Post Drilling Outer Casing Cement Remediation and Recommissioning of a Rotokawa Well

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ABSTRACT

This paper describes the successful remediation of a geothermal production well in Rotokawa, New Zealand six years after its drilling which left it with an incomplete cement job on an outer casing annulus. As an initial risk mitigation prior to commissioning in 2017, a pack-off assembly was added to the effected annulus to contain any shallow hot aquifer fluids, to allow thermal expansion of trapped water between the casings, and to allow the well to be put into service. While this was effective initially, the cement job in this annulus continued to degrade over time, allowing the release of shallow fluids through the annulus and pack-off. The leak rate became unmanageable, and the well was shut in November 2022 until a proper repair could be implemented. The repair plan included upgrading the annulus pack-off hardware and conducting a reverse cementing method to re-cement in the casing. To reduce the potential of failure of the 24" casing connections and risk of casing collapse, a detailed re-commissioning warmup program was designed to slowly release potentially trapped water in cement voids between the casings. This program included a prescriptive flow schedule developed using a volumetric and heat transfer-based digital model of the wellbore fluid movement which was calibrated and confirmed by implementing downhole wireline and surface monitoring techniques. The well has since been returned to service, with monitoring showing that the repair job was competent. The reverse cementing and warmup modelling methods should be useful on future similar types of well interventions.

1. INTRODUCTION

1.1 Location and subsurface context

Rotokawa is a developed, high-temperature (>300°C) geothermal field located in the central Taupo Volcanic Zone. The field supports two power stations: an Ormat combined cycle plant, Rotokawa (34 Mwe) commissioned in 1997, and a triple flash plant, Ngā Awa Pūrua (138 Mwe), commissioned in 2010. The field is run in partnership between Tauhara North No. 2 Trust and Mercury NZ Ltd.

The subsurface geology of the field is defined by a NE-SW "graben" structure, with basement Mesozoic greywacke overlain by a nearly 3-km thick volcanic sequence (Milich et al. 2020). Production fluid is extracted (and subsequently reinjected) predominately between 1000 and 2500 metres below ground level, from the deep volcanic sequence and – to a lesser extent – top of the basement rock.

The field has significant surface thermal manifestations, most notably geothermal Lake Rotokawa and the surrounding thermal area. Mixing of geothermal fluids and/or gases within shallow (above reservoir) aquifers is seen throughout the field which can lead to considerable challenges during drilling/well construction (e.g. shallow, high temperature aquifers) and post-drilling (e.g. well integrity issues related to corrosive fluids).

1.2 Background

Obtaining fully cemented casing strings in geothermal wells has always been a required challenge from both slurry design and cement placement practice perspectives. The extreme temperature changes experienced in a well's life impose thermal expansion loads on the well casings which, if not supported with a competent cement sheath along the entire length, can lead to extreme wellhead growth, failures in the form of buckled or collapsed casing, and/or shallow aquifer thermal fluid leaks and cross contamination. Geothermal wells are typically drilled into under-pressured (with respect to water column) layered formations, which often have sections with high permeability. Cement used typically has a specific gravity of 1.6 to 1.85 to water, so cement losses to the formation are normal and getting a full cement sheath is usually quite difficult.

To complicate matters, cement slurry setting times are highly affected by placement temperatures which can vary extremely along the depth of the casing string in a geothermal well, so various combinations of retarders or accelerators are required to optimize the time spent waiting on cement (WOC) and to prevent early flash set or overly extended set up times prior to the final placement being achieved.

This paper presents a case study of a big bore geothermal production well drilled in 2017 in which the 18-5/8" intermediate #2 casing string was not fully cemented to surface. Water was left trapped in the annulus from surface level to the top of cement in the annulus above the previous casing shoe, leaving up to 165m of uncemented casing. This occurred during well construction as the primary cement job was being pumped. During the cement job, returns were lost to the formation after the top of cement had reached above the previous 24" casing shoe, which was set at ~250 metres depth, but before the top of cement reached surface and the cement flash set near the shoe within that annulus. Standard procedure to flush out any cement in the casing-by-casing annulus out to the formation loss zone could not be completed because the annulus pressured up when the cement set inside the casing at the shoe. Normal practice is to follow the water flush with a reverse circulation back squeeze top up cement job to fill the annulus from surface to the shoe with good cement, so this also could not be completed.

Considering the annulus was sealed with cement at the shoe and acting as a competent primary pressure barrier, a secondary barrier in the form of a casing pack-off was installed after the rig was demobilized, and the well was put into production service to supply steam to the power station. During the years following 2017 while the well was

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producing, plant operators noticed that that annulus would pressure up, so they would release the pressure routinely and eventually left the annulus on a slow bleed through the pack-off side to a nearby sump. Over time, the annulus side bleed valve washed out, would leak even when shut and the flow from the annulus slowly increased to a point where it was not manageable. This led the well engineering team to presume that the cement near the shoe had degrading over time or the 24" casing had failed and that the primary pressure barrier was compromised. In November 2022, the well was shut allowed to cool and a plan was put into place to repair it.

2. WELL CONSTRUCTION

RK35 was constructed in 2017 as a "big bore" directionally drilled production well. The big bore design included four cemented casing strings to the top of the reservoir, which were required to meet "NZS2403:2015 New Zealand Standard: Code of practice for deep geothermal well" due to the high temperatures present in relatively shallow formations. The big bore well schematic is shown in Figure 1 and has a 13-3/8" production pressure control casing with 9-5/8" and 7" perforated liners through the reservoir section. The 40" conductor pipe was set at 37m prior to the big rig arriving location. The top of reservoir was prognosed at approximately 1000mVD, where the 13-3/8" pressure containment casing was set and cemented.

Well construction began with the 30" surface casing string being set and cemented at 86m and the 24" Intermediate #1 casing string being set and cemented at 250m. When the 18-5/8" intermediate #2 casing was being cemented at 682m, the primary cement slurry was routed down the well through a 5" drill pipe inner string inside the 18-5/8" casing and proceeded up the annulus to the point where the top of cement in the annulus reached approximately 165m from surface when fluid returns stopped. Cement bond logs confirmed that the top of cement was at 165m. This was also verified later by calculations based on final displacement pressure and by the amount that the casing thermally expanded after well heat-up. This put the cement above the 24" casing shoe, which was at 250m, leaving approximately 85m of cement inside the 24" x 18-5/8" casing by casing annulus.

The 24" casing string had premium threaded casing connections that had flush internal and external profiles. This had the benefit of removing external couplings which allows the large diameter casing to slide with more ease into the hole and also facilitates quicker casing makeup when compared to welding the joints and saves the associated rig time and cost. Unfortunately, this connection style had only 55% load rating in compression of the pipe body strength. Based on the anulus discharge fluid temperatures realized as the well was produced, the 24" casing connections were suspected to have plasticly yielded and possibly failed which could be another source for the leak up this annulus.

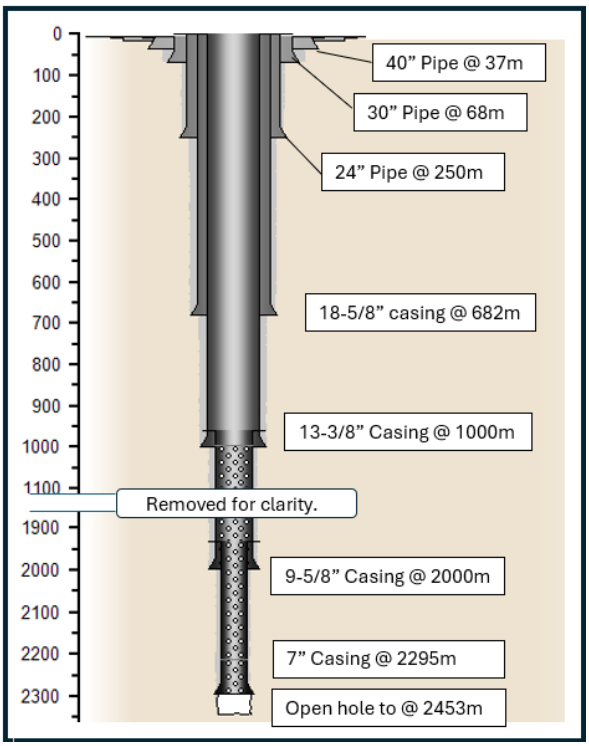


Figure 1: As-built wellbore schematic.

After dropping the drill pipe wiper dart and displacing the drill pipe with water, as per procedure the cementing pumps were connected to the annulus side outlet valves and an annulus flush was attempted to clear the cement from the casing-by-casing annulus, push it into the formation and establish a circulation pathway for the back squeeze cement job that would have come next. When attempting to flush water, the pump pressure rose rapidly to 440 psi and the pump was stopped to prevent over pressuring and collapsing the 18-5/8" casing. Pressure was bled off from 440 psi to 160 psi over 30 minutes. The annulus was not taking significant fluid. Further attempts to flush the annulus were unsuccessful. The cement left in the annulus was considered adequate to be a competent pressure containment barrier for well control purposes to drill the next section to 1000m. This was confirmed by achieving an adequate formation integrity test after drilling out of the 18-5/8" shoe to 884m where a 17.9 EMW (0.93 psi/ft) test gradient was achieved confirming effective pressure containment. Well construction continued generally as per drilling program to targeted depth, and the rig was moved off the location.

3. WELL BARRIER DEGRADATION

After the rig was removed and further risk assessment was completed focussed on the uncemented annulus, the drilling and production technical teams agreed that a secondary pressure control barrier was justified so a bespoke annulus pack-off device was designed and installed. Figure 2 shows the fabrication drawing of this pack-off. The pack off was

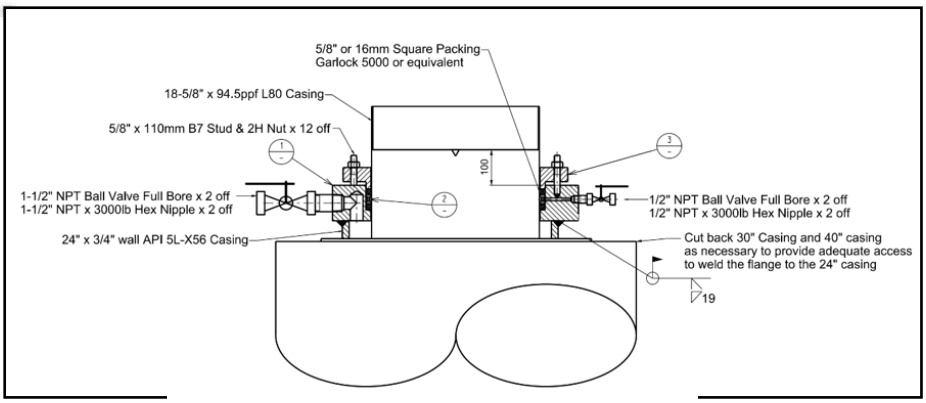


Figure 2: 24" x 18-5/8" casing annulus pack-off

welded to the 24" casing and had compressed graphite rope pressure seal to the outer diameter of the 18-5/8" casing. The pack-off was rated to 30bar which was considered adequate to hold any shallow high temperature aquifer pressures that might leak through the partially cemented annulus. Electronic continuous pressure monitoring was installed on the annulus.

The well was heated up, commissioned and put into service successfully later in 2017. It performed as a good production well contributing up to ~260 tph (~15 MWe) flow to the geothermal power station for the next five years. During that time, wireline (PTS, X-Y calliper, and High Temperature Casing Calliper – HTCC) monitoring showed that the 13-3/8" pressure containment casing string was competent and in good condition.

When the well flow was first initiated and over the first few years, annular pressures approaching the 30-bar pressure rating of the pack-off were observed developing behind the pack-off in the 24" x 18-5/8" annulus. The pressure was alarmed in the plant control system and was regularly bled-off by station operators. Presence of cement contamination in the discharging fluid was detected, indicating the cement barrier was being dissolved, but this was not considered the conclusive reason for the flow from the annulus. As mentioned, the 24" casing connections also could be a failure point that allowed leaks from the shallow aquifer above any cement in the annulus. Any repair program would need to ascertain where the flow was coming from so that cement could be placed correctly and along the full length.

After 2020, the pressure build up was happening more quickly (in a matter of a few days), and the annulus pressure was put on bleed continuously through a throttled pack-off side valve and through cellar drain lines to a nearby sump. Over time, both annular side valves and downstream piping were eroded out to a point the well annulus could not be shut in 100%. The pressure buildup, increasing flow over time, and degraded side valves and related piping lead to eventually the recommendation in 2022 that the well be shut in and the annulus repaired in a more permanent fashion.

As the well cooled, evidence showed that the pressure and flow from the annulus was significantly driven by heat from the main wellbore, which heated up the water in the annulus, and likely the surrounding aquifer, encouraging it to boil and flow up through the annulus passing through either the impaired cement or the potentially failed 24" casing connections. It was also observed that the intermediate aquifer had some artisan pressure, because, even after the inner wellbore cooled after shut-in, flow continued coming from the annulus albeit at a lower temperature and rate.

4. WELL INTERVENTION

The well intervention project was divided into three phases:

1. Diagnostics operations: inject cold water in annulus and assess its injectivity and integrity of the 24" connections.
2. Pack off maintenance: kill annulus with heavy brine, replace 24" pack off valves, and refresh the upper casing pack-off.
3. Cement job: pump customised slurry to fully cement the annulus.

4.1 Phase 1: Diagnostic operations

Prior to the well repair, diagnostic operations were conducted to obtain injectivity data and assess the 24" casing status. Annular injection testing was performed by pumping cold water into the annulus through the pack-off side valves to measure injectivity. Results of the injection testing showed that a flow rate of 2-3bbl/min of cold water could be achieved through a single side valve without exceeding the pack-off pressure limits.

While injecting cold water in the annulus, several PT surveys were run in the main well bore. A baseline PT was done down to 600m before beginning the cold-water injection in the annulus. Additional PT surveys were run following the injection of 13m^3 and 290m^3 of injected cold water (Figure 3). Analysis of this data confirmed that cooling water was traveling out of the 24" casing shoe at 242m and cooling down to a depth of 330m. These results confirmed the integrity of the 24" casing, and the temperature profile gave confidence that a main well bore quench within the innermost 13-3/8" pressure containment casing would not be required for cementing the annulus.

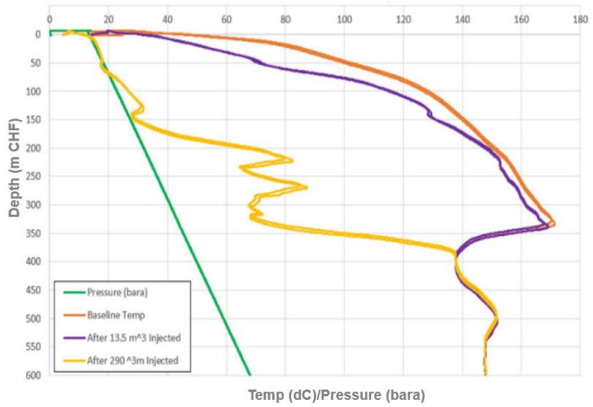


Figure 3: Collated PT survey data from diagnostic operations.

Additionally, the results of the diagnostic allowed specialized cement recipes to be developed by the contractor's cement lab to suit the expected pumping parameters.

4.2 Phase 2: Pack-off Maintenance

Directly after Phase 1 was completed, the quench pump was used to inject salt weight fluid into the annulus to kill the artesian flow. A potassium chloride and water mixture was made up to 1.08 SG (9.2 ppg) mix and injected in the annulus. The well became static at this stage, which allowed the following mechanical works to be completed:

1. Extended the 18-5/8" casing and install a new 18-5/8" x 13-3/8 pack-off on the inner casing annulus with new side valves: when the 24" x 18-5/8" casing annulus cement repair is completed, this will lock the 18-5/8" casing in place and put new loads on the 13-3/8" casing that beforehand were allowed to expand with the 18-5/8" casing. The original 13-3/8" casing had a foam cement job that could give way now that it would be held in compression, so, to mitigate that risk, the technical team chose this method to ensure a proper secondary barrier on that annulus was installed.
2. Installed new side valves on the 24" casing pack-off annulus, which replaced the old washed-out valves in a size large enough to be used to pump cement through.
3. Refreshed the 24" x 18-5/8" pack-off materials and re-energize the seal: this provided the pressure seal necessary to squeeze cement into the annulus in the next phase.

4.3 Phase 3: Cement job

With the data collected from the diagnostic phase, and with the repair of the pack-offs and side valves completed, the cement repair program proceeded. Cold water injection was resumed to cool the wellbore for cement.

The cementing operations began with mixing up enough mix water to provide a total of 170 bbls of cement slurry. Cement was pumped into the annulus through both side valves at an initial rate of 3 bbl/min. The annular pressure steadily dropped as cement was pumped into the annulus, which was expected due to the increase in hydrostatic pressure provided by the cement. After 120 bbls of cement was pumped, the pump rate was lowered to 2 bbl/min for the final 20 bbls. The cement in the annulus slumped some, and the annulus was topped up with cement by connecting a hose from one side valve of the annulus to a tote filled with cement. In total, 158 bbls of cement was pumped into the annulus, which indicated that the entire 24" x 18-5/8" annular space was cemented. An additional 37 bbls was pumped into the formation below the 24" casing shoe.

After the cement was allowed to cure, an XY caliper survey tool was run to confirm there were no casing anomalies induced into the 13-3.8" inner casing string and to ensure the well was ready for heating up and placing back into service.

5. HEAT-UP PROGRAM MODELLING

High heat-up rates can cause water trapped in cement to expand rapidly, resulting in casing collapse of the inner casing string. This is a well-known failure anomaly seen in geothermal wells (Southon 2005). It is theorized that slow well heat-up rates will give time for trapped water to escape through the micro-annulus, cement cracks, and/or casing connection, which help release the high pressures developed by water expansion.

5.1 Heat-up program methodology

Precautions were implemented in the repair program to avoid water from entering or becoming trapped within the annular space during the cement squeeze. However, it was possible that trapped water existed in the old cement between 165 - 242 metres depth, which likely had formed channels/cavities as a result of the previous continuous flow from the intermediate aquifer to the surface since drilling. Because it was impossible to guarantee that the repair slurry filled every cavity/channel, there was a higher risk of trapped water in this repaired well than in a normally cemented well.

The objective of this project phase was to warm up the well as slowly as practicable to minimize the risk of casing collapse. The methodology presented here aimed to replicate the natural heat-up rates that the well (at the depth of interest) had experienced post-cement job, until the well was fully warmed up. The proposed steps of this methodology are below:

1. Leave well to naturally warm up. Carry out PT during the process and confirm temperature profiles match or are near to the baseline in situ formation temperatures;

2. Establish a maximum natural heat-up rate (for which water expansion rate is proportional to) at the depth of interest (in this case, the section of casing from 165m to the shoe of the 24" of 242m);

3. Calculate the expected downhole temperature profiles during commissioning:

   a. Initial temperature profile - just before well is placed on bleed.

   b. Subsequent temperature profiles at time increments during bleeding and until area of interest is fully heated.

4. Determine the transition time between temperature profiles time, using Step 2's maximum natural heat up rate;

5. Calculate a bleed-off flow rate schedule to move the deeper higher temperature fluids up the well bore, so temperature changes do not exceed the that maximum heat-up rate.

6. Calculate temperatures along the area of interest and flow rates vs time and up to surface, so that the change in temperature anywhere along the area of interest does not exceed the natural heat up rate established in Step 4.

7. Start the heat-up bleed following the flow schedule from Step 6, while monitoring the temperature of the fluid exiting the well bore and use this to calibrate the model. The calibrated model can be used to adjust the flow rate schedule. Theoretically, there should be significant heat lost to the formation so that flow rates can be increased to keep the surface temperatures on the projected schedule.

The rational for these steps is that – if the trapped water has been naturally heated up (expanded) at natural heat up rates without casing failure as shown by the bleed pre-warmup X-Y survey – then keeping the same rates should mitigate the risk of casing failure during the bleed heat-up cycle. The rate of expansion of the water should then be less than the capability of the system to release pressure (through micro-annulus, cement cracks, casing connections).

Assumptions were made to prepare this model:

1. The trapped water's properties are uniform throughout the depth of interest (eg. 165-242 metres depth);
2. Conductive heat transfer from the fluids in the wellbore to the cooler rock outside the well was neglected in the model and would be compensated by the recalibration process in Step 7.
3. Flow from the well is single liquid phase until most of the heat up is completed.

5.2 Actual heat-up PTs and natural heat-up rate calculations

Two PT runs were completed to allow calculation of the heat-up rates:

1. A baseline PT: a pre-repair job PT was conducted, with the annulus fully cooled down, just before pumping cement.

2. Heat-up PTS + XY calliper: 11 days after the repair job, a heat up PTS was conducted as well as XY calliper to check casing condition. There were no defects encountered.

Using these PT runs, an average temperature was calculated for 10-metre sections, and the heat-up rate was calculated. Assuming steady heat-up rate, the maximum rate calculated was 2.93°C / 8 hours at 170- 180 metres depth.

This rate was interpreted to be the maximum heat up rate experienced in the annulus. It is important to note that this is a conservative approach, as the rates tend to be higher at the beginning of the heat-up period then slow down as the temperature reaches equilibrium to the surrounding formation.

An additional consideration that makes this method conservative is that the transient temperature measured with PTS within the main wellbore would be lower compared to the one seen by the 18-5/8" – 24" annulus, which is closer to the formation temperatures (Figure 4).

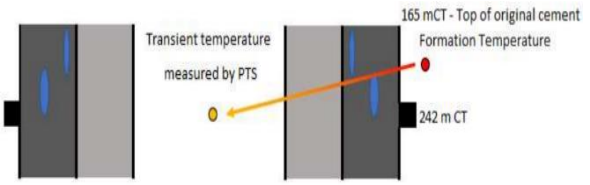


Figure 4: Conceptual sketch of annular vs main wellbore temperatures.

The shut downhole temperature profile just before starting bleed showed that the well was full of single-phase liquid to surface. The stabilised shut-in wellhead pressure (WHP) before the repair job was circa 13 barg. Eleven days post-cement job, at WHP=12.2 barg, the top section of the well was still heating up (see temperature profile plotted in yellow in Figure 5**).** The expected natural "fully heated up" temperature profile is plotted in red in Figure 5**,** which assumes a WHP at circa 13 barg; this was interpreted as the initial temperature profile before starting with the controlled bleed, called T0.

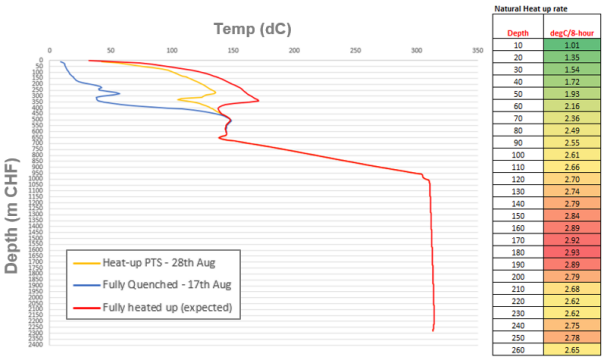


Figure 5: Actual PTS runs (fully quenched prior to cement repair and 11 days (28th Aug) after repair) and fully expected heat-up temperature (T0 for the controlled bleed program).

5.3 Modelled subsequent temperature profiles during controlled bleed program

As the well is opened and allowed to bleed, the temperature profile T0 representing the column of fluid in the well will move upwards. Temperature profiles through time were calculated for every 10 m section until 300°C was reached across the entire section of interest (165-242 m). This gave 95 temperature profiles, T1, T2… T95.

The modelled progressing temperature profiles as the well is bled off are shown in Figure 6. As part of the program, the wellhead pressure was checked to ensure that the wellbore fluids were not flashing up to a time late in the bleed schedule, which ensured that flashing effects could be neglected in the model.

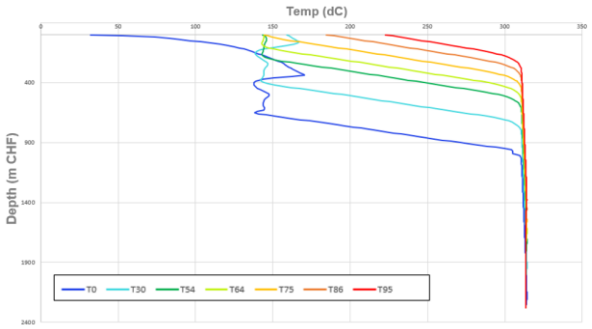


Figure 6: Modelled temperature profiles for controlled bleed program.

The temperature profiles were corrected for heat loss, assuming only heat transfer from the wellbore fluid to the production casing $-Q_{fluid} = Q_{pcsg}$. Heat loss to cement and intermediate casing was not taken into account to simplify the model. This represents a conservative approach, since as the wellbore fluid moves up it will lose heat and actually warm up slower if heat lost to cement and formation were considered.

The temperature increments from T0 to T1, T1 to T2, etc, were calculated for each 10 m section of casing. Then, using the max heat-up rate, the transition time between these profiles was computed for each 10 m section. This translated into the amount of volume (flow rate times flow duration) that could be removed from the top of each column (through bleed line) to move the column up the well while remaining within the maximum heat up value: since the volume in between each temperature profile equals the volume within 10 m of casing and the 13 3/8" capacity is 78.08 l/m, then 780.87 litres should be evacuated for each 10 m section. With this volume and the transition times already computed, the flow rate was calculated for each 10 m section. This approach gives different flowrates for each depth within the well at that given time. Therefore, the flowrate selected for the entire well was the lowest flow rate calculated in the depth of concern.

5.4 Preliminary bleed schedule

A single value of flow rate for each temperature profile transition (T0-T1, T1-T2, etc) and volume (780 lts) allowed plotting of flow rate and temperature vs time. This gave a preliminary flow schedule to follow during commissioning (Figure 7).

For this particular well, T0 showed a colder section (temperature reversal) between 350 and 650 metres depth. This colder front would cool down the already heated casing above as it moves up, so it was decided that the evacuation rate of this cold front could be increased when passing through the zone of interest.

To help the potential trapped water expand and leak off through cement cracks and micro annulus, it was proposed to do minor thermal cycles onto the cemented annulus as part of the controlled bleed off. By opening and bleeding the well during day shift, and allowing to cool down during night, it would encourage the creation of new cracks/microannulus that can be used by any trapped water as a path to relief pressure. The preliminary bleed schedule was overconservative due to the assumptions made:

1. Heat loss: It was assumed that no there is no heat loss to the cement or intermediate casing. However, in actuality, this will occur, therefore actual temperatures were expected to be lower in both the wellbore and in the second annulus. This meant that the actual heat-up rates are likely to be milder than modelled.

2. Heat transfer rate: The potential trapped water in the second annulus (165-242 metres depth) will heat up at slower rate than the wellbore/production casing, since there are additional layers isolating the cemented annulus from the wellbore, and heat transfer area increases with diameter.

3. Natural heat up rate: Maximum natural heat-up rate already occurred in the first hours/days of the well heat-up post-cement job. By using two data points (PTS 17th Aug and PTS 28th Aug), the calculated maximum heat up rate is lower than the actual one.

These considerations lead to the proposal to increase the preliminary flow rates over the daytime and shut the well at night, so that average daily flow rates will be close to those of the preliminary bleed schedule. This enabled the small thermal cycling method and helped with minimizing manpower during the heat-up.

With the bleed schedule and temperature modelling complete, the following was plotted in Figure 7: expected wellhead temperature (orange), cumulative evacuated volume (gray) as casing content percentage, bleed flow rate (blue) in lpm per 8hrs vs days.

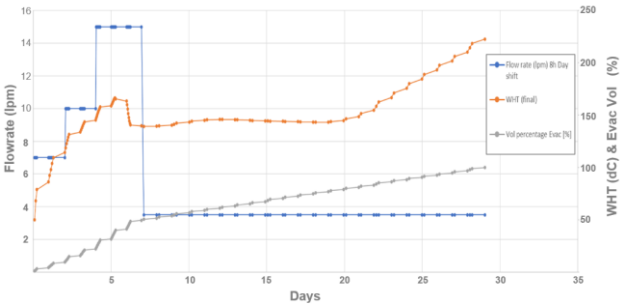


Figure 7: Bleed schedule plot.

Note that, by doing this analysis, the temperature at the wellhead is not necessarily a reflection of the downhole temperatures. Figure 8 demonstrates how surface temperature compares with downhole temperature profiles. When utilising this method, it is recommended to look at the downhole temperature profile to determine heat-up rates, rather than base it solely on wellhead temperature. In this particular well, wellhead temperature was expected to be constant while downhole temperature at the depth of interest increased during the initial bleed.

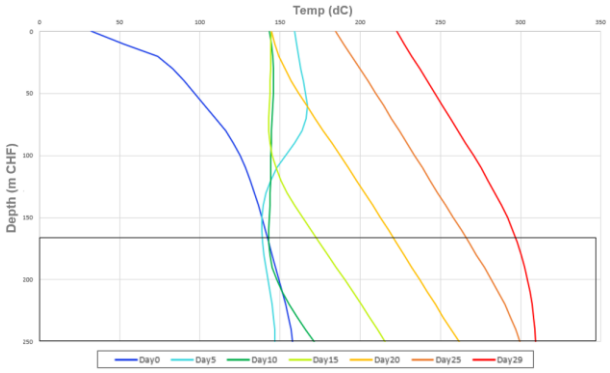


Figure 8: Surface temperature (depth = 0 m) compared to modelled downhole temperatures through time.

This model allowed the following bleed schedule to be generated, with recommended downhole logs to confirm the model:

1) Day 0: Run a PTS and XY calliper the day prior to scheduled start to confirm the T0 profile and to confirm that the casing has remained in good condition. Update model and bleed schedule as necessary.

2) Bleed the well under controlled conditions aiming for the flowrates and wellhead temperatures forecasted, whichever is reached first. Bleed during day (8 hours), then shut the well in during night.

3) Day 8: PTS recommended to ensure that the hot front is approaching the 24" shoe at 242 metres depth at the modelled rate. Readjust bleed accordingly.

4) Day 29 onwards: The model expects that the depth of interest (165-242 m) has heated up to maximum temperature by this point. For the next 48 hours, the well should be put on continuous light bleed, and then on hard bleed until full WHP is reached.

5) Run a final PTS with XY calliper under full bleed conditions, for quality assurance purposes prior to putting the well back into full production mode to the power station.

6. WELL HEAT-UP AND COMMISIONING

The well was readied for heat-up and commissioning using the above-described heat-up program with a few additional execution procedures. An additional bleed line and wellhead instrumentation was installed on the 1" bleed piping to help control and accurately monitor wellhead parameters, so that the slow bleed schedule was followed. This instrument pack included temperature and pressure sensors, a flow meter, wellhead height measurement instrument, a throttling valve for minor flow rate adjustments and orifice plate station (3 to 6 mm orifice pates) for major flow adjustments. This meter run was very useful for accurately controlling the well discharge rates and will be setup to be a removable package that can be used in other future well warm up projects.

As mentioned, the main variable measured during this period was the wellhead temperature with the goal to of maintaining a slow heat-up. The actual heat up duration was 70 days, compared to the modelled 30 day heat up. The actual versus modelled heat up surface temperatures are shown in Figure 9.

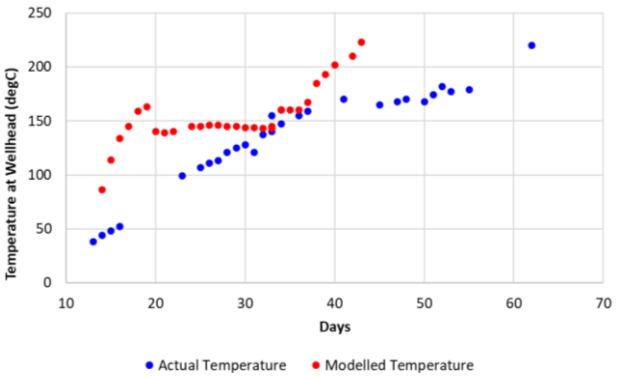


Figure 9: Comparison of actual temperature against modelled temperature from heat up model.

Lessons learned and adjustments made during this heat-up period were:

- The flow rates specified by the model were too low, which made it difficult to measure using the ultrasonic flow meter that we had installed. A more accurate higher temperature rated magnetic flow or Coriolis type meter would be better to use in the future. As a result, controlling flow was more effectively done by changing the orifice plate size as soon as target wellhead temperature was achieved for the shift/week.
- To achieve a higher wellhead temperature near the end of the program, the 1" bleed line was changed so that flow through the master valve bypass drain could be used which was a 2" line and allowed higher flow rates. Future programs should allow for easily stepping up to 2" flow path.

Once the target wellhead temperature was reached, the well was left on heavy bleed for 2 months. A final XY-caliper was performed to confirm casing condition before bringing the well to station. The heat up and commissioning was successful, with no casing issues detected. Well productivity remained consistent with pre-shut in levels.

Prior to this annulus repair program, wellhead vertical growth between shut in and cool condition to full production was 260 mm. This indicates that almost 165 meters of casing were not restrained abased on the thermal expansion calculation. After the 24" annulus was cemented and the well was heated up, that measurement was reduced to 44 mm, which indicates that the 24" x 18-5/8" cement job was restraining the casing significantly better than before.

Precise ground level surveys were conducted prior to and after the cement squeeze, with the most recent completed one month after well re-commissioning. Surveys confirm that no abnormal growth has been seen at the wellhead since the workover.

6. CONCLUSION

By all measures, the repair of this Rotokawa geothermal production well's outer casing cement job was successful. The subject well had significant capacity that could not be safely used because of an incomplete cement job during initial construction and subsequent degradation of that annular cement during 6 years of subsequent operations. Extra engineering efforts for the repair and heat-up procedure were taken to ensure the success of the project. These included the

following that may have been used in other similar well intervention projects:

- A bespoke well annular packoff design can be an effective secondary pressure containment barrier to allow a well with imperfect outer cement job be put into production.
- Appropriate annular quench and injectivity procedures with the use of a pressure/temperature wireline survey can help to diagnose potential outer casing pressure containment failures and determine where and if there is enough flow path for conducting a cement repair job.
- Wellbore temperature and flow modelling can be a useful method to simulate downhole well heat-up rates and determine appropriate well bleed schedules that allow management of temperature changes along the downhole casing and cement column.
- Conductive heat transfer to the formation and cement plays a significant role in how fast a well heats up. That is, for this well, actual bleed rates needed to follow the proposed heat up schedule had to be almost double of those modelled because of the heat lost through conduction to the formation.

While each well intervention project is different, the authors hope the methods developed and used in this project are useful for others to enable or improve success on similar projects.

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