GEOTHERMAL DRILLING – KEEP IT SIMPLE

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ABSTRACT

The cost of drilling geothermal wells has risen dramatically over the past 10 years - this rise in costs is out of proportion with inflation and with the cost increases seen in plant and steam gathering system construction. Drilling is now a much larger part of total project cost pie. This increased drilling cost is now threatening the viability of many geothermal projects.

There is little we can do to control Drilling Contractor, Service Company, and the Drilling materials costs – these are largely influenced by the Oil & Gas Industry market.

We can however, have some influence over the costs associated with:- Bureaucracy and Management; Procurement processes; Well location and Drilling Pad preparation; Well Design; Casing specification; Drill Bit and Bottom Hole Assembly Components; Cementing Techniques; Mud Engineering; Directional Drilling; and Completion Testing. It is clearly evident that if we seek to simplify all of these processes drilling risk and drilling cost can be optimised and reduced.

Keep It Simple!!

1. GEOTHERMAL WELL DRILLING COST

1.1 Drilling costs over the past 40 years

During the mid 1970s to early 1980s the cost of drilling geothermal wells in New Zealand was in the order of NZ$1.8 to NZ$2.0 million (1980 $). However, the period 1982 to 1985 saw the oil industry boom and subsequent bust, which impacted upon the drilling industry globally, including New Zealand Geothermal drilling operations.

It is to be noted, that at this time almost all of New Zealand's geothermal drilling was carried out by the Government's Ministry of Works and Development, utilizing its own equipment, which somewhat insulated it from the impact of the '82 to '85 boom and bust, however the costs of imported materials such as casings and drilling bits were affected, pushing the drilling cost rise slightly above the then rate of inflation.

The 1990 to 2000 period saw well drilling costs rise from around NZ$3.2 million to NZ$4.0 million, an increase which approximately followed inflation, but from 2003 a significant acceleration in cost rise began to occur. The typical cost in 2003 was approximately NZ$4.3 million; but 10 years later, the 2013 typical cost was approximately NZ$8.5 million, representing an inflation of approximately 19% per annum over the period.

Over the same period, the New Zealand CPI ('consumers price index') inflation averaged around 2.7%. Ref: Statistics New Zealand, RBNZ, (Note: Interest rates are excluded. Latest data Sept. 2013).

Figure 1 graphically presents the sudden and dramatic increase in drilling costs that commenced between 2003 and 2005 and continued to the present. In addition, Figure 1 plots the nominal inflated drilling cost from 2003 at the inflation average New Zealand inflation rate during the period of 2.7% per annum.

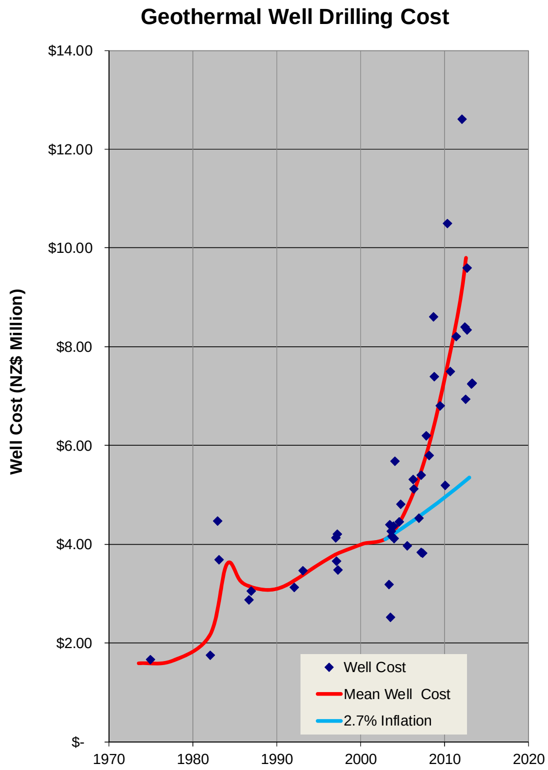

Figure 1: Geothermal Well Drilling Cost

1.2 Are we comparing apples with apples?

The geothermal wells drilled in the 1970s and 1980s were predominantly to depth of 700 m to 1800 m; they were vertical, and drilled with relatively small drilling rigs. The wells drilled between 2000 and 2013 were predominantly drilled to depths between 1800 m and 3000 m; they were more often than not directional wells, and were drilled with drilling rig of two to three times the size of the earlier rigs.

On the face of it, if the comparison is made purely on the basis of cost per well, then it would seem more reasonable that a range of well categories be established to allow a more specific comparison. However, if all of the wells are compared on the basis of productivity, it is evident that they all fall into a similar average production capacity envelope of between 5MWe to 10MWe, and are therefore similar. On this basis that it seems reasonable that the cost comparison be made.

1.3 Drilling cost as a proportion of total development cost

During the 1980s and 1990s geothermal drilling cost accounted for a little above 40% of the total development cost of a 'nominal' 50 MWe geothermal development. The sudden increase in drilling cost that commenced between 2003 and 2005 and continued to the present, has seen the drilling cost proportion rise from around 43% in 2000, to approximately 54% in 2013.

Figure 2 plots the approximate relationship of drilling cost and total development cost of a 'nominal' 50 MWe development.

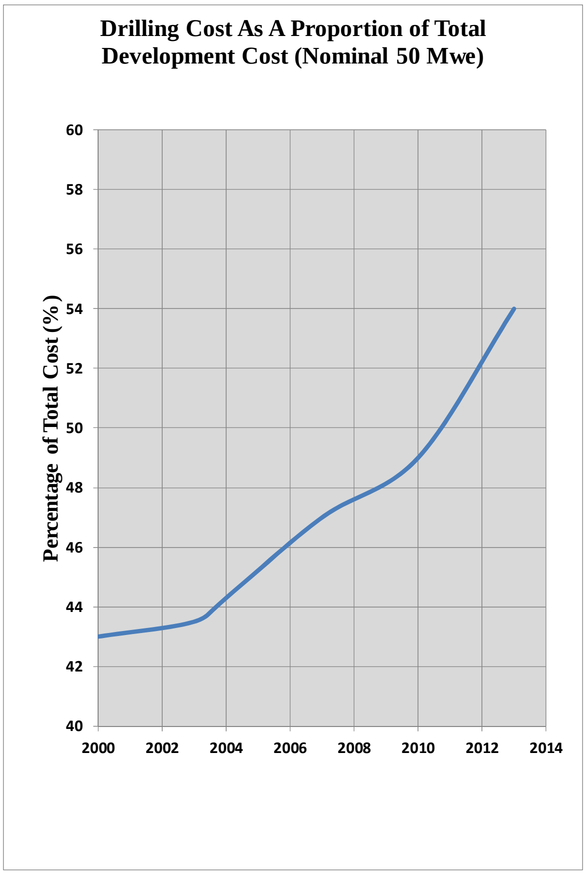

Figure 2: Drilling cost as a proportion of total development cost (nominal 50 MWe) for the period 2000 to 2013

1.4 Increase in risk profile

A 'spin-off' of the increased proportion of the total cost being due to drilling, is an increase in the 'risk profile' of the Project. The Drilling portion is high risk, whereas the plant and steamfield construction is relatively low risk. This 'risk profile' is a sensitive item for Project finance and insurance. Any increase in risk profile decreases the finance and insurance opportunities.

1.5 Project viability threat

The increase in drilling costs and thus the overall project cost, and the associated increase in risk profile places the viability of many potential geothermal development projects, especially smaller developments, in a threatened position.

2. WHAT IS DRIVING UP DRILLING COST

There are two categories of influences that are driving up the cost of drilling:-

- Cost increases we have little or no control over.
- Factors that can increase drilling cost that we can control.

2.1 Drilling cost components we have little or no control over

The prices and costs of drilling services, including primary drilling services contractors (drilling rig suppliers) and secondary services contractors (such as cementing cervices, directional drilling services, mud engineering services, etc.) are all directly affected by the Oil and Gas industry market, which is controlled by the price of oil.

In addition, the costs of Oil and Gas industry materials that we utilize to drill geothermal wells, such as steel tubulars and accessories; Oilwell cement and additives, and drilling mud and additives, are all influenced by the Oil and Gas industry and by the price of oil.

The sudden peak in drilling costs seen in 1982, and then later in 2003 were a direct result of oil price increases.

There is little we can do to control or influence the costs of these components.

2.2 Drilling cost components that we may influence

There are a number of factors over which we can have significant influence and thus impact the drilling cost:-

- Bureaucracy and management
- Procurement
- Wellhead and drilling pad location and preparation
- Well design
- Casing specification
- Drill bit and bottom hole assembly components
- Cementing
- Mud engineering
- Directional drilling
- Completion testing.

2.2.1 Bureaucracy and management

Typically large organizations drill more costly wells than small organizations, simply because there are higher overheads with more bureaucratic process involving more people and introducing more opportunity for error and waste. More people are employed to carry out and oversea a function that may be carried out by one individual in a small organization. The management structure of larger organizations often has a significant vertical component resulting in lost time in decision making, with decisions often being made by a technically "unqualified and experienced" "boss". In any drilling organization it is important to push drilling decision making down to the people who "KNOW BEST" – the people on the drilling site running and managing the drilling operation.

2.2.2 Procurement

Procurement processes are often controlled by intricate and overbearing Corporate, Government, and/or Funding

Agency policies which do not align well with the often urgent and unpredictable needs of a drilling operation. Significant amounts of lost time can be incurred simply to process purchase specifications because the system requires individuals who have no knowledge or understanding of the needs must be involved. This often results in extended periods of downtime, and may result in materials and equipment being provided that do not meet specification or are less than optimum quality.

Procurement Processes need to be Optimized and Simplified.

2.2.3 Wellhead and drilling pad location and preparation

All to often the wellhead location and thus the drilling pad location is dictated by a 'dazzlingly' exact set of target requirements based on survey data which includes a healthy quantum of imagination. It is critical that the drilling engineering design team sit with the civil engineering and earth science teams ('team' may optimally be one person) and resolve a realistic target and well-track and thus the wellhead and drilling pad location, such that civil works can be minimised.

It is important to keep an open mind on site preparation techniques. Figure 3 depicts the use of a stone column piling machine which was able to prepare a load bearing area for a large drilling rig in a period of less than one day, rather than an excavation, backfilling and compaction process that was likely to have taken many days.

It is recommended that a small diameter test well be drilled at the chosen location to test:-

- Near surface geotechnical conditions
- The need for site grouting
- The required Conductor depth
- The required surface casing depth

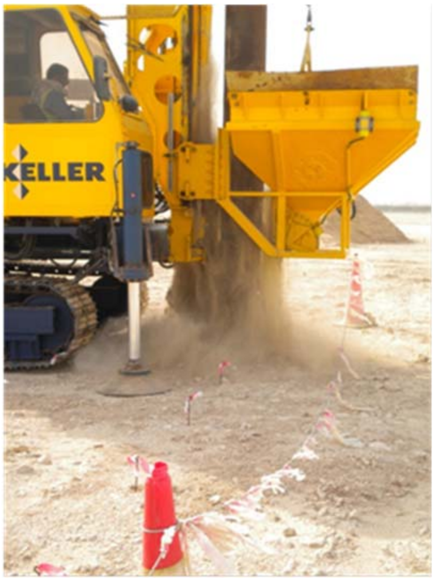

Figure 3: Drilling pad preparation - stone column piling operation

2.2.4 Well design

Well design must be carried to some formalized set of standards, typically NZS2403:1991 and applicable API and ASME standards. However, equally important, is the requirement to keep the well design simple, such that drilling risk is minimised or where possible eliminated.

Avoiding the use of the following:-nested; liners, tied back casings; staged cement collars (and therefore staged cement jobs); and hangers, provides for a simple and effective approach, as long as

- Nested Perforated liners – the use of a pair of nested liners allows the drilling of reduced open hole sections, with the upper liner being hung from the production casing shoe, and the bottom of the upper liner cemented so it can be drilled through safely. The bottom hole section is drilled, the bottom liner run and either hung from the shoe of the top liner, or simply squatted on the hole bottom. In theory this is a good safe option, however, in practice the time and cost of the double procedure, and the risk of setting a hanger, and then drilling through a perforated liner is high. Drill cuttings tend to pass through, and collect behind, the perforated upper liner while circulating. As soon as circulation is stopped, such as when a connection is made the cuttings tend to flow out into the hole presenting a high risk of trapping the drillstring.

- Tied Back Casings – It is relatively common that production casings are run and cemented in a two stage process to reduce the risk of poor cementation. However the process is both expensive and has some significant risk of malfunction. It is therefore considered preferable to run and cement the production casing in one section, as long as the depth of the production casing shoe does not exceed around 1500 metres.

- Stage Cement Collars – this type of device allows the cementing of a casing to be carried out in two steps, thus increasing the chances of performing a satisfactory cement job. However, stage collars have a history of malfunction which presents a higher risk of failure.

- Hangers – the Oil and Gas industry utilise casing hangers to hang liners from a production shoe. This allows the liner to be placed in tension, avoiding possible helical buckling and compressive collapse. However, in geothermal wells a hung liner, in time, may become pinned both at the top by the hanger, and at the liner bottom by debris from the open hole section. Contraction and expansion on heating and cooling may subsequently buckle or pull apart the liner.

It is therefore preferable, where possible to avoid use of the above devices, to minimize risk. Figure 4 represents a simple and effective casing design schematic as is recommended by NZS2403:1991.

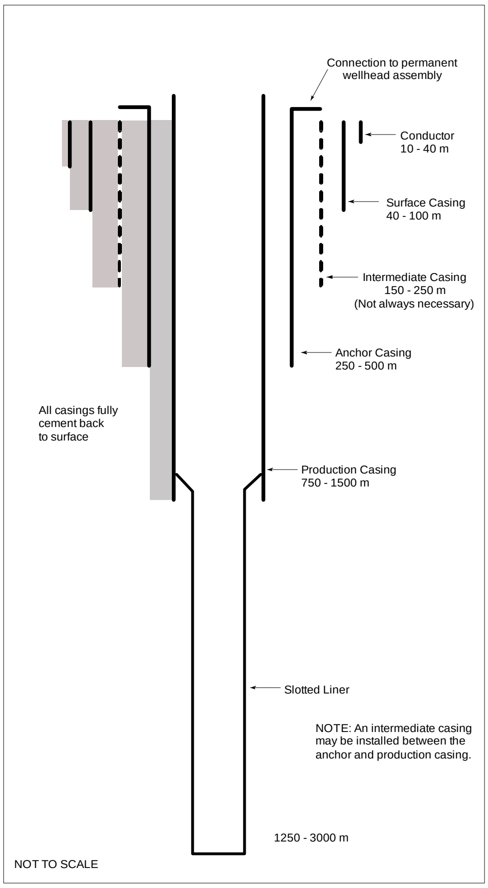

Figure 4: Classic simple well and casing design

2.2.5 Casing specification

There has been a tendency to move from 'Standard Buttress' threaded casing connections to 'Premium' (or Proprietary) Casing Connections.

Casing with 'Premium' connections are significantly more expensive - as much as 3 to 5 times the cost of standard Buttress threaded casing. In addition, these types of casings are often more complex and slower to run, resulting in higher running costs.

The primary arguments presented for utilizing these types of casings are that the connections are 'gas tight', and that higher compressive strength connections than Buttress are available.

The Oil and Gas industry often requires 'gas tight' connections to contain high pressure hydrocarbons, and in accordance with this a number of Oil Companies with Geothermal interests have adopted the use of 'Premium' connections as a matter of policy. However, there is no evident need for 'gas tight' connections for geothermal wells, as has been proven by the satisfactory performance of 'standard Buttress' connections in many hundreds of geothermal wells Internationally.

Likewise, the argument that standard buttress connections have insufficient compressive strength is not supported by the almost total lack of buttress threaded casing connection failures. There are numbers of instances of compressive failure of casings, but these are predominantly found within the body of the pipe, not in the connection. Typically these failures are the result of poor casing cementation.

The thermal compressive loadings imposed on geothermal well casings is significant. The compressive stress induced in a 1000 m length of Grade K-55 casing fully cemented to prevent expansion, and heated from say 40°C to 200°C, will exceed the minimum yield strength of the pipe. The majority of producing New Zealand Geothermal fields and those elswhere demonstrate temperatures considerably in excess of 200°C, and yet we do not see compressive failures of the buttress casing connections, despite the pipe body yielding under compression.

Casing specification should be kept simple, and utilize standard API sizes and casing weights to minimize cost and reduce running risk.

2.2.6 Drill Bit and bottom hole assembly components

Procurement processes must be adapted to allow the purchase of the highest quality drill bits available, not the least cost. The typical cost of an 8½" metal seal tungsten carbide insert drill bit is in the order of NZ$20,000, which represents approximately 7 hours of operational rig time.

The time cost to round trip a bit from say 2000 metres is usually around 8 hours each way, that is approximately double the cost of the drill bit. It is therefore logical that drill bits providing optimum performance must be sought. Consideration must be given to utilizing PDC (Polycrystalline Diamond Compact) drill bits which can provide up to two or three time the life depending on the formations being drilled and the skill of the driller.

It is recommended that simple bottom hole assemblies be utilized, typically this will involve a near bit stabiliser and one string stabiliser only. It is also recommended to minimize the use of mud motors and MWD (Measurement While Drilling) equipment, other than when building angle and direction in a directional well. The advantages in increased rates of penetration gained by utilizing mud motors is offset by the high cost and high risk, especially in higher temperature formations.

Simplify bottom hole assembly design.

2.2.7 Cementing

Complicated cementing process and special materials should always be avoided if possible. Stage cementing and tied back liners should be avoided - these more complex processes add risk to an already difficult task. Cementing a geothermal well is not an easy task as it typically involves cementing under partial or total loss of circulation conditions. For this reason the simplest approach usually works better.

Long run casing cement jobs are simplest, but require careful management and rapid progression from each stage of the job to the next. Typically a long run cement job will involve the pumping of a light weight scavenge slurry, followed by a heavy weight main cement job being circulated through the casing. More often than not, in the typically highly permeable New Zealand resources, full circulation of this primary cement job is not achieved. Permeability of the formations causes losses of the cement slurry circulation, requiring an immediate back flushing of the casing to casing annulus, followed immediately by a primary backfill cement job pumped down the annulus.

This is often followed by a series of backfill hesitation grouting jobs, to bring the cement back to the surface. This process requires absolute care to avoid the entrapment of water pockets within the casing to casing annulus, which can cause collapse of the inner casing.

It is recommended that “special” materials such as slurry lightening products such as silica beads, and nitrogen foaming techniques are avoided. The more complex nature of utilising these products increases the risk of failure.

Recent research work has suggested the use of high proportions of crystalline silica in the slurry which is used to prevent thermal degradation of the cement, introduces a high risk of carbonation of the silica in the presence of CO_2 rich geothermal fluids which results in very rapid increases in porosity of the cement. This work has now determined that the use of 15% to 20% of amorphous silica optimizes the thermal stability while minimising the carbonation process.

Keep the cementing process simple.

2.2.8 Mud engineering

In the vast majority of geothermal fields it is not necessary to utilize specialized drilling muds. Simple non dispersed, water based bentonite ‘spud’ mud with a pH of around 9.0 is typically used for the upper lower temperature hole sections. As soon as some temperature is encountered simple water based lightly dispersed mud with polymer viscosifiers, thinners, and pH maintenance is used.

When circulation is lost and when the production section of the hole is drilled, no bentonite is utilized at all. Drilling is carried out either “blind” with water, or preferably with aerated water with low grade polymer sweeps for hole clearing purposes.

The mud circulating system must be fitted with effective mud cooling equipment. This is often a forced draft cooling tower which is usually most economic, or mud chilling system. Mud circulating temperature must be maintained well below a nominal maximum of 50°C, and typically around 35° to 40°C.

The important factor is that the mud system and its maintenance should be kept as simple as is possible

2.2.9 Directional drilling

Figure 5 depicts a simple “J” type welltrack which is optimum for geothermal wells. The well design of a directional well should include a directional “kick-off” occurring just below the Anchor casing shoe, with a build rate of between 2° and 3° per 30 metres. The final inclination should be between 25° and 35°.

A nominal directional well design would have the Anchor casing shoe set at approximately 450 metres depth and the “kick-off” with the use of a mud motor and MWD occurring at around 480 metres depth. If the build rate was 2.5°/30m, the final inclination of 30° would be reached at a depth of around 840 m (Measured Depth). At this depth the mud motor and MWD equipment could be pulled from the hole and a rotary drilling “locked-up” assembly utilized to continue. If the production casing shoe was to be set at between say 1000 metres to 1200 metres measured depth, then it would be likely that the directional drilling assembly would be retained in the hole until that depth was reached, unless a drill bit change was required before hand.

The open hole – production section of the well would normally be drilled with a rotary “locked-up” assembly such that the inclination and azimuth was maintained. Directional measurements of both inclination and azimuth are periodically measured using an EMS (electronic multi-shot) instrument.

It is important that the “kick-off” occur as shallow as is practical, and that directional corrections to both inclination and azimuth are kept to an absolute minimum. It is usually of little concern if the well ‘walks’ slightly in one direction or the other, the required accuracy of the target is typically not great. Over correction of inclination and azimuth often results in increased drilling torque and drag, which is the most common reason for geothermal directional wells to fail achieving the target depth.

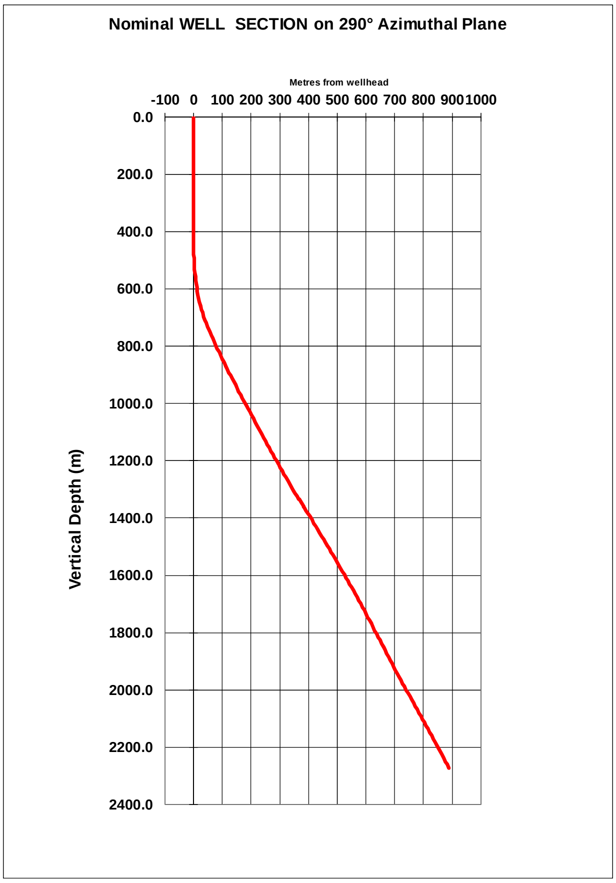

Figure 5: A simple “J” Welltrack

Keep the welltrack and build-up section simple.

2.2.10 Completion testing

There is a tendency to over test wells during and after completion of drilling, carry out just what is needed.

The tests typically performed on geothermal wells may include injectivity testing at various stages during the drilling process, although this is rare; formation imaging after completion of drilling but prior to running the perforated liner; and completion tests after running the liner which will include injectivity, pressure temperature and spinner logs while water is being pumped to the well; transient testing immediately after stopping the water being pumped to the well; and finally a series of thermal recovery pressure and temperature logs.

The most cost and risk intensive tests are those carried out after drilling is completed but prior to the running of the perforated liner. These logs are usually either acoustic formation imaging or other forms of formation imaging, and are typically extremely expensive and place the well at high risk. An acoustic imaging log can take up to 24 hours to run with the tool being run into the open hole. The cost and risk is high, but the information gather is of high value. A careful balance between needs, cost and risk must made, and such logs run only if absolutely necessary, and only if the open hole is absolutely stable.

After the perforated liner has been run, the hole is safe, and therefore the risk significantly reduced. Typically the time required to carry out the injectivity an transient tests is less than one day. On completion of the injectivity tests, the drilling pumps are shut off, and the drilling rig released from the well. The thermal recovery pressure and temperature logs begin and continue periodically until full thermal recovery has occurred.

3. CONCLUSION

Keep It Simple!

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