ROTOKAWA: RESERVOIR RESPONSE OF 172 MW GEOTHERMAL OPERATION

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1. ABSTRACT

Located in the Taupo Volcanic Zone, production in the Rotokawa geothermal field began in 1997 with a 27 MWe flash-binary power station, expanded to 34 MWe in 2006. In 2010, the installed capacity increased to 172 MW with the commissioning of triple-flash condensing 138 MWe Nga Awa Purua. To date, there are thirteen production wells supplying steam to both power plants and five wells to inject brine and condensate.

During the last five years, the changes in pressure and enthalpy have required an adaptive management strategy to maintain full fuel supply to both stations. Reservoir pressure drawdown variation is up to 38 bar and production enthalpy varies up to 700 kJ/kg across the field. Therefore, identifying the underlying physical processes that occur in each well has been the primary goal of the geoscience, engineering and operations teams. The in-house development and usage of reservoir and wellbore modelling tools has been the cornerstone for the testing of theories and the assessment of the long term production and injection strategies.

This paper summarizes the results from the pressure and temperature monitoring and the findings from the modelling activities that aided the current production and injection strategy.

2. INTRODUCTION

The first exploration wells in Rotokawa were drilled in the centre and the south of the reservoir in the decade of the 1960s. The first wells showed an isothermal profile starting at -500 masl indicating the presence of good permeability and temperatures above 300 ºC.

The probable resource covers an area of approximately 8 km^2. To date 31 wells have been drilled on the field, of which 18 are used to support 172 MW of electrical generation capacity. Currently the Rotokawa field makes use of 13 active production wells and 5 injectors (1 shallow, 4 deep) (Figure 1). Most of the early wells have been abandoned due to casing failures, while other wells are used for monitoring.

Rotokawa is a compartmentalized reservoir, with pressure drawdown from 4 to 42 bar in different production areas. The localized changes in pressure have increased the boiling in some areas of the reservoir creating large differences in enthalpy. The operation of the Rotokawa field requires a monitoring plan that detects these changes to optimize the total fluid enthalpy to the plant and design a sustainable production strategy.

There are indications that the geological structures play a role in the performance of the production wells.

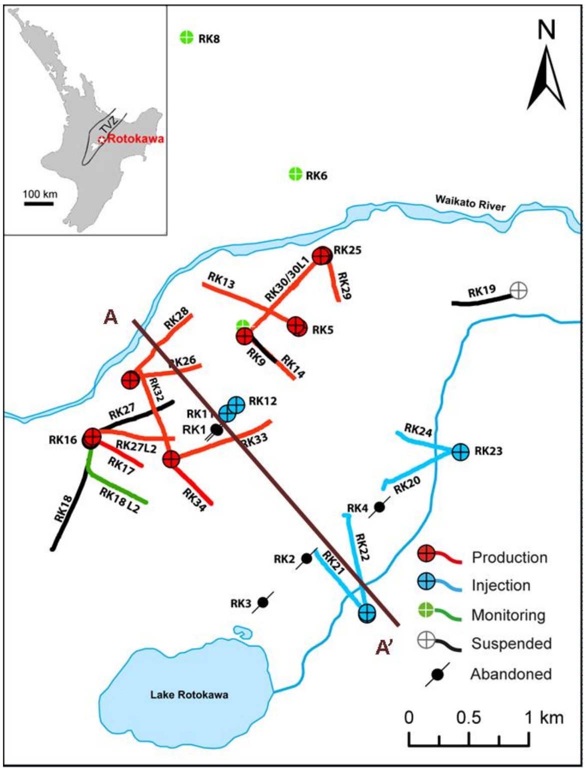

Figure 1: Wells in the Rotokawa Geothermal Field

Acoustic imaging logs confirm a predominant NE-SW fracture direction in the reservoir, aligned with the main faults in the reservoir. In the west region a preferential NE-SW path was found as a result of a tracer test carried out in RK18 (Bowyer and Holt, 2010; Wallis *et al.*, 2013; Sewell *et al*, 2015a, Addison *et al*, 2015c). The wells in the western area have experienced very similar pressure and temperature evolution; some show common temperature inversions at similar elevations. This structure has implications in the management of this sector: for example, it was decided to move injection into the south once this connection was found. Another structure with a NE-SW direction, the Central Field Fault (CFF), has a very important role for the management of the injection returns, slowing down the injection fluid returning to the production area.

The steep gradients in chloride concentration, chloride/boron ratio, Na-K-Ca geothermometry and NCG are consistent with the idea of a compartmentalized reservoir; the preferred model is shown in Figure 2. (Winick *et al*, 2011, Wallis *et al*, 2013, Sewell *et al*, 2015a). This model considers a single parent fluid in the south of the reservoir with different entries into the production area corresponding with the high temperature areas found in the reservoir; with progressive dilution from south to north indicating that it mixes with deep conductively-heated northern inflow and more diluted water.

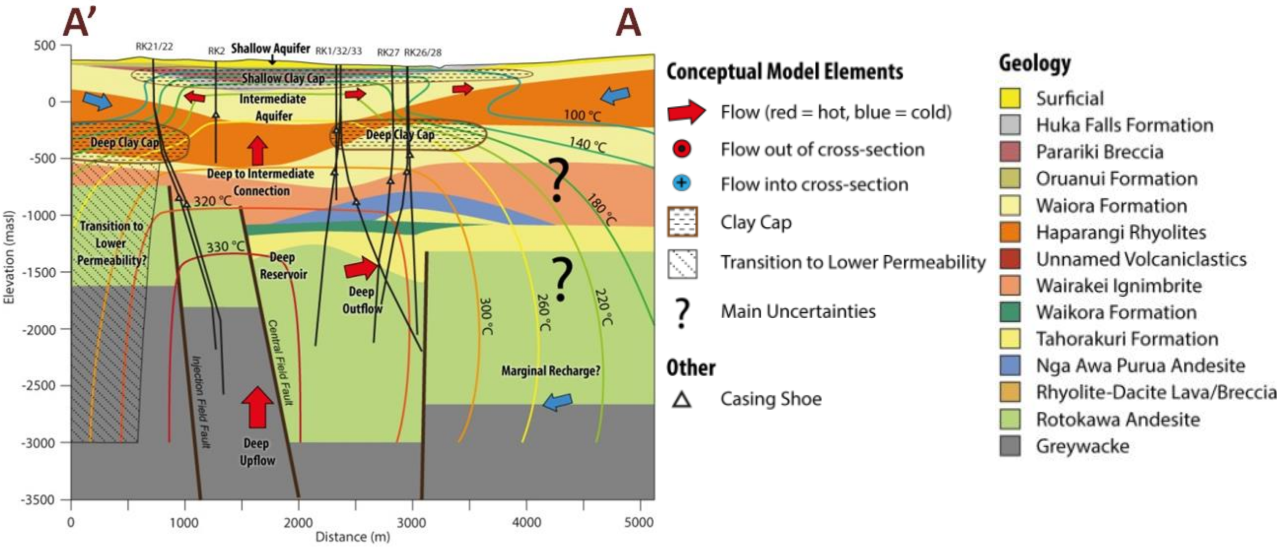

Figure 2: N-S cross section through RK2, RK5 and RK6 with wells RK1, RK3, RK4, RK9, RK13 and RK14. Conceptual fluid flow pathways are indicated by arrows. Sewell et al., 2015a

In the interval of 100 to -450 masl there is an extensive 'intermediate aquifer' where cold groundwater (<100 °C) mixes with upwelling geothermal fluid (>100 ºC) that overlies the entire reservoir. Geothermal fluid from the deep reservoir appears to go up through a connection somewhere between RK1/11/12 and RK2/3/4. This connection is close to the Central Field Fault and therefore this structure could act as a conduit for this fluid.

The reservoir is capped by an impermeable layer with a very similar shape and thickness in all the wells drilled in Rotokawa. This layer starts at -450 masl and extends down to -650 masl. It is slightly deeper in the south where the convective temperature profiles are seen first at -750masl. This offset is clear between the wells on different sides of the Central Field Fault.

All the current active wells in Rotokawa show a convective profile along the reservoir with no sign of reduction of permeability down to the drilled depths. The top of the deep reservoir starts at -500 masl in the northern wells and -750 masl in the southern injectors. This information was obtained from inferred natural state temperature and permeability distribution at shallower reservoir. Micro-earthquakes (MEQ) have been used to constrain the base of the reservoir. MEQs are interpreted to be mostly related to changes in temperature around injection wells. The MEQs do not appear to 'sink' much below the point of injection, with most of the activity disappearing at -4000 masl, which may indicate that vertical permeability, at least in the southern injection area, is generally poor (Sewell *et al*, 2015b).

2.1 The natural state of the reservoir

The pre-development state of the deep reservoir at Rotokawa was liquid dominated with a significant 2-phase region at the top of the reservoir (approx. -500 masl to -1000 masl). Some wells also reach the boiling point within the intermediate aquifer, particularly at the top of the aquifer (approx. 200 masl). This is usually followed by an inversion in temperature due to cooler groundwater flows within the extensive intermediate aquifer.

In the pre-development state, the deep reservoir has an isothermal profile showing a pure liquid section. It is important to note that the natural state temperatures were interpreted from the heating profiles since some wells are connected to the station for production before reaching temperature equilibration with the reservoir. In some cases the actual natural state reservoir temperature was refined a few years later when new information was available.

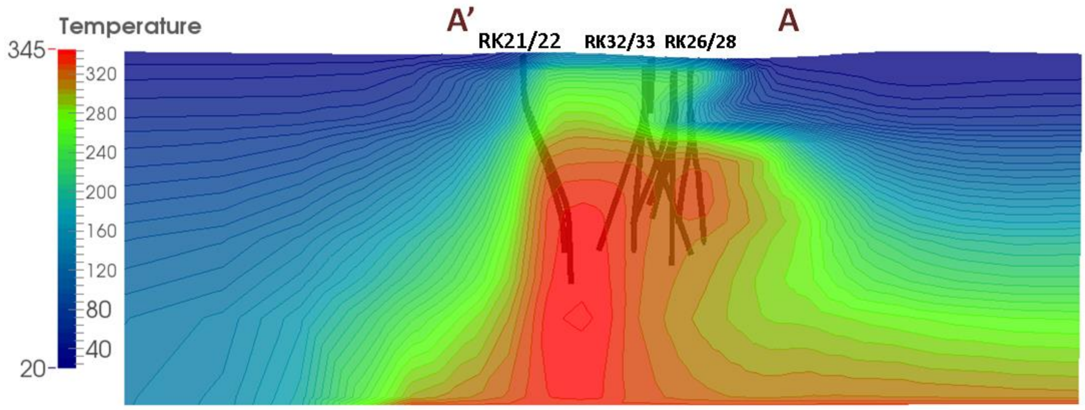

Figure 3: Model of the Natural state temperature in A-A' (see Figure 1)

The maximum measured temperature in the reservoir was observed in the south-western sector of the field with 337 ºC in RK22, which is currently used for NAP brine injection. The deep reservoir temperature decreases from south to north with temperatures below 300 ºC in RK8.

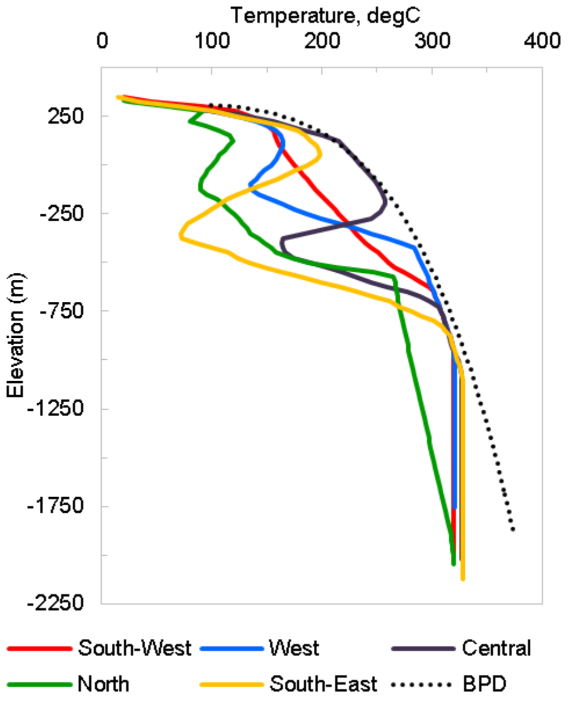

Figure 4: Interpreted natural state temperature in different areas of the Rotokawa reservoir. (BPD = Boiling Point for Depth

The presence of an intermediate aquifer is obvious in all the temperature profiles in the reservoir, except for several wells in the centre and southwest of the field (RK1/11/12 and RK2/3/4). In this area, the upflow from the reservoir overcomes the effect of the colder, cross-flows within the intermediate aquifer.

The pre-production reservoir pressure was interpreted from the measurements of the early deep wells RK4, RK5, RK9, and shallow wells RK1, RK1/X, RK11 and RK12. The deep reservoir pressure is ~10 bar higher pressure than the intermediate aquifer at -750 masl, due to the clay cap. The pressure in the intermediate aquifer is close to the hydrostatic gradient, controlled by the flow of cold water above the clay cap. The deep reservoir has a hydrodynamic gradient equivalent to a column of water with an average temperature of 295 ºC.

3. PRODUCTION HISTORY

Mass extraction from the reservoir started in 1997 from RK5 and RK9 to feed the Rotokawa power plant (RKA) with initial generation of 24 MWe. After a station upgrade in 2006, RK13 and RK14 were also connected to supply RKA resulting in increased generation capacity of 34 MWe. All the initial wells are located in the centre of the reservoir.

Shallow injection was shifted to deeper zones at ~1000-3000 m depth in RK16 and RK18 in 2005. The decision to move to deep, edge-field injection was made in response to increasing intermediate aquifer pressures that developed as a result of the shallower injection. In order to shift deep injection off of the preferred southwest-northeast structural flow axis and therefore minimise injection returns, six new deep injection wells (RK19 – 24) were drilled in the east and southeast of the field from 2007 to 2009. Injection from RKA was moved from RK18 to the new injection area (RK20) in October 2008. From 2008 to 2010 new production wells for the Nga Awa Purua development were drilled (RK25 – 30). Since 2010, three new production wells, RK32, RK33 and RK34 have been drilled to provide make-up production for Nga Awa Purua.

Since the commissioning of NAP in 2010, the production and injection configuration has been fairly stable. The main production section covers an area of 3 km^2 that extends from the northeast to the southwest. The injection area is concentrated in the southeast bank of the field and has a distance of approximately 1 km from the nearest production well.

Most of the production occurs within one kilometre below the clay cap (-1000 masl to -2000 masl) whilst injection is approximately 1 km deeper (-1500 to -3000 masl) allowing the injected fluid to heat up before returning to production, minimizing the thermal impact and providing pressure support.

Figure 5 shows the total take and injection for the Rotokawa field. The take increases by a factor of four after the commissioning of Nga Awa Purua.

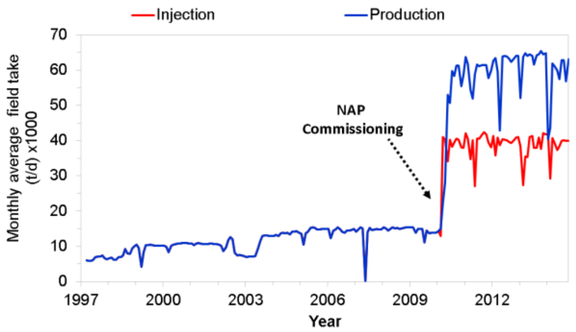

Figure 5: Total take and injection in the Rotokawa field between 1997 and 2015. N.B. prior to NAP, approximately 100% of produced fluid for RKA was injected.

The current extraction is approximately 63,000 t/d, and around 75% of the total take is injected into the reservoir, due to the use of an evaporative cooling tower at NAP.

This, along with the loss of mass due to evaporative cooling at NAP, creates a voidage in the deep reservoir producing the pressure drawdown observed in Figure 7 to Figure 9 in the production area. Approximately 20% of the total injection is placed in the intermediate aquifer.

3.1 Liquid pressure change

The pressure in the deep reservoir after the start-up of NAP has generally followed a progressive stabilization after an initial fast decrease, with only minor changes in the last two years. However, the total pressure drop is very different across the reservoir. This has revealed the existence of compartments in the production area that have variable hydraulic connection to each other and the wider reservoir, and variable magnitude and sources of recharge.

The pressure of the production wells in the western compartment decreased at a rate of 12 bar/yr in the beginning, but this rate later stabilized to 0.5 bar/yr after four years and a total decrease of ~35 bar since production started (Figure 6).

The production wells in the centre-east edge of the reservoir have shown a total pressure drop of 10 to 20 bar, significantly less than most other wells. This is generally consistent with the tracer results summarized in Addison *et al*, (2015) and agrees with the concept of pressure support from the injection area to this region.

The most significant case of pressure support is the well RK29 with a capacity of more than 600 t/h. In this production well the pressure has decreased only 5 bar compared to the natural state pressure. This well presents the highest percentage of tracer returns (~9% of RK24 injection in RK29 production) and it is also one of the closest to the injection area.

During the last year, the liquid level in most production wells has not dropped significantly while shut-in well head pressures have shown a decrease of around 25 bar in some wells, interpreted as a decrease of the steam cap pressure that correlates with the stabilization of the liquid pressure (see Figure 10).

Figure 7, 8 and 9, show the pressure contours in 2010, 2012 and 2015 respectively, created from static Pressure, Temperature and Spinner (PTS) surveys or downhole pressure tubing, clearly showing the concept of production compartments in the west, east and centre, highlighted inside the dotted lines.

Figure 6 shows the variation of the pressure over time in the main production areas. The centre of the field shows some pressure decrease before NAP started in 2010 because of the central wells that supply the Rotokawa power plant started producing in in 1997.

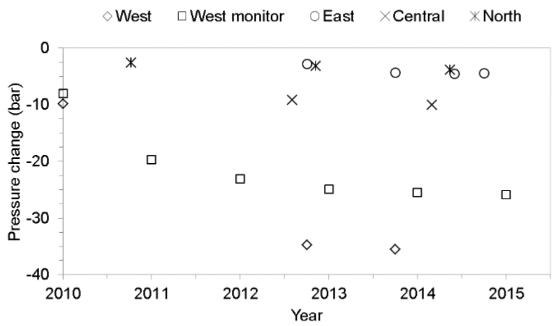

Figure 6: Downhole pressure evolution in different production areas

The pressure in the injection area is monitored with downhole pressure tubing in an unused well plus regular static PTS surveys in the current injectors. The results indicate that the pressure to the south of Central Field Fault is very stable, with a net increase of less than 1 bar.

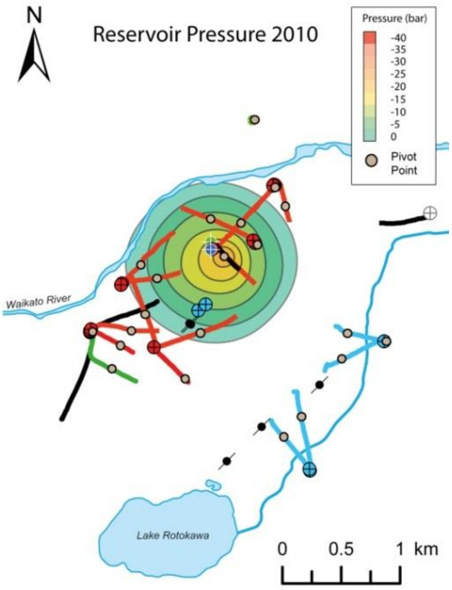

Figure 7: Reservoir pressure change 1997-2010

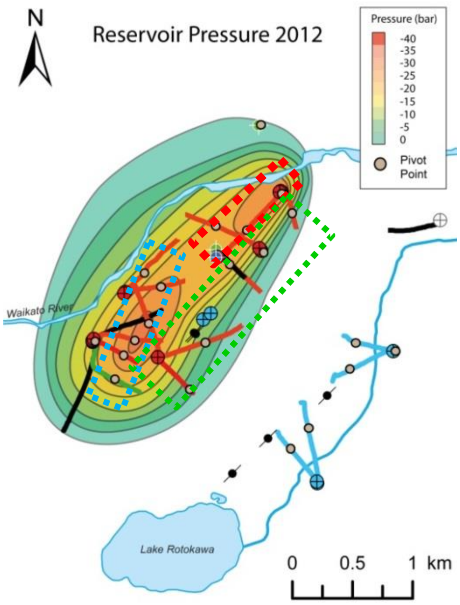

Figure 8: Reservoir pressure change 1997-2012

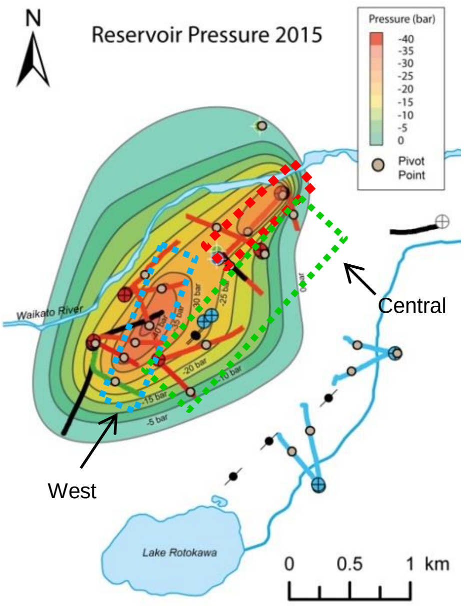

Figure 9: Reservoir pressure change 1997-2015

3.2 Vapour pressure change

The wells in the western compartment have developed a steam dominated region due to the decrease in the liquid level from -600 masl to -1000 masl that can be observed in the static and flowing temperature profiles. Some wells in the east have also created a localized steam section; mostly due to low permeability.

The pressure in the steam dominated section is estimated by monitoring the shut-in pressure in the well head and calculating the gradient to the first feed zone assuming a value for the enthalpy (see Figure 10).

The western area has a faster drop due to a higher concentration of feed zones in the shallower depths and a production of around 1000 t/h in the same compartment.

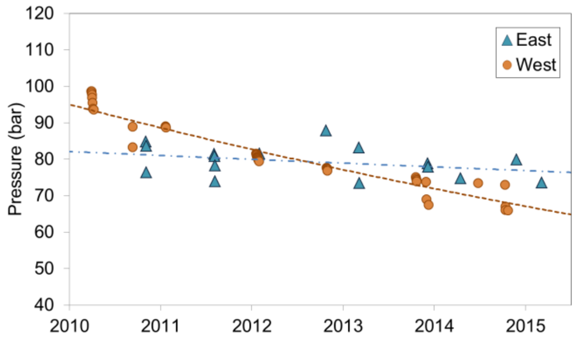

Figure 10: Shut in well head pressure evolution in the east and the west compartment

3.3 Reservoir temperature

The changes in the reservoir temperature are monitored through direct downhole measurements like PTS or indirectly with the use of geothermometers. The silica concentration in the fluid produced from a reservoir can be correlated with the fluid temperature using the solubility of quartz as a function of temperature. At high temperatures found in a hydrothermal reservoir the solubility of silica is controlled by quartz, a crystalline form of silica.

Flowing PTS is the main source of information used to calculate the temperature at each individual feed zone. In the cases in which the state of the fluid is fully liquid, the temperature of the feed zone is a direct function of its enthalpy. In the cases where the fluid temperature is at saturation (i.e. boiling), an estimate on the fluid saturation is needed to determine the fluid enthalpy.

A study of the northwest section of the reservoir during 2014, has identified cooler inversions of temperature at similar depths (-1400 masl) in RK13, RK17, RK18L2, RK27, RK26, RK28 and RK32. Some of these features were identified in the initial logs but were considered to be related to cooling during drilling. With a larger number of surveys under stable conditions, some of these inversions appear to be permanent and may indicate lateral recharge that is likely one of the reasons for faster decline in enthalpy in the western section (see Figure 11). Temperature changes measured so far are relatively minor (10 ºC-20 ºC) at around -1400 masl.

On the other side of the reservoir, it is interesting that even wells that have shown injection returns (from tracer test and chloride measurements) do not indicate cooling, maintaining measured deep liquid temperatures above 330 ºC.

The largest temperature changes are found in the south area around the injection wells, where the current temperature is 100-200 ºC lower than the natural state temperature.

3.4 Reservoir enthalpy

The production enthalpy is determined by TFT surveys carried out approximately every two months in all of the production wells.

The mass weighted average enthalpy in the different compartments of the reservoir is shown in the Figure 11. After an initial decline in liquid level in 2011, a steam cap was formed in some of the wells in the western compartment. In wells like RK25 and RK30 the pressure drawdown was localized due to the lower near-wellbore permeability, generating steam-dominated sections at -700 masl.

The discharge enthalpy in Rotokawa depends on the contribution of the feed zones and the evolution of the liquid level. Most of the wells have feed zones in both liquid- and steam-dominated sections. The differences in reservoir pressure drop, due to the compartmentalization of the reservoir, also produce a variation in enthalpy across the reservoir. The wells in the central region have feed zones distributed along the wellbore in the reservoir section, thus the production of liquid and steam is more balanced. This fact, combined with pressure support from injection, led to a stable enthalpy in this region during the last five years.

Some of the shallowest wells in the western compartment (e.g. RK17) initially reached 1800 kJ/kg before decreasing in enthalpy due to steam cap pressure drawdown. This decrease in steam pressure caused a rise in liquid level. In the same area, RK27 has been the most stable well with most of the production (>90%) entering the well at deeper depths, avoiding the effects of the change in liquid level. Intrusions of colder fluid at -1400 masl in this area may also contribute to the slightly faster decline compared to other areas.

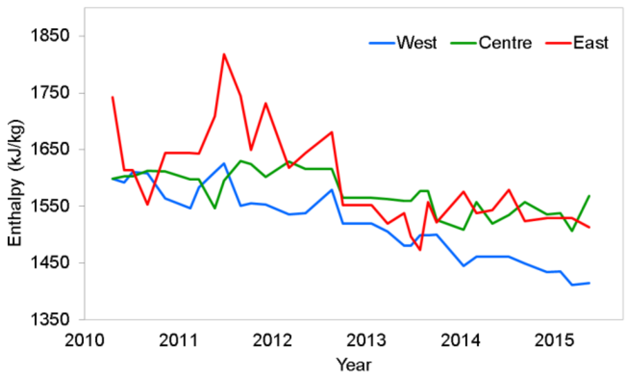

Figure 11: Weighted average enthalpy from TFT measurements in west, centre and east production wells

4. RESERVOIR MANAGEMENT

4.1 Modelling and simulation

Modelling of the reservoir and well performance is a priority for better understanding the reservoir response to various production and injection strategies.

Five numerical models of the Rotokawa reservoir have been built since 1992 and described, in Hernandez *et al*, 2015. In 2011, 18 months after the increase in production associated with Nga Awa Purua, Mighty River Power (MRP) in collaboration with IRL developed a numerical model in TOUGH2 (Burnell, 2011). This model was coupled with lookup tables generated from a wellbore simulator for all the current and future wells used for production. A model that correlates the production enthalpy with steam and brine flow rates is used to simulate the two power plants.

The monitoring strategy is designed to provide data to refine the numerical model through a better understanding of key parameters like permeability distribution, stratigraphy and structure, temperature, pressure, feedzones and fluid characteristics. These data are used for analysis and forecast of the resource under production and injection. The modelling approach adopted by MRP usually consists of building a process/sector model(s) that covers a smaller reservoir area/volume than the full-field model with a coarser spatial discretization. These process models have the advantage of faster running times for testing theories about compartments, recharge and/or production strategy. The process/sector models are also used to test the sensitivity of the output to variation in the parameters that could be used in the full-field model.

The numerical model has been run in a large number of scenarios. The results show that the current production and injection strategy has a gradual decrease of production enthalpy of 100 to 200 kJ/kg, in the next 50 years (see Figure 12). The enthalpy decline in the model is due to a combination of injection returns and downflow from the intermediate aquifer with a slight decrease of the steam dominated region in the west. The total pressure drawdown reaches 40 to 50 bar in some areas of the deep reservoir. The modelling shows that the current injection strategy is sustainable in the long-term, providing some pressure support to the production area whilst minimising reservoir cooling and enthalpy decline.

The same scenarios have been used to test the effects of deep reservoir production on the surface thermal features, making use of the capability to couple the wellbore to reservoir model. The results show negligible variations, due to the buffering effect that the clay cap has in the transmission of the pressure. The main effects are located near the connection between the deep reservoir and the intermediate aquifer, where the model shows an additional 4 bar drop in the next 50 years.

For short-term (5 year) planning a decision analysis model was built using the enthalpy and productivity change from the numerical model with power plant performance and financial modelling. This allows the planning of drilling campaigns and alignment with the company strategy once the need for new wells are identified with a numerical model.

During the last five years Mighty River Power has built a modelling team to support an in-house model development and scenario simulation. The current efforts are focused on transferring the numerical model to a new in-house-built software. This will include coupling to the wellbore model Paiwera (Franz, 2015) and to pipeline and power plant "surface" models.

4.2 Injection management

During the first year after NAP was commissioned brine was injected in RK21 and RK22. During this time a change in the pressure trend in the monitoring well RK18L2 (which is in the proximity of western compartment producers) indicated a potential strong connection between these two areas and it was decided to move the injection to RK24 on the southeast side of the reservoir. Currently, about a 65% of the total take is injected in the deep reservoir while the rest of the injection is injected into the intermediate aquifer.

During the planning for the NAP development, the return of injection to production was identified as one of the greatest risks to production enthalpy due to the relatively small distance between the production and the injection wells. For this reason, five tracer tests have been conducted since 1997, using naphthalene sulphonates and Iodine-125. Injection returns from RK24 have been detected in RK29, RK14, RK5, RK30, RK25 and RK33 (Addison *et al*, 2015). These wells are in the east-centre part of the reservoir and correspond to wells with higher pressure support. Tracer return profiles show that the injection fluid has a relatively long travel-time to production (~60 days) and that ~12% of the injected fluid is returned to production wells over a one year time frame. This accounts for the fact that there is no sign of cooling to-date from injection and highlights the role of the Central Field Fault in slowing down injection fluid return to the production wells (Sewell et al., 2015b).

Due to known returns based on tracer test and the consequences that cooling would have in the production area, the monitoring of the flowing temperature of the central wells is a priority, with regular PTS and TFT surveys to monitor the trend of the chemical indicators and the flowing temperature.

Different injection strategies and the impact on production enthalpy have been also tested with the reservoir numerical model. Figure 12 displays the results of the simulation showing how the connection between RK21 and the production area could impact the enthalpy compared to the injection in the southeast. The impact was not considered significant and part of the injection was moved during 2015 to RK22.

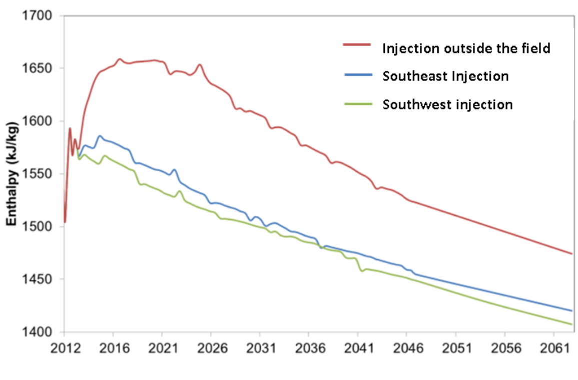

Figure 12: Simulation of the production enthalpy with different injection strategies

Between 2010 and 2012, the capacity of the largest injector increased to 200t/h/bar, likely due to the change in temperature in the rock when injecting a fluid of ~130 ºC into rock at more than 300 ºC.

Since 2012 the injection capacity has reduced to the original value before stimulation. The potential causes are:

- Increase of reservoir pressure.
- Change of the temperature of the fluid injected.
- Decrease of permeability and porosity due to deposition of silica and anhydrite in the reservoir.
- Increase in casing roughness due to deposition, most likely to be silica.

The temperature of the fluid has remained constant and the reservoir pressure in the area is constantly monitored and has not shown a significant change.

Nga Awa Purua injects some of the highest silica concentration fluids in the world, approximately 400ppm above produced reservoir fluids. The power plant makes use of sulfuric acid for silica management; however no sulfate returns to production are seen indicating anhydrite formation within the reservoir. A complete review of the brine silica management is given in Addison *et al*. 2015. Go-devil surveys have not encountered any blockage along the casing, so the most likely cause of the decline in injection capacity is deposition in the near wellbore formation or in the reservoir of silica.

Downhole pressure capillary tubing has been installed in all injection wells providing data to allow continuous monitoring of the liquid level and injectivity index. There is also a plan to carry out two transient tests and two injection PTS surveys in the next year to identify the contribution of the feedzones, skin and average permeability-thickness.

In parallel, a geochemical numerical model was developed in TOUGHREACT to calibrate some of the parameters that take place in the chemical reaction. The results are shown in Buscarlet *et al*, 2014. The aim of this model is to understand the silica deposition process in the Rotokawa reservoir and design the most appropriate operation to recover injection capacity. The model showed that a slight improvement can be obtained by injecting condensate, but the process of scaling is generally not reversible and will lead to major injection capacity loss for brine injectors.

4.3 Enthalpy management

An enthalpy management strategy is designed to supply fuel to both power plants within the optimum range and anticipate potential changes that may impact the generation. The monitoring plan to support this strategy is designed to track the flowing temperature in the most representative wells of each reservoir compartment at least once a year.

The rest of the wells are surveyed once every 2 or 3 years unless any significant change occurs. Recently a permanent stinger (downhole tool guide) has been installed in all the wells. In the past if a flowing survey was required, the well had to be shut during the installation of the stinger, decreasing generation. Permanent stingers facilitate access to the well at any time without requiring shutting the well. The surveys can now be aligned to create a snapshot of the flowing temperature of the wells at regular time periods.

In Rotokawa the pressure decrease has induced recharge from marginal fluids with, in some cases, lower temperature than the initial fluid in the pre-production state as indicated by temperature inversions. In addition, the pressure decline in the steam-dominated region combined with low temperatures above the clay cap prevent the creation of a high pressure steam cap, leading to a decrease in enthalpy in the western region.

In areas with a decrease in steam pressure, the wells with deep feed zones in the liquid are prioritized. This helps to lower the liquid level, and as a results it would induce more boiling and maintain the pressure of the steam-dominated zone. The production wells with deeper liquid feed zones produce lower enthalpy, but in return deeper extraction would provide better recharge mechanism to the steam cap and preserving the steam cap pressure for a longer period of time.

The production from central wells with more pressure support and no evidence of cooling is maximized, even though this would require more resources to monitor these wells to anticipate any potential changes.

In addition, modelling the behaviours of boiling liquid region (Figure 13) has helped to optimize infield drilling program in an effort to manage the steam cap and the liquid level in the reservoir.

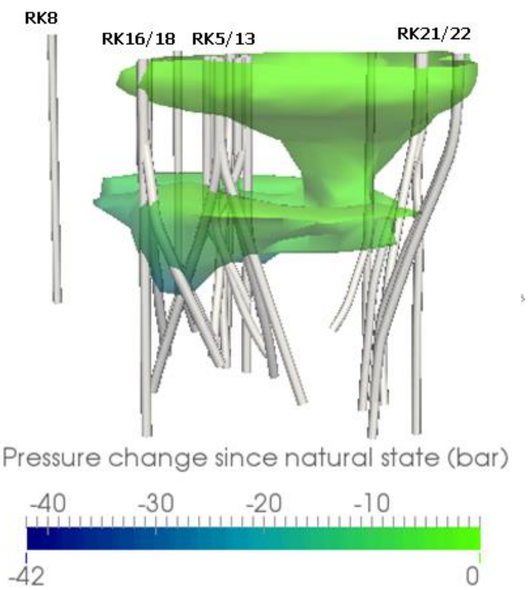

Figure 13: Extension of the 20% steam mass fraction coloured by pressure change

4.4 Intermediate aquifer: downflow

MT surveys identified a weakening of the clay cap in the area where mixing of an upflow from the deep reservoir with the intermediate aquifer exists. Increasing sulphate in some production wells and studies of sulphur isotopes suggests permeable conduits may allow shallow, sulphate-rich, cooler fluids to flow into the reservoir. The main leak is located somewhere around the centre of the reservoir between RK11/1/12 and RK2/3/4. Those wells were found initially at saturation conditions and an upflow of two-phase fluid was interpreted from early exploration data.

A small amount of around 300t/h is still injected into the intermediate aquifer between RK9, RK11 and RK12. The monitoring of the pressure change in the shallow and the intermediate aquifer is carried out with downhole monitoring tubing located at RK15 (150masl) and RK11 (-200 masl). To-date there has not been a significant change in pressure that might indicate a downflow. The reservoir numerical model indicates that a pressure drawdown of more than 35 bar in the deep reservoir is required to reverse the fluid upflow, but in the centre of the reservoir the pressure drawdown is less than 20 bar.

It is possible that a downflow exists in the northern area while the upflow continues in the south. However the temperature profiles in the production area have not yet shown indication of a significant downflow considering observed temperature changes in the western production wells have been 10-30 °C. Therefore, if downflow is occurring, it is likely small amounts of fluid with a relatively long travel time before arriving to production.

5. CONCLUSIONS

During the first five years of operation after the commissioning of Nga Awa Purua, there have been numerous challenges to maintain the production enthalpy inside the optimum range of operation.

The flowing PTS surveys have revealed interesting temperature profiles that correlate with geological structures and geochemical indicators, showing the value of multidisciplinary and coordinated work between geologists, geochemists and reservoir engineers.

Feedzones identifications, combined with reservoir modelling has allowed management of the liquid level to maintain production enthalpy within optimum levels. Availability of pipeline interconnections and spare capacity for production has also been important to balance the pressure between liquid- and steam-dominated regions (i.e. reducing the take from shallow western wells and increasing from deeper central wells).

A proper management strategy requires an integrated model that considers the long term implications of different strategies at all levels: reservoir sustainability, pipeline layout, power plant optimization and financial forecast. For this reason the current efforts within MRP are oriented to couple the reservoir and wellbore model with the surface equipment using in-house built software.

6. ACKNOWLEDGMENTS

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