Proceedings World Geothermal Congress 2020+1
Reykjavik, Iceland, April - October 2021

Using the Pressure While Drilling Data to Inform Drilling Decisions in the Kawerau and Rotokawa Geothermal Fields, NZ

Morgane Le Brun[1], Lutfhie Azwar[2], Andrew Marsh[3],

1. Antea Group, France
2. Star Energy, Indonesia
3. Mercury NZ Ltd, 283 Vaughan Rd, Rotorua , New Zealand

Morgane.Le.Brun.44@gmail.com

Keywords: Injectivity, Pressure While Drilling, Feedzones, Capacity modelling

ABSTRACT

During the 2016-2017 drilling campaign, one injection well and three production wells were completed at both Kawerau (KA55 and KA56) and Rotokawa (RK35 and RK36) geothermal fields in New Zealand. These four wells were drilled in high temperature reservoirs to ensure adequate injection capacity and fluid supply to the Kawerau power plant and adequate fluid supply to the Nga Awa Purua power plant generating about 100 MWe and 138 MWe respectively.

The losses and drilling breaks observed while drilling were good indicators to identify qualitatively the feedzones of the wells. However, these types of information were not sufficient to quantify the strength of the feedzones (i.e their Injectivity Index) and translate it into well capacity, especially when total loss conditions were encountered. This quantification is usually done with a completion test which implies to stop drilling and pull-out the drilling tools to run a PTS tool. Once the data or gathered and analysed, the decisions to TD the well or start a sidetrack can be taken. This waiting time on data and the cost associated with it can be reduced using a tool measuring the pressure in the well while drilling.

A methodology was derived during this drilling campaign to provide an estimate of the Injectivity Index (II) of the wells and the wells capacity in real-time while drilling. This methodology used the PWD data (annular and pipe pressure) obtained from pressure sensors located in a sub in the drillstring close to the drill bit, for each depth drilled into the reservoir section of these wells. The computation of the II and the wells capacity while drilling enabled the TD decision to be based on more quantitative information and with less waiting time on data.

This methodology followed a two-steps process to translate the PWD data first into injectivity information then into well capacity information. The first step calculated the Injectivity Index (II) of the well per depth drilled using the annular pressure of the PWD tool, the loss rate into the well and the reservoir pressure. This II depth series gave information on the depth of the feedzones and the well total II of the well. This approach was cross-checked with a second approach using the PWD data recorded at two different loss rates.

The second step converted the II data into well capacity under operational conditions using an in-house wellbore modelling tool. For the injection well, the change in mobility of the fluid between the drilling conditions and the operational conditions was taken into account by calculating the formation Injectivity Index called II'. The capacity of the injection well was then simulated for the hot brine conditions at the maximum Well Head Pressure achievable by the station. For the production well, the II was translated into a Productivity Index (PI) to take into account the reduction in formation permeability due to the heating of the formation and the change in fluid phase under operational conditions. The capacity of the production well was then simulated at the minimum Well Head Pressure achievable by the well to provide the fluid at the appropriate separation pressure for the station.

This methodology thus provided two results, a continuous II monitoring and a well capacity range while drilling. These results were very valuable information for determining well success and for decision making during drilling. They informed decisions to drill deeper based on risk of interference, on permeability evolution in the reservoir, they informed decisions to side-track a well and also to TD the well as the targeted II and well capacity were achieved.

The comparison of the results of this methodology with post drilling tests shows these results are conservative whilst giving reasonable estimates of the flowrates obtained once these wells are connected to the stations. Further work is needed to improve this methodology for the future make-up wells. One area of improvement is the underestimation of the II with this methodology compared to the completion test II, the other area is the calculation of losses under partial losses conditions.

This paper describes the different elements of the methodology used to interpret the PWD data into II evolution and well capacity. It describes how these two types of information were used to add value to the drilling decisions and how these results compare with post-drilling tests. It highlights the limitations in the usage of this PWD methodology to inform the continuation of drilling during the drilling operation and provide suggestions to improve the quality of information obtained with this methodology.

1. INTRODUCTION

In 2016 and 2017, a drilling campaign was organized to drill one injection well and three production wells in two geothermal fields in New Zealand, the Kawerau and Rotokawa geothermal fields (Figure 1-A). These fields are high enthalpy geothermal fields supporting the generation of about 100 MWe and 180 MWe respectively.

This drilling campaign started with a depth target and an injection/production capacity target for each well. A regular update on the capacity of the well once drilling in the reservoir section was one key parameter to decide when to stop drilling and complete the well. This stage of reaching the Total Depth of the well and running the last liner is summarized with the term "calling TD" in this paper.

One standard method in the geothermal industry to update the capacity of a well during the drilling stage is to perform stage tests (Grant and Bixley, 2011). These tests require pulling out all the drilling tools from the wellbore and performing a three-stage flow test while using a Pressure Temperature Spinner (PTS) tool to record the evolution of the pressure inside the wellbore. For this drilling campaign, this stage-test option was kept as a back-up option as it was increasing the drilling/stand-by time for the rig and was giving only discrete information on the capacity of the well at that particular depth.

Another methodology was used to update the well capacity more regularly while drilling and thus make better decisions about when calling TD. This methodology required to have access to regular measurement of the pressure in the wellbore close to the drill bit along with regular estimates of the losses in the wellbore. The losses could be calculated using the recorded flowrates in and out of the well and the mudlogger data. For the pressure data, a sub installed in the drillstring was already used by the drilling team to give real time information (every 30 seconds) on the behavior of the well in terms of stability (i.e accumulation of cuttings around the drill string). This tool was called a Pressure While Drilling tool (PWD) and was installed in the Bottom Hole Assembly (BHA), circa 20m above the drill bit, when drilling into the reservoir section (Figure 1-B&C). This tool measured the annular and the pipe pressure using sensors within the BHA. These two parameters along with other information from the well (Torque, Rate of Penetration, length of open hole) were used by the drilling team to inform the timing of wiper trips, sweeps of LCM (Loss Control Material) which limited additional pull out of hole and thus made the drilling of the well more efficient.

Using these real time pressure data from the PWD tool, the reservoir engineering team developed a methodology to monitor continuously the Injectivity Index (II) of the well and calculate the well capacity for each depth drilled. This PWD methodology provided more regular information about the well capacity compare to the stage test methodology. It also provided more quantitative information than the losses and drilling breaks observed while drilling to characterize the permeability found by the well. This helped the team assess the status of the well compared to the success targets and make quicker decisions based on more data from the hole.

The geological setting of the wells and the type of expected permeability in the reservoirs are described in section 2 of this paper, the PWD methodology is described in section 3, the results obtained using this methodology are described in section 4, along with discussions on the reliability of the methodology.

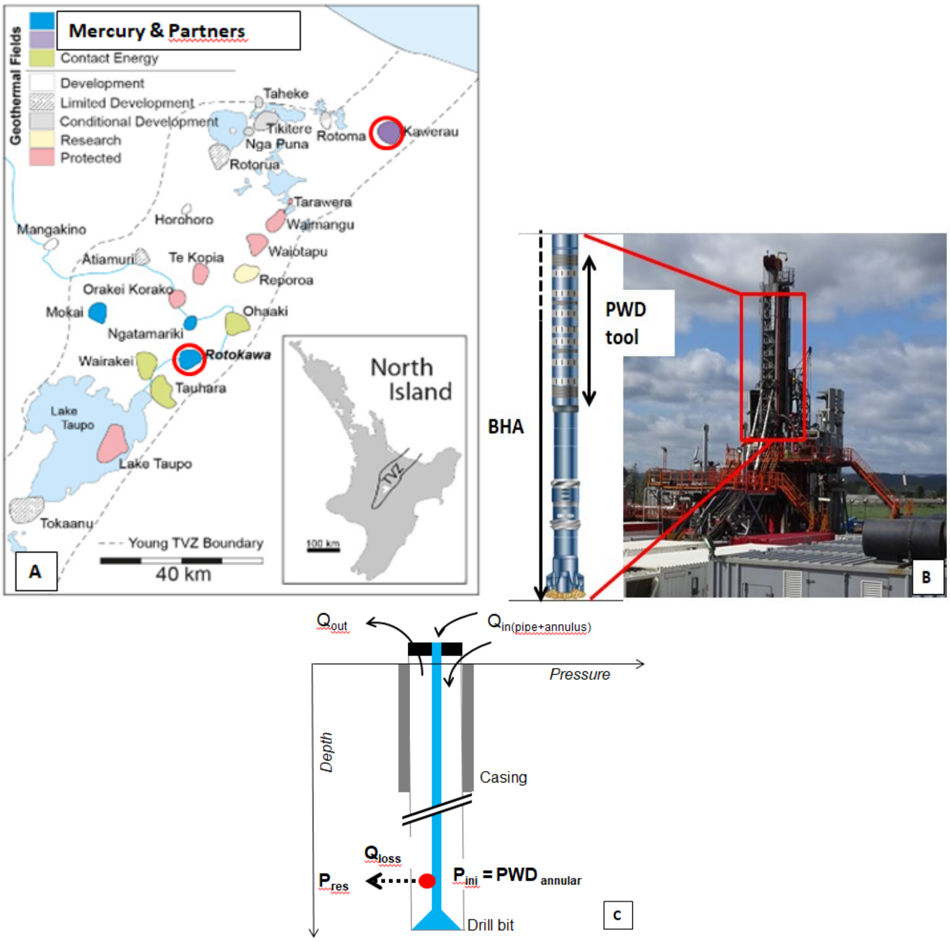

Figure 1: A) Location of Kawerau and Rotokawa geothermal fields in Taupo Volcanic Zone (TVZ) of New Zealand. B) Setting of the PWD tool within the Bottom Hole Assembly while drilling the reservoir section of the wells. C) Pressure and flowrate elements used for the II calculation

2. GEOLOGICAL SETTING OF THE RESERVOIRS

As the Injectivity Index (II) of the well is linked to the geology and type of permeability of the reservoir, this section highlights the main geological features observed in the Kawerau and Rotokawa reservoirs. Elements about the flow circulation within the reservoir and change of fluid phase within the reservoirs are also described as they will influence the assumptions made on the reservoir parameters and the results obtained with wellbore modelling to translate the II into a well capacity.

2.1 An active tectonic setting

The reservoirs where the PWD methodology was derived are high temperature geothermal fields located in an extensional zone in the Central North Island called the Taupo Volcanic Zone (TVZ). This TVZ concentrates 25 geothermal localities with 7 geothermal high enthalpy geothermal fields providing electricity to the country. This active rifting is linked to the oblique subduction of the Pacific plate under the North Island of New-Zealand (Rowland and Simmons, 2012) as illustrated on Figure 2-A. This rifting resulted in the formation of a graben structure about 2Ma ago (McNamara et al, 2015) displaying a faulted metamorphic basement composed of Greywacke infilled with quaternary age volcanic formation and sediments as illustrated on Figure 2-B.

The Rotokawa and Kawerau reservoirs are located in this normal fault environment and display fractures that follow the overall NE-SW structural trend of the TVZ (Figure 2-C). They are associated with andesite and rhyolite volcanism and a high heat flux that leads to temperatures up to 330ºC in the Rotokawa geothermal field (Figure 2-B). This hot fluid rises to the surface by buoyancy and follows the higher permeability pathways in the formation created by formation heterogeneities and the natural fracture network inherited from the active tectonic setting described above. As this fluid rises towards the surface, it boils and can create a zone dominated by the vapour phase if the vertical permeability is sufficient (Grant and Bixley, 2011). This boiling changes the viscosity and mobility of the fluid, which in turn decreases the apparent productivity index (PI) of the well which is one key parameters entered in the wellbore models to calculate the well capacity.

The large faults present in the field can act as preferential pathway but also as barriers for the fluid flow. Indeed, for the Rotokawa field, the Central Field fault channels the reinjection fluid in a specific part of production area and compartments cause different pressure drawdown in wells located close to each other. These behaviours are illustrated on Figure 2-C where a difference of 35 bars was observed between production wells located less than 100m apart (pink circle) and the fluid reinjected in the East of the field is only detected in the Northern wells production wells (Addison et al., 2017; Mountain and Winick, 2012).

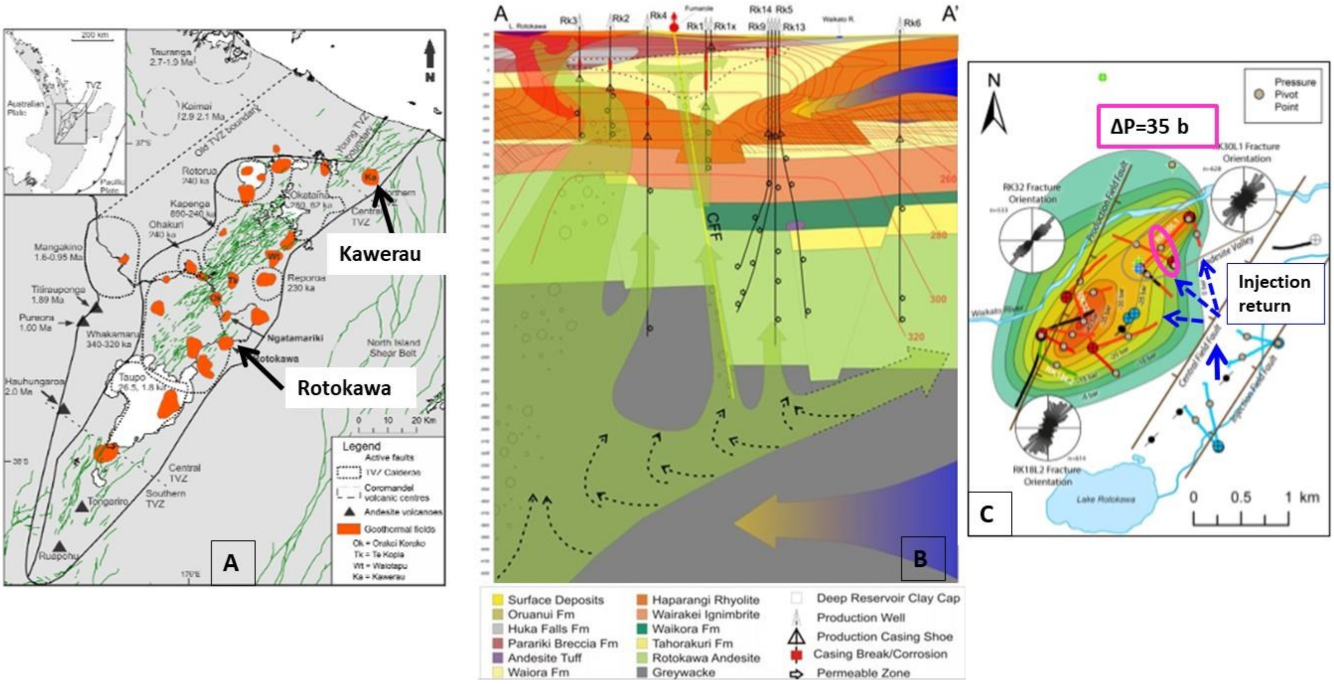

Figure 2: A) The structural setting of the TVZ and the different geothermal fields (from Eastwood, 2013). B) N-S cross-section in the Rotokawa reservoir showing the Greywacke basement and the volcanic/sediment formations along with the conceptual fluid flow pathways (Winnick et al, 2009). C) Comparison of pressure evolution, major geological structure and fracture orientation in the wells for the Rotokawa field (Sewell et al, 2015)

2.3 Formation permeability and feedzones

Feedzones correspond to zones of enhanced permeability in the reservoir that channel preferentially the reservoir fluid into the well. These feedzones occur mainly in the Andesite and Greywacke formations in the Rotokawa field (Figure 2-B), in the volcaniclastic and the Greywacke basement in the Kawerau reservoir. Permeability in volcaniclastic formation is typically controlled by a mixture of fracture and matrix (Grant and Bixley, 2011), with the fracture component generally increasing with depth. Within the metamorphic greywacke basement and the andesite, fractures and micro-fractures create a fracture network that enables the hot fluid to percolate from the reservoir into the wells. By comparing the depth of the feedzones and the geology, two main categories of preferential fluid pathways can be identified such as the lithology heterogeneity and the fractures. Thus, feedzones in the first category can be found at the contact between two different lithologies or correspond to heterogeneities within the volcanic formations (breccia, altérations). Feedzones in the second category can be found where fractures intersect the wellbore and are connected to the wider reservoir via a fracture network.

Fractures generally represent a small volume of the reservoir but contribute to a high percentage of the flowrate entering a wellbore. A study by Wallis et al. in 2015 estimated the fracture volume in two reservoirs at less then 5% of the reservoir volume intersected by the wells using core analysis, well log images and reservoir modelling results (Figure 4 and Figure 3-B). Well image logs such as accoustic logs (Figure 3-A) help identify fractures opened to flow when combined with flow logs such as Pressure Temperature Spinner logs during completion tests (Massiot et al, 2017). Accoustic logs where not available for this drilling campaign in 2016-2017 so the feedzones were characterised using information from the PWD tool, the drilling breaks, drilling fluid losses and the PTS logs done after the completion of drilling.

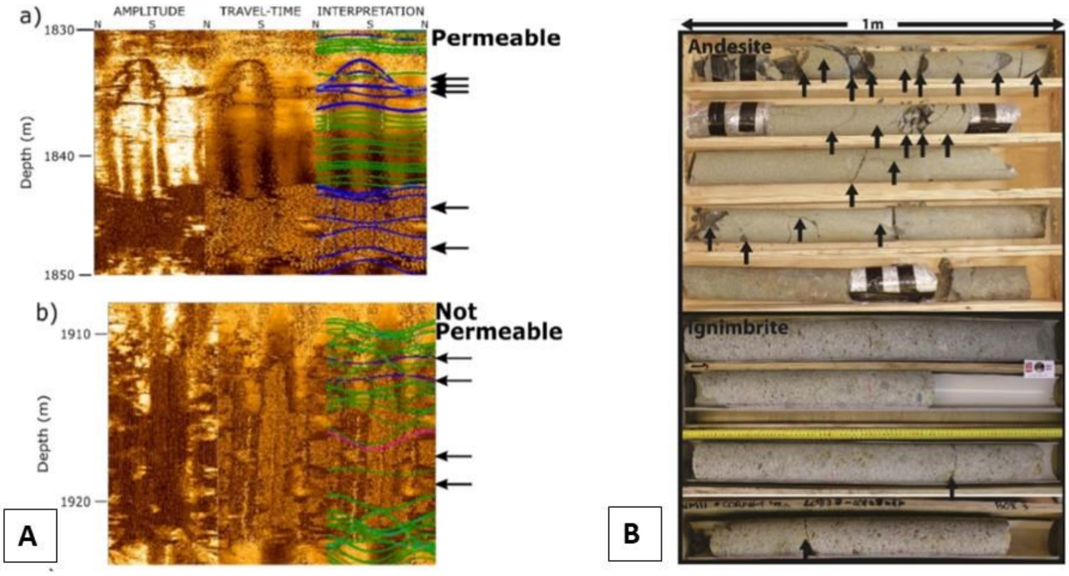

Figure 3: Permeability on AFIT (Massiot et al, 2017); B) Natural fractures in two cores retrieved from reservoir depths within andesite (upper core) and ignimbrite (lower core) (Wallis et al, 2015).

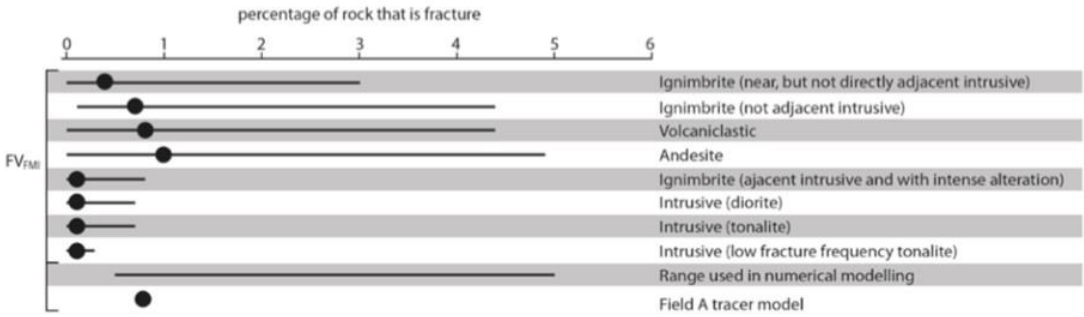

Figure 4: Fracture volume calculated from FMI logs recorded at reservoir depth in different type of rocks (Wallis et al., 2015)

3. METHODOLOGY USED TO INTERPRET THE PWD DATA INTO WELL CAPACITY

Increase losses of fluid while drilling is a good indicator that the Injectivity Index of the well is getting higher and thus the production capability of the well is improving. This qualitative assessment of the permeability while drilling is utilized in most of the deep geothermal project. The PWD methodology provides a more quantitative assessment of the permeability to inform the drilling of the well. This quantitative assessment is composed of two types of information: the injectivity of the well as per depth drilled and the corresponding capacity of the well for the geothermal station at surface.

The injectivity of the well was defined as the ability of the well to accept the cold water used while drilling the reservoir section and was quantified using the Injectivity Index (II) reported in t/h/bar. This II was calculated at each depth drilled, which enabled the reservoir engineer team to build depth series of the II and thus highlight the depths at which new feedzones were encountered, even under total loss conditions. The calculation of this II is described in section 3.2 as the first step of the methodology leading to the next step of calculating the capacity of the well.

The capacity of the wells was defined differently for the production and injection wells. For the production wells, the capacity of the well was defined as the flowrate and enthalpy expected from the well at the lowest WHP achievable with the well connected to the station. For the injection well, it was defined as the flowrate accepted by the well at the highest WHP achievable with the well connected to the station. The calculation of the capacity of the wells required the use of wellbore modelling techniques and assumptions about the reservoir conditions and the well completion. Several scenarios for the reservoir conditions were tested to provide a range of capacity values and the most likely value that can be expected (section 3.3). Before describing the two steps of the PWD methodology, the key parameters used in these steps are described in section 3.1.

3.1 Computation of the key parameters used in the methodology

Three parameters are the building blocks of the methodology and are illustrated on Figure 1-C. They are the losses in the well (Q_{losses}), the injection pressure in the wellbore (P_{inj}) and the reservoir pressure (P_{res}).

3.1.1 Computation of the loss rates at each depth (Q_{losses}) with the MWD data

The losses are computed every hour by the mudloggers on site, using the evolution of the level of fluid in the mud tanks over a certain time period. These data are accurate but sparse and harder to correlate to the 30s PWD data. They were used as a reference to calibrate the losses obtained every 30 seconds as part of the Measurements While Drilling (MWD) which can directly be correlated to the PWD data. These losses computed with the MWD data are calculated as the difference between the total flow in the well and the flow out of the well as illustrated on Figure 1, C:

$$Q_{losses} = Q_{in} - Q_{out} \tag{1}$$

Where Q_{losses}, Q_{in}, Q_{out} (t/h) are the rate of fluid lost in the hole (t/h), the rate of fluid going into the hole (inside the drill pipe and the annulus) in t/h, the rate of fluid coming out of the hole (t/h), respectively.

The rate of fluid going into the hole was obtained from the strokes of the pumps feeding the different lines going to the drill pipe and the annulus. The rate of flow coming out was estimated with a paddle sensor whose relationship with the flowrate was calibrated with mudlogger flows. These two measurements were communicated as a time series along with other drilling parameters by the drilling team. The accuracy of the calculated losses is linked to the accuracy of the quantification of the flowrates. The quantification of the flow out of the well was less accurate than the flow going into the well as it relied on the calibration of the paddle sensor with the mudlogger losses. This calibration was not always done for each well, thus the calculated MWD losses were generally too high compare to the mudlogger losses. Once the losses were total, the loss rate was better constrained. An example of this comparison is shown on Figure 5-A, with the mudlogger losses in red and the MWD losses in orange.

The influence of the loss rate on the resulting II is shown on (Figure 5-B). Using the PWD data and the MWD losses, the II (called "PWD II") seems higher in the upper portion of the well than the II calculated with the mudlogger losses (called "mudlogger II").The uncertainty linked to the losses calculation under partial losses will be described in the section 4.3 of this paper.

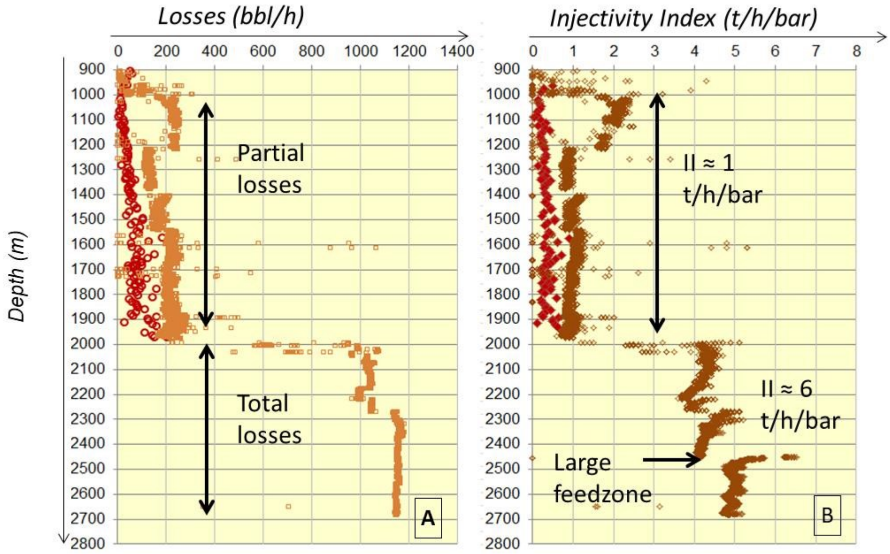

Figure 5: A) Losses for the well RK36 with partial losses down to 2000m and total losses dominating below 2000m. B) Injectivity Index of the well RK36 with spikes values indicating feedzones.

3.1.2 Computation of the injection pressure (P_{inj}) at each depth using the PWD data

The pressure needed to calculate the injectivity of the well at a certain depth is the pressure of the fluid in the wellbore, labelled P_{inj} on Figure 1-C. In the PWD data, this data is represented by the annular pressure, labelled $PWD_{annular}$ on the same figure.

These data can be used directly at a 30s interval when drilling is occurring. As the PWD tool is part of the BHA and continuously records data, the tool records different pressure for the same depth when the BHA needs to be worked up and down (i.e wiper trips, trip outs). For the approach 1 of the II calculation that will be described in section 2, a routine was built to only select the pressure data recorded when the tool was going down. This selection process helped remove the effects of surge and swab pressures during tripping in and out. This made the communication of the injectivity evolution easier by providing a clearer a graph of the II versus depth.

An illustration of the annular pressure for KA56 after the selection process is represented by the dots on the Figure 6, the colour corresponding to different time of drilling. The graph starts at 1400m as the top of the reservoir was estimated at this depth and the

PWD tool was installed on the BHA when drilling below the top of the reservoir. An illustration of the PWD data without filtering is shown on Figure 8 with the blue dots.

3.1.3 Computation of the reservoir pressure at each depth (Pres) using reservoir pressure profiles scenarios

To compute the II per depth, a pressure profile Pressure vs Depth of the reservoir was used to calculate the reservoir pressure at the drilled depth, labelled P_{res} on Figure 1-C.

This pressure profile depends on two main reservoir characteristics in the newly drilled area, the state of depletion and the temperature of the reservoir. The state of depletion was quantified with a pressure drop component decreasing the natural state reservoir pressure by a given value. The natural state pressure of the reservoirs was calculated using the pressure recorded at the pivot point of the first wells drilled in the fields before production. The temperature of the reservoir was represented with the pressure gradient. Three scenarios of reservoir pressure profiles were used to take into account the uncertainty on these two components.

Two reservoir pressure profiles scenarios assumed the reservoir to be at the average reservoir temperature to compute the pressure gradient component. One scenario used a low pressure drop value to reflect the expected state of depletion in the drilled area. This value was defined based on the last shut PTS from the nearby wells and on the data from nearby pressure monitoring wells. The second scenario used a high pressure drop value to take into account possible interference with nearby producing wells or the potential effect of a compartment. This value was based on the pressure measured in wells experiencing a higher depletion state in the field were the new wells was drilled. The high pressure drop scenario would give the most conservative results for the II. These two scenarios are illustrated on Figure 6 for KA56 with a difference of 15 bar between these two scenarios.

The PWD data also helped reduce the uncertainty on the reservoir pressure during the drilling of the well, an example is given for KA56 with the Figure 6. The PWD data obtained during the bit trip of the 17^{th} of December (orange circles) showed the low pressure drop scenario (red dotted line) was not realistic as the PWD data under injection were lower than this reservoir pressure.

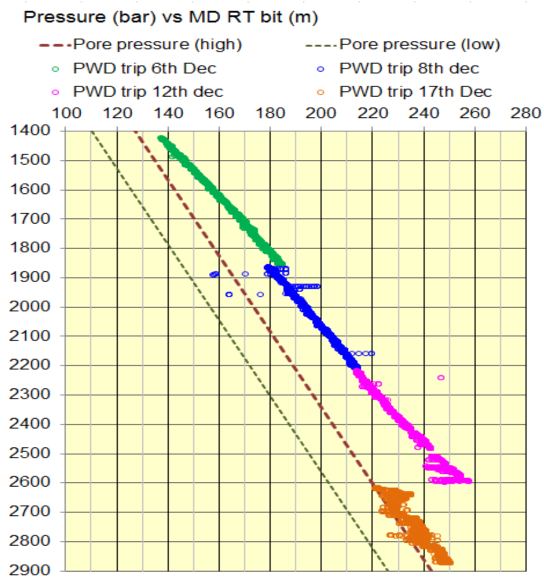

Figure 6: Annular pressure of the PWD tool (circles) plotted against the low reservoir pressure drop scenario (red dotted line) and the high pressure drop scenario (green dotted line) for the well KA56.

The third reservoir pressure profile scenario assumed the reservoir in close vicinity of the well to be cooled down by the continuous injection of the drilling fluid at about 15˚C at surface. The cooling of the reservoir is influenced by the temperature inside the wellbore which depends on the injection rate of the drilling fluid and where the fluid is injected (annulus and/or drill pipe), which vary depending on the drilling operations and the size of the hole drilled. Thus, the flowrate is lower during bit trips, wiper trips and when the diameter of the hole to drill gets smaller, allowing the wellbore and thus the near wellbore to reheat. The wellbore temperature also increases when the fluid is only injected into the annulus of the hole and not in the drill pipe. The influence of these variations in flowrate on the wellbore temperature can be monitored using the MWD data from a sub located closed to the BHA, as illustrated on the Figure 7. The comparison of these profiles shows how the wellbore temperature can vary between 120˚C and 25˚C during the drilling operations in the reservoir section.

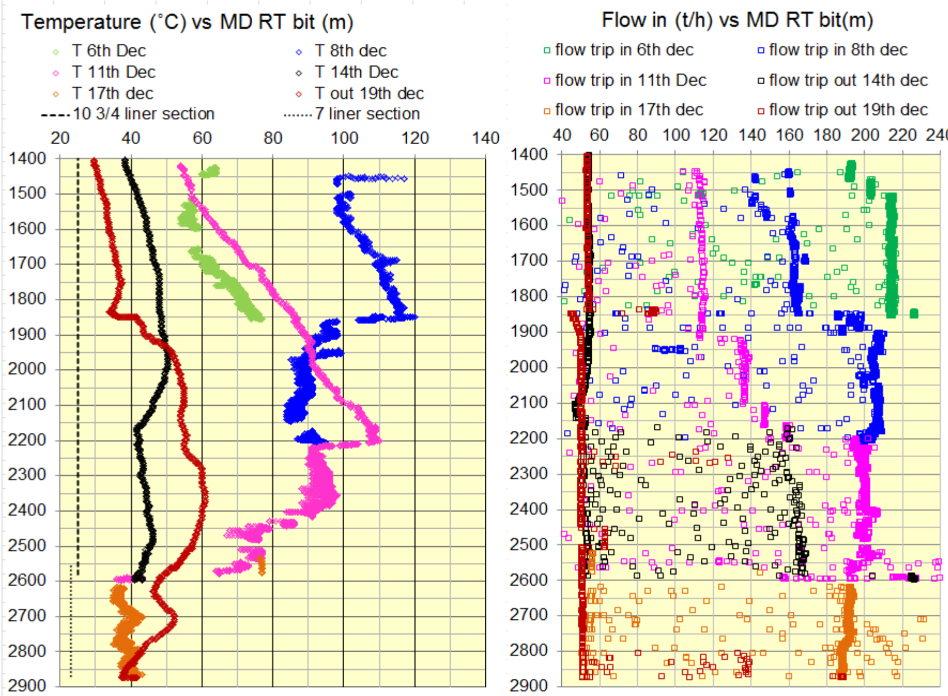

Figure 7: Temperature (left) and flow into the well (right) recorded every 30 seconds and plotted versus depth. Each colour represents one event, a "trip in" during drilling or a "trip out" when the BHA was pulled out of the hole

This third reservoir pressure profile scenario is more representative of the later stage of drilling when injection into the reservoir has been sustained for several days. This colder temperature effect was taken into account by using an equivalent density to fit the pressure gradient given by the PWD when tripping in or out of the well. The pressure profile was built assuming the pressure given by the PWD tool when pulling out of the hole without injection was representative of the near wellbore reservoir. This third reservoir pressure profile scenario is illustrated on Figure 8 with the black dotted line

Figure 8 also display a hot reservoir pressure profile scenario with a black line. When comparing these two cold and hot pressure profile scenarios, the difference in the gradient is getting bigger as the well goes deeper. This difference illustrates how the II of the well will get underestimated with the hot reservoir profile compare to the cold reservoir profile as the drilling gets deeper. This resulting difference in II is described in the following section.

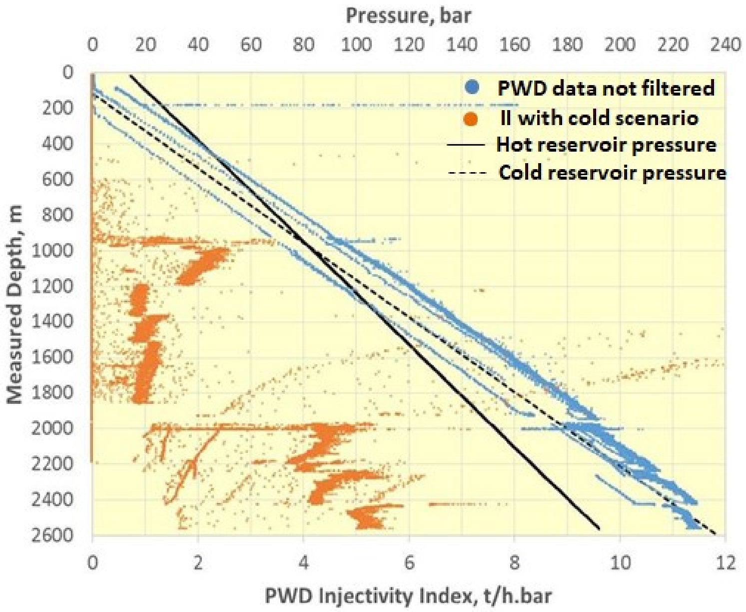

Figure 8: Comparison of the cold and hot reservoir pressure profiles for the well RK36. The two profiles cross because of their different pressure gradient and different reservoir pressure drops.

3.2 Step 1 of the methodology: monitoring the Injectivity Index (II) with two approaches

The three key parameters described in the previous sections were used in two different approaches to provide a range of II and give a more representative range of possible outcomes for the wells capacity.

Approach 1 combined the PWD data and the reservoir pressure and provided a depth series of the evolution of II of the well. Approach 2 used the PWD data recorded at different loss rates to check the total II of the well.

3.2.1 Approach 1: Injectivity Index (II) using the PWD data and the computed reservoir pressure

This first approach to calculate the II of the well used the losses in the wellbore (Q_{loss}), the reservoir pressure (P_{res}) and the measurement of the annular pressure from the PWD ($PWD_{annular}$). The II was computed using the formula below, derived from the general II formula (Clearwater et al., 2015):

$$II = \frac{Q_{losses}}{P_{inj} - P_{res}} \tag{2}$$

Where II, Q_{losses}, P_{inj}, P_{res} are the Injectivity Index (t/h/bar), the losses rate (t/h), the PWD annular pressure (bar), the reservoir pressure (bar), respectively.

The II was computed using non filtered PWD data and also PWD data filtered to provide clearer II evolution versus depth. An example of non-filtered II is shown on Figure 9, an example of filtered II is shown on Figure 13.

The parameter bearing the most uncertainty was the reservoir pressure profile. The example of RK36 is used below on Figure 9 to illustrate the variation of the II depending on which reservoir pressure profile scenario was used. With the cold reservoir scenario, the II of the well is about 8 t/h/bar instead of 5 t/h/bar with the hot reservoir gradient.

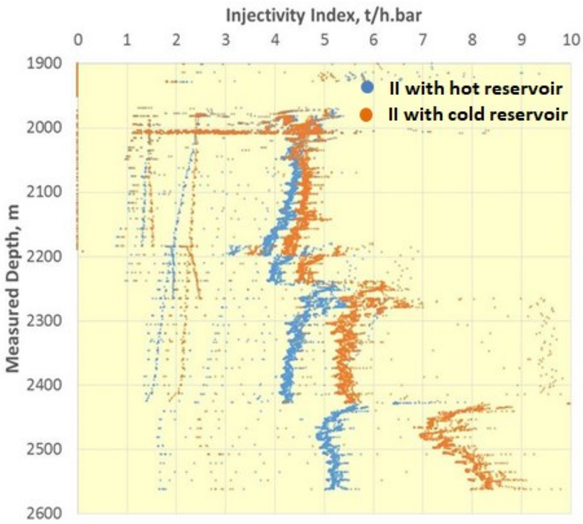

Figure 9: Comparison for the well RK36 of the II with hot reservoir scenario and II with cold reservoir scenario

The hot reservoir scenario shows a decreasing trend with the increasing depth in some sections but the reduction in II seemed too conservative as the losses were increasing over depth. With the cold reservoir scenario, the II seemed more align with an increase in losses over depth and less influenced by the difference in pressure gradient between the wellbore and the formation.

It also appears that the injectivity index decreases after a loss zone was hit. One explanation for this permeability reduction was the invasion of the feedzone by the cuttings during drilling.

The PWD data shows a clear increase in injectivity at about 2430m, which indicates a new feedzone in RK36. This illustrates how the continuous PWD data and the use of the different pressure scenario were used to identify real time how close from the II target the well was and thus when the TD of the well could be called based on the targeted II.

3.2.2 Approach 2: Injectivity Index (II) using PWD data at different loss rates

Given that the II is a key parameter to define the TD of the well, another approach was used to confirm the II obtained with the first approach. It was particularly useful when the II calculated with the first approach was close to the target II to TD the well. This second approach doesn't use the reservoir pressure in the II calculation. It relies on identifying a depth interval close to the bottom of the well where two loss rates and two set of wellbore pressure with the PWD tool were recorded.

The II can then be calculated with the formula below, similar to an injectivity test:

$$II = \frac{Q_1 - Q_2}{P_1 - P_2} \tag{3}$$

Where II, Qi, Pi are the Injectivity Index (t/h/bar), the loss rates and their corresponding PWD pressure, respectively.

The changes in loss rates at a particular depth interval were of two types. One was a change in injection rate due to a wiper trip or a trip out. Another type was a more formal differential flowrate test (i.e PWD stage test). The first type of change in loss rate was used preferentially as it was interfering less with the drilling operations.

The Figure 10 illustrates the change in loss rates and corresponding change in pressure from the PWD tool in the interval 2000m-2700m for the well RK36. The deeper interval depth with two loss rates and two set of pressure data is the interval 2300m – 2400m. By taking the data in green as Q1 and P1, the orange data as Q2 and P2, the injectivity index of the well is calculated at about 5.4 t/h/bar, for the depth of 2400m. When we compare this value with the II from the approach 1 for the same well (Figure 9), this confirmed the colder pressure gradient is closer to the real injectivity of the well.

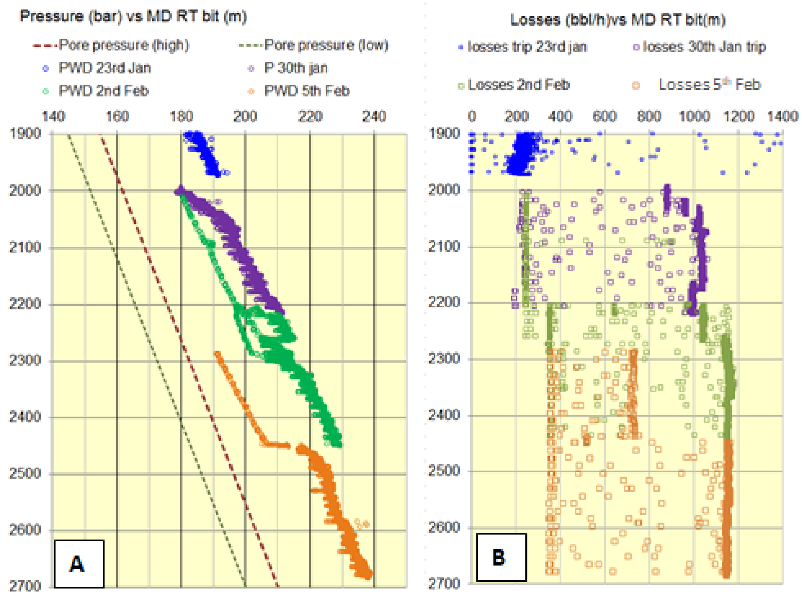

Figure 10: A) Pressure from the PWD and reservoir pressure. B) Losses for the well RK36 in the interval 2000m-2700m. The data are color coded by days of recording to differentiate the different stage of drilling (i.e blue for the 23rd of January, purple for the 30th of January, green for the 2nd of February, orange for the 5th of February).

Having the PWD data and the calculated losses every 30 seconds meant that the II could be confirmed without having to organize a formal stage test with the rig. This stage test would have taken more time to organize and slowed down the drilling of the well.

Approach 1 and approach 2 described above gave a range of Injectivity Index that was then used in wellbore modelling to estimate the capacity of the well

3.3 Step 2 of the methodology: Modelling the well capacity using the II and reservoir conditions scenarios

The drilling campaign was based on achieving specific capacity targets, thus the II needed to be translated into capacity to inform the continuation of drilling. Two different methods were used for the production wells and the injection wells as described in section 3.3.1 and 3.3.2.

3.3.1 Method used for the injection well capacity

For the injection well, the II in t/h/bar was transformed into a formation II in m^3. This step was necessary to take into account the change in viscosity and density of the fluid when the well would be put under brine injection with a hotter temperature (between 110 ˚C and 130˚C). The II in m^3 was representative of the permeability without the influence of the mobility of the colder injected drilling fluid (about 15˚C at surface, 40˚C once the fluid reaches the deep section of the well).

The formula used to change the initial II in t/h/bar into m^3 is as below:

$$II' = \frac{II}{Mobility} \tag{4}$$

Where II', II, Mobility are the Injectivity Index in m^3, the Injectivity Index in t/h/bar, the mobility calculated as the ratio density/viscosity for the fluid at the temperature of the feedzone, respectively

This value of II in m^3 was then used in the wellbore model to simulate the well under operational conditions with the injection brine. The wellbore model used the wellbore simulator Paiwera (Franz, 2015). The output of the wellbore model was an injection curve providing the capacity of the well at different Well Head Pressure (WHP) as illustrated on Figure 11.

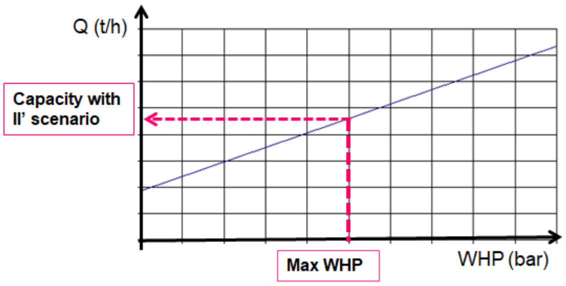

Figure 11: Injection curve (blue) obtained with wellbore modelling using II' and reservoir conditions scenarios

The maximum WHP achievable by the well once connected to the station was obtained from the process engineer team to take into account the pressure drop in the pipes connecting the well to the station. With this maximum WHP, the capacity of the well was obtained from the injection curve. As KA55 was the only injection well drilled during the drilling campaign, one result is summarized in Table 1 in section 4.

<u>3.3.2 Method used for the production wells capacity</u>

For the production wells, the II was transformed into Productivity Index (PI), then this value was used in the wellbore model to simulate the well under operational conditions.

The transformation of the II (t/h/bar) into PI (t/h/bar) consisted in downgrading the II by a %, with the worst case scenario using a 70% reduction, the average scenario using a 50% reduction, an optimistic scenario using a 30% reduction. This downgrade of the II to PI takes into account the reheating of the formation when the well is put under production. The reheating of the formation causes the rock to expand, reducing the aperture of the fractures (Siega et al., 2014, Grant and Bixley, 2011). This reduction from II to PI also takes into account the potential change of fluid phase in the reservoir when put under production. If the fluid is at boiling condition in the reservoir, the steam and brine fraction of the fluid will create an apparent decrease in mobility which will decrease the PI (t/h/bar) of the feedzone.

This PI scenarios were then included in a wellbore model to produce mass capacity and enthalpy estimation. Another assumption in the wellbore models was the enthalpy of each feedzones. A low and a higher enthalpy values were used as an input based on the nearby wells. The wellbore model used the wellbore simulator Paiwera (Franz, 2015) which takes into account changes in viscosity, density and flow regime of the fluid. The outputs from the modelling were a series of output curves showing the capacity of the well at different well head pressures. Each series corresponded to a PI and reservoir conditions scenario, an example of these curves is provided in Figure 12.

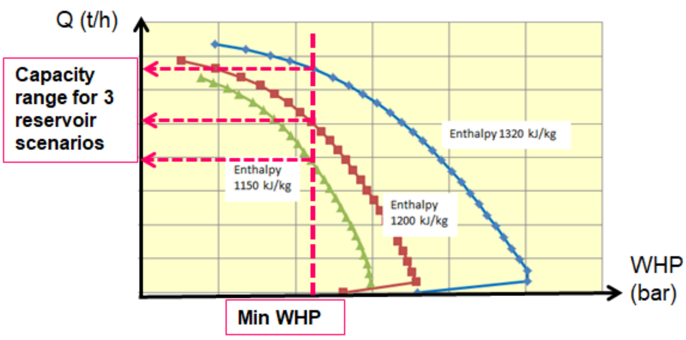

Figure 12: Output curve (green, red, blue) generated with wellbore modelling using PI and reservoir conditions scenarios

The minimum well head pressure (WHP) achievable by the well once connected to the station was obtained from the process engineer team to take into account the pressure drop in the pipes connecting the well to the station. With this minimum WHP, the capacity of the well was obtained from the output curves thus these various scenarios provided a range of capacity, which are summarized in Table 1 in section 4.

4. RESULTS AND DISCUSSION

The evolution of the II and the range of estimated capacity were discussed with the wider drilling team during the decision process of calling the TD of the well. The next section describes particular decision points for each well and how this additional information added value to the decision. As the PWD tool was used for the four wells, insights were derived about the accuracy of the II calculation and the partial losses calculation as described in the last sections.

4.1 Results of the methodology adding value to TD decisions while drilling

<u>4.1.1 Identification of feedzones and possible interference with nearby wells</u>

For the first well of the drilling campaign, KA55, the II derived from the PWD data enabled the identification of the major feedzone in the well close to the feedzone of a nearby injection well. This information highlighted the risk of potential reduction in capacity due to interference upon brine injection once connected to the station. The use of the PWD data and wellbore modelling helped quantify the expected impact of this interference on the injection capacity of the new well. Along with the other drilling parameters, this information from the PWD methodology contributed to make the decision of continuing drilling to lower this risk of interference and to provide enough injection capacity to the station.

4.1.2 Quantifying benefits of drilling deeper

For the production well KA56, the II of the well became more critical when drilling open hole at a depth close to the maximum depth planned. A decision to continue drilling could be made if they were signs of enough permeability improvement that would make the risk of drilling deeper worth the reward of getting more production.

The interpretation of the PWD data along with the losses in the hole showed a progressive increase in injectivity towards the bottom of the well at 2600m as illustrated on Figure 13.

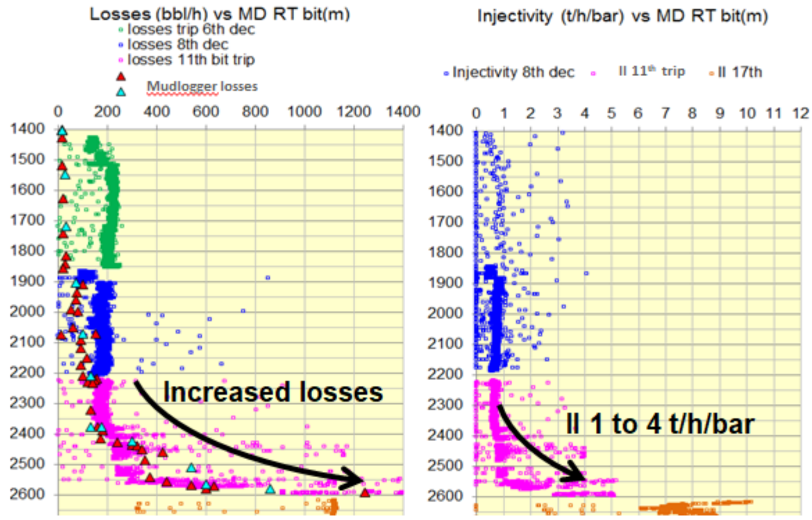

Figure 13: Losses and injectivity index for the well KA56 showing an improvement in permeability towards the bottom of the well.

With the methodology, the II was translated into well capacity, which enabled the project team to balance the added cost of deepening the well with the expected increase in mass flow. Given this increase of injectivity, losses and encouraging signs of more drilling breaks, the decision was made to run the 10 ¾ liner and then continue drilling. The liner was run to make the hole safer and a major feedzone was intercepted few meters below the liner as shown by the II data in orange on Figure 13.

4.1.3 Refining II calculation with the cooling of the well

For the production well RK36, the PWD data enabled the reservoir engineer team to take into account the cooling of the reservoir under drilling conditions. As the BHA was pulled out of the hole, the flow was minimum in the wellbore and the resulting wellbore pressure was used as a proxy to define a cold reservoir pressure gradient. Using this profile as described in section 3.2.1, the injectivity index of the well was refined to a higher value (8 t/h/bar instead of 5 t/h/bar as shown on Figure 9) and the TD of the well could be called. The availability of the PWD data at any time and depth of the drilling was key to make a better decision based on additional data.

4.1.4 Refining the set depth for a side-track plug

For the production well RK35, the continuous availability of the PWD data enabled a better decision process to choose which depth to target after the BHA got stuck in hole and the first hole had to be abandoned. The PWD data were used to estimate the contribution of the different feedzones intercepted so far in the well. This informed the minimum set depth of the plug for the side track to ensure these permeability zones were not damaged. The PWD data, along with data from the nearby pressure monitoring well and the losses indications helped quantify the value of drilling again to the depth of the first hole. The side track leg of RK35 was drilled to the same depth as the first leg and encountered the expected permeability that enabled the well to hit the targeted injectivity.

4.2 Reliability of the PWD methodology using a comparison with post drilling tests

After the wells were drilled, two tests were performed that helped appreciate the reliability of the estimations derived from the PWD data and the methodology.

4.2.1 PWD II generally more conservative than the completion test II

The first test was the completion test performed for each well with a PTS (Pressure, Temperature, Spinner) tool after the last liner was run into the well.

The injection test performed as part of this completion test provides a reference II because it can take characterize more precisely the feedzones (i.e the pressure measurement is very accurate, the three different injection rates are more stable, it can quantify the inflows above the main feedzone of the well, it is performed once the well has its final completion with the perforated liner). The comparison between the injectivity from the PWD and the completion test are presented in Table 1.

Table 1: Comparison of the II and well capacity pre and post drilling for the four wells

Well	Type	II PWD (t/h/bar)	II completion test (t/h/bar)	Production/injection capacity from PWD and wellbore model (t/h)	Production/injection capacity from well clearing (t/h)
KA55	Injection	120	150	675	(*1)
KA56	Production	10 to 23	40	300 to 400	400 down to 300
RK36	Production	8 to 17	8 to 26	300 to 750	900
RK35	Production	7 to 10	16	500.00	400

The II from the PWD data were overall lower than the injectivity from the completion test. An explanation for this difference can be the cleaning of the cuttings after the well completion. During drilling, drilling cuttings develops in the wellbore. When drilling has reached the reservoir section and some permeability is intersected causing partial or total losses, some or all drilling cuttings will escape to the formation through the permeable zone(s). This condition is believed to have caused some level of near wellbore formation damage during drilling, making the II from the PWD to be lower than that from the completion test. During completion test, some amount of injection is put into the well creating a "cleaning process" to the permeable zone(s). In pressure transient, this process is represented as negative (-) skin factor, or near wellbore permeability improvements. This condition is believed to have caused a higher II to some extent during the completion test than that obtained from PWD.

This shows that the PWD gives a conservative estimate of the injectivity of the well without being too far off the value that would be obtained from a standard stage test with the PTS tool. This level of accuracy from using the PWD tool is acceptable from the company' stand point because the key advantage from using the PWD is from the time saved while drilling by not having to trip out of hole to perform the stage test with the PTS. Having said the above, however, the company is continuously learning to understand other factors that may contribute also to the underestimation of the PWD II to help make assessment during drilling of the future wells more accurate.

4.2.2 Modelled well capacities closed to the production test capacities

The second test was the clearing of the production wells during which the capacity of the wells were estimated using the lip pressure method. This method is used to give an indication of the capacity of the wells while they heat up before they get connected to the station and their capacity is confirmed with TFT (Tracer Flow Test) surveys. These capacity values were compared to the capacity values obtained with the combination of PWD and wellbore model during the drilling of the wells. The results are shown in Table 1.

For KA55 (1*), the comparison can't be made as the well was acidized after the drilling and this was not included into the wellbore model.

For KA56, the clearing showed the well following the expected curve from the PWD+wellbore model at the start of the clearing but then decreasing towards the end of the clearing. This indicated a possible change of the fluid entering the wellbore during the flowing of the well and confirmed the initial assessment of the capacity with PWD+wellbore model was realistic.

For RK36, the capacity from the clearing showed the well had more capacity than expected from the PWD+wellbore model. This was driven mainly by an overestimation of the pressure drop in the wellbore model.

For RK35, the well was not as stable as expected during the clearing, which prevented the well to maintain the expected 500 t/h capacity from the wellbore model. This is interpreted as a different permeability structure in the wider formation changing the recharge of the well, process that was not known before flowing the well.

4.3 Uncertainties on flows and under partial losses condition affecting the calculation of the II

During the drilling of the four wells, the accuracy of the flow measurements in and out of the wellbores was one point of focus to lower the uncertainty on the II calculation, especially under partial losses conditions. Another uncertainty was the sensitivity of the PWD data to change in wellbore pressure under partial losses conditions.

4.3.1Uncertainty on the flow into the well under total loss conditions

The flow in the well is the sum of the flow going into the pipe and the flow going into the annulus. These flows are relatively accurate as they are calculated based on the strokes of the pumps. The uncertainty on these flows is greater under total losses conditions when the vacuum at the wellhead can cause the injected drilling fluid to by-pass the pumps. This uncertainty can be reduced by comparing this pump loss rate with the mudlogger loss rates calculated from the mudtank with sonic sensors.

4.3.2Uncertainty on the flow out under partial losses conditions

The higher uncertainty came from the estimation of the flow out. This flow out is calculated based on the opening of a paddle sensor in the flow out line. The relationship between the opening of this paddle and the flowrate is calibrated once. Depending on the accuracy of this calibration, the flow is more or less representative of what is actually coming out of the hole. This calibration is usually not done with a high accuracy as the rate of partial losses is usually taken from the mudlogger tanks. This flow out was used in this drilling campaign to aid the calculation of the injectivity along the wellbore at the same time as the PWD data was recorded (i.e every 30 s). Aside from a more accurate calibration of the paddle sensor, a flow meter could be included on the flow out line to reduce the uncertainty on the losses.

4.3.3Uncertainty on the PWD data under partial losses conditions

Another uncertainty under partial losses conditions is the behavior of the PWD data as the wellbore is constantly full of water. Thus the variation of pressure recorded by the PWD tool when addition losses are found in the hole is less emphasized, with the liquid level always being at the top of the well. The experience from the drilling campaign shows that the partial losses conditions were usually correlated to an Injectivity Index (II) lower the target injectivity index. The uncertainty linked to the II under partial loss conditions may be too high and the additional information on permeability too marginal to justify improving the flow measurements.

5. CONCLUSION

This paper relates our experience of using the PWD data to support the drilling of the four successful wells for the Kawerau and Rotokawa fields. A methodology was derived to translate the PWD data into well injectivity then well producing/injecting capacity. This methodology provided a framework to build templates that enabled the reservoir engineering to quickly update information about the well permeability as the well was drilled. This information helped the decision process of completing the wells or continuing drilling/side tracking to find the targeted permeability.

Using this technique for the four wells enabled a continuous improvement of the methodology from one well to the other. From this experience, the PWD methodology seems to underestimate the injectivity and capacity of the wells drilled. The conservative results for the injectivity are not too far off what would be obtained with a stage test. Combined with the time saved with the PWD tool compare to the stage tests, these results give a strong argument to first rely on the PWD methodology and use the stage-tests as back up plans.

The wells capacity obtained from this methodology gives insights into what the well would be capable of producing/injecting once connected to the station. These conservative results show that they help make better drilling decision based on more information but they don't take into account some changes that could occur into the reservoir upon the start-up of the well (i.e cooling of feedzones upon production, compartments creating additional pressure drop, recharge maintaining higher pressure, formation stimulation upon colder injection).

Applying this methodology to these four wells highlighted some limitations that need more focus for the future wells to reduce uncertainties linked to this methodology. This focus could consider the accuracy of the flowmeters to calculate the losses, the use of reservoir modelling to quantify the impact of reservoir heterogeneity and level of interference once the well is operating, the quantification of the permeability reduction upon reheating of the formation for the production wells (Siega et al., 2014). Reducing these uncertainties will increase the quality of information that can be derived from the PWD tool and help justify the extra cost for using the tool and the added risk of losing the tool in the hole in case the BHA gets stuck in the hole.

REFERENCES

Addison, S., Azwar, L., Clearwater., J, Herrnandez, D., Mountain, B., Blair, A., Siratovich, P.: Improving the conceptual understanding through a recent injection of 200 GBq of Iodine-125 at the Rotokawa geothermal field, New Zealand, *Proceedings*, 42nd Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, CA (2017)

Clearwater, J., Azwar, L., Barnes, M., Wallis. I., Holt, R.: Changes in injection well capacity during testing and plant start-up at Ngatamariki, *Proceedings*, World Geothermal Congress, Melbourne, Australia (2015)

Franz, P.: Paiwera, a robust wellbore model simulator for geothermal applications, *Proceedings*, 37th New Zealand Geothermal Workshop, Taupo, New Zealand (2015)

Grant, M.A., Bixley, P.F.: Geothermal Reservoir Engineering. Elsevier, Oxford (2011)

Grant, M.A, Clearwater, J., Quinao, J., Bixley, P., and Le Brun, M.: Thermal stimulation of geothermal wells: a Review of Field Data, *Proceedings*, 38th Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, CA (2013)

Massiot, C., McLean, K., McNamara, D., Sepulveda, F., Milicich, S.: Discussion between a reservoir engineer and a geologist: permeability identification from completion tests data and borehole image logs integration, *Proceedings*, 39th New Zealand Geothermal Workshop, Rotorua, New Zealand (2017)

McNamara,D., Sewell, S., Buscarlet, E., Wallis, I.: A review of the Rotokawa Geothermal Field, *Geothermics*, **59**, 2016, 281 – 293

Mountain, B., Winick, J.: The thermal stability of the naphthalene sulfonic and the naphthalene disulfonic acids under geothermal conditions: experimental results and a field-based experience, *Proceedings*, 34th New Zealand Geothermal Workshop, Auckland, New Zealand (2012)

Rowland, J.V. and Simmons, S.F.: Hydrologic, magmatic and tectonic controls on hydrothermal flow, Taupo Volcanic Zone, New Zealand: implications for the formation of epithermal vein deposits, *Economic Geology*, **107**, 2012, 427-457

Siega, C., Grant, M.A., Bixley, P., Mannington, W.: Quantifying the effect of temperature on well injectivity, *Proceedings*, 36th New Zealand Geothermal Workshop, Auckland, New Zealand (2014)

Wallis, I., Moon, H., Clearwater, J., Azwar, L., Barnes, M.: Perspectives on geothermal permeability, *Proceedings*, 37th New Zealand Geothermal Workshop, Taupo, New Zealand (2015)

Winick, J., Powell, T., Mroczek, E.: The natural state chemistry of the Rotokawa reservoir, *Proceedings*, New Zealand Workshop, Auckland, New Zealand (2009)