NOTICE CONCERNING COPYRIGHT RESTRICTIONS

This document may contain copyrighted materials. These materials have been made available for use in research, teaching, and private study, but may not be used for any commercial purpose. Users may not otherwise copy, reproduce, retransmit, distribute, publish, commercially exploit or otherwise transfer any material.

The copyright law of the United States (Title 17, United States Code) governs the making of photocopies or other reproductions of copyrighted material.

Under certain conditions specified in the law, libraries and archives are authorized to furnish a photocopy or other reproduction. One of these specific conditions is that the photocopy or reproduction is not to be "used for any purpose other than private study, scholarship, or research." If a user makes a request for, or later uses, a photocopy or reproduction for purposes in excess of "fair use," that user may be liable for copyright infringement.

This institution reserves the right to refuse to accept a copying order if, in its judgment, fulfillment of the order would involve violation of copyright law.
Purpose

The development of the Australian geothermal industry is unique as, especially in the early exploratory phases, the industry is driven by capital investment raised via equity markets. This equity is supported in some instances by grants provided by the Commonwealth Government through its Geothermal Drilling Program (GDP) and, in the case of the commercial demonstration of the technology, via the Renewable Energy Development Program (REDP).

The costs involved in the deep exploration phase are significant, as are those involved in the commercial demonstration of the technology. It is understood by the industry that until it has been able to prove the commercial reality of its projects, all funding is required to come from equity markets or government grants.

Australian geothermal companies are therefore, in essence, competing for a limited pool of risk capital from the equity markets and grant monies from the Commonwealth government. This money will be provided to those projects and companies which are expected to deliver a commercial project and this provide the best returns.

A number of reviews by Equity brokerage firms have been provided recently (Morgan Stanley, RBS Morgans and Goldman Sachs JB Were) reviewing the prospects of the industry and commenting on each of the companies within the sector. It is not the purpose of this paper to review individual companies' prospects, however these papers have provided a summary of the key parameters for company attractiveness:

- Experience of the board and management;
- Presence of project partners, and the experience and size of such;
- Development options of the company (effectively the breadth of the project portfolio to diversify risk);
- Funding capability through access to government grants and large partners at either the project or equity level;
- Project quality assessed in respect of location, quality and risk.

The ability to attract the capital (human as well as financial) to develop a project is ultimately a function of the project quality. The project quality in turn is a function of a number of competing factors which will be discussed in more detail below, but is ultimately determined by the expected cost of production of geothermal energy arising from the project.

Australian geothermal companies therefore are competing for limited capital allocations on the basis of their project’s forecast cost of production. This cost of production is typically evidenced by a calculated Levelized Cost of Electricity (LCoE) or Long Run Marginal Cost (LRMC).

Recognizing the importance of this figure in the allocation of capital within the industry, the Australian Geothermal Energy Association (AGEA) formed an Economics Committee to develop a framework for the reporting of Economic parameters to the public to ensure consistency across releases.

This paper represents that framework which defines the key parameters in the economic assessment of the project, and thus which assumptions need to be released to support any economic releases. It also highlights the need, in a developing market, for the industry to provide data sets where available of what has been achievable in respect of these assumptions elsewhere in the world to give interested parties an independent benchmark of what has been previously achieved and prompting explanations from companies as to where their assumptions sit on this frequency distribution curve and why.

Long Run Marginal Cost Calculation

Alan Knights of AGEA presented a paper at the 2009 AGEC on the calculation of the levelized cost of electricity. This LCoE is essentially the same as the LRMC and was based on the following equation:

$$LRMC = \frac{\sum_l \left[ (K_l + M_l) \left( 1 + r \right)^{-l} \right]}{\sum_l \left[ E_l \left( 1 + r \right)^{-l} \right]}$$

Where:
- LRMC = Long Run Marginal Cost of power per MWh
- $K_l$ = Capital expenditures in year $l$
- $M_l$ = Operating and maintenance expenditures in year $l$
- $E_l$ = Net electricity generation in year $l$
- $r$ = Discount rate
- $\Sigma_l$ = The summation over the life of the power generator including evaluation, construction, operation during the economic lifetime and decommissioning of the plant.
Another way of representing this is to say that the LRMC is the price the project needs to receive to deliver a specified return based upon cost estimates, which would represent the formula as:
\[
\sum \left[ E_i \times LRMC \right] \times (1+r)^t - \sum \left[ (K_i + M_i) \times (1+r)^t \right] = 0
\]

This is the financial modeling aspect of project assessment and the key parameters within this are the cost, net generation, project life and discount rate assumptions.

Apart from the discount rate, the other assumptions are technical assumptions related to the specific engineering and geological inputs into the project and will be addressed in more detail below.

**Technical Assumptions**

The capital expenditure of the plant is made up of:
- Plant Costs
- Downhole costs required to deliver the geothermal brine to the plant

**Plant Costs**

There are two broad categories of geothermal plant which can be utilized by a project:
- Binary, or Organic Rankine Cycle plant – of which there are a number of alternatives
- Flash steam plant of which there are a number of alternatives based on flash cycles

The plant choice will be based upon the specifics of the geothermal fluid, most notably the temperature of the fluid given that there are temperatures below which flash will not work.

The plant cost is a function of the unit cost of the plant typically expressed in US$ per mW applied to the size of the plant, which in turn is a function of the size of the market, the parasitic load requirements of the project (for pumping and injection) and the presence of transmission losses. This can be represented by:

\[ K_{\text{plant}} = f(\text{unit cost of plant, market, parasitic load, transmission losses}) \]

The parasitic load of the plant is itself a function of the geology of the reservoir and temperature of the brine fluid; especially the pressure of the reservoir which will determine injection power requirements and the temperature and flow of the fluid determining the need to pump the production well.

Transmission losses are a function of the size of market and the transmission distance.

Taking this into account, the plant capital can therefore be represented as:

\[ K_{\text{plant}} = f(\text{unit cost of plant, market, reservoir pressure, brine flow, brine temperature, distance to market}) \]

**Downhole Costs**

Downhole costs reflect the costs associated with bringing the amount of geothermal brine to the plant to generate the required energy at the plant to meet the market assumption. These costs therefore reflect the number of wells drilled, the cost of drilling, and casing each well and the gathering system required to deliver the fluid to the plant.

\[ K_{\text{well}} = f(\text{wells drilled, cost of drilling, casing, stimulation and gathering}) \]

**Number of Wells**

The number of wells drilled is a function of the total generation of the project, which is equal to the peak generation target plus allowance for parasitic load plus transmission losses; the energy available per well which defines the number of production wells and the ratio of production to injection wells.

The energy available per well is a function of the temperature differential between the fluid at the entrance to the plant and the temperature of the reinjection fluid (ΔT) and the flow rate of the fluid. The brine temperature at the plant is a function of the brine temperature in the reservoir less any loss of temperature in the well and gathering system; which loss is also a function of the flow of the well (the higher the flow the lower the temperature loss).

Flow is impacted by the size of the production well, reservoir pressure, as well as by any pumping in the well (which is then a function of technical fluid temperature constraints).

The casing for each well will be impacted by the fluid chemistry where the presence of gases such as CO2 and sulfur can create acification issues in the well, requiring a higher grade of casing to complete the well.

\[ \text{Producer Wells} = f(\text{total load, brine reservoir temperature, } \Delta T, \text{ brine flow, brine chemistry, well diameter, temperature loss, reservoir pressure}) \]

The ratio of producer to injector wells is based upon the pressure differential between the producer and injector wells which is a function of the ΔT, and the reservoir pressure being reinjected into.

\[ \text{Injector Wells} = f(\text{producer wells, } \Delta T, \text{ reservoir pressure}) \]

**Cost of Wells and Gathering System**

The unit drilling cost of wells is a function of the availability of rigs (which impacts on the supply-demand dynamics), the depth of drilling and the diameter of the well.

The availability of rigs is, itself, a function of the depth of drilling and the diameter of the well. The typical geothermal well is deeper and wider than a petroleum well, and the industry has discovered that the rigs available to the petroleum industry are not sufficiently powerful to drill the size of wells required for geothermal, significantly increasing the cost of drilling geothermal wells in Australia.

The unit cost of drilling will also be impacted on by economies of scale and understanding of the geology being drilled. The unit cost for a well will be lower the greater the drilling and the diameter of the well.

The availability of rigs is, itself, a function of the depth of drilling and the diameter of the well. The typical geothermal well is deeper and wider than a petroleum well, and the industry has discovered that the rigs available to the petroleum industry are not sufficiently powerful to drill the size of wells required for geothermal, significantly increasing the cost of drilling geothermal wells in Australia.

The unit cost of drilling will also be impacted on by economies of scale and understanding of the geology being drilled. The unit cost for a well will be lower the greater the drilling program committed arising from the amortization of mobilization and demobilization costs over a greater number of wells; an increase in the number of wells being drilled increases the long term utilization of a rig and contractors will offer a lower price for a bigger commitment plus as more wells are drilled in an area by a specific team, their understanding of the drilling conditions will improve providing a higher rate of penetration.
The size of the drilling program is directly related to the size of the market.

The RoP itself is a function of the geology and rock type encountered in the well and is thus geologically specific for each project.

Cost of wells = \( f(\text{well depth, well diameter, market size, rig availability, well lithology and brine chemistry}) \)

**Cost of Stimulation**

The need for stimulation is a function of the presence of an aquifer or not, ie water at target; the presence of natural faults along which fluid can be passed and the geology at target. The amount of fracture zones is a function of the flow rates being targeted and the ability to multi-zone stimulate will be affected by the temperature of the fluid at the stated depths.

Cost of stimulation = \( f(\text{aquifer, natural faults, fracture zones, temperature}) \)

**Cost of Gathering**

The cost of the gathering system is a function of the distance of the wells to the plant plus the pressure of the fluid, where higher pressure will require reinforced steel. The fluid chemistry will also impact on the gathering system.

Cost of gathering = \( f(\text{distance to plant, reservoir pressure and brine chemistry}) \)

**Transmission Cost**

Transmission cost is a function of the substation costs required at the plant plus the line costs to connect to market, both of which are a function of the size of the load being generated. The line cost is further a function of the distance between the plant and the market being connected to and the consitions over which the line must be built.

Cost of Transmission = \( f(\text{size of load, distance to market, local consitions}) \)

**Capital Cost Conclusions**

The key variables determining cost can simply be defined as those variables which impact on each of the parameters to the greatest extent and especially those parameters which impact the majority of the cost segments.

The key variables impacting on the capital cost of the project can therefore be defined as:

- Market size
- Reservoir temperature,
- \( \Delta T \)
- Reservoir Pressure
- Brine flow
- Brine chemistry
- Parasitic losses
- Well depth and diameter
- Distance to market

**Operating Costs**

The annual operating and maintenance cost of a project in this definition is a function of any fuels which are required to support the generation (such as iso-pentanes in a binary system), the labour costs to manage the plant and delivery of the power to market plus any on-going well maintenance.

O&M Cost = \( f(\text{labour costs, fuel usage, well upkeep}) \)

**Revenue Parameters**

The revenue aspect of the equation is the MWh sold into the market. The impact of parasitic and transmission losses are taken into account as costs, so it is not the total capacity of the plant that is relevant but rather the generation which is actually sold to the market.

The efficiency of the generator is impacted on by the ambient temperature of the location combined with the cooling mechanism employed. The efficiency losses of high temperature can be reduced through water cooling of generators, however it is assumed in the current Australian political context that air cooling will be required; thus the actual sales MWh will be driven by the ambient temperature.

The sales to market are therefore a function of the size of that market and its ability to accept the generation when it is available. The percentage of time that a plant can access a market can be expressed as the load factor of the market reflecting the ratio of peak capacity to the average generation of the plant.

For local loads, this is a function of the load size and profile of the demand centre. For loads connected to the National Electricity Market, this is a function of the presence of any transmission constraints and scheduling priorities of generation in the region.

The time of generation will also be impacted by the time that plant is on-line and any maintenance scheduled. This is expressed as the capacity factor the plant and is different than the load factor described above. This could be expressed as a single number being:

Project Capacity Factor = Plant Capacity Factor * Market Load Factor

Finally, for NEM connected loads, the Marginal Loss Factor (MLF) of the connection point is an important determinant in the revenue of a project. The Australian Energy Market operator (AEMO) calculates the MLF for each point in the system and, in simplistic terms, reflects the need for transmission upgrades derived from a particular connection and also reflects assumed losses from the nodal point at which prices are calculated. This number can vary widely and, if less than 1, results in a discount on all output sold into the market.

Generation Sales = \( f(\text{ambient temperature, capacity factor of plant, load factor of market, transmission constraints, MLF}) \)

**Key Assumption Release**

A requirement for companies to release their full technical and financial models is not a reasonable solution. Given the capital flows which can result from a positive project assessments, if companies wish to make statements about the relative attractive-
ness of their projects, it is important that the key assumptions underpinning these assessments be released as well. This allows capital owners to make reasonable assessments on the relative attractiveness of specific projects.

The functional parameters affecting all aspects of the cost and revenue of a project have been defined above. Expecting the statement of all of these parameters would be too onerous a requirement; however it is reasonable to expect the release of the supporting critical parameter assumptions.

These critical parameters are assumed to be:
• Total Capital Cost ($ m) – it should not be a requirement to provide specific breakdowns of components, however the following supporting information should be provided:
  ○ Reservoir Temperature
  ○ ΔT
  ○ Flow Rate
  ○ Producing MW per well
  ○ Reservoir Pressure
  ○ Parasitic Loss (%)
  ○ Distance to connection
  ○ Given the potential cost impact arising from the presence of some chemicals in the brine, the specific brine chemistry should at least be commented on in respect of the lack of such compounds being present.
• Total O&M Cost ($/MWh)
• Project Capacity Factor and MLF
• Ambient Temperature
• Discount Rate used

Existing Geothermal Project Parameters

The Australian geothermal industry is at a very early stage in its development and the knowledge and understanding of the critical potential providers of capital (human financial) is limited. It is therefore essential for the industry to not only provide the critical information as above, but also to provide the context of such information. This requires the critical parameter assumptions to be provided in a way which allows comparisons with what has been achieved elsewhere in a purely objective fashion.

Further work has therefore been identified for the industry to provide a compilation of the available information on the critical parameters for exiting geothermal projects, allowing Australian project assumptions to be assessed against what has been achieved elsewhere in the world.

This work is being scoped and is scheduled to be completed in late 2010 (and is therefore not able to be presented in this version of the paper).

Conclusion

The need for economic disclosure requirements is driven by the extensive competition for investment funds and government grants amongst the geothermal sector; with funding flowing to projects with the lowest perceive cost of production. The Australian geothermal market is relatively immature with no project performance data upon which to rely; so all assessments are required to be made on estimated project outcomes. Given the importance of production cost estimates to funding flows, the industry has recognized the need to inform the investor market of the key parameters driving the financial project outcomes and ensuring those parameters are announced in any public economic statement.

This paper has defined those critical parameters to ensure projects can be compared on a reasonable basis. It has also addressed the lack of public information in Australia in respect of the reality of resource parameters, and provides graphical relationships of the 3 key resource parameters of temperature, flow and depth. It further raises the need to provide these parameters in an international context of what has been achieved in existing geothermal developments.

Through the development of this position, the geothermal industry has increased the knowledge of the investor market in respect of the economic drivers of project attractiveness and the inter-relationship between the key resource parameters. This increased knowledge of performance and risk will help the market allocate funds to the industry in an optimally efficient way leading to the maximization of the growth potential of the industry.