Improving the economics of geothermal development through an oil and gas industry approach

Geothermal energy offers the compelling prospect of baseload power generation that operates continuously – regardless of weather conditions, and with negligible fuel costs and greenhouse gas (GHG) emissions — ***Amy Long***

It has the potential to help insulate energy consumers from future rises in the oil price and in the cost of emitting GHGs. For many countries, it could also have strategic value, providing a secure source of energy.

In addition, recent advances in technology have the potential to make geothermal development more widespread: with the impending commercialization of Enhanced Geothermal Systems (EGS), geothermal exploitation has the potential to shift from natural-resource extraction to that of a process industry that can be applied in a greater number of locations.

However, many potential investors are deterred by the large capital investment and high level of risk involved. A new approach to development is needed to encourage this fledgling industry.

In order to improve the economics of EGS, developers must reduce subsurface risk and their reliance on drilling as the primary means for exploration; they must also lower the cost per well drilled and optimise asset productivity. With production from heavy oil, carbonate, and basement reservoirs increasing, and ever-deeper drilling, there is considerable scope for transferring technology used in oil and gas projects to the geothermal industry. EGS can benefit greatly from the expertise of oilfield services companies, particularly those with knowledge of high-temperature domains and natural-fracture exploitation.

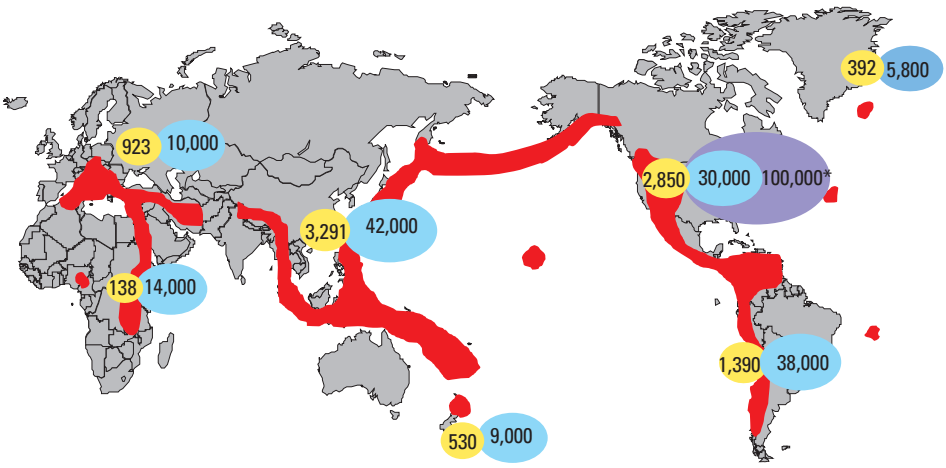
Renewable Energy Sources	Capacity Factor (%)	Reliability of Supply	Environmental Impact	Main Application
Geothermal	86-95	Continuous and reliable	Minimal land usage	Electricity generation
Biomass	83	Reliable	Minimal (non-combustible material handling)	Transportation, heating
Hydro	30-35	Intermittent dependent on the weather	Impacts due to dam construction	Electricity generation
Wind	25-40		Unsightly for large-scale generation	Electricity generation (limited)
Solar	24-33			

Note: Capacity Factor = Total Energy Produced / Energy Produced if at Full Capacity
Source: Geothermal Energy Organisation

Figure 1: Comparing renewable energy sources

Introduction

Given the strength of commodity prices in recent years, concerns over energy security and widening adoption of carbon-emissions pricing, renewables are well positioned to play a growing role in the global energy mix. Geothermal energy is, on the face of it, one of the most attractive members of the renewables portfolio *(figure 1)*. By harnessing the heat of the Earth itself, geothermal power plants tap into a virtually inexhaustible and continuous source of energy, using a small-footprint



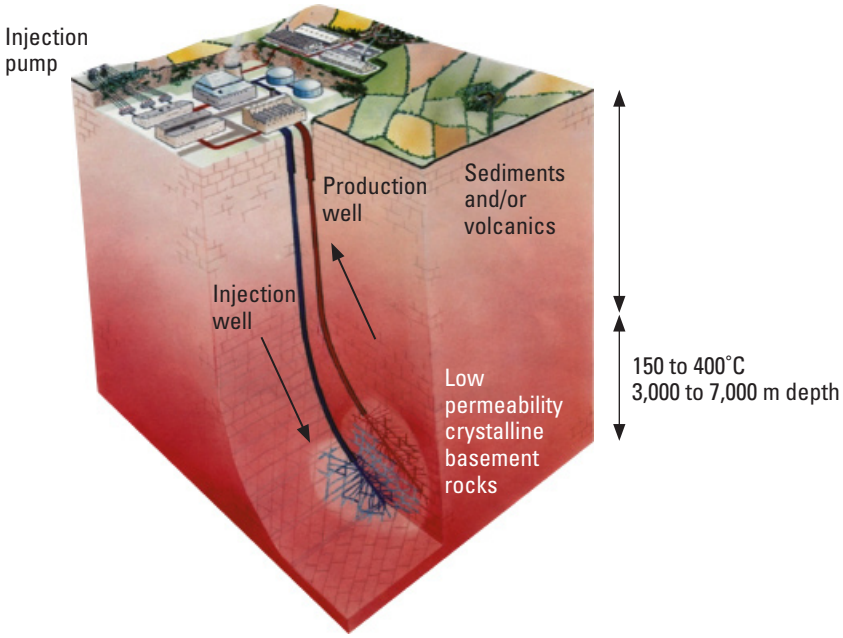
Potential hydrothermal resources

Installed hydrothermal capacity
Source: Update on World Geothermal Development (GEA 2007) and IGA (2005))

Potential hydrothermal capacity
(Source: Bertani, R. "What is Geothermal Potential", IGA and Gillnir Energy Research. "United States – Geothermal Energy Market Report" Sep 2007)

Potential capacity using EGS in the US alone (estimates for other regions have not been made)
Source: "The future of geothermal energy", MIT (2005

Figure 2: Current and potential geothermal capacity 2007



Source: MIT "The Future of Geothermal Energy" 2006; Schlumberger Water Services

Figure 3: EGS schematic

facility to provide baseload electricity that is virtually CO_2 and waste-free.

Hydrothermal systems: geothermal today

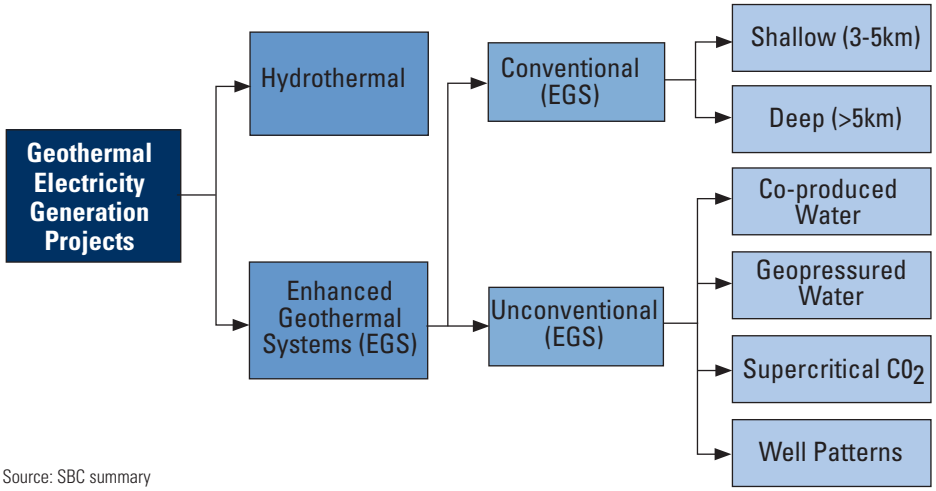
Geothermal projects today centre around the exploitation of hydrothermal resources – reservoirs of naturally occurring hot water. Hydrothermal developments have tended to cling to areas of high tectonic activity, where hot-water reservoirs are abundant, naturally productive and, therefore, cheaper to exploit. It is no coincidence that the countries with the largest installed geothermal capacity – the US, Philippines, Indonesia, Japan and New Zealand – all lie on the Pacific Ring of Fire *(figure 2)*. Just as oil seeps used to mark the spot, hot springs, volcanoes, and geysers are good indicators of hydrothermal potential. Unfortunately, however, volcanoes and geysers are not usually where large population centres – and thus electricity markets – tend to be located.

Enhanced geothermal systems: geothermal tomorrow

This could change with EGS, a new form of geothermal exploitation being tested in areas that are not hydrothermal, such as Australia and France. Unlike hydrothermal developments, EGS does not require hot-water reservoirs. It is an engineered reservoir system. In its simplest form, the only requirement is a hot, dry rock to act as a crucible – such as basement rock typically found at depths greater than 3 km *(figure 3)*. Water is pumped down an injection well and heated in situ; it accesses a production well via natural or stimulated fractures and is produced to the surface, where it flashes

into steam and is used to generate electricity. It is then re-injected to complete the closed-loop system.

EGS geothermal power plants have the potential to be sited closer to population centres, reducing transmission and infrastructure costs and providing developers with access to larger markets. This could transform geothermal energy natural-resource exploitation into a process industry that can be adopted in many more locations than hydrothermal, boosting energy security and reducing GHG emissions. Significantly, it is also EGS that could benefit the most from existing oil and gas technology and expertise, particularly in refining the more unconventional EGS technologies *(figure 4)*.



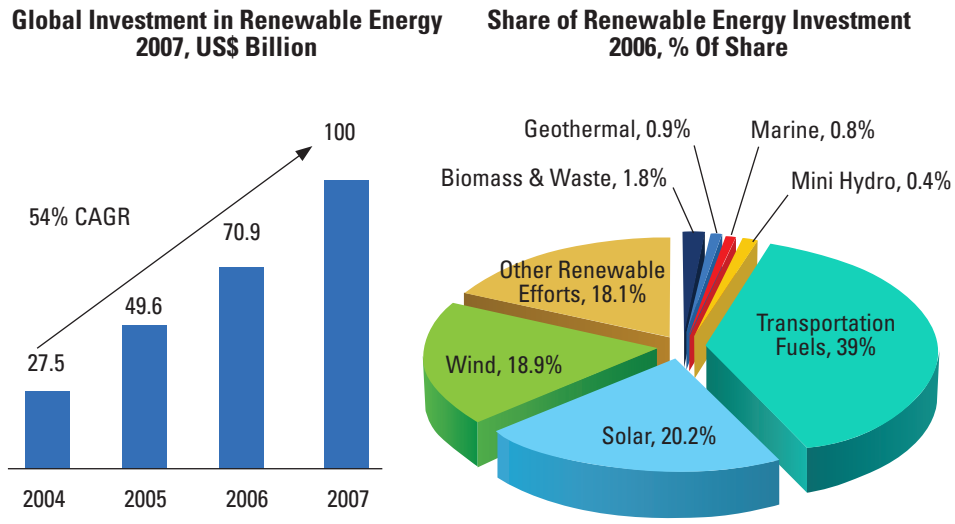
Source: SBC summary

Figure 4: Types of geothermal electricity generation projects

Dim prospects

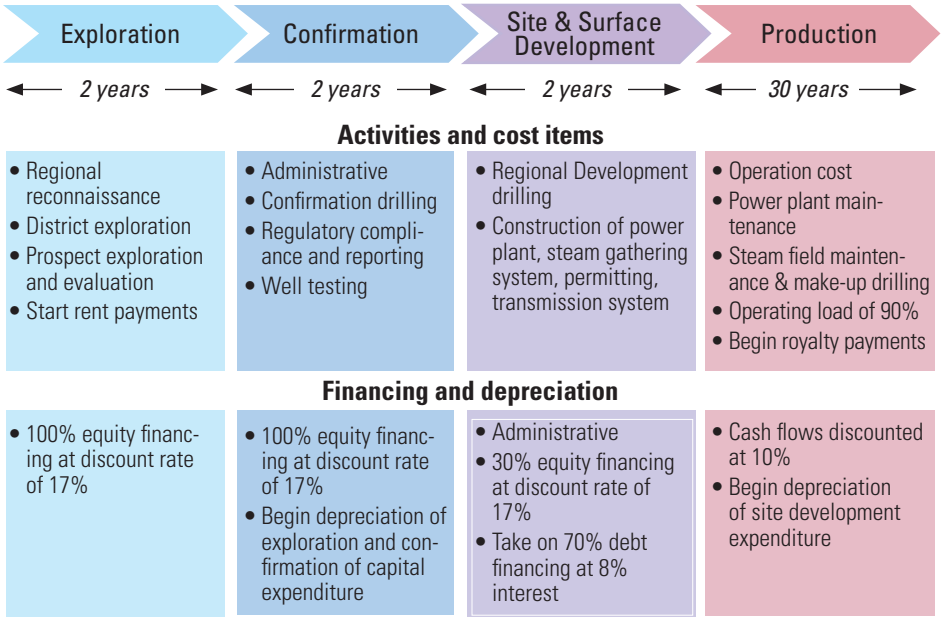
However, notwithstanding Google.org's recent $10.25 million investment in EGS, geothermal remains one of the most underfunded energy sources. Hydrothermal and EGS capture less than 1% of total investment in renewable technologies *(figure 5)*. At this rate, the vision of sustainable, reliable, clean baseload energy will remain a distant prospect.

The fundamental structure of geothermal's project economics must change if the technology is to be widely adopted. Operating cost (opex) is low, but initial capital requirements are high enough to make net present value (NPV) and internal rate of return (IRR) inferior to those of rival technologies.



Source: UNEP SEFI

Figure 5: Worldwide investment in renewables



Source: GEA, "Factors affecting costs of geothermal power development", Aug 05; Deloitte, "Geothermal Risk Mitigation Strategies Report", 15 Feb 08

Figure 6: Lifecycle activities and financing for the typical 50 MW geothermal project

Specifically, a 50 MW hydrothermal project *(figure 6)* would yield an IRR of less than 11% *(figure 9)* and a profit-to-investment (P/I) ratio of 0.8, whereas a large oil and gas project would typically yield an IRR of almost 16% and a P/I of 1.5, according to Goldman Sachs[1]. EGS returns are expected to be even lower than that of hydrothermal projects, at least initially, given the high costs associated with an as-yet-uncommercialised technology. The key to improving the economic attractiveness of EGS lies in reducing finding and development risks – and thus expenditure – through the adoption of approaches and technologies that have been successfully deployed in the oil and gas industry.

These include:

- Reduction of subsurface uncertainty
- Reduction of reliance on drilling as the primary means of exploration
- Reduction of the cost of each well drilled
- Optimization of asset productivity.

In the oil and gas, and geothermal industries, risk – measured by the number of unknown factors and their potential impact on NPV – is greatest at a project's early stages. Selecting a highly productive or, conversely, a very poor reservoir will have a greater impact on lifetime project returns than cost reductions in plant operations. Over the decades, the oil and gas industry has developed technologies that reduce these risks and improve the quality of upstream decisions. The geothermal industry has borrowed and modified many of these techniques but, with fewer projects and less research and development funding available, breakthroughs have occurred on a much smaller scale than in oil and gas.

However, adopting approaches used in the exploitation of heavy oil, carbonate/basement formations and ultra-deep reservoirs – relatively new but rapidly growing areas for oil and gas companies – could accelerate the commercialization of EGS. Schlumberger is receiving a growing number of requests to intervene in geothermal projects, reflecting the considerable scope for the transfer of technology from the upstream oil and gas industry to geothermal. Meanwhile, in addition to Chevron and Statoil, which have long been leaders in hydrothermal development, a growing number of oil and gas companies, including Australian firms Woodside Energy and Origin Energy, are becoming active in EGS.

High risk = high capex

Hydrothermal and EGS projects following a similar series of development steps to oil and gas projects, but geothermal developers are constrained by a relative shortage of information and, in order to assess possible plays, must undertake more basic reconnaissance work than most oil and gas operators would consider acceptable.

Subsurface risk

The ultimate goal of geothermal exploration, whether for a hydrothermal or EGS development, is to identify high-temperature resources at a drillable depth with high permeability, favourable fracture systems and sufficient water flow rates to transport the heat to the surface. An added complication for EGS projects, according to MIT, is that the appropriate resources are commonly "associated with somewhat lower flow rates, lower conversion efficiencies (because of lower temperatures), and greater depths (required to encounter economic

[1] *Goldman Sachs*

temperatures)"[2]. Site selection is thus of critical importance to project economics.

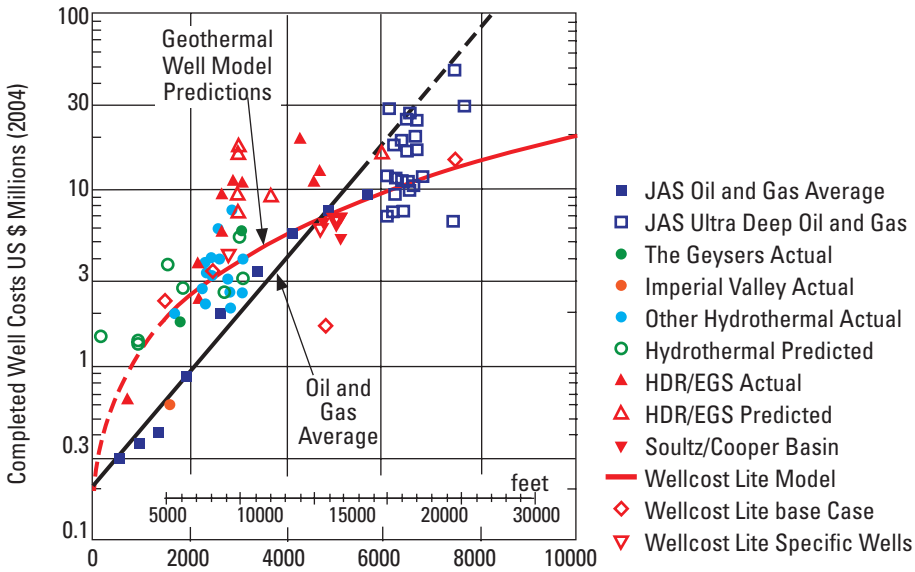
Starting at the beginning of the exploration and development value chain, the developer needs to select acreage in which to undertake reconnaissance activities. Even in this initial step, geothermal developers face elevated risk: databases with basic subsurface data from government-sponsored or privately funded surveys, are generally not available, claims the Geothermal Energy Association; whereas they are routinely expected by oil and gas companies as a prelude to any acreage evaluation.

Once a geothermal developer settles its acreage position, geophysical surveys (gravity/magnetic/seismic) and geochemical analyses are conducted, as with oil developments. However, EGS developers are constrained by the limitations of interpretation software, which has been developed for sedimentary basins, deltaic systems and channel sands – systems that might bear hydrocarbons. Given that EGS producers seek deep basement rock, they do not benefit greatly from these technologies.

As in oil exploration, static and dynamic modelling of porosity, permeability, and fracture systems would be the next step. Again, however, geothermal developers are hampered: while advances in thermally rated logging tools are being made, the high rock temperatures (>250°C) encountered in geothermal drilling limit the use of downhole instrumentation, including borehole-imaging tools used to characterize natural fractures. Furthermore, detailed temperature-with-depth logging is not yet possible, making it difficult to understand the chemistry of rock/water systems in the reservoir itself. Where dynamic modelling is concerned, reservoir simulators are weak on temperature and fracture mapping, which take on increased significance in an EGS context. Thus, at present, the EGS developer simply does not have the tools with which to understand phenomena that impact asset productivity. These include:

- Development of channels through which fluid can bypass portions of the fracture system (short circuiting)
- Loss of fluid in the reservoir
- Effect of adding make-up water to the reservoir to address pressure drawdown in the production stage. This not only represents an additional cost, but can hasten cooling of the reservoir
- The impact on scale formation, mineral precipitation and rock dissolution on reservoir permeability over time, which could eventually limit the amount of recoverable heat.

Costs for Completed Oil & Gas, Hydrothermal, and EGS Wells 2004 US$ Millions



Notes: JAS = Joint Association Survey on Drilling Costs. Well costs updated to US$ (yr 2004) using index made from three-year moving average for each depth interval listed in JAS (1976-2004) for onshore, completed US oil & gas wells. A 17% inflation rate was assumed for years pre-1976. Ultra-deep well data points for depths greater than 6km are either individual wells or averages from a small number of wells listed in JAS (1994-2000). "Other hydrothermal actual" data include some non-US wells

Source: MIT "The Future of Geothermal Energy" 2006

Figure 7: Drilling cost comparison

Given the extremely high degree of uncertainty involved in well siting and design, hydrothermal exploration success rates are around 25%[3] today, compared with a worldwide oil wildcat success rate of 45% in 2003[4].

Dependence on drilling

To compensate for their scant understanding of the reservoir, geothermal operators must drill more exploration and appraisal wells to fill in their knowledge gaps. Given the high cost of drilling, the oil industry trend is to invest resources in reservoir modelling and to employ wells selectively as opportunities to confirm and refine computer models. As shown in *figure 7*, drilling is even more expensive in the EGS

[2] *MIT "The Future of Geothermal Energy" 2006*

[3] *GEA "A Handbook on the Externalities, Employment and Economics of Geothermal Energy" 2006*

[4] *IHS*

industry, given harsher subsurface environments and deeper wells, yet cannot be avoided under the existing approach to geothermal development.

Aware that only rudimentary subsurface characterization is available to geothermal developers, financiers typically require 25% of hydrothermal reserves to be proved through drilling before extending debt. It is reasonable to assume that the same standards will apply to EGS projects.

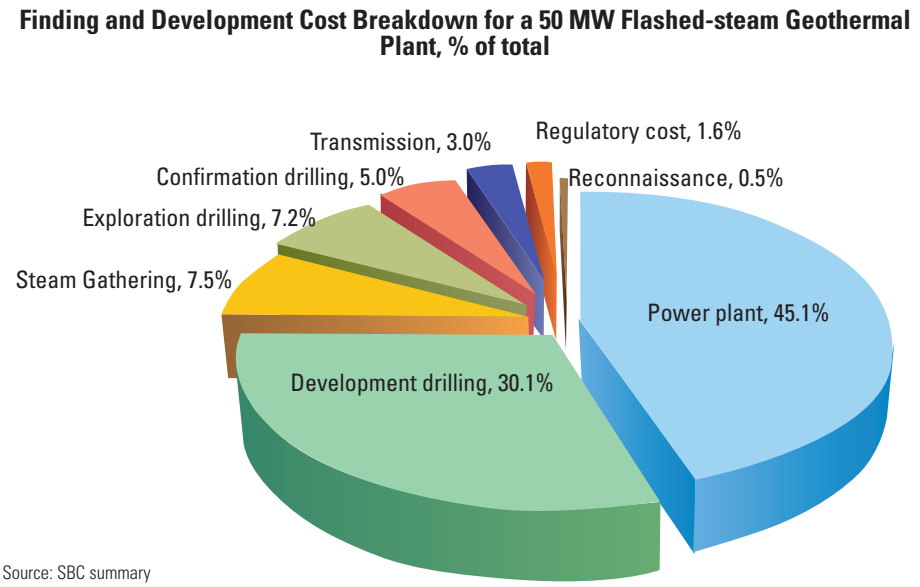


Figure 8: F&D cost break-down

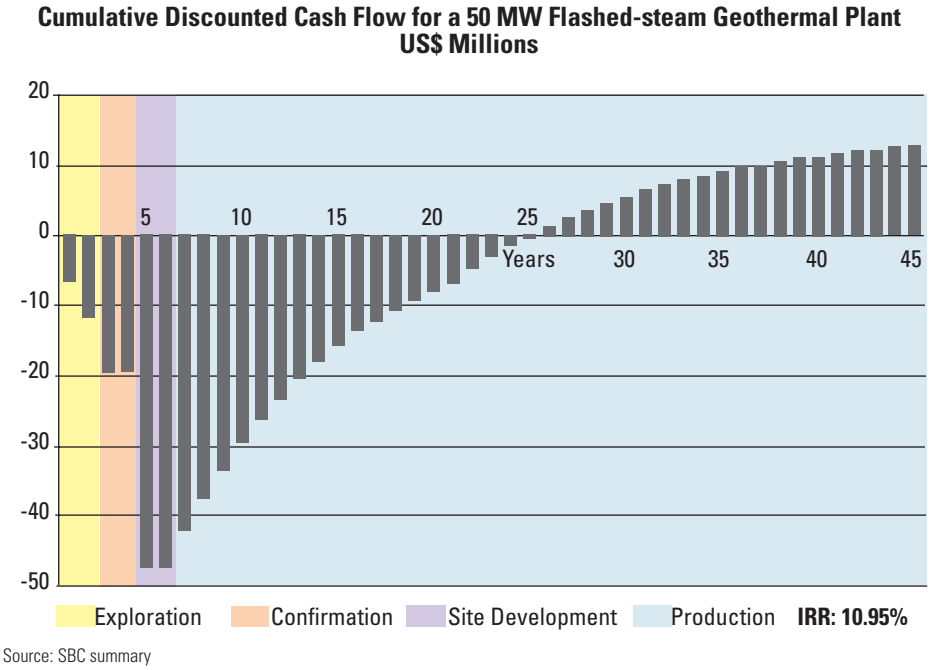


Figure 9: Discounted cashflow for typical 50 MW geothermal project

Reliance on drilling damages project economics in four ways. First, drilling significantly increases capex. In a simple hydrothermal project, drilling accounts for 40% of a project's capex *(figure 8)*. In an EGS development, drilling consumes about 60% of capex. High capex raises barriers to entry and stalls the development of the industry, where as many pilots as possible are needed to prove and refine the concept.

Second, more intensive drilling lengthens time to first steam – typically 6-8 years at present. The delay reduces NPV.

Third, without a detailed reservoir model, well placement is not likely to be optimal; as a result, there is a risk that the facilities will not be the right size for the reservoir. Whether they turn out to be over-sized or under-sized, capital is wasted.

Fourth, the inability to instill confidence in lenders without drilling results requires operators to employ almost 100% equity financing in the early stages of the project, driving up the cost of capital. The high cost of financing ties the hands of operators who would prefer to achieve economies of scale by developing larger projects.

Saddled by the original sin of high risk and resulting high capex, and subject to the same escalating input costs that have been experienced by the oil industry, it can take 20 or more years for a prototypical 50 MW hydrothermal project to break even in the present operating environment *(figure 9)*. EGS, with an even higher cost structure, is simply not economic at this point. It is no wonder that investors balk at geothermal.

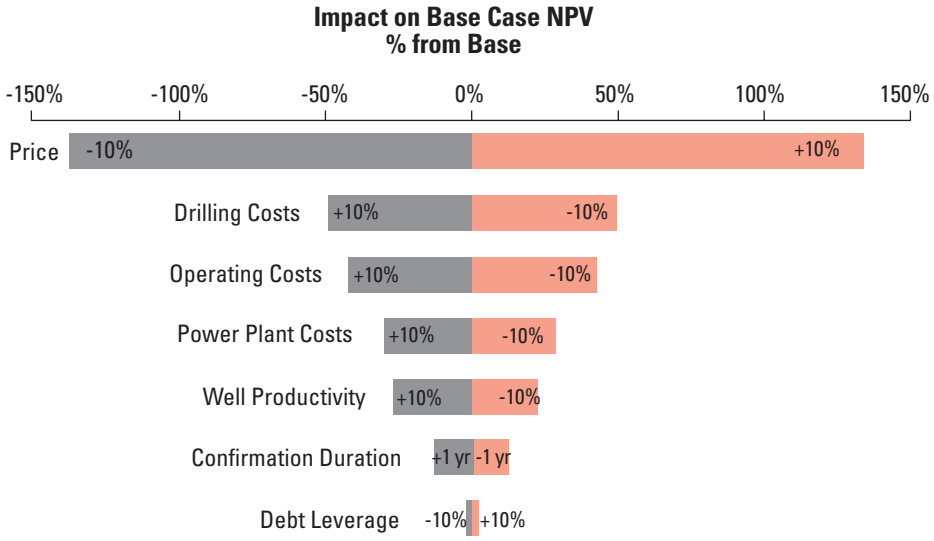
Nevertheless, the appeal of clean, renewable baseload power generation is too great to abandon. What measures might improve the attractiveness of geothermal in general and EGS in particular?

Commercial levers

The greatest single influence on NPV is a commercial factor: the electricity sales price *(figure 10)*. The experiences of Asia's hydrothermal industry in the past decade furnish two cautionary examples.

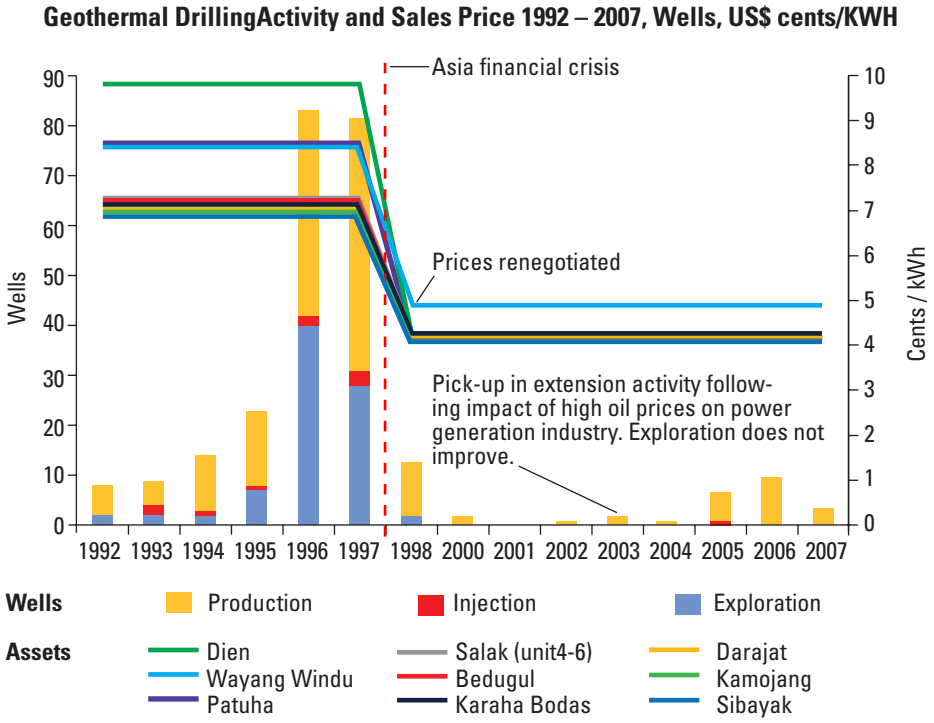
Following the 1997 Asian financial crisis, Indonesia compelled geothermal power producers to renegotiate electricity prices almost 50% below pre-crisis contracts *(figure 11)*. Geothermal electricity is now sold at an average of 4.52 US cents/kWh[5]. The hydrothermal industry instantly ground to a halt and remained paralysed until recent high oil prices and the partial removal of diesel subsidies made it more attractive. However, prices are still not high enough to trigger resurgence in exploration activity. No greenfield geothermal projects have been completed since 1997. In an effort to rejuvenate the geothermal industry, the Indonesian energy and mineral resources ministry is now considering schemes to raise the price of geothermal electricity.

In the Philippines, deregulation of the power market via the introduction of a build-operate-transfer scheme in 1990 encouraged private power utilities to enter and fund hydrothermal plants. From 1990 to 1998, installed hydrothermal capacity more than doubled, from 888 MW to 1,861 MW. Following the crisis, the termination of high-cost independent power producers' contracts and the imposition of a royalty



Source: SBC summary

Figure 10: NPV sensitivities

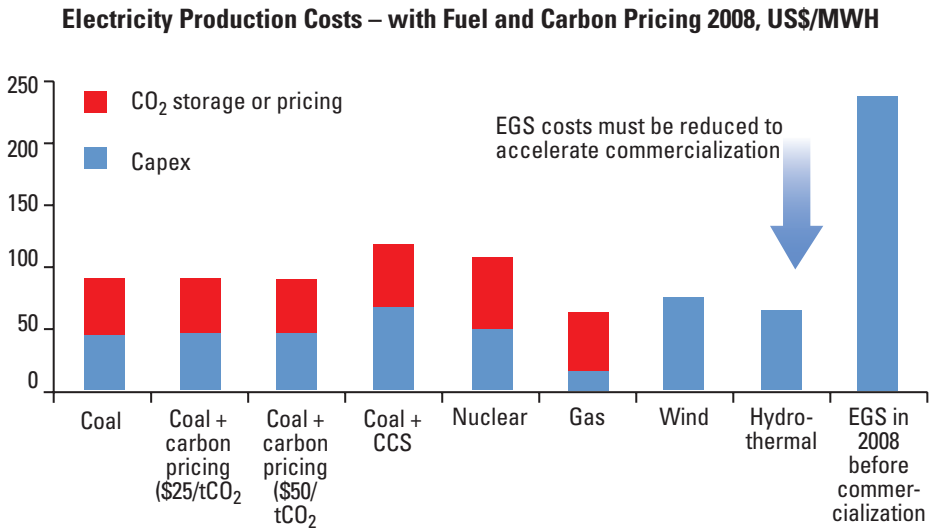


Source: SBC summary

Note: 1999 no data available

Figure 11: Indonesia geothermal activity and prices

[5] *Compared with 17.1, 7.7, and 5.5 US cents/kWh for diesel, natural gas, and coal, respectively*



Note: Fuel price assumptions used: Coal $102/ton; Oil $113/bbl; Gas $7/mmbtu
Source: Schlumberger Water Services

Figure 12: Comparative electricity production costs

tax on the net proceeds from geothermal operations reduced interest among investors in geothermal schemes. Only 22 MW was added to the total installed capacity from hydrothermal power plants between 1998 and 2005.

Conversely, the US Production Tax Credit (PTC) for Renewable Energy, worth 1.9 cents / kWh, has been credited with doubling the number of announced hydrothermal projects in the US since it came into effect in 2005.

Industry players in every geothermal province expend great effort in seeking price supports, most commonly in the form of fiscal support at the exploration stage, financial support (subsidies or loans) in the development stage, and tax credits or favourable purchase prices in the production stage. These are not unlike the incentives that are extended to solar and wind developments in Europe.

However, the greatest degree of financial support for the geothermal industry is likely to come from the application of carbon-emissions pricing. Unburdened by fuel costs, geothermal projects enjoy lower operating costs than oil, gas, or coal-fired power plants – particularly in countries that have put a price on emitting carbon. Geothermal-generated electricity yields almost-negligible emissions of 27-40 kg CO2/MWh, compared with 994 kg CO2/ MWh for coal, 758 kg CO2 / MWh for fuel oil and 550 kg CO2/MWh for natural gas[6] . With European Union Allowances trading at around €18.50 in mid-November 2008, this represents a significant cost advantage. Unfortunately, only one country – New Zealand – has both significant geothermal production and an emissions-trading system.

Geothermal projects may also gain new revenue streams through the sale of carbon-offset credits. Chevron's Darajat hydrothermal plant in West Java, for example, is eligible to receive 650,000 Certified Emissions Reduction (CER) credits a year. In August 2008, December 2008 vintage CERs were worth €21 per unit. By providing rewards for the green aspects of geothermal energy *(figure 10)*, the carbon markets (combined with high fuel costs) could provide the price support that geothermal developers have been seeking.

EGS, offering the potential for baseload energy with almost zero carbon emissions, could prove to be a game-changer for the power industries in the European Union and Australia, which trade or will soon trade in carbon emissions and are piloting the technology. However, *figure 12* also shows the extent to which EGS costs must be reduced if adoption is to accelerate. This can partly be achieved through the application of technology levers.

Technology levers

The six technology levers that can have the greatest impact on project NPV are all related to improving subsurface understanding, drilling and stimulation technology – three directly (drilling capex, well productivity and time to first steam) and three indirectly (plant capex, opex and cost of financing).

Some of the tools being developed to improve the exploitation of oilfields may, with minimal adaption, be used to unlock value for the fledgling EGS industry. In recent years, the oil industry has expanded into heavy oil, carbonate and basement reservoirs, and ultra-deep reservoirs. Each of these segments has more in common with the challenges faced by geothermal operators than oil and gas projects have generally had in the past – providing geothermal

[6] *MIT, "Report on Future of Geothermal Energy" 2006*

developers with a near-term opportunity for improving their technology.

Carbonates/basement exploitation

Technology developed for carbonate fields, which are estimated to contain 60% of the world's oil and 40% of gas reserves[7] but constitute only 30% of production, could be applied in the emerging EGS sector. As Schlumberger explains:

"Most carbonate reservoirs are naturally fractured. The fractures exist at all scales, from microscopic fissures to kilometre-sized structures called fracture swarms or corridors, creating complex flow networks in the reservoir. As a consequence, the movement of hydrocarbons and other fluids is often not as expected or predicted. Just a few very large fracture corridors can be highways for fluids in the middle of a carbonate reservoir; therefore, knowing their exact position is critical for planning new wells and for simulating and forecasting reservoir production."

Similar problems are faced in the exploitation of basement granites, a new area that is picking up pace in Vietnam, among other locations. Oil and gas operators are finding that geomechanical correlations for sands and shales do not hold up and new research is needed. Geomechanics in carbonates and basement rocks is particularly relevant to EGS, which relies on a network of natural or man-made fractures in basement rock to achieve communication between injector and producer wells. While the objectives and outcomes of basement oil and EGS exploitation are very different, EGS would benefit from improvements in the understanding of this rock type.

[7] *EIA "World Energy Outlook" 2006*

Ultra-resistant drilling

As they target deeper reservoirs, oil and gas operators are becoming more frequently exposed to extreme temperatures and pressures – and difficulties with well control, logging and equipment wear and tear commonly encountered by EGS operators. Between 1995 and 2006, the number of wells drilled in the US with total vertical depth of greater than 4,500 metres more than doubled[8]. Although EGS conditions remain more hostile than those even of ultra-deep oil wells, there is an urgent need for the oil industry to find solutions to drill in similarly hard and abrasive environments and to cope with high bottom-hole temperatures and pressures. Again, technology developments in the oil and gas industry should be transferable to EGS.

Thermal oil production

Heavy oil has become an increasingly important part of the energy mix, given conventional oil decline rates and mounting concerns over access to reserves. To date, thermal production technologies using steam injection have yielded the highest recovery factors for heavy oil. However, this type of operation involves oilfield equipment capable of withstanding temperatures far beyond those in conventional reservoirs. Heavy-oil operators today speak frequently of breaking the "magic 250°C" barrier.[9]

Heavy-oil operators are pioneering research into high-temperature-rated instrumentation, logging, cement, artificial lift, casing, and junctions for multi-lateral wells – all of which are considered urgent priorities for EGS commercialization. With thermal production projected to reach 2.4 million barrels a day by 2015[10] in Canada alone, the oil industry now shares this priority.

[8] *From 554 in 1995 to 1,134 in 2006. Spears & Associates "Drilling and Production Outlook" 2006*

[9] *SBC study of heavy oil production challenges in the Americas, 2008. Included interviews with 40 interviewees across 10 operators in North & South America.*

What opportunities do technologies being developed by oil companies – in carbonate and basement developments, ultra-deep drilling operations and thermal oil and gas production – present to geothermal operators in reducing risk and capex?

Impact area one: reservoir modelling

Carbonates and basement oil exploitation could yield useful technologies in fracture detection and mapping, and geomechanics. Enhancing understanding of the subsurface is the single greatest lever for:

- Reducing the number of wells drilled in the exploration and confirmation stages, by increasing success rates
- Improving well productivity, by placing wells in the most productive zones of the hydrothermal reservoir, and by improving the efficiency of water re-injection programmes in the production stage
- Optimally designing surface facilities for expected production rates, pressure maintenance, and scale/corrosion issues.

As described in *figure 13,* even assuming an increase in expenditure on reservoir characterization of 20%, a subsurface-intensive development approach could conservatively be estimated to yield NPV of 75% higher than methods in use at present.

[10] *Announced SAGD and CSS projects. Delivered volumes are expected to be lower due to postponement of investment, delays in receiving equipment, and shortage of personnel. Oil & Gas Journal 9 July 2007.*

Impact area two: drilling and completions

Simply reducing the cost of each well drilled, even if the same number of wells is required, can improve lifetime NPV for a hydrothermal project by as much as 50% *(figure 13)*. Reducing expenditure on drilling is also the key to making EGS economic. Some opportunities for collaboration and technology cross-over include:

Carbonates/basement

- Geosteering.

Ultra-resistant drilling

- Resistant bits
- Air or aerated drilling to prevent loss of circulation of drilling fluid
- Carbon-fibre-based composites/titanium/aluminum drill strings
- Extension in the length of casing intervals which reduces the diameter of the surface and intermediate casing required
- Blow-out preventer pipe shearing.

Thermal oil production

- High-temperature casing, cement, and seals
- Expandable tubular casings to prevention of casing damage from thermal expansion and contraction
- High-temperature junctions to open the possibility of new EGS configurations.

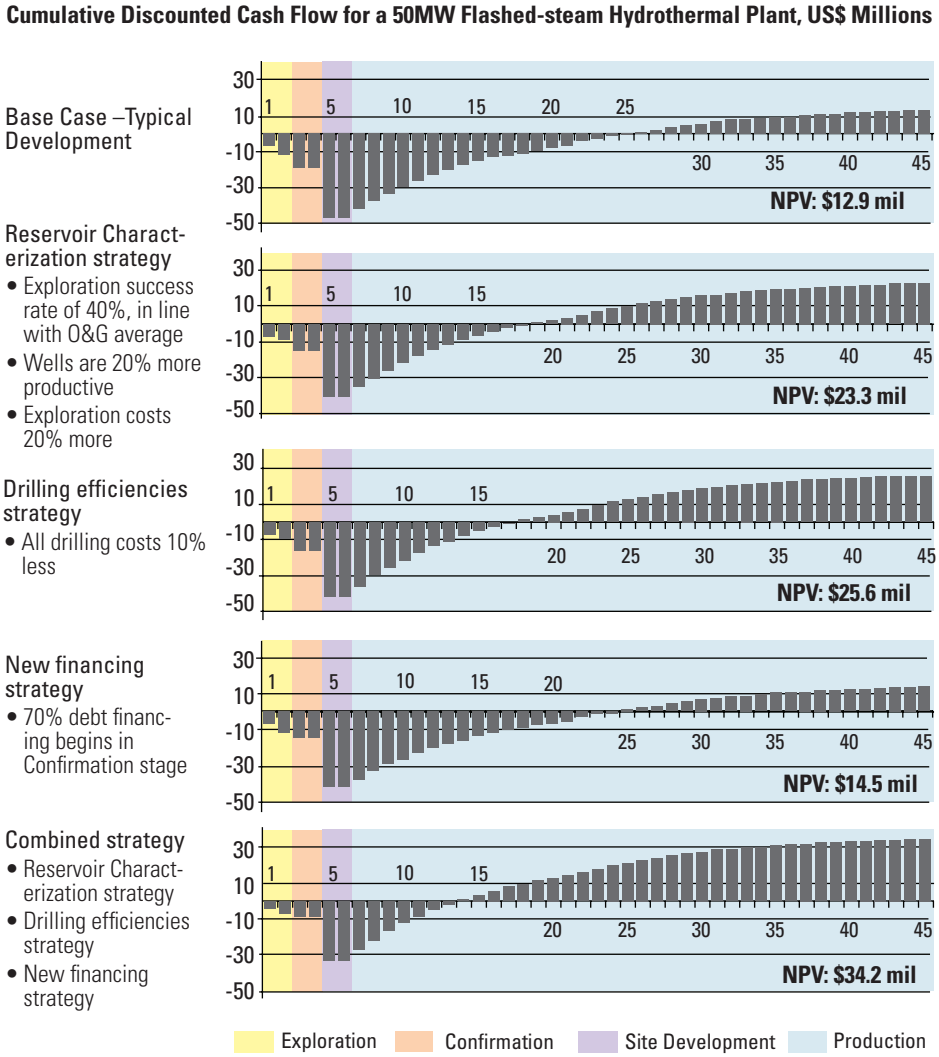


Figure 13: Geothermal strategies

Impact area three: financing

A more accurate understanding of the subsurface could also remove the convention that makes drilling a requirement for debt financing. If debt financing could be applied at an earlier stage of the project, this could boost NPV by up to a further 7% by reducing financing costs.

Conclusion

Geothermal energy presents an attractive opportunity for consumers to use heat deep within the earth to power improvement of living standards on its surface. Beyond being environmentally friendly, harnessing geothermal is necessary as oil resource security becomes an increasingly pressing concern. The key to increasing the use of geothermal ironically involves greater co-operation with the oil and gas industry. Through joint collaboration on technology research and co-siting of pilot projects, the geothermal industry has the potential to change the structure of its economics and the trajectory of its development.