanyal and Morrow also present aggregate statistics field by field as shown below, indicating that a substantial majority of fields produced success rates above 50 percent.

SUCCESS RATE	NUMBER OF FIELDS	SUCCESS RATE	NUMBER OF FIELDS
33% - 40%	4	71% - 80%	10
41% - 50%	5	81% - 90%	8
51% - 60%	9	91% - 100%	5
61% - 70%	11		

Source | *Sanyal and Morrow 2012.*

ANNEX 3

AN ILLUSTRATIVE CASE OF GOVERNMENT COST-SHARING OF EXPLORATION COSTS

METHODOLOGY

The illustrative financial analysis of a hypothetical 50 MW geothermal project used in this handbook is based on a customized Excel spreadsheet model. The model calculates the internal rate of return (IRR) on the project and its net present value (NPV), as well as the rate of return on equity investment and its respective NPV. These are common decision making criteria in project finance. In addition, the model calculates the levelized cost of energy (LCOE), although it is not an integral part of the return and NPV calculations. The LCOE is calculated as the discounted stream of project costs (including both capital and operating expenses) over the life of the project, divided by the stream of corresponding energy outputs discounted by the same discount rate.

The dollar amounts are given in real terms. To convert the results into nominal terms, escalation factors would need to be introduced for all cost items as well as for the tariff. The NPV on the project and its respective IRR take the perspective of all investors, including the suppliers of debt (lenders). The cash flow used in this part of the caclulation is based on the concept known in project finance as free cash flow, sometimes defined more specifically as the free cash flow to the firm (FCFF). In our case the "firm" is the project, so the cash flow is denoted as free cash flow to the project (FCFP). The formula to determine the project NPV is:

$$NPV_{proj} = \sum_{t=0}^{n} \frac{FCFP_t}{(1+WACC)^t}$$

where $FCFP_t$ is the free cash flow to the project in year t in the project life of n years; WACC is the weighted average cost of capital. WACC is found by the formula WACC = interest rate of the debt x (1– corporate tax rate) x proportion of debt in the project capital + (required rate of return on equity x proportion of equity in the project capital). When grants are included, they reduce the amount of capital to be covered by debt and equity.

The NPV of the cash flow to equity and the respective rate of return take the perspective of equity investors only. The cash flow used in this caclulation is based on the concept of free cash flow to equity (FCFE). The formula to determine the equity NPV is:

$$NPV_{equity} = \sum_{t=0}^{n} \frac{FCFE_t}{(1+R_e)^t}$$

where $FCFE_t$ is the free cash flow to equity in year t in the project life of n years; and R_e is the required return on equity. Discounting by R_e (rather than by WACC) is consistent with the fact that the annual interest and principal payments for the debt are already made and the entire remaining cash flow belongs to the equity investors. The latter generally require a higher return from this cash flow to compensate for the higher risk associated with being the last in line to receive the payoff.

The level of the risk premium and the resulting R_e depends strongly on the nature of the project. As noted in this book, common equity investors in a geothermal project may require a return between 20 and 30 percent. However, as also noted in Chapter 3, this can be lowered by proper cost sharing arrangements. Partial grant support from the government during the crucial early stages of the project, for example, may reduce the required rate of return considerably.

SUMMARY TABLES

A Hypothetical Geothermal Project - Financial Analysis

Abbreviations used in this annex:

Capex	Capital expenditures (or investment costs)
EBIT	Earnings before interest and taxes
EBITDA	Earnings before interest, taxes, and depreciation/amortization
FCFE	Free cash flow to equity
FCFP	Free cash flow to the project
IRR	Internal rate of return
NPV	Net present value
O&M	Operation and maintenance costs
PV	Present value
R_e	Required rate of return on equity
WACC	Weighted average cost of capital

SUMMARY TABLES

A Hypothetical Geothermal Project - Financial Analysis (constant 2011 US$)

BASE CASE: NO GRANTS; TARIFF US$ 0.12 / kWh								YEARS 7...30	
	YEAR 0	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	YEAR 7	YEAR 30
	2011	2012	2013	2014	2015	2016	2017	2018	2041
Installed capacity, MW	50.00								
Total investment cost of project in US$	196,000,000.00								
Total capital costs in US$ per MW	3,920,000.00								
Required return on equity	25.0%								
Interest rate of the loan	6.00%								
After-tax Interest rate of the loan	4.80%								
Loan maturity period, years	25								
Tax rate	20.0%								
WACC	11.221%								
Depreciation period, years	30								
Fraction of capex incurred	0.010	0.015	0.064	0.064	0.411	0.436			
Grant-financed percent of capex	0.000	0.000	0.000	0.000	0.000	0.000			
Equity share in after-grant capex	1.000	1.000	0.300	0.300	0.300	0.300			
Installed capacity, MW	50.00								
Capacity factor	90%								
Number of hours per year	7,884								
Power output, GWh							394.2	394.2	394.2
Tariff, US$/kWh	0.12						0.12	0.12	0.12
	2011	2012	2013	2014	2015	2016	2017	2018	2041
Total investment cost, US$	2,000,000.00	3,000,000.00	12,500,000.00	12,500,000.00	80,500,000.00	85,500,000.00			
Grant, US$	-	-	-	-	-	-			
Investment cost after grant, US$	2,000,000.00	3,000,000.00	12,500,000.00	12,500,000.00	80,500,000.00	85,500,000.00			
Equity, US$	2,000,000.00	3,000,000.00	3,750,000.00	3,750,000.00	24,150,000.00	25,650,000.00			
Debt, US$	-	-	8,750,000.00	8,750,000.00	56,350,000.00	59,850,000.00			
Loan balance, US$	-	-	8,750,000.00	17,500,000.00	73,850,000.00	133,700,000.00	128,352,000.00	123,004,000.00	-

A Hypothetical Geothermal Project - Financial Analysis (constant 2011 US$)

	YEAR 0	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	YEAR 7	YEAR 30
Revenues, US$							47,304,000.00	47,304,000.00	47,304,000.00
Operating expenses							16,862,533.33	16,862,533.33	16,862,533.33
O&M							10,192,000.00	10,192,000.00	10,192,000.00
Depreciation							6,533,333.33	6,533,333.33	6,533,333.33
Other							137,200.00	137,200.00	137,200.00
EBITDA							36,974,800.00	36,974,800.00	36,974,800.00
Operating Profit (EBIT)							30,441,466.67	30,441,466.67	30,441,466.67
Interest							8,022,000.00	7,701,120.00	320,880.00
Principal							5,348,000.00	5,348,000.00	5,348,000.00
Total debt service							13,370,000.00	13,049,120.00	5,668,880.00
Earnings before taxes							22,419,466.67	22,740,346.67	30,120,586.67
Net Income							17,935,573.33	18,192,277.33	24,096,469.33
Income tax, US$							4,483,893.33	4,548,069.33	6,024,117.33
Free cashflow calulations									
Note: FCFP = Free Cash Flow to the Project; FCFE = Free Cash Flow to Equity									
FCFP (calculated from EBIT) in US$	(2,000,000.00)	(3,000,000.00)	(12,500,000.00)	(12,500,000.00)	(80,500,000.00)	(85,500,000.00)	30,886,506.67	30,886,506.67	30,886,506.67
Project IRR (based on FCFP)	13.4%								
Project NPV (based on FCFP) in US$	23,677,501.41								
FCFE (calculated from Net Income) in US$	(2,000,000.00)	(3,000,000.00)	(3,750,000.00)	(3,750,000.00)	(24,150,000.00)	(25,650,000.00)	19,120,906.67	19,377,610.67	25,281,802.67
Return on equity (based on FCFE)	24.5%								
Equity NPV (based on FCFE) in US$	(740,354.05)								

SUMMARY TABLES

A Hypothetical Geothermal Project - Financial Analysis (constant 2011, US$)

GOVERNMENT SUPPORT Case: GRANTS IN EARLY STAGES; Tariff US$ 0.12 / kWh								YEARS 7...30	
	YEAR 0	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	YEAR 7	YEAR 30
	2011	2012	2013	2014	2015	2016	2017	2018	2041
Installed capacity, MW	50.00								
Total investment cost of project in US$	196,000,000.00								
Total capital costs in US$ per MW	3,920,000.00								
Required return on equity	25.0%								
Interest rate of the loan	6.00%								
After-tax Interest rate of the loan	4.80%								
Loan maturity period, years	25								
Tax rate	20.0%								
WACC	11.132%								
Depreciation period, years	30								
Fraction of capex incurred	0.010	0.015	0.064	0.064	0.411	0.436			
Grant-financed percent of capex	0.000	0.500	0.500	0.500	0.000	0.000			
Equity share in after-grant capex	1.000	1.000	0.300	0.300	0.300	0.300			
Installed capacity, MW	50.00								
Capacity factor	90%								
Number of hours per year	7,884								
Power output, GWh							394.2	394.2	394.2
Tariff, US$/kWh	0.12						0.12	0.12	0.12
	2011	2012	2013	2014	2015	2016	2017	2018	2041
Total investment cost, US$	2,000,000.00	3,000,000.00	12,500,000.00	12,500,000.00	80,500,000.00	85,500,000.00			
Grant, US$	-	1,500,000.00	6,250,000.00	6,250,000.00	-	-			
Investment cost after grant, US$	2,000,000.00	1,500,000.00	6,250,000.00	6,250,000.00	80,500,000.00	85,500,000.00			
Equity, US$	2,000,000.00	1,500,000.00	1,875,000.00	1,875,000.00	24,150,000.00	25,650,000.00			
Debt, US$	-	-	4,375,000.00	4,375,000.00	56,350,000.00	59,850,000.00			
Loan balance, US$	-	-	4,375,000.00	8,750,000.00	65,100,000.00	124,950,000.00	119,952,000.00	114,954,000.00	-

SUMMARY TABLES

A Hypothetical Geothermal Project - Financial Analysis (constant 2011 US$)

	YEAR 0	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	YEAR 7	YEAR 30
Revenues, US$							47,304,000.00	47,304,000.00	47,304,000.00
Operating expenses							16,862,533.33	16,862,533.33	16,862,533.33
O&M							10,192,000.00	10,192,000.00	10,192,000.00
Depreciation							6,533,333.33	6,533,333.33	6,533,333.33
Other							137,200.00	137,200.00	137,200.00
EBITDA							36,974,800.00	36,974,800.00	36,974,800.00
Operating Profit (EBIT)							30,441,466.67	30,441,466.67	30,441,466.67
Interest							7,497,000.00	7,197,120.00	299,880.00
Principal							4,998,000.00	4,998,000.00	4,998,000.00
Total debt service							12,495,000.00	12,195,120.00	5,297,880.00
Earnings before taxes							22,944,466.67	23,244,346.67	30,141,586.67
Net Income							18,355,573.33	18,595,477.33	24,113,269.33
Income tax, US$							4,588,893.33	4,648,869.33	6,028,317.33
Free cashflow calulations									
Note: FCFP = Free Cash Flow to the Project; FCFE = Free Cash Flow to Equity									
FCFP (calculated from EBIT) in US$	(2,000,000.00)	(3,000,000.00)	(12,500,000.00)	(12,500,000.00)	(80,500,000.00)	(85,500,000.00)	30,886,506.67	30,886,506.67	30,886,506.67
Project IRR (based on FCFP)	13.4%								
Project NPV (based on FCFP) in US$	24,843,206.83								
FCFE (calculated from Net Income) in US$	(2,000,000.00)	(1,500,000.00)	(1,875,000.00)	(1,875,000.00)	(24,150,000.00)	(25,650,000.00)	19,890,906.67	20,130,810.67	25,648,602.67
Return on equity (based on FCFE)	27.8%								
Equity NPV (based on FCFE) in US$	3,539,419.61								

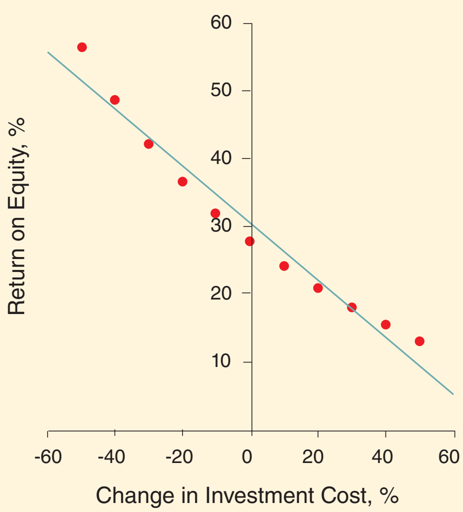
SENSITIVITY ANALYSIS

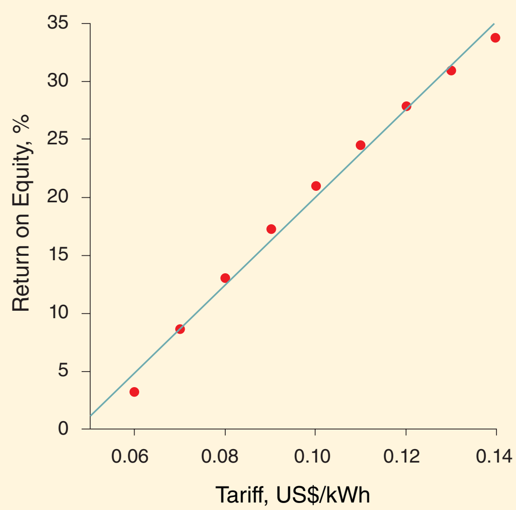
Various risk assessment tools can be employed in investment project analysis. Sensitivity analysis is one of them. To make the decision to commit resources to a project, the investor needs to be satisfied that the return on the investment is sufficiently robust under various scenarios affecting key parameters, such as the capital (investment) cost of the project, the recurring costs of operation and maintenance (O&M), and the likely level of tariff received per kilowatt hour sold to the grid, as well as the capital structure and terms of financing of the project.

To assess the likely impact of these key parameters on the investor's return, sensitivity analysis is typically performed. This type of analysis is sometimes called "what-if" analysis because it shows what happens to the key variable of interest to the investor if another variable (or, rather, its assumed value) changes. The variables whose impact is being determined are usually changed one at a time (although several variables can also be changed simultaneously to see their cumulative impact). If this approach is chosen, each variable is returned to the initial value assigned to it in a certain reference scenario before proceeding with the next variable. Such an analysis usually requires a cash flow model to be sufficiently accurate. The example above was calculated using an Excel spreadsheet model that simulates the cash flows to the equity investor.

ANNEX 3, FIGURE 1

Sensitivity of Return on Equity to Various Levels of Investment Costs and Electricity Sales Price (Tariff)





Source | Authors.

Given the uncertainty about the investment cost per megawatt eventually incurred by the project, it helps to review the impact of a deviation of the investment cost from the reference case. Using the Government Support Case (see Chapter 3), the graph shown in Annex 3, Figure 1 on the left side illustrates that a cost overrun of 20 percent would reduce the return on equity from about 28 percent to about 21 percent.

The graph on the right shows that, while a tariff of US$ 0.09 per kWh allows the investor to achieve a 17 percent rate of return, it would take US$ 0.11 per kWh or higher to achieve a 25 percent return on equity. One can observe that the relationships illustrated above are not exactly linear, but the sense of direction is clear.

The key findings from analyzing the impact of other variables can be summarized as follows.

- If the interest rate on the loan changes from 6 to 10 percent, the return on equity falls from 28 percent to about 24 percent.
- If the equity share in the project capital costs changes from the 30 percent assumed in the reference scenario to 50 percent (after Year 2, since we are assuming the first two years' investments will have to be entirely equity-financed), the return on equity falls to about 21 percent. Conversely, if the share of equity is decreased to 20 percent, the return on equity reaches 33.5 percent. This is due to the leverage effect of the loan that replaces equity in the capital structure by the same amount that equity decreases.
- If the capacity factor of the power plant is assumed to be 70 percent instead of 90 percent, the return on equity falls to 18.5 percent.
- If the O&M costs prove to be 50 percent higher than envisaged in the reference scenario, the return on equity will fall from 28 percent to 23.5 percent; on the other hand, if the O&M costs turn out to be 50 percent below the reference scenario, the return on equity is close to 32 percent.

It bears repeating that these results of the "what-if" simulation are built around the Government Support Case which includes partial grant financing in the early years of the project. The impact from excluding the grants from the calculation negatively affects the return on equity, and the results of the sensitivity analysis would be affected as well. Unless other factors intervene (for instance, if the tariff in the Base Case is set at a higher level than in the Government Support Case), all the curves describing the relationships of the input parameters with the return on equity would shift downward by a few percentage points.

Return on equity is not the only key figure that may be of interest to the investor, and sensitivity analysis may be conducted for many other dependent variables. For example, since the equity investor is typically not the only investor in the project, the return on the project as a whole may be as important as return on equity. A cash flow model for return on the project as a whole would be based on the same investment cost and operational data, but would focus on the cash flow available to all investors, including providers of debt financing. The rate of return calculated on this basis will often be lower than the return on equity (due to the positive leveraging effect of debt in the latter case), but this does not necessarily make the project less attractive since the required return would also be lower on average. The process for the sensitivity analysis would be essentially the same.

Besides the two measures of return mentioned above, other variables could lend themselves to a meaningful sensitivity analysis. In addition, it should also be kept in mind that the financial model used above does not substitute for an economic analysis of the project or for a power systems expansion analysis. The three are all needed for various purposes of developing a geothermal investment program, that is: (a) optimizing the size of a particular geothermal investment from the overall system's perspective; (b) understanding the economic merits of a geothermal investment from a societal cost point of view; and (c) understanding the impacts of key financial assumptions, including costs of capital and financing structures—on the required tariffs and incentives to private sector developers of a specific investment.

ANNEX 4

CLAIMING CARBON CREDITS

REQUIREMENTS FOR CLAIMING CARBON CREDITS

Renewable energy projects, such as geothermal power projects in developing countries, have the potential to obtain additional income through the sale of emission reductions or 'carbon credits', project-based emission reductions, or Certified Emission Reductions (CERs). Such income can be derived through a number of schemes in both regulated and voluntary markets, such as the Clean Development Mechanism (CDM) of the Kyoto Protocol and the Voluntary Carbon Standard, together with other schemes under development in a number of countries, such as Australia, Japan, and South Korea.

The additional income from the sale of emission reductions can improve the financial viability of geothermal projects.

For any project to be eligible to claim carbon credits, it needs to meet the following criteria:

- Project should be in accordance with national policies on sustainability
- Project should avoid negative environmental, social and cultural impacts
- Credits should be 'additional' to the business-as-usual scenario

As a first step to generate carbon credits, the project should meet the following requirements to be registered with the CDM Executive Board:

- Additionality demonstrates the project activity would not be implemented in the 'business-as-usual' scenario due to the existence of a barrier (e.g., investment, technical, institutional, etc.) or to low financial returns.
- Baseline establishes that, in the absence of geothermal power generation, the equivalent power would have been supplied from a mix of generation sources connected to the power grid emitting more GHG.
- Eligibility indicates the project meets CDM requirements, such as:
    - a) Start date of the project
    - b) Meeting methodology requirements
    - c) Prior CDM revenue consideration in investment decision proven by documented evidence
    - d) Requirements related to host country approval
- Stakeholder Consultation involves meeting with local stakeholders to obtain public input on the environmental and social impacts of the project(s). Mitigation measures should be included in the project implementation plan.

ADDITIONALITY

According to the Tool for the Demonstration and Assessment of Additionality endorsed by the CDM Executive Board of UNFCCC, geothermal power projects have an opportunity to prove additionality using either investment analysis or barrier analysis. The following table outlines a few barriers identified by project developers in proving additionality using barrier analysis:

ANNEX 4, TABLE 1
Barriers to Analyze in Establishing Additionality

TYPE OF BARRIER	EXAMPLES
Investment Barriers	• General country risks • Risks due to level of tariffs not sufficient to generate investment return commensurate with the return required by the investors • Difficulty in accessing financing
Technical Barriers	• Geological risks • Unreliability of transmission lines • Lack of technology or service providers • Longer transmission lines to supply electricity to main grid
Other Barriers	• Unstable political situation • Issues regarding ownership

Source | Harikumar Gadde and Nuyi Tao.

However, considering that many geothermal projects fall into the large-scale category (with over 15 MW capacity), for which the CDM Executive Board prefers to use investment analysis, these large-scale geothermal projects might need a detailed assessment of financials to demonstrate that the project is not financially viable without consideration of CDM revenues. This includes assessment of various input parameters used in the financial analysis and their validity and applicability at the time of investment decision making process.

PROJECT- VERSUS PROGRAM-BASED CDM APPROACH

CDM allows access to carbon funds either through registration of individual projects under a project-by-project approach or under a programmatic approach. The first approach is suitable for individual developers with a capacity to access to carbon funds and to develop their projects on their own. The programmatic approach is best suited for supporting policies that promote clean energy investments, for scaling up developments with reduced transaction costs [vi] and for supporting small developers with no capacity to develop the carbon assets on their own.

Though project-by-project CDM approach is well proven and relatively standardized, the programmatic CDM approach is expected to accelerate implementation of activities, to reduce transaction costs and to help a government implement its policy initiatives effectively. The Program of Activities (PoA) approach is intended for use in cases where a policy or goal is being implemented with the benefit of carbon finance, such as in the case of the proposed geothermal promotion proposals in Kenya and others. A PoA that supports the implementation of the government policy should be structured so that it addresses barriers (such as incremental cost, high upfront investment cost, and financing difficulty), in a comprehensive manner to promote geothermal development, while considering the revenues from sale of carbon credits. Such policy supporting programs ensure that the PoA is not just a simple, bundling of large geothermal projects, but is helping to scale up geothermal project development throughout the country.

Under the PoA approach, any number of similar eligible projects can be added at any time throughout the program lifetime.[vii] This inclusion of projects is expected to avoid the time-consuming CDM single project process that involves a global stakeholder consultation, a host country approval, a detailed validation, and CDM registration.

Caution, however, needs to be exercised when opting for the programmatic approach. Since the CDM Executive Board approved the PoA Procedures in its 32nd meeting on June 22, 2007, only 5 PoAs have been registered, and approximately 40 are currently undergoing validation. These PoAs are all dispersed, small-scale projects (less than 15 MW for renewable energy projects and less than 60 GWh savings per annum for energy efficiency projects) that follow the CDM Executive Board's simplified procedures for small-scale projects.[viii] Installed capacities for geothermal projects are in most cases larger than 15 MW. Whether the PoA approach is suitable for large-scale renewable energy project remains to be tested and proven,[ix] particularly in regard to the processing time for CDM registration and scale-up development support.

[vi] Due to the evolving nature of PoA approaches and guidelines, the timelines till registration for programs are still longer than expected. Even the stand-alone projects are taking longer times for registration due to continuous improvements with the CDM procedures, guidelines, and resulting new requirements to demonstrate their CDM eligibility.

[vii] According to the procedures for registration of a PoA, the length of the PoA should not exceed 28 years. That means the duration of crediting period of any CDM Project Activity (CPA) included shall be limited to the end date of the PoA regardless of when the CPA was added. For example, if a CPA is added at 22nd year of the program, it will be eligible to claim emission reductions for only 6 years. The crediting period of a CPA is either a maximum of 7 years, which may be renewed at most 2 times, or a maximum of 10 years with no option of renewal.

[viii] Except one in Vietnam that proposes to use large-scale methodology for hydropower development projects.

[ix] Currently, there are no clear guidelines on how to demonstrate additionality, which is core for CDM eligibility, for large-scale project activities under PoA approach.

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