CONTACT ENERGY DRILLING CAMPAIGN 2005-2013 – RESULTS, LEARNINGS AND EVENTS

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ABSTRACT

Contact Energy has completed a significant geothermal drilling campaign that stretched from April 2005 until December 2013. The initial programme planned to drill two wells with an option on four more. However as economic benefits were realised, and Contacts desire to invest further in geothermal development grew, this campaign grew to finally produce 102 wells in four geothermal fields. The drilling programme has supported the following: (1) make up drilling for the Wairakei, Poihipi and Ohaaki power stations; (2) the investment in two new power stations (Te Huka and Te Mihi); (3) one direct heat application (Tauhara Tenon); (4) an appraisal programme for the Tauhara geothermal field; (5) subsidence investigation programme for the Wairakei and Tauhara geothermal fields; and (6) exploration drilling in a green-field geothermal area (Taheke).

During this campaign, numerous lessons were learned. The drilling techniques, equipment and materials used were modified and improved over the duration of the project. Significant problems were encountered with hole collapse and a variety of methods were used to overcome this particularly vexatious problem.

This paper aims to describe this drilling campaign, and to summarise the learnings and changes both evolutionary and revolutionary that were made during it's course.

CONCEPT AND INITIAL CONTRACTING

In 2004 Contact initiated a strategic plan to develop geothermal options in the Taupo Volcanic Zone. Options considered included production and exploration drilling in existing production fields such as Wairakei and Ohaaki, plus exploration options at Tauhara and in new fields not currently explored.

Tenders were drawn up for the drilling of two wells, and the option on another four wells. Contracts were awarded in late 2004 for key drilling services (rig services, cementing, air drilling services, drilling fluids, consultancy, mud logging) and materials were procured.

The first well on this project was spudded on the 15th of April 2005.

EVOLUTION OF THE DRILLING CAMPAIGN

The drilling on the initially contracted wells enjoyed good success. This success coupled with a desire to continue with the development of geothermal fuels led to additional wells being added to the project. Contracts were repeatedly extended by issue of letters - this method of contract extension was used almost exclusively for the remainder of the project.

In late 2005, a second , smaller (220,000 lb hook-load guyed-mast double) rig was contracted under an extension to the initial rig contract. This smaller rig was utilised for shallow- to medium-depth drilling and workover operations sporadically for the remainder of the project.

At the start of the project, overall management was undertaken by a small Contact staff team, with all well engineering and other specialist expertise being provided by consultants. Starting in mid-2006, Contact began to build internal engineering and specialist capability to be able to manage and control the project directly in-house, with much less reliance on consultants. The team working on the project grew over time from 3 people to a final headcount of 12 persons, including geologist, drilling engineers, HSE officers, logistics, managers and reservoir engineers. Contact now has a very strong and capable multi-disciplinary geothermal development team.

Initial drilling was for well production and exploration, but from late 2006, reinjection wells were included to allow for disposal of separated geothermal water.

In 2008, Contact wished to undertake exploratory coring of the Tauhara field to better understand the nature and cause of subsidence in the field. This required a new 'slim-hole' well design and a smaller specifically-tailored drilling package. A new rig contractor was engaged to supply a specialised rig package that was suitable for slim-hole coring. This rig package consisted of a hybrid rotary-drilling/coring rig with a full BOP system, mud tanks and elevated substructure. The slim-hole coring project was successfully completed with wells being drilled in both Tauhara and Wairakei providing high quality core recovery that was valuable in understanding subsidence in the fields. This time also marked the high water mark in terms of activity, with three rigs operating concurrently.

In addition to drilling in explored areas for fields, new areas of existing fields were explored. At Wairakei, drilling extending to the south of the Karapiti thermal area to create the 400-series set of wells, and out to the far west to create the Poihihi West 860-series wells. Step-out drilling undertaken at Tauhara confirmed the extent of the field and proved that a significant commercial resource was available.

2010 marked a significant milestone when three slim-hole cored exploration wells were drilled at Taheke. This was only the second new field to be exploration-drilled in New Zealand for over 30 years. This was followed later by a single full sized exploration well drilled in 2013.

In 2012, the primary drilling rig was replaced with a new-build 'super-single' rig that provided improvements in capability and safety. This rig was used from late 2012 until the end of the project in December 2013.

EVOLUTION OF WELL DESIGN

The initial casing design was as follows. Buttress casing is noted as 'BTC'.

Casing Stage	Hole	Casing	BOP size on csg
Conductor	None	None	NIL
Surface	26"	24" x 0.5" wall 5LB welded	NIL
Intermediate	24-26" under-reamed	20" x 133 ppf K55 BTC	21-1/4"
Anchor	17 ½"	13-3/8" x 68.0 ppf K55 BTC	21-1/4"
Production	12 ¼"	9-5/8" x 47.0ppf L80 BTC	13-5/8"
Perforated Liners	12 ¼" Or 8 ½"	*10-3/4" x 51ppf K55 Seal Lock Boss *7-5/8" x 29.7ppf Hydril 513 (set with casing hangers or on bottom depending on length)	13-5/8"
Wellhead	10" or 12" Class 900 Master Valve (MV) 2 x 3-1/8" x 3000 psi Side Valves 11" or 13-5/8" x 3000 psi screw on CHF with 2 x 3-1/8" x 3000 psi side outlets		

This design permitted a full 21-1/4" BOP stack to be used on the 24" casing, but the hole size for setting the next sized 20" casing was unable to be drilled through this BOP using a drill-bit due to insufficient clearance between BOP, drillbit and 20" casing couplings. Instead of a drillbit, an expanding under-reamer was used to open out the hole below the 24" casing to produce a sufficiently large hole.

Issues occurred early on with the 20" casing being unable to pass clearly through the 21-1/4" BOP stack, so the first modification to the design was to replace 20" with 18-5/8" BTC as the Intermediate casing, to allow greater clearance.

In 2006 it was recognised that the under-reamer was a potential liability – the unit being used was hard to replace and spare parts were becoming increasingly scarce. The alternative found was to change the hole size being drilled to 20-3/4" (which fits through a 21-1/4" BOP as a complete drill-bit) and to use a modified Buttress Special Clearance Coupling size for the 18-5/8" casing to provide sufficient clearance. This became standard from this date forward.

Late in 2006 the installation of precollared casing was introduced. This involved installing a fully cemented casing (usually 30" but later increased in some instances to 40" or 42") down to approximately 36m as part of the wellsite civil works, before the main rig was brought to site. This cased out shallow loss zones, allowed for the installation of a BOP stack from the start of drilling, and saved a number of rig days.

Design changes to deal with hole collapse

From early in the project, hole collapse was a very predominant problem in many wells. This collapse almost always occurred while drilling the hole for the 18-5/8" or 13-3/8" casing. In addition to a high risk of getting the drillstring stuck, hole collapse prevented hole sections being drilled to the planned depth, or if the full depth was achieved, the hole collapsed before the casing could be installed.

Initial actions to mitigate hole collapse were cement and lost-circulation-material plugs to try and retain circulation and to try and stabilise formations. This was wholly ineffectual.

Another action was sustained washing and hole cleaning if returns were available. Equipment modifications were made to allow aerated circulation through a 21-1/4" BOP and whilst this improved the clearing of cavings from the well, it did not prevent collapse. In general, all these techniques had very limited success in dealing with hole collapse.

Endeavours were made to wash casings down past collapse bridges using crossover 'water-bushings' between the casing and top-drive, so that the casing acted like a drillstring, with the ability to rotate, pump and reciprocate the casing. This met with limited success, and insufficient torque could be applied to the casings to be really useful.

A number of changes to the well design were initiated to help over-come hole collapse problems.

16" casing

The vast majority of hole collapse occurred trying to get either the 18-5/8" casing or the 13-3/8" casing to depth. Regardless of which casing could not get to depth, it was clear that another casing between these two casings would be advantageous. This could either be used to compensate for a shallower 18-5/8" casing shoe, or to stabilise the hole enough to allow the 13-3/8" to get past the collapse zone.

The only API casing size between 18-5/8" and 13-3/8" is 16". This is a very tight fit between these two casings, so in order to provide more clearance, both the 16" and 13-3/8" couplings could be cut down to SCC. This modification, plus using a lighter-wall 16" casing and using a 14-3/4" drillbit to drill out the inside of the 16" casing produced a viable solution.

When used, the modified 16" BTC-SCC casing was run as a liner and set on hole bottom. Final cementing was undertaken with drillpipe stabbed into a stab-in float collar, and cementing ports were created just above the float shoe to allow cement circulation.

For this method to work, it was important that one casing must partially cover some of the hole collapse zones – the more collapse zone covered, the better. This reduced collapse problems enough in the next hole section so that the next casing could be installed to its desired depth.

This use of a contingency 16" BTC-SCC casing was successful in overcoming hole collapse on three occasions during the project. RBL logs indicated good cement jobs in the reduced annuli.

Reaming and Drilling with Casing

The adoption of a Casing Running Tool provided a significant improvement in casing running capability. This equipment directly connects the casing string being run to the Top Drive, allowing full rotation, torque, pumping and reciprocation directly to the casing. This was a vast improvement over using a water-bushing to assist with casing running.

BTC is not capable of withstanding high levels of torque, so BTC connections were strengthened by the inclusion of special torque rings to increase their capacity. These torque rings fill in the 'J-Area' gap between casing body pins inside the coupling so that a direct force path exists between each casing body. This both provides full torque transfer between connections, and also increases the compressive strength of the connection, which is valuable for geothermal conditions.

In order to fully utilise the newfound torque and reaming capability of this system, a drill-shoe was required. This is a casing shoe with cutting structure similar to a drillbit that can be reamed and drilled down to depth. Once the casing has been finally cemented into place, the drill-shoe can be drilled out from the inside so that drilling can recommence.

The use of the Casing Running Tool, high torque connections and a Drillshoe effectively turned the entire casing into a string of 'fat drillpipe' and this system was used on 7 occasions to ream through bridges and to even drill new hole. In one well, an additional 67m of new hole was drilled using this method.

Strategic Casing Setting Depths

Once sufficient data was available to predict likely zones of hole collapse, a successful technique to overcome these problems was by selecting casing setting depths for strategic reasons rather than based on well control depths.

The method of 'strategic setting depths' is to identify a shoe depth just above the hole collapse zone, set deep enough to case out all likely loss zones. The next hole section is drilled through the likely collapse zone but no further – the intent is to try and maintain full circulation for this section which will help with wellbore stability, and to get a casing across the weak zone and cemented as quickly as possible.

This design method required more casings than might normally be used, but the additional cost of this design was more than outweighed by the cost benefits of not having to deal with collapse problems.

Strategic casing setting depth design was also used to prevent annular flows behind casing, which is discussed in the section on cementing.

Overall improvement in dealing with hole collapse

Over the 7 years of the project, more than half a year was lost to hole collapse problems.

At the start of the project, hole collapse problems were adding weeks to the time required to drill each well that suffered from it. The worst-case well had 46 additional days of problems from hole collapse and one well had 60% of it's drilling days attributable to the problem.

By the end of the project, hole collapse problems were dealt with in a matter of hours to days, or eliminated completely by using the well design and construction methodologies described above.

Introduction of GeoConn

During the progress of the drilling project, a new connection product called GeoConn came onto the market. This connection is a modified BTC connection that is fully interconnectable with BTC (pin-box or box-pin) and can be locally repaired and machined easily. This connection provides both full torque capability and increased compressive capacity over BTC, without having to use torque rings, all at a modest increase in cost. This connection was initially adopted by Contact from 2008 for all production casings in production wells, and eventually it was the preferred casing for all 9-5/8" and 13-3/8" casing strings for all wells.

Changes to perforated liner specification

In 2007, the inability to secure timely deliveries of 7-5/8" perforated liner, an inability to have the Hydril 513 connection repaired in New Zealand, and a large quantity of casing connections that arrived damaged in transit from the wharf forced a change in this liner specification.

The specification changed from 7-5/8" Hydril 513 to 7" BTC. The BTC casing was able to be secured in a much more timely manner (frequently ex-stock materials ready for perforation) and it could also be easily repaired in New Zealand. The down-side with this change was losing the ability to run the 5" drillstring into the liner This was considered low probability and if necessary, an alternate 3-1/2" drillstring could be picked up and used inside the liner.

The 10-3/4" liner specification was changed from 51.0ppf to the thinner-walled 40.5 ppf - this allowed a more common 9-7/8" bit to be run into the liner – otherwise a special-order sized 9-5/8" bit was required.

The material specification for both the 7" and 10-3/4" liner strings was also changed to L80 class material in order to provide the maximum resistance to compression buckling for casings set in compression on bottom. This reduced the need to use liner hangers for long strings of liner.

Annulus Casing Packers (ACP)

In a few instances, production casing shoes were set too shallow for the desired reservoir isolation. This was typically due to casings not reaching a suitable depth or cold inflows being discovered after open-hole logging. In these instances, it was either not possible, or very undesirable, to run another smaller casing to achieve the desired casing shoe depth.

A solution was found using Annular Casing Packers (ACPs). These devices are inserted into the casing string and consist of a section of casing with an inflatable external bladder that can be pumped up to seal the wellbore annulus.

For this application, the ACP was run along with a stage collar in a liner string with perforated liner below the ACP and solid liner above it. Once the liner was run to depth, the ACP was inflated, thus isolating the annulus. The stage collar was then opened and the upper un-perforated liner section was cemented into place whilst leaving the lower perforated section exposed to open hole, thus providing a new effective shoe depth for the well.

ACP's have also been used to install a scab liner into a well after repair work. In this use, no perforated liner was used, and the ACP and stage collar were placed at the bottom of the scab liner which allowed the scab liner to be cemented into place.

ACP's have been used successfully on 4 occasions during the project, at depths as deep as 1275m and static formation temperatures of up to 225 degC.

Slimhole Well Design

The introduction of a slimhole coring requirement into the drilling project required a new well design. Options available were to utilise coring casings, welded sections of construction pipe, or to use API casings. The decision was made to construct these wells as fully compliant geothermal wells using known materials, so API casings were selected. The slimhole well casing design was as follows:

Stage	Hole	Casing	BOP size on csg
Conductor	NIL	18-5/8” if reqd	NIL
Surface or Conductor	16”	13-3/8” x 54.5 ppf K55 BTC	21-1/4” annular if reqd
Surface or Intermediate	12.25”	9-5/8” x 40 ppf K55 BTC	13-5/8” annular if reqd
Intermediate	8.5”	7” x 23ppf K55 BTC	9” stack
Production Casing	6.125”	4-1/2” x 12.6ppf L80 BTC	9” stack
Open Hole	HQ core hole or 3-3/4”	*3-1/2” x 9.2ppf L80 Hunting Seal Lock Flush perforated, or *HQ3 or NQ3 core rods perforated	9” stack
Wellhead	4-1/16” x 3000 psi Master Valve 2 x 2-1/16” x 3000 psi Side Valves 4-1/6” CHF screwed onto 4-1/2” casing with 2 x 2-1/16” side outlets		

These slim holes were drilled using a combination of continuous coring and rotary drilling. A centralised inner-sleeve consisting of HWT coring casing was run into each API casing string to help stabilise the core-rods. An HQ coring string was then run through this and the next section cored. Upon completion of the coring, the HWT was pulled out and the hole opened to its correct size with a drillbit before the next casing was run and cemented.

Full well control was maintained throughout the coring operation by using a combination of pump-in tees and stripping glands at surface to allow safe running and recovery of core barrels.

Master Valves and Wellheads

Early in the project, parallel slide master valves were used as they were held in stock by Contact. The desire was to replace these with expanding gate master valves, but delivery times were 9-12 months. To bridge the time gap before the arrival of expanding gate valves, Chinese-manufactured wedge-gate valves were available on very short delivery, so these were used from late 2006 to mid 2007.

In service, parallel slide valves have given the worst performance. Wedge-gate valves provided acceptable service, and good quality expanding gate valves are considered by far the most superior master valve option. The well design standardised on expanding gate master valves.

The well design also standardised on Class 900 master valves even when the well service or pressures would allow a lower specification valve. The rationale for this was to aid in standardisation of mating wellhead items and recovery equipment, and also to provide for maximum flexibility for all eventualities – a Class 900 valve can be used on lesser pressured wells, but a lower pressure-rated valve cannot be used for a higher pressure than its rating.

All wells were constructed with screw-on Casing Head Flanges (CHF) being installed on the production casing, with the master valve being directly connected to the CHF. This provides a compact wellhead that aids in future workover options.

Master valves were frequently installed before drilling the final well section, so were drilled through prior to well completion. As a precaution jetwashing was undertaken through the valve before final closing. No adverse effects were seen from this practice and it was considered a good risk mitigation strategy to eliminate the risk of undertaking a BOP-to-Master-Valve swap under the rig over a live well.

Two wells were drilled as super-wide diameter with 18-5/8” casing. These were equipped with 20” wedge gate master valves – the first being Class 150 and the second being Class 300.

Linepipe threaded connections

In 2012, a trial was undertaken on alternatives to welding of linepipe connections. Each butt weld typically takes between 2 to 3hrs to complete. A threaded linepipe connection called ‘NOV Viper’ was trialled for the 30” and 24” casing runs. This provided a strategic advantage by significantly reduced the casing running time and consequent exposure to hole problems prior to getting the casing successfully installed, although the base cost for the connections exceeded the cost savings in rig time.

The final well design at the end of the project was:

Casing Stage	Hole	Casing	BOP size on casing
Conductor	Nil	40” or 42” welded linepipe	NIL
Conductor or Surface	36”	30” x 0.5” w.t. welded linepipe	30” (+26-3/4” optional) with banjo box
Surface or Intermediate	26” or 27”	24” x 0.5. w.t. welded linepipe	30” (+ 26-3/4” optional) with banjo box
Intermediate	20-3/4” or 22”	18-5/8” x 94.5ppf K55 BTC-SCC R3	21-1/4” + 26-3/4” with banjo box
Contingency	17-1/2”	16” x 75 ppf K55 BTC-SCC (if run, next section is 14-3/4” hole with 13-3/8” BTC-SCC casing)	21-1/4” + 26-3/4” with banjo box
Intermediate / Production	17-1/2”	13-3/8” x 68ppf L80 GeoConn	13-5/8” with banjo box
Production	12-1/4”	9-5/8” x 47ppf L80 GeoConn	13-5/8” with banjo box
Perforated Liner	12-1/4” or 8-1/2”	10-3/4” x 40.5ppf L80 BTC perf 7” x 29ppf L80 BTC perf	13-5/8” with banjo box
Wellhead	10” or 12” Class 900 expanding gate MV 2 x 3-1/8” x 3000 psi expanding gate Side Valve 11” or 13-5/8” x 3000 psi screw-on CHF with 2 x 3-1/8” x 3000 psi side outlets		

EVOLUTION OF DRILLING EQUIPMENT

The project was started with the following drilling rig package:

Rig Type	Free standing treble derrick
Rating	720,000 lb static hook load
Pumps	2 x 1000 hp triplex
Drillstring	5” x 19.5ppf G105 NC50 R2 drillpipe
Rotary Table	27-1/2”
Top Drive	Tesco 700 hp, later 1200hp
BOP Equipment	29-1/2” x 500 psi diverter 21-1/4” x 2k annular and double ram 13-5/8” x 3k annular and double ram
Air Drilling	1 x Booster, 2 x Compressors Banjo Box for 13-5/8” BOP stack

Drillstring standard

At the outset of this project, problems were seen with drillpipe body failures. Inspection intervals had been set as an inspection every 2 wells, which generally was about 700-1000 rotating hours, and should have been sufficient.

The contracted drillpipe inspection standard was to API RP-7G - this is a common inspection standard however under this standard the pipe body inspection is optional, not mandatory. The contractor chose not to inspect the pipe bodies and was only inspecting the tool joints. This issue was remedied by changing the inspection standard to TH-Hill DS-1 Category 4, which is a more comprehensive and rigourous inspection standard. No further pipe body problems occurred for the remainder of the project after the adoption of this improved standard.

In 2010, an internal study was undertaken that indicated that 6-3/4” NC50 drillcollars were superior to the 6-1/4” NC46 drillcollars that were supplied with the rig. The specification was changed and all replacement collars were to the newer specification.

Aerated drilling capability

The initial set-up permitted aerated drilling only in the 12-1/4” and smaller hole sections. For larger hole sizes, the options were limited to plugging losses with LCM and cement, or drilling ahead without returns, which holds risk of getting stuck in hole. This was particularly limiting as significant losses occurred in the shallower sections, and these larger hole sections are the ones that would benefit most from clearing cuttings.

In 2006 a larger Rotating Control Head and Banjo Box was introduced to the project that permitted aerated drilling in hole sizes from 20-3/4” – this reduced drilling loss problems and improved drilling days and the drilling risk profile significantly.

In 2011, a major breakdown occurred on one of the air drilling boosters which led to a long delay in getting spare parts. As a precaution, an additional booster and an additional compressor were brought into the project. These were initially intended as spares, but were included in the well pad layout ready to be used if required, and ultimately were brought into operation for instances where aerated returns could not be regained using a single booster and 2 x compressors. Ultimately they were considered a full part of the drilling system and were used as such. The instances where aerated returns could not be achieved dropped significantly with the adoption of a 2 x booster and 3 x compressor package and this is now considered to be a required technical package.

Main rig replaced with new-build rig

In 2011 a desire from Contact to include more automation and safety features on the rig culminated in an offer from the contractor for a completely new drilling rig, based on requirements provided by Contact. An agreement was reached, and a new contract was put in place to replace the existing large rig with a new-build drilling rig. This rig was supplied and started drilling in late 2012. The specifications on this new rig package are as follows:

Rig Type	Soundproofed hydraulic automated super-single
Rating	700,000 lb static hook load
Pumps	3 x 1000 hp triplex
Drillstring	5” x 19.5ppf G105 NC50 R3 drillpipe
Rotary Table	37-1/2”
Top Drive	Integrated 600 hp
BOP Equipment	30” x 1000 psi annular 26-3/4” x 3000 psi double ram 21-1/4” x 2000 psi annular 13-5/8” x 5k annular and double ram
Air Drilling	2 x Booster, 3 x Compressors Banjo Box for 30”, 26-3/4” and 13-5/8” BOP stacks

This new rig offered many safety and capability improvements.

- The 37-1/2” rotary table permitted drilling a 36” hole directly through the rig floor without having to remove the rotary table.
- The addition of a third mud pump increased the pumping rate, annular velocities and capability of pumping options.
- The larger set of BOP’s allowed full well control options from a shallower depth and in larger hole sizes than the previous rig.
- The soundproofed design of the rig allowed operations closer to built up areas whilst remaining in compliance with stringent resource consents for noise levels.
- The hydraulic automated nature of the rig eliminated a significant amount of potentially hazardous manual pipe handling by rig personnel. For tasks such as drilling, making connections and tripping pipe, the personnel count reduced from four persons working out in the weather, down to a single man working in an enclosed air conditioned control station.
- The increased size of aerated drilling wellhead equipment increased the maximum size of hole that could be drilled from 20-3/4” up to 28”.
- In addition to the above improvements, the new rig also had a smaller footprint, larger tank capacity and improved mud cleaning equipment.

The introduction of this rig was not without draw-backs. Key capability reductions were:

- Slower tripping rate
- Lost of ability to undertake Ream with Casing and Drill with Casing without further equipment investment.
- Slower running of welded pipe sections (20” and 24”) due to loss of ability to run as 24m pre-welded doubles.
- Increased risk of single-point-of-failure events, where one sensor or solenoid failure can disrupt or fully shut down the rig operations.

This new drilling rig drilled from late 2012 until the end of the project in 2013.

Revertible string floats

The use of aerated drilling fluids is considered by Contact to be a game-changing method. The only significant downside to using the technique is the string floats installed in the drillpipe. These string floats are non-return-valves that obviate the need to bleed down pressure from the entire drillstring during connections, by closing on backflow so only the pressure trapped above the top string float is bled down. String floats prevent the free running of wireline tools through the drillstring – these wireline tools are required to be run when taking directional surveys, temperature logs, or for explosive back-off shots required to get free from a stuck drillstring.

In late 2013, Contact trialled a new type of revertible string float called 'Switchfloats' that can be locked open to allow safe passage of wireline tools into and back out of the drillstring. The Switchfloats can then be switched back into normal mode for resumption of drilling. These tools were considered a success as they removed the only remaining downside to aerated drilling, and thus they were fully adopted.

EVOLUTION OF CEMENTING

Cement Formulation

At the initiation of the project, the base cement used was a blend of Class A cement and Blast Furnace Slag (BFS)– the BFS was intended to provide a source of silica to aid in strength retrogression.

This base cement was seen to have very variable results in terms of bonding, and had a habit of flash-setting during placement.

Starting in 2007 a project was initiated involving the key parties in the New Zealand geothermal cementing community to determine a better geothermal base blend. The results of this testing indicated that Class A + BFS had poor long term performance, and its use was discontinued.

Class A + BFS was initially replaced with neat Class A, but concerns existed over the extensive inclusion of additives by cement manufacturers, to adjust Class A chemistry to suit the specification. Class G has a tighter specification with more control on base chemistry, so Class G was soon adopted as the base cement blend.

Once the final results of the cement testing were complete, a final cement blend of Class G + 25% BWOC micro-silica was settled on. This geothermal-specific cement blend was used for the remainder of the project.

Data used for cement jobs

Starting in 2012, an XY caliper was run prior to running casing to determine hole washout, condition and required cement volume. This proved to be very useful to help select correct cement volumes and from the data collected, a significant database was built up that measured the degree of washout recorded against well, depth, formation and bit size. This database has permitted a statistical assessment on hole washout and conditions which has been very useful for cement volume forecasting purposes. The tool was also equipped with a temperature logging instrument which assisted with an improved selection of slurry design temperatures.

From 2010, Radial Bond Logs (RBL) were undertaken after each cement job for the 18-5/8", 13-3/8" and 9-5/8" casings. This is a wireline log inside cemented casing that determines the existence and degree of bonding of cement behind the casing. Logs were run both without internal pressure, and with 500 psi internal casing pressure – this permitted both an indication of cement behind casing and an indication of the location and extent of microannuli. The use of this RBL data was vey useful in reviewing and improving our cementing operations, and permitted remedial work to be undertaken if it was deemed necessary.

Cement Placement

The majority of problems with geothermal wells are caused by poor casing cementing. You only get one chance to cement each casing in properly, so all efforts must be made to do it properly the first time. Contact devoted a significant investment of time and materials into well casing cementing in order to produce strong wells with a long projected life.

Almost all casing cement jobs were started with a total-loss-of-circulation (TLC) due to aerated drilling being used in the drilling sections.

For these instances, the primary job was considered to be only required to get cement around the shoe and up to the lowest loss zone. During the primary cement job with no returns, water was pumped continuously down the annulus – this was done to keep temperatures down and also to keep the bottom loss zone open and un-cemented. On completion of the primary job and top-plug displacement, water was turned off to the annulus and the backfill cement job was commenced. This was considered the actual main job and was larger than the primary job. Following the backfill and a sufficient wait-on-cement time, top-up jobs were undertaken to fill the annulus back up to surface.

In the rare event that returns were seen at the start of the cementing job, attempts were made to get full cement returns to surface prior to displacing cement from the inside of the casing. If losses occurred during the job, then the cementing was continued as per the TLC cementing methodology.

The cementing techniques used by Contact used more cement than other methods, but maximised the likelihood of a good quality cement job. Subsequent RBT logs indicated that Contact's procedure was very effective in producing good cement jobs.

Apart from rare exceptions, all casings were cemented as 'long-string' cement jobs, rather than stage cemented or liner-tieback jobs. This provides the maximum control over cement placement. This method requires a larger cement capacity onsite to handle these larger cement jobs, and placed more reliance on the reliability of the cementing equipment, but the end results were very good.

Specific Cementing Problems

Trapped Water

Whilst every effort was made to prevent it, on several occasions water became trapped between casings and cement, which led to a production casing deformation. The cause of this trapped water was not able to be determined. One theorised cause was a partial bridge within the annulus during backfill jobs which may have filtered out cement particles and left a water-rich slurry below the bridge.

Cement scale inside casing

In one well the casing could not be filled after cementing. On inspection, it was found that the cementing plugs had been damaged by a build up of hard cement scale on the inside of the casing, and had allowed water to pass, contaminating the shoe track cement.

The cause of this scale was determined to be from free-falling cement globules inside the casing sticking to the casing wall that had been heated by a shallower steam zone behind the casing.

To overcome this problem, the cementing procedures were modified to include flowing cold water down the annulus during cement jobs with no returns, and also by installing the bottom plug and fully displacing to the bottom of the casing with water before starting the primary cement job.

Annulus flow

In some locations, a pressure difference can occur between different formations in the same hole section. Once casing had been run and cementing was undertaken, the pressure differential could create an internal downflow in the annulus that washed out cement, and in some instances prevented the backfill cement job from remaining in the annulus at all. In some wells, annular flowrates were calculated to be in the order of 2 m/sec. Trying to get cement to set in this situation is likened to trying to cement up a waterfall. In some instances the cement above the inflow managed to set, so that a significant centre section of the casing was uncemented but with a full cement job above and below this zone.

This problem was avoided once identified, by the use of strategic casing setting depths, to case out the inner flow zone prior to drilling the next section.

The never-ending-backfill-job

Wells drilled into one formation in an area of Wairakei were very difficult to back-fill and top-up. This may have been caused by internal vertical flows, cross-flows or extensive formation weakness and/or permeability. Backfill jobs in this formation took days to get cement returns back to surface - the worst case was a single backfill job that took 13 days and 49 backfill cement jobs to get returns to surface.

This problem was partially remedied by using a lighter thixotropic cement slurry with no control on fluid loss, but the improved results may have also been due to partial plugging of the losses by the huge volume of cement already placed into the formation from previous cement jobs on wells from the same pad.

EVOLUTION OF OTHER TECHNIQUES

Directional Drilling

Directional drilling was initially steered with a mud-pulse Measurements-While-Drilling (MWD) system. However, mud pulse MWD does not work with aerated drilling fluids as the signal is sent thought the mud column inside the drillstring, and aerated fluids attenuate the signal. With a mud-pulse MWD it is desirable to maintain circulation to get a signal, so if losses are seen, either risky blind drilling (without returns) has to be undertaken, or directional drilling operations have to halt so that losses can be healed. This can cause significant time delays and risks.

In 2006 the mud-pulse MWD was replaced with an e-field MWD system. This system sends electrical signals directly through formations from the tool to surface so it can be used with aerated fluids, and also has the advantage of sending signals such as tool temperature during periods of no pumping. This last feature greatly aids in management of tool temperature to avoid cooking expensive directional drilling equipment.

The benefits of this e-field MWD system meant that directional drilling could be undertaken past loss zones, and to greater depths than had been previously considered safe.

On a number of wells a Pressure While Drilling (PWD) module was trialled in the drilling assembly along with the standard MWD equipment. This equipment measured bottom hole pressures in real-time and sent the data to surface. This data was used to assess well injectivity during drilling rather than during wireline logging at the end of the well. This data served as a useful aid in timely decision-making during drilling and reduced the rig time and risks associated with running open hole logs.

Bit Selection

Tricone bits were typically used for larger hole sizes (36” to 16”) and PDC bits were the predominant bit type for 14-3/4” and below. PDC bits performed very well and they were essential to achieving long bit runs in the deeper and hotter parts of the well. The lack of bearings, elastomers and moving parts meant that these types of bits do not have the limited life at high temperatures that tricone bits do.

One ‘hybrid’ drillbit (consisting of a combination of PDC and tricone technology) was run as a trial. This was the first run of this design of drill bit in hot geothermal conditions in the world. The bit produced good Rate of Penetration (ROP) but was absolutely destroyed within 2m of drilling into a very hard formation.

In 2013, Contact brought in a specialist drilling bit performance engineer. The introduction of this specialist role shifted the emphasis on bit selection criteria from ‘best price’ to ‘best features for role’. In combination with this bit selection change, emphasis was placed on the drillers optimising drilling parameters such as weight-on-bit and rotating speed to maximise the ROP. The introduction of this role produced significant cost savings over the remainder of the project.

DRILLING PHILOSOPHIES

After such a long campaign, Contact formed a number of guiding philosophies that it considered good practice.

‘Quality decision making with quality data’

During the course of the project, more and more logging tools became available to Contact, and these were used increasingly to get good-quality data to feed into good-quality decisions.

The project started with a full mud logging suite and this was invaluable to provide post-job and post-event data. Situations such as stuck pipe could be deeply analysed by close examination of the events leading up to the event. Though it was not used every day, the fact that the data was captured and could be reviewed for any day, depth or operation was invaluable.

Down hole logging tools such as Radial Bond Log (RBL) tools provided good data on cement jobs. XY calipers were used to determine hole geometry. Multi-finger calipers and downhole cameras were used to assess casing conditions.

The ability to make decisions based on good quality data was extremely valuable, and the time taken to collect this data was considered a good investment.

In addition to good quality data, good decision-making was enhanced by having the right people at the right levels within the organisation who were given clear decision-making authorities. When escalations were required, collaborative discussions were easy to undertake due to the proximity of the key team members to the rigsite and to each other.

‘Keeping on the path’

Problem-free wells make drilling look easy. Over the period of the project it has been seen as a truism that as soon as some event or issue has occurred that pushes drilling off the intended ‘path’, additional problems and corrective actions can quickly escalate and a snowball effect may push the drilling operations well away from the intended well construction routine of ‘drill-case-wellhead-repeat’.

These trigger events can be seemingly small at the time, and can include such things as equipment failure, poor procurement decisions, poor quality, unexpected downhole conditions, a lack of experience and procedures, and knee-jerk reactions to events.

Significant effort should be made to remain ‘on the path’ using reliable processes, equipment and materials. Corrective actions for unexpected events and issues should be reviewed before action against a larger background of the potential for further diversion from ‘the path’. In real terms, this might mean deferring operations and collecting data to be able to make the right decision, rather than forging ahead and making expedient but potentially destabilising decisions.

‘Prepared for anything’

Flexibility of options was regarded as very important to all aspects of the well construction process. Contingencies were built into the well design, allowing the well to be completed to depth even if events such as hole collapse or stuck pipe were encountered. This was essential for achieving value from the programme. Procurement was extended to hold a wide range of contingency items and ensure a high degree of flexibility. Decisions on remedial actions included consideration of whether they increased or decreased future options, with the former being given more weight in the decision-making process.

Hierarchy of importance

Contact undertook its project with the following hierarchy of importance:

1. Safety and Environment
2. Well Quality
3. Well Cost

All operational decisions were assessed against this hierarchy and it worked very well to guide the project.

NOTEWORTHY EVENTS

The project held some events worthy of special note:

- Two super-wide diameter wells were drilled – each with 18-5/8” casing and a 20” Master Valve.
- Contact’s deepest well was drilled, to a depth of 3020m.
- The hottest wells yet drilled were created in the Ohaaki, Wairakei and Tauhara fields.
- The Tauhara field was discovered to hold a resource suitable for large-scale electricity generation.
- Both the Te Huka (23 MW) and Te Mihi (160 MW) power stations were constructed and fully supplied with steam as a result of the project.
- A three-fold increase in geothermal fluid reinjection was made, using wells created in the project.
- A local direct-heat application was commercialised as a result of the project.

LEGACY

The entire project ran continuously from the 15th of April 2006 until the 16th of December 2013. In this time interval, a total of 102 wells were drilled for a combined distance of 151,548m of hole drilled.

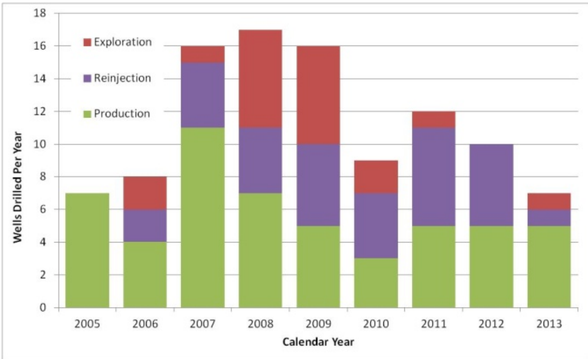

Figure 1: Wells Drilled per Year

Well depths ranged from 157m to 3,020m, with an overall project average of 1,403m.

WELL SUCCESS RATE

Of the 102 wells drilled, the following wells had some known issues upon completion;

Nature of defect	No. wells	Outcome
Casing buckling on heating	1 well	Unable to be fixed - well abandoned
Casing collapse due to trapped water	2 wells	Workover and repair – wells useable
Uncemented section of casing	1 well	Well useable for lower temp fluids
Annular flow behind casing	2 wells	1 well remedied and on production, 1 wells useable but requiring remedial work
Potential minor casing defect	1 well	Expected to be useable after additional logging

So in terms of completion of wells, the project produced 93% of the wells defect-free, and 99% of the wells useable for service.

SUMMARY

Contact views it’s drilling project 2006-2013 as exceptionally successful in producing good quality wells, improving reinjection and powering two new power stations. Significant evolutionary changes were seen over the course of the project.