QUANTIFYING THE EFFECT OF TEMPERATURE ON WELL INJECTIVITY

Christine Siega[1], Malcolm Grant[2], Paul Bixley[1], Warren Mannington[1]

[1]Contact Energy, Wairakei, New Zealand

[2] MAGAK, Auckland, New Zealand

Christine.Siega@contactenergy.co.nz

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ABSTRACT

This paper studies the trend of the injectivity at varying injection temperatures using the data of Contact Energy's injection wells in the Wairakei – Tauhara geothermal system. Temperature is a major factor that affects the injectivity of the wells and it is the objective of this study to quantify and consequently forecast the effect of temperature change to injectivity.

Across all wells analyzed, a similar direct proportionality trend between increasing formation temperature versus percentage decrease in injectivity is observed. The result of the study provides a correction factor that will help improve the injectivity value prediction in the operation and management of the injection system involving different temperature conditions such as:

- Performance monitoring of injection wells at varying injection fluid temperature
- Projection of injectivity calculated during drilling to the temperature condition of the injection system.

1. INTRODUCTION

Contact Energy operates five geothermal power stations in the Taupo region with a total generation of 400MWe. Separated Geothermal Water (SGW) injection is done in both infield and at the periphery of the field, with a typical injection fluid temperature range of 85-156^{o}C. The focus of this paper is on the injection wells in the Wairakei- Tauhara geothermal system (Figure 1). A total of twenty one (21) injection wells were evaluated for this study.

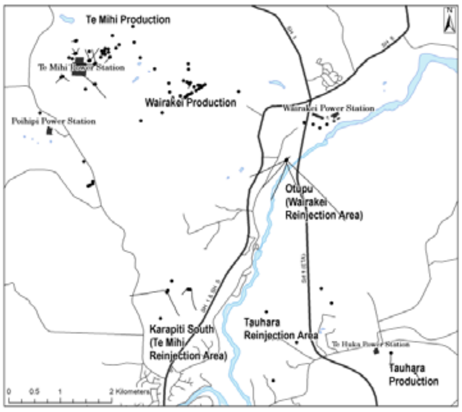

Figure 1: Location Map of Major Production and Injection Areas in the Wairakei - Tauhara Geothermal System.

The injectivity of the wells plays an important role in the operation and management of the injection system. It is one of the factors evaluated in the injection strategy of the field, and in the workover and drilling decisions, as follows:

- Injection Well Protocol – The protocol places operational limits on WHP and injection loading, in accordance with leak-off test pressures and well injectivity.
- Well Drilling Completion – Stage tests are conducted before completing a well to measure the injectivity. The injectivity, among other factors, will dictate the completion of the well.
- Injection Well Workover – Injectivity is measured in real time to monitor the well performance to assess priority and timing for well maintenance.

1.1 Injectivity and Its Response to Temperature Change

The injectivity of a well can be affected by the change in feedzone formation temperature, brought about by the injection of fluid with hotter or cooler temperature than the formation. This has been the subject of several published papers such as those written by Ariki in 1998, Gunnarsson in 2011, and Grant in 2013. The injectivity may decrease when the formation temperature gets hotter with injection, and conversely will usually increase with time when injection cools the formation. This is due to the thermal expansion or contraction of the rock in a fractured type reservoir (Grant). However the amount of change in injectivity versus temperature has never been fully investigated.

1.2 Temperature Change in Actual Operations

In Contact Energy's operations, the temperature of the reinjected fluid or injectate commonly varies over a small range depending on system controls. These temperature variations caused a subsequent change to the injectivity of the wells, which make the management of the injection process difficult. Table 1 lists the different operating temperature conditions that affect well injectivity and the impact of the injectivity change to the injection process management.

Table 1: Injectate Temperature Variation Affecting Injectivity and Injection Process Management

Injection Management Process	Injectate Temperature Variation Causing Injectivity Change	Impact of Injectivity Change
Injection Well Protocol	Otupu: Injectate temperature varies from 85°C (with binary) to 120°C (binary shut) Karapiti South: Injectate temperature varies from 105°C (with acid dosing) to 133°C (acid dosing shut); and a few occasions during the commissioning stage of Te Mihi: from 105°C (with Low Pressure operating condition) to 156°C (high pressure operating condition)	- Operational limit must be updated according to change in injectivity with temperature. - The changes in operational limit with temperature should be forecasted beforehand to project injection capability vs requirement.
Injection Well Workover		- Injectivity changes at varying injection temperature. Monitoring well performance is difficult when temperature of injection is changing over time.
Well Drilling Completion	Reservoir Condition at post drilling test is colder than actual operating condition	- Well injectivity computed during post drilling decreased upon heat up of the well. The post drilling injectivity is an over estimate of the actual injectivity at higher injection temperature operating condition.

It is the objective of this study to quantify the change in injectivity with temperature. The result will enable the projection of injectivity from one temperature condition to another, and hence improve the process of managing the injection wells. The effect of feedzone depth and geology to the relationship between temperature and injectivity is also assessed.

2. METHODOLOGY

The data that were used in the study are the following:

- Post drilling completion test data: shut and injection downhole pressure at permeable zone, WHP, downhole temperature profile
- Injection Data from SCADA: injection load, injection temperature, and WHP; and if available, downhole pressure and temperature survey results

These data were collected from the twenty one (21) injection wells of Otupu, Karapiti South, and Tauhara areas. The data of each well are compared at the same time frame to eliminate other factors affecting injectivity such as scaling and casing integrity issues. Effects of stimulation, non-linear injectivity, and interference are not included in this study.

The injectivity was calculated considering the major permeable zone only. The post drilling injectivity are based from short term test using 3 to 4 injection rates with downhole pressure measurement.

During the operation at the injection system, the injectivity of the wells are calculated using the formula:

$$II = \frac{Q}{P_H + WHP - P_F - P_{FZ}}$$

Where:

II	= Injectivity, t/h/bar
Q	=Flow rate, t/h
P_H	= Hydrostatic Pressure, bar
WHP	= Wellhead Pressure, bar
P_F	=Pressure due to Frictional Losses, bar
P_{FZ}	=Pressure at the permeable zone, bar

The feedzone depths for the injection wells vary from 400 m to 2600 m, with formation temperatures of 100 °C to 240 °C.

Both the injectate and feedzone formation temperature during injection are collected to help differentiate the effect of each factor on injectivity.

In summary, the data collection starts from post drilling injection to actual operation, in three different injection areas with different reservoir temperature. This is to capture the injectivity change at a wide range of temperature differences, and at various injection depths and lithologies.

Table 2 shows the types of correlation used in the study between the change in injectivity and change in temperature as a result of injection. The injectate and formation temperatures were separately correlated to the change in injectivity to determine which of the two parameters can give a better injectivity vs temperature relationship trend.

Table 2: Types of Data Correlation Used in the Study

Injectivity Change	Correlation	
	Type 1	**Type 2**
Injectivity (II) values from test done immediately after drilling vs after heat-up	**II change vs change in injectate temperature.** The injectate temperature is measured close to the wellhead of the well.	**II change vs change in formation temperature, brought about by the change in injectate temperature.** The formation temperature is taken at the feedzone depth.
Injectivity value immediately after drilling vs injectivity value calculated during injection to system		
Change in injectivity values using different injectate temperature in the injection system		

Other factors that may affect the injectivity and temperature relationship such as well stratigraphy and feedzone depth are also evaluated.

3. RESULTS AND OBSERVATION

3.1 Using Injectate Temperature Values to Understand the Injectivity Change

The injectate temperature data showed no clear relationship to the change in injectivity (Figure 2). This is observed on short term injectivity tests done immediately after drilling or tests done after a well has heated up. Correlation of data in these conditions shows a change in injectivity but with no change in injectate temperature.

This is exhibited for example in the case of WK409. WK409 had an injection test after drilling on 13 March 2012 using an injection fluid with temperature of 15 ˚C. Another test was done on 19 March 2012, after the well was heated up for 6 days, using injection fluid of similar temperature. The injectivity value from the post heat-up test on Figure 3 showed a drop by 39% from the pre-heat-up test despite the use of the same injectate temperature. Investigation of the downhole temperatures measured on the well during injection and after an hour of shut on both injection scenarios indicates the following:

- The injectate temperature is not equal to the temperature at the feedzone during injection.
- The feedzone temperature is almost the same for the two injection scenarios.
- The downhole temperature profile after one hour shut (Figure 4) showed a higher temperature for the post heat-up test, which is consistent with the drop in injectivity during this test.

These observations suggest that for short term tests, the injectate temperature and even the feedzone temperature during injection may not capture the change in the near-well formation temperature that is causing the injectivity to change. An immediate shut temperature profile is needed to determine the real near-well formation temperature changes with injection. The injectate temperature therefore is not appropriate to use in understanding the relationship between injectivity and temperature.

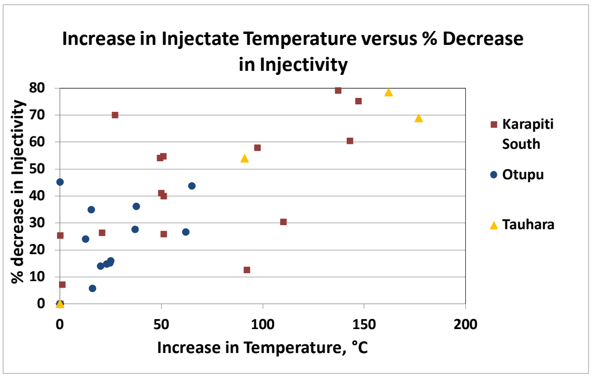

Figure 2: Change in Injectivity versus Change in Injectate Temperature

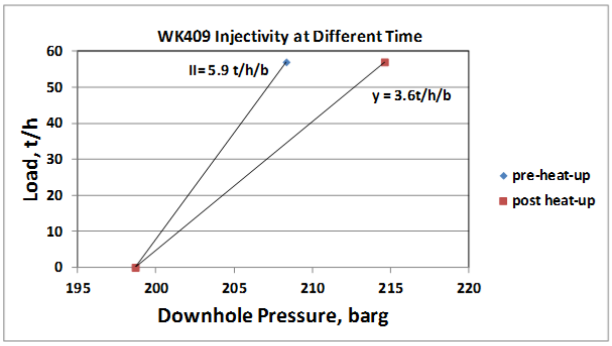

Figure 3: WK409 Injectivity Before and After Heat-up Test Using Injection Temperature of 20°C

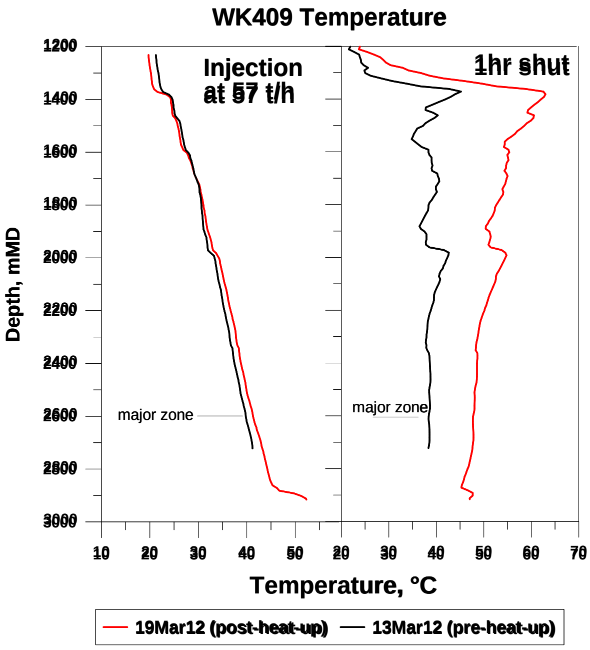

Figure 4: WK409 Downhole Temperature Profiles

3.2 Using Near-well Formation Temperature Values to Understand the Injectivity Change

From the section 3.1 discussion, in the case of short term injection tests, the near-well formation temperature was taken at the feedzone with consideration of both injection and immediate shut profiles.

This is demonstrated by WK404 on Figure 5. The feedzone temperature during injection ranged from 60°C to 80°C. But on the 1hr shut (no immediate shut survey available), the temperature rose to 160°C. Given this condition, the near-well temperature was taken to be 120°C, which is the average of 80°C (lowest rate) and the immediate temperature of 160°C to account for the well heat-up after an hour of shut. WK403 on Figure 5, on the other hand showed a consistent feedzone temperature, suggesting that the near-well reservoir was cooled during the injection. In this well, the near-well formation temperature was taken to be 15 °C as shown on the plot.

For wells already operating in the injection system, the near-well formation temperature is always assumed to be the same as the injectate temperature as both these parameters equilibrate with long-term continuous injection. WK308 on Figure 6 is an example of this, wherein the downhole temperature of both the injection and immediate shut survey reflect the injectate temperature after a long period of utilization at the same condition.

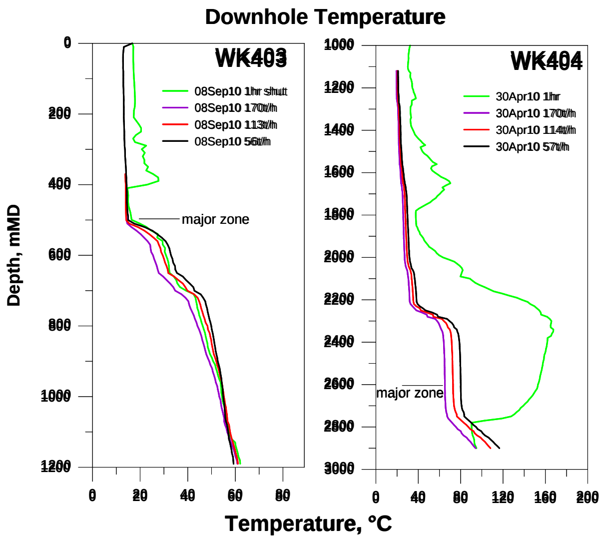

Figure 5: WK403 and WK404 Downhole Temperature Profiles

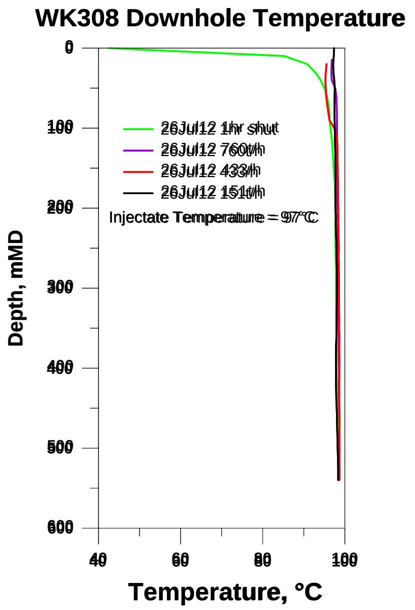

Figure 6: WK308 Downhole Temperature Profile at Injectate Temperature of 97°C

3.3 Reversibility of Injectivity

Data of injection wells demonstrates that injectivity varies according to the temperature of the injectate. For wells that have been utilized for a long period, this injectate temperature is equal to the formation temperature as discussed in section 3.2.

The injection data plot of WK403 on Figure 7 is an example of this occurrence. At 105°C injection temperature, the well accepts 900t/h load at 8bg wellhead pressure. With the increase in injection temperature to 155°C, the well can only accept 750t/h load with wellhead pressure increased to 14bg. Correspondingly, as shown in Figure 7, the calculated injectivity decreased by 55%. When the injection temperature was reverted back to 105°C, the injectivity returned back to the previous value. This shows that the injectivity can be reversed accordingly with change in the near-well formation temperature, assuming that there are no other factors influencing the injectivity.

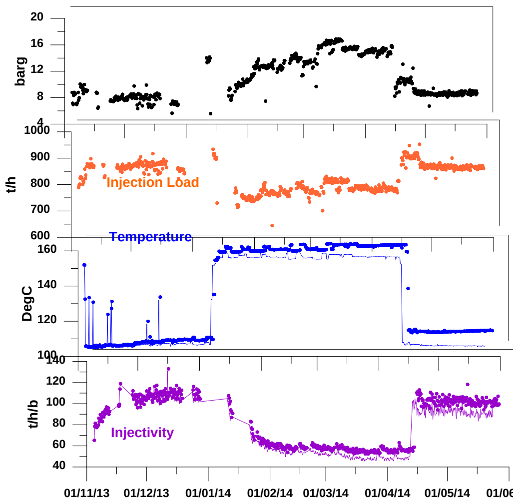

Figure 7: WK403 Actual Injection Data

3.4 Relationship of Injectivity with Reservoir Temperature

The calculated changes in injectivity were plotted with the near-well formation temperature for all interpreted data points of wells across Te Mihi, Wairakei, and Tauhara fields (Figure 8). There is a clear relationship with increase in formation temperature to the percentage of injectivity reduction. On the plot, with a minimum increase in formation temperature of 20°C, there is a corresponding reduction in injectivity of 15-25%. The highest observed decrease in injectivity is 80% for formation temperature increase of 120°C. Since the temperature effect on injectivity is found to be reversible, the plot on Figure 8 can be adjusted to be used as a guide to also estimate the potential increase in injectivity for every decrease in formation temperature (Figure 8A).

The influence of stratigraphy and feedzone depth to the relationship between injectivity and formation temperature was also evaluated, as shown on Figure 9 and 10. But both factors do not show any clear effect to the amount of change in injectivity with temperature.

The injectivity at varying injection data from three wells in Iceland (Gunnarson, 2011) were added to the plot on Figure 8 and fitted to give the final plot on Figure 11. The Iceland data shows consistent trend with that observed from the wells at Contact Energy. The percentage of decrease in injectivity is generally increasing on a linear trend from temperature increase of 1°C to 100°C, but tapers off after 100°C. The overall trend can be fitted by a polynomial curve.

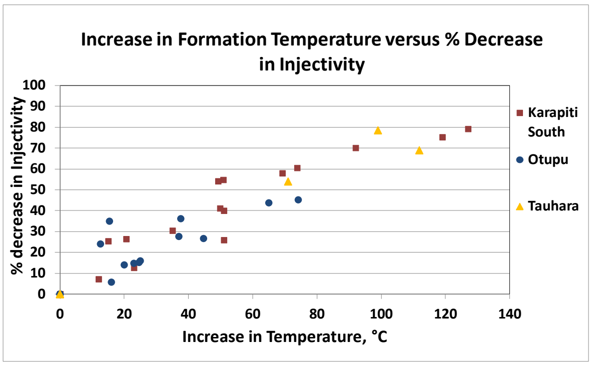

Figure 8: Decrease in Injectivity versus Increase in Formation Temperature

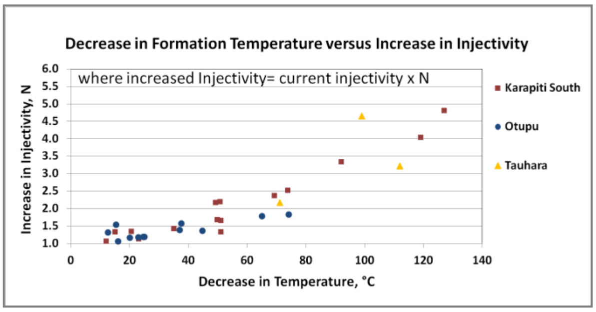

Figure 8A: Increase in Injectivity versus Decrease in Formation Temperature

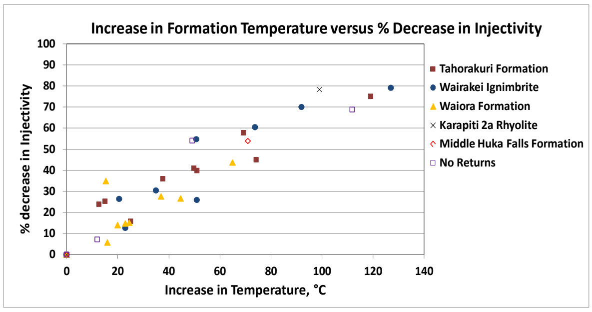

Figure 9: Change in Injectivity versus Change in Formation Temperature with Feedzone Stratigraphy

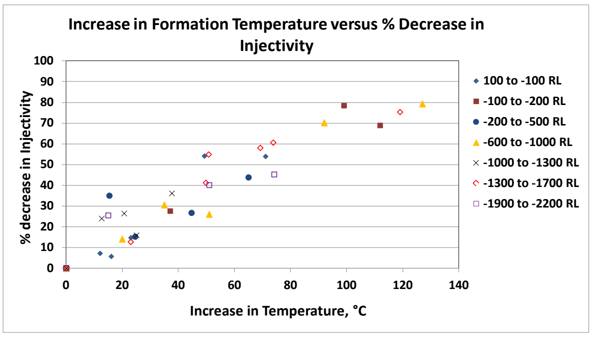

Figure 10: Change in Injectivity versus Change in Formation Temperature with Feedzone Depth

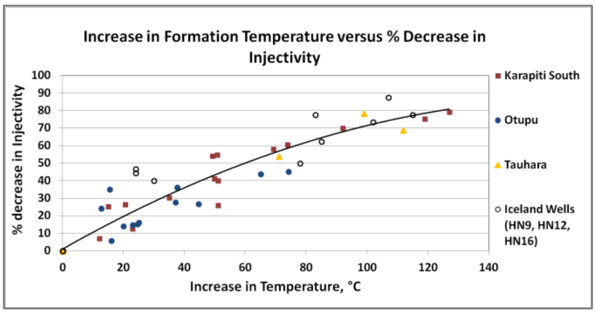

Figure 11: Fitted Change in Injectivity vs Change in Formation Temperature with Iceland Data

4. PRACTICAL APPLICATION

The observed correlation between the increase in near-well formation temperature and percentage decrease in injectivity (Figure 8) is useful to correct injectivity values from actual reservoir temperature conditions to the desired operating injection temperature conditions. This same is plot can also be used to estimate the increase in injectivity for a decline in near-well formation temperature. This correlation will facilitate a more accurate estimation of the injection capacity of the wells.

4.1 Application to Drilling Decisions

A hypothetical example below demonstrates the impact of the injectivity change with temperature, and the value of knowing the amount of change in injectivity during drilling.

Example:

- Total Injection Capacity Requirement for the Power Station: 600t/h
- Design Injection System Temperature: 150 °C
- WHP Limitation: 5barg

Table 3: Data at Drilling Condition

Wells	Reservoir T, °C	Injectivity, t/h/b	Capacity at 150 °C, t/h
Well 1	90	10	202
Well 2		12	234
Well 3		15	276
		Total Capacity	**712**

All well data: 7” Top of Liner=520m, 9-5/8” Production Casing, Perm Zone at 800m

Table 4: Data Corrected from Drilling to Operating Condition

Wells	Reservoir T, °C	Corrected Injectivity , t/h/b	Capacity at 150 °C, t/h
Well 1	90°C corrected to 150°C (60° increase in temperature) will result to a drop of 50% in injectivity based on Fig. 7	5	109
Well 2		6	129
Well 3		7.5	167
		Total Capacity	**405**

All well data: 7” Top of Liner=520m, 9-5/8” Production Casing, Perm Zone at 800m

The total injection capacity computed from Table 3, with the reservoir still in cold condition, is more than enough for the required capacity. However, once the reservoir temperature equilibrates with the injection temperature of 150°C, the total capacity is actually 33% short of the total plant requirement (600t/h). This unexpected capacity shortfall due mainly to the temperature change can lead to generation losses and unscheduled drilling of more wells.

Correction of the injectivity calculated during drilling stage by 50% using the correlation in Figure 8 provides a way of determining if the existing three wells already drilled is sufficient to meet the capacity requirement. If not, additional measures can be considered such as drilling the last well deeper to acquire more permeability or drilling of another injection well.

4.2 Application to Well Monitoring and Protocol Set-up

For the monitoring of the well performance over time, it is vital that the injectivity calculation is referenced/ corrected to a single reservoir temperature basis. Otherwise, the injectivity trend will change with temperature and misinterpretation of trend could take place. Based on the result of this study, the actual injectivity trend with time can now be corrected from any temperature effects, and any misinterpretation of injectivity trend can be avoided. Figure 12 shows the difference of injectivity trending over time with and without correction. After the correction is done, the proper trend of the injectivity over time can be clearly observed.

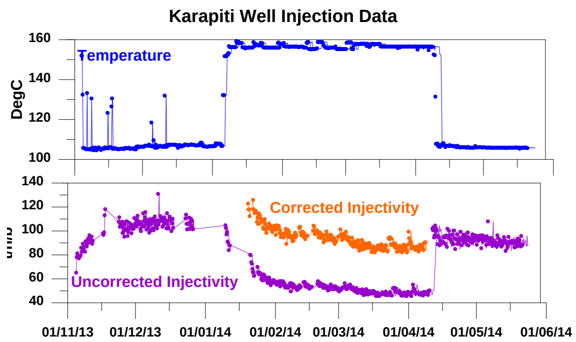

Figure 12: Corrected vs Uncorrected Injectivity Trend

At Contact Energy, injection well protocols are set at different injectate temperature to capture the change in well injectivity. Subsequently, this allows proper estimation of the injection capacity of the wells and provides a better forecast of the total injection capability versus the requirement.

5. SUMMARY

A quantification of the effect of temperature with injectivity is developed. This study made possible the adjustment of the injectivity values at different reservoir temperature condition. As more information is collected across the fields, this correlation will be improved further. There is also a need to calibrate the results and findings presented in this paper with data from other fields.

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