Identifying formation scale in geothermal wells

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ABSTRACT

Operational geothermal wells tend to block up over time with mineral deposits, leading to declines in well capacity and ultimately generation. The mineral deposits are called "scale" – and can be calcite, silica, silicates, or a mix. The issue affects both production and reinjection wells. In production wells, scale forms where there is boiling. In reinjection wells, scale forms as minerals exceed the saturation limit of the reinjected fluid. Scaling can be within the wellbore ("wellbore scale"), or the reservoir beyond the wellbore ("formation scale").

Wellbore scale is easier to identify as it can be accessed directly within the wellbore using wireline tools, such as calipers or gauge rings. Formation scale is more difficult to identify as it sits outside of the accessible wellbore and cannot be detected by any of those direct methods.

The presence of formation scale has typically been inferred indirectly, by ruling out other culprits. If a well is declining rapidly, and the decline cannot be explained by changes in reservoir conditions, and no wellbore scale is found, then formation scale is assumed to be the culprit. However, a higher level of certainty is desirable to decrease the risk to the operator of unsuccessful chemical cleans, as methods to remove formation scale (chemical cleaning) are expensive.

There are several methods for identifying formation scale more directly and with more certainty. These include: vertical discharge methods, tracking of productivity/ injectivity index, and tracking of skin factor and permeability from pressure transient analysis. This paper reviews all methods of identifying formation scale, both indirect and direct, for production and reinjection wells, and provides examples. This is intended as a guide to decrease the risk of chemical cleaning jobs, and can also form the basis for well monitoring program design.

1. INTRODUCTION

Scaling of geothermal wells can be a significant maintenance issue for geothermal operations. Some geothermal fields naturally have higher levels of dissolved minerals than others, and therefore have more scaling issues. Scaling issues can also worsen over time, if pressure drop in the reservoir induces cooler highly mineralised peripheral fluids to be drawn in to the reservoir. Increased scaling issues in Contact's geothermal fields have led to an increased focus on this issue and how to mitigate it.

Wellbore scale is relatively easy to detect and remove, as it can be accessed within the wellbore using tools suspended from the surface. Techniques for removal of wellbore scale are all mechanical and have been successful for many years. Formation scale is both difficult to detect and remove, as it is located outside of the liner within the formation rocks themselves, where it cannot be detected directly or removed mechanically.

The only current option for removal of formation scale is chemical cleaning. Chemicals with the ability to dissolve scale are delivered to the scale location dissolved in fluid pumped from the surface. Whilst a proven industry-standard technique, when compared to mechanical cleaning the art of chemical cleaning is relatively undeveloped and has been a focus area for numerous companies in recent years. Chemical cleaning so far is more expensive than mechanical cleaning, and also requires quenching and lost generation in the case of production wells. It is therefore necessary to be as certain as possible that there is indeed formation scale present prior to carrying out a chemical clean. If no prior work is done, and a chemical clean is performed, this is a gamble. Sometimes the gamble will pay off and result in an uplift, however, sometimes there will be minimal or no uplift. The question will remain: did the chemicals fail to dissolve the formation scale, or was there no scale present? This is a situation to be avoided as much as possible.

Absolute certainty is not possible due to the location of formation scale. However, it is possible to decrease the risk of unsuccessful cleans with a thorough assessment of reservoir engineering data prior to the job, using common indirect methods and less-common direct methods as outlined in this paper. It is the intention of this paper to comprehensively list those methods, rather than delve into the chemical cleaning process itself.

2. BACKGROUND

2.1 Types of scaling

Making the distinction between wellbore and formation scale is important as methods to identify and to mitigate their impacts are different. Wellbore scale occurs within the well itself, either in the production casing or the liner. Wellbore scaling in production wells is typically localised at the flash point, where boiling is induced as pressure decreases. Formation scale occurs within the reservoir, if the fluid is boiling, often close to the wellbore due to production-induced pressure drop there.

In injection wells, scaling can occur within the wellbore and/or the reservoir, also the station and steamfield. Scaling in injection wells is caused by minerals precipitating as they become oversaturated, when the fluid composition and temperature change through the power generation process. It typically occurs over a very large area as opposed to in production wells, where the scaling is typically localised around the flash point. A schematic showing the relative

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location of wellbore and formation scaling in a production well is shown in Figure 1, and for an injection well in Figure 2.

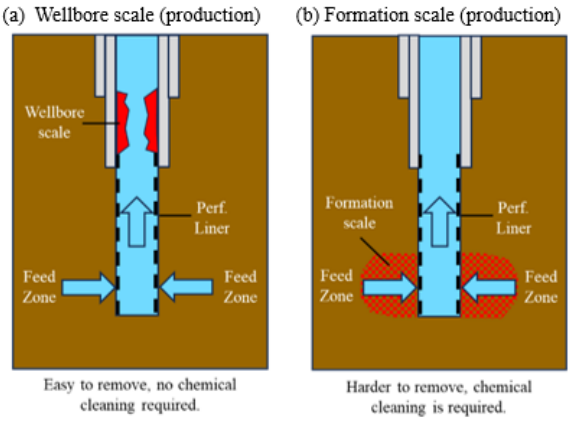

Figure 1: Schematic of wellbore and formation scaling in production wells.

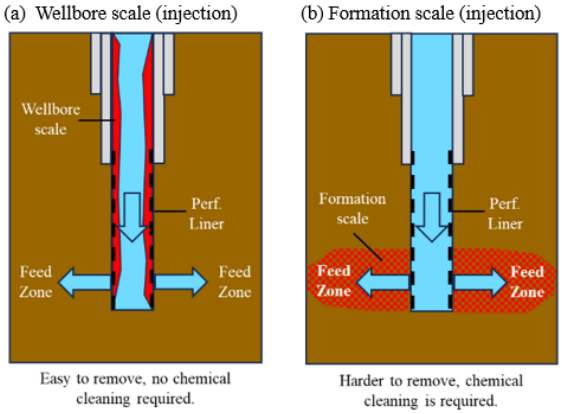

Figure 2: Schematic of wellbore and formation scaling in injection wells.

Figure 3 shows a schematic close-up of formation scaling, comparing fluid flow through clean formation (Figure 3a) to restricted flow through scaled formation (Figure 3b). It is apparent that due to the narrowness of the flow pathways, they are vulnerable to even small amounts of scaling.

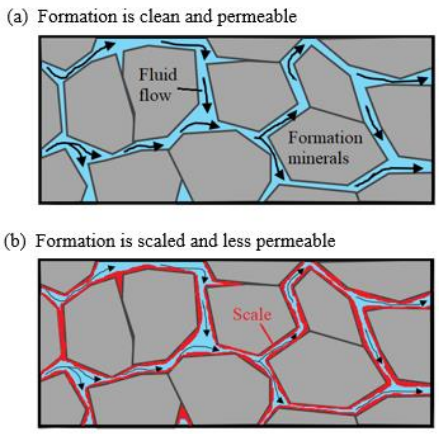

Figure 3: Schematic showing (a) clean formation (grey); (b) scaled formation (red scale on grey).

2.2 Tools for identifying wellbore scale

Wellbore scale can be directly accessed by tools suspended on wireline from the surface. The simplest tool for this purpose is gauge rings or "go-devils". These are metal tools of fixed radius, which can be run through casing or liner to see if it is clear all the way to the bottom. If scale is located within the wellbore, then the gauge rings will not be able to pass through, identifying the presence of scale and also the location of the top of the scale. As gauge rings only tag the top of the scale, they cannot provide a scale profile along the wellbore. Calipers can do this. A commonly used caliper for this purpose is the High-temperature X-Y Caliper (HTXY), which is a simpler version of the multi-finger caliper. This tool uses two axes to provide the blockage profile inside the wellbore (Figure 4).

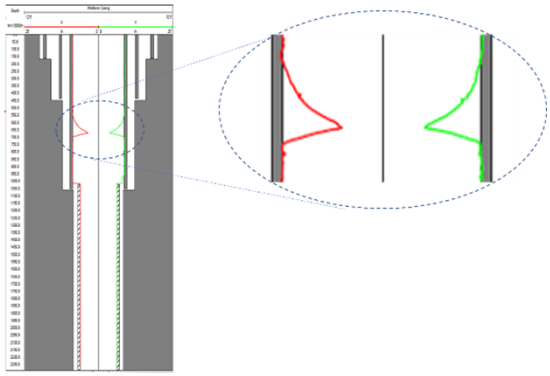

Figure 4: Scale profile inside production casing based on HTXY caliper data.

The HTXY data offers a clear understanding of the scale build-up and possible casing anomalies, which is used to determine the type of cleanout required and estimate the volume of scale to be removed. A collaboration between the companies Probe and Western Energy has developed the first HTXY caliper for the geothermal industry rated for downhole temperatures up to 325°C.

2.3 Methods to remove wellbore scale

There are various methods to remove wellbore scale which are applicable depending on the nature and extent of the scaling.

2.3.1 Live well cleanout (LWC) using Coiled Tubing Hammer (CTH)

LWC using the CTH tool has been performed by Western Energy on geothermal wells in New Zealand since 2016 and in the Philippines starting in 2024. The objective of this intervention is to remove wellbore scale while the well is flowing to the surface, lifting the scale debris. The CTH tool, with its specially designed bottomhole assembly (BHA), operates with a percussive motion powered by pumped nitrogen gas. The CTH tool can also remove scales in reinjection wells offline by using nitrogen gas to assist in lifting the well fluid and scale debris to the surface.

Since its development in partnership with Contact Energy (Wilson and Anderson, 2021), this intervention method has gained recognition in the global geothermal market compared to small drilling rig-based cleanout due to the following benefits: (1) efficient mobilisation and rig up/down; (2) smaller footprint; (3) scale debris brought to the surface; (4) minimised operational downtime; (5) no quenching/heatup for production wells.

2.3.2 Killed Well Cleanout (KWC) using Coiled Tubing Motor and mill/bit (CTM)

This type of intervention is conducted for wells suitable for quenching and those identified with mechanical-based blockages or damages inside the wellbore. The specific type of mill or bit is chosen based on the known wellbore blockage. The motor and mill/bit are powered by pumped water. For wells with multiple obstructions, there are cases where CTM is implemented to create a "pilot hole," followed by a CTH run.

2.3.3 Broaching

Broaching is a wireline-based intervention that involves running a series of sharp-edged tools to remove wellbore scales. This intervention is most effective when the well is nominally vertical, and the mineral scales are still soft and newly formed. The well should ideally be shut or highly throttled so that the uplift force of the fluid does not oppose the downward jarring force of the broach tool.

2.3.4 Small Drilling Rig

Historically, geothermal wells have been cleaned out using a small workover drilling rig. The high cost of this method is related directly to the costs of employing the rig and the associated lost production time (Wilson and Anderson, 2021).

With the availability of coiled tubing methods and broaching, using a small drilling rig for wellbore scale removal is deemed uneconomic. Additionally, rig-based cleanout requires quenching, which is risky for the casing.

2.4 Methods to mitigate formation scale

2.4.1 General description of chemical cleaning

The focus of this paper is on identifying the presence of formation scale, rather than the process of removing it. It is however of interest to briefly note some background on removal methods. As formation scale is not accessible by mechanical interventions the only viable option to remove the scale is chemical cleaning. This is applicable to both calcite scale in production wells and silica scaling in injection wells. Depending on the chemicals used, there is also potential for chemical stimulation to occur, where the chemical dissolves formation minerals instead of scale (Setiawan et al., 2021).

2.4.2 Chemicals used

The bulk of chemical workovers published in the literature have involved the use of hydrofluoric acid (HF) and hydrochloric acid (HCl) - or a combination of both - to treat calcite or silica scale (Ferguson et al., 2024). More recently the use of other acids such as formic acid has been explored. HF is extremely hazardous and the use of sodium hydroxide (caustic) as a viable alternative to treat silica scale has been highlighted by multiple authors, including laboratory and field trials (Ferguson et al., 2024).

In addition to the primary chemicals used for cleaning, a treating agent may be added to keep the dissolved scale in solution longer, preventing rapid re-precipitation in the reservoir. Also, when acid is being used, an inhibitor is added to mitigate corrosion of the well casing and liner.

2.4.3 Targeting feed zones

When identifying the target feed zone for production wells, reservoir properties must be considered, as not all feed zones are the same enthalpy. Stimulating a lower-enthalpy feed zone could potentially decrease overall energy production from the well, even if mass flow is increased (Pasikki et al., 2010). Wellbore modelling is typically performed to assess the effect of treating ranges of feed zones. Careful job design is required to ensure chemicals are delivered to the target feed zones (and not undesirable feed zones), without being diluted by inflows or diverted by higher feed zones (McLean et al., 2021). Sometimes this is achieved with bull-heading from the surface and careful flow rate control, and sometimes with the use of CTU for chemical injection.

2.4.4 Drilling

The only other option is to avoid the issue completely and drill a new well. Drilling is much more expensive than chemical cleaning, so this is unlikely to be financially viable if the purpose is purely to counteract the loss of capacity due to scaling. However, if the purpose is because of reservoir conditions, for example by relocating production away from a cooling front and into a hotter/higher enthalpy part of the reservoir, then drilling will still be required.

3. INFERRING FORMATION SCALE INDIRECTLY

3.1 Typical process

Due to the fact that formation scaling cannot be accessed directly via the wellbore, its presence is typically inferred indirectly. The steps of this process are as follows:

1. Identify that the capacity of the well is declining. This is seen as a decrease in the normalised mass flow from production wells, and normalised mass flow or injectivity index for injection wells.
2. The decline cannot be explained by reservoir conditions. For example: decreasing reservoir pressure will decrease mass flow from production wells regardless of scaling. Wellbore modelling can rigorously determine the effect of reservoir conditions on well capacity. This can also be determined by assessing nearby wells as a group, and unless all the wells are affected similarly, the decline is unlikely to be explained by reservoir conditions in that area. Scaling is suspected if step 2 rules out reservoir conditions as the culprit.
3. Flash point location (for production wells) - assessing the location of boiling in that well as this determines the location of scaling. This is done by looking at flowing pressure-temperature-spinner (PTS) data. If the flash point is located up inside the production casing, it is isolated from the reservoir and boiling/scaling can only be in the wellbore. If it is down in the liner, there could be boiling/scaling in both the wellbore and the adjacent formation. If it is not present in the wellbore (feed zones are all steam or two-phase) there could be boiling/scaling in the formation.
4. Geochemical conditions (production and reinjection wells) – geochemical modelling can predict whether the chemical conditions for mineral deposition (saturation) are present in the formation and at any stage along the wellbore, provided there is sufficient chemical and reservoir data to constrain the modelling.
5. Checking for wellbore scale with tools (e.g. calipers, Section 2.2). If wellbore scaling is suspected to be the cause of decline after previous steps, then its presence or absence can be confirmed with wireline tools.

Formation scaling is inferred to be the culprit (for the capacity decline observed in step 1) in the event that step 2 rules out wider reservoir conditions, step 3 and step 4 confirm that the thermodynamic and geochemical conditions necessary for scaling to form are present in the formation in this well, and step 5 confirms a lack of wellbore scaling.

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3.2 Less common - development of cyclical behaviour

One less-common phenomenon that indicates a decline in well capacity is the development of cyclical behaviour in production wells with relatively low permeability. Well cycling refers to fluctuations of the mass flow and/or the wellhead pressure (WHP) with time. The presence of cyclical behaviour in a well itself does not indicate scaling, just that permeability is low. However, if the well develops cyclical behaviour over time, this indicates a progressive decrease in permeability, which can be attributed to scaling.

For example, BR066 at Ohaaki is a previously stable well which has developed WHP cycling since going into service 8 years ago (Figure 5). The cycling is relatively subtle as it is seen only in the WHP and not the mass flow of the well. This indicates the permeability of BR066 has decreased. Formation scale is inferred to have developed, as there have been no changes to the reservoir conditions in that part of the reservoir, the flash point is located outside the wellbore, and the wellbore is free of scale.

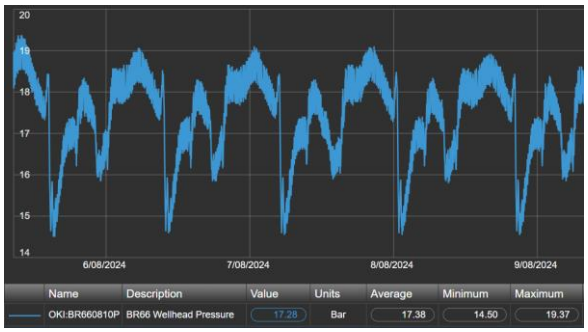

Figure 5: Example of WHP cycling in BR066

3.3 Fishbone diagram for visualisation

Formation scaling is one potential cause of output decline that may occur alongside other reservoir and wellbore processes. The fishbone diagram, also known as the Ishikawa diagram, is an effective tool for visualising cause and effect. It aids in systematically listing and evaluating all potential causes. This comprehensive approach allows reservoir engineers and geoscientists to identify and rule out the most likely causes of capacity decline, as an aid to the process described in Section 3.1.

Figure 6 shows an example fishbone diagram. The effect in this case is capacity decline of a well, at the head of the fish. The bones of the fish are the groups of potential causes, which in this case are: reservoir processes, wellbore issues, wellbore scaling, and formation scaling. Each group can have multiple factors.

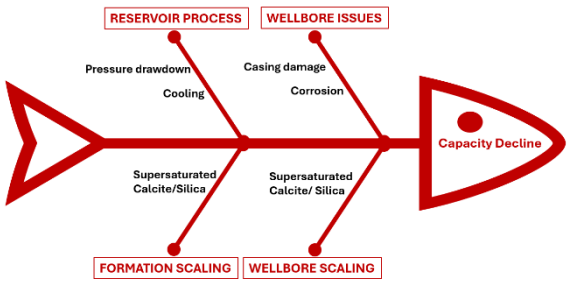

Figure 6: Fishbone diagram for geothermal production well capacity decline root-cause-analysis.

4. NON-STANDARD METHODS OF IDENTIFYING FORMATION SCALE

In addition to the typical process and tools for inferring formation scale indirectly (Section 3), there are some further methods available to identify formation scale more directly and with more certainty. These include vertical discharge methods for steam production wells, tracking productivity/injectivity index, and tracking changes in skin factor/permeability from pressure transient analysis.

4.1 Vertical discharge methods for steam wells

4.1.1 Description of method

Vertical discharge of steam wells can be used to identify if there is formation scaling. The primary method is to analyse the shape of the output curve to determine whether wellbore effects or formation effects dominate. Other associated indicators include: (a) well cannot sustain discharge, (b) well surging, (c) fragments of scale discharged to the surface.

Examples of vertical discharge of three steam wells in the Wairākei reservoir are presented. These are steam production wells WK251 and WK228 which are drilled into the production-induced steam cap at the top of the Wairākei reservoir, and are declining due to suspected formation scaling. The third well is WK249 which is a monitoring well located in the same steam cap and not expected to be scaled, for comparison. A description of the testing and data from each well is given, followed by analysis of the output curves.

4.1.2 WK251 testing and data

A plot of WHP, lip pressure and calculated mass flow during WK251 testing is shown in Figure 7. WK251 was vertically discharged using a 3” lip pipe. From a shut in WHP of 6.2 bg, WHP dropped to 1.98 bg and kept on declining. Lip opening was then reduced to 15% to increase the WHP but only minimal gain was achieved. The lip size was then increased to 6” and flow could not be sustained. The test did not yield the three stable data points (mass flow and WHP) required for plotting an output curve and so the shape of the output curve could not be analysed. It can be inferred indirectly that WK251 has formation scaling, as nearby steam wells are still producing, and a recent caliper survey indicates little wellbore restriction.

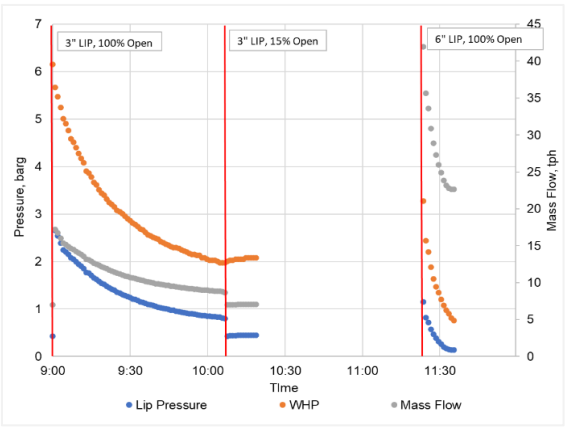

Figure 7: WK251 vertical discharge data.

4.1.3 WK228 testing and data

WK228 was discharged using a 6” lip pipe, based on the experience of discharging WK251. During the initial hour of the discharge test, WK228 was observed to be surging, as seen in the WHP and lip pressure in Figure 8. After a while, the WHP stabilised to 3.3 bg at fully open condition. Lip pipe

opening was decreased to 60%, 30% and then 25% to yield the data required for plotting an output curve (Figure 10).

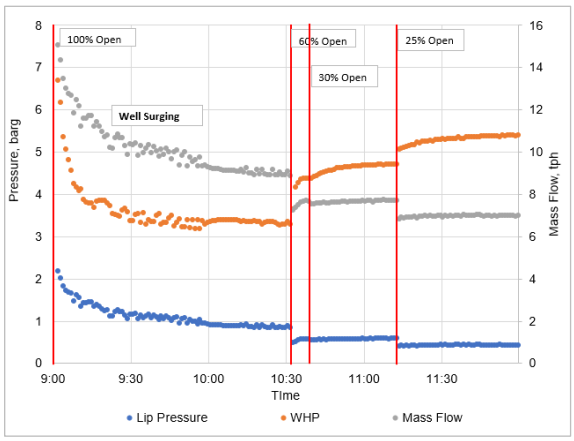

Figure 8: WK228 vertical discharge data.

4.1.4 WK249 testing and data

WK249 is a monitoring well never utilised for production. If there are signs of formation scaling in WK249, this could mean that the scaling is widespread in the steam cap. Figure 9 is a plot of WHP, lip pressure and calculated mass flow. Unlike the two previous wells, stabilisation was rapid. Sufficient stable data points were gathered to plot an output curve (Figure 11). During the test, surging was present but also not as evident as for WK228. This means that there is no significant formation scaling at WK249 and that scaling is not widespread in the steam cap.

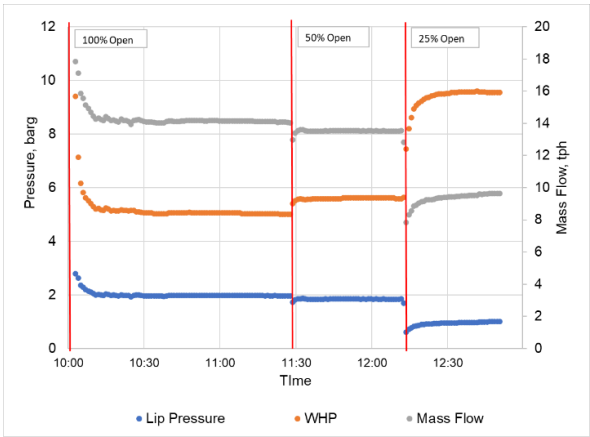

Figure 9: WK249 vertical discharge data.

4.1.5 Equations for analysis of output curve shape

The shape of the output curve from the vertical discharge can be analysed to test for the presence of formation scale. The empirical equation typically used to analyse output curves of steam wells is the following (Sanyal et al., 2000) which is based on performance of gas wells:

$$W = C\left(P_s^2 - P_f^2\right)^n \qquad \text{(Eq. 1)}$$

Where: W = mass flow; P_s = static (shut-in) wellhead pressure; P_f = flowing wellhead pressure; C = an empirical constant unique to a well, the steam well productivity index; n = a dimensionless constant.

The apparent value of n ranges from 0.5 to 1 depending on the wellbore or formation behavior. If the wellbore losses account for the largest part of the delta pressure ($P_s^2 - P_f^2$) then n should be close to 0.5. This would be the case for wells with wellbore scaling, restriction or limited wellbore capacity. On the other hand, n should be close to 1.0 when the formation permeability is very small (e.g. with formation scaling) or if the formation dominates the response because the wellbore is too large (Acuna et al, 2008).

Acuna et al, 2008 set out a new deliverability equation for dry steam wells based on parameters that can be measured such as productivity index and wellbore pressure loss. The equation is:

$$P_s^2 - P_f^2 = \frac{1}{A} W^2 + \frac{2\nu_s}{PI} W \qquad \text{(Eq. 2)}$$

$$A = \frac{1}{C_{wb} - \left(\frac{\nu_s}{PI}\right)^2} \qquad \text{(Eq. 3)}$$

Where: C_{wb} is a new constant called wellbore coefficient, ν_s is kinematic viscosity of steam, and PI is well productivity index (m^3).

4.1.6 Analysis of WK228 and WK249 output curve shapes

An output curve for WK251 could not be plotted as three stable data points could not be measured during testing. The output curves for WK228 and WK249 are shown in Figure 10 and Figure 11, using both Eq. 1 (Sanyal et al., 2000) and Eq. 2 (Acuna et al., 2008). Both equations are equally good at describing steam well performance.

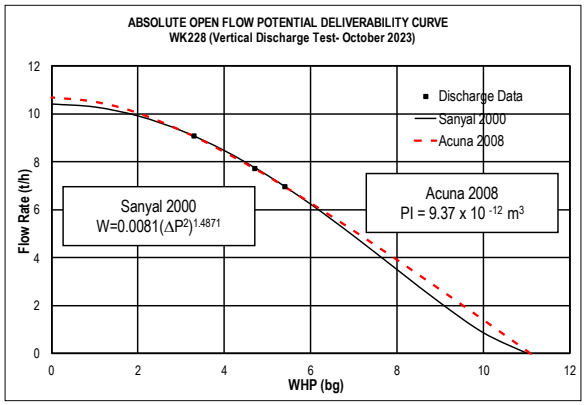

Figure 10: Output curve shape analysis for WK228.

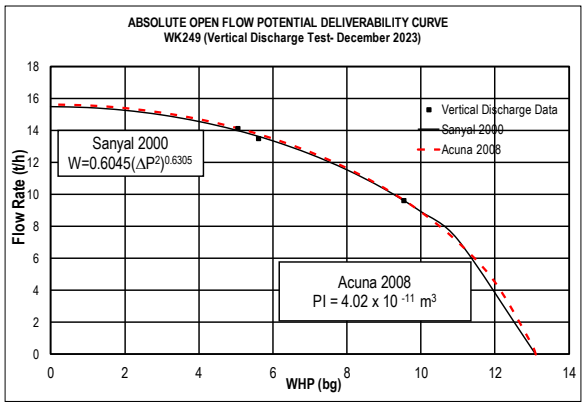

Figure 11: Output curve shape analysis for WK249.

WK228 output curve (Figure 10) has a steeper curve and "n" from Eq. 1 is closer to 1 than to 0.5. This means that the well has potential formation scaling. On the other hand, WK249, a monitor well and not suspected of formation scaling, has a flatter curve and its n is closer to 0.5 (Figure 11). In terms of Eq. 2, the PI of WK228 is 9.37 x 10^{-12} m^3 while that of WK249 is 4.02 x 10^{-11} m^3. It can be inferred that WK249 has

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lower formation scaling compared to WK228 due to higher PI, corroborating the results from using Eq.1.

A variation of Eq. 2 from Acuna et al (2008) has been published (Acuna et al., 2010), to correct the fluid properties based on the effects of gravity. However, it was found that for the WK249 vertical discharge data, the output curve did not change significantly with its application. Hence, the original Eq. 2 has been used as it is relatively easy to use.

4.1.7 Discharge of scale fragments

When WK228 was discharged, formation scaling was indisputably identified as there were scale products to the surface (Figure 12). XRF elemental testing was performed to determine whether these were fragments of scale or formation. The presence of silica, calcium and aluminium possibly indicates calcite scaling (typical in production wells) as well as aluminium silicates (clay) and silica scale.



Figure 12: Fragments of scale discharged during vertical discharge of WK228.

4.1.8 Surging/cycling

Well surging is also a sign of formation scaling, and was quite apparent during the initial discharge of WK228. "Surging" is a term describing high-frequency cycling, a sign of low permeability as discussed in Section 3.2.

4.1.9 Additional certainty gained from VD testing

Comparing the results of the vertical discharge of WK251 and WK228 (both suspected with formation scaling) with the monitor well WK249 (less likely to have formation scaling) increased the certainty in the presence of formation scale.

No stable data points were derived from the discharge of WK251 so there was no output curve to be analysed. Not sustaining discharge is the main indicator of formation scaling in this well (indirect).

For WK228, an output curve was generated from the vertical discharge and analysed and compared with WK249 using Eq. 1 and Eq. 2. The value of "n" of WK228 in Eq. 1 is closer to 1.0, which means formation permeability is very small due to formation scaling. The value of "n" of WK249 is closer to 0.5 which means formation scaling is less likely. This is supported by the results for Productivity Index (Eq. 2) which show the PI of WK228 is lower than that of WK249. Further indications of formation scaling in WK228 were the discharge of scale fragments (direct), and surging (indirect).

4.2 Productivity/Injectivity index decline

4.2.1 Overview of theory

Various processes can affect the production/injection capacity of a well (t/h). These processes can be wellbore, reservoir, or surface processes, such as: wellbore scaling or obstruction, formation scaling, corrosion, cooling, and pressure drawdown. Most geothermal wells can encounter multiple processes at a time.

Productivity index (PI) and injectivity index (II) are slightly different, as they quantify the ability of the reservoir/formation to discharge or inject fluid, in isolation of other processes. In production wells the PI of a permeable zone is defined as mass flow produced per unit of differential pressure between static and flowing pressure at the depth of the permeable zone in the reservoir (t/h/bar). Similarly, for injection wells II is defined as mass flow injected per unit of differential pressure between injecting and static pressure at the depth of the permeable zone in the reservoir (t/h/bar).

PI and II values therefore represent the hydraulic properties (permeability) in the near-wellbore reservoir formation. PI/II values can be obtained and calculated from PTS surveys, as these measure all the necessary data at reservoir/formation depths (flow, downhole pressure at different flow rates). Decline in PI and II through time is a direct indicator of formation scaling. Values for PI/II can be obtained directly by actual PTS measurements, or from wellbore modelling.

4.2.2 PI/II from actual PTS measurements

PI/II values decrease with formation scaling and are unaffected by wellbore scaling, as they relate only to the ability of the formation to flow in response to the downhole pressure differential. If regular downhole PTS surveys are conducted in a well, PI/II of each permeable zone in the reservoir can be tracked and formation scaling can be inferred based on trends. However, due to the cost associated with these surveys, availability of PI/II values from actual measurement is frequently limited, and hence the need to use wellbore modelling to deduce PI/II trends. The temperature of injectate can vary significantly, which will significantly affect the II values. In order to compare II from different temperatures, it is necessary to correct them to a single temperature by the method proposed by Siega et al (2014).

4.2.3 PI/II from wellbore modelling

Wellbore modelling can be used to estimate PI/II. Isolating the impact of non-formation scaling processes is necessary to estimate the changes in PI/II. A comprehensive approach using wellbore modelling helps in understanding how different processes influence PI/II (t/h/bar) and performance (t/h). Wellbore modelling is used to quantify the impact of each process. Therefore, it does not only allow identification of potential formation scaling but also enables estimation of associated steam loss or injection capacity loss. This steam or injection capacity loss can then be used to assess the economic benefits of conducting chemical clean in the well.

The first step of this method involves creating a wellbore model to estimate fluid, wellbore and reservoir parameters. Accurate calibration of this model requires data from the well in pristine condition, providing a reliable baseline for the initial PI/II. The next step is to estimate the changes to PI/II with time by calibrating the wellbore model against the historical production/injection data.

4.2.4 Wellbore modelling hypothetical example

Figure 13 is a hypothetical example to illustrate results of historical wellbore modelling to infer and quantify the effects of formation scaling in a well.

Typically, the first step is to establish a baseline wellbore model, defining the: (1) feedzone locations, (2) pressure and enthalpy of each feedzone, (3) initial PI/II value of each feedzone, and (4) wellbore geometry. The baseline hydraulic model is calibrated against the well's initial production considered as its pristine condition/performance.

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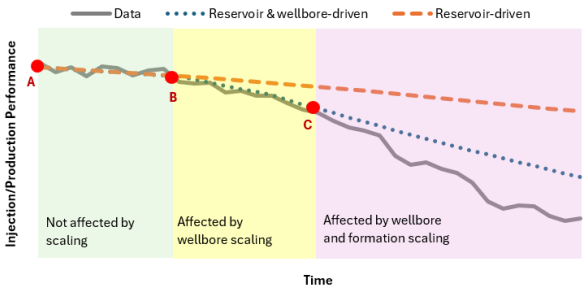

Figure 13: Method of inferring formation scaling (PI/II decline) through historical wellbore modelling.

Through time, the wellbore model will be run and calibrated each time new production or injection data becomes available. At each calibration point, the pressure and enthalpy of each feedzone will also be updated based on available information from the actual well, comparable nearby wells, or the reservoir numerical model. The line generated from this exercise represents the expected "reservoir-driven" performance of the well. Ideally, if the well is not affected by wellbore and/or formation scaling, actual data should coincide with such line. This behaviour is represented by period A-B.

From the "reservoir-driven" performance simulation, wellbore geometry changes through time (mostly from buildup of wellbore scale), obtained from available downhole surveys (e.g. "go-devils"), can then be incorporated to simulate the expected well performance brought about by changes in wellbore geometry in addition to the pressure and enthalpy of feedzones. This is represented by the "Reservoir and wellbore-driven" line. Period B-C represents a behaviour that is affected by wellbore scaling since it does not overlap with the "reservoir-driven" performance. However, since it reasonably matches the data during this period, this suggests that similar to period A-B, PI and II values during period B-C do not warrant changes. It can then be inferred that formation scaling is not yet impacting the performance of the well.

Lastly, from point C, the behaviour of the well can no longer be explained by the predicted "reservoir and wellbore-driven" performance. At this point, assuming that there is sufficient confidence in the inputs for the pressure/enthalpy changes in feedzones and wellbore geometry changes through time, there is apparent need to reduce the PI/II values to match the data. This simulated reduction in PI/II values conceptually suggests scaling in the formation. The distance between the "reservoir and wellbore-driven" line and the actual well data quantifies the potential recoverable gain (i.e. steam or injection capacity) from removing the formation scale.

It is important to re-state that in the absence of actual downhole surveys that would directly measure reduction in PI/II values, the interpretation of formation scaling through historical wellbore modelling is heavily dependent on the accuracy and sufficiency of pressure/enthalpy assumptions for the feedzones and wellbore geometry data through time. However, the main advantage of historical wellbore modelling is it allows quantification of the impact of several processes that can affect well performance through time.

4.3 Pressure transient analysis

4.3.1 PTA, skin factor and permeability

Pressure transient analysis (PTA) is a powerful tool for assessing reservoir/formation condition. It is able to assess whether the near-wellbore reservoir/formation has a relatively low permeability compared to the wider reservoir, as would be expected for formation scaling (Figure 14).

The two key PTA parameters of interest for this purpose are skin factor (s), and reservoir permeability (k). The dimensionless skin factor (s) describes the relative permeability within the skin zone (typically modelled as within 5m of the wellbore, Figure 14) compared to the permeability of the wider reservoir. When s is zero there is no difference in permeability. When s is negative the permeability is higher in the skin zone, this is called "stimulation" and can result from drilling-induced tensile fracturing, for example. When s is positive the permeability is lower in the skin zone, this is called "damage" and can result from obstruction with mud, cuttings, or – over the long-term – formation scale. The reservoir permeability (k) of the wider reservoir is also of interest, as this can still be affected by formation scaling, because although formation scaling tends to be concentrated close to the wellbore, it can extend further into the reservoir.

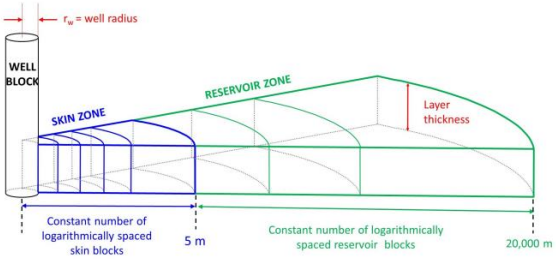

Figure 14: Schematic of PTA numerical model grid (McLean, 2020).

4.3.2 Long-term changes in skin factor and permeability

Geothermal wells usually have a negative skin factor at the time of drilling, as they tend to be drilled with aerated water to clear cuttings, and are drilled into naturally fractured reservoirs (McLean, 2020). As formation scale forms in a well, the skin factor will increase. If it starts negative, then it will become less negative over time, pass through zero, and perhaps even become positive in the long-term. So, a single value of skin factor will not diagnose formation scaling, it is the increase in skin factor over time that indicates formation scaling. A baseline skin factor for the well in clean condition at the commencement of long-term production is highly recommended, so that future skin factors can be compared to this. If formation scale forms further away from the wellbore in the wider reservoir, then the permeability (k) will decrease. A combination of skin factor increase and permeability decrease may be observed.

In practice due to the costs of downhole PTS runs and limited uptake of PTA methods, reliable values of s and k through time are rarely available. In this case PTA can be put to different use as described in the following section.

4.3.3 Sudden decrease in skin factor with chemical cleaning

If formation scaling is present in the well, the skin factor will be higher than when the well is in a clean condition. Therefore, the effect of removing the formation scale is to decrease the skin factor. Before- and after- PTA testing (from injecting or discharging PTS) is recommended to measure the change in skin factor. A decreasing skin factor confirms the presence of scale and its removal with the chemical clean. The permeability may also increase. These PTA methods are applicable to both production and reinjection wells.

4.3.4 Production well example

PTA in production wells can be from a pressure buildup after discharge/shut-in, or pressure transients from step changes in flow (up or down) during injection (Mclean, 2020). The production well BR52 at Ohaaki geothermal field underwent chemical cleaning in 2021, after formation scaling was inferred indirectly via the methods outlined in Section 3. The skin factor prior to the job was positive s = 3 as determined from the pressure buildup derivative match shown in Figure 15. After chemical cleaning the skin factor was negative s = -2 (Figure 16). The decrease in skin factor as a direct result of chemical cleaning is only explainable by the removal (and therefore presence of) formation scale in this well. The permeability (k) increased from 100 to 200 .e-15 m^2, indicating the presence of scale far beyond the 5m skin zone.

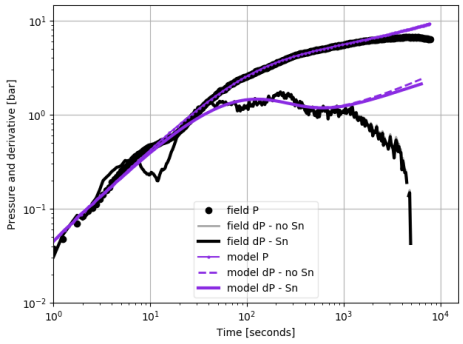

Figure 15: BR52 pre-job PBU pressure derivative plot.

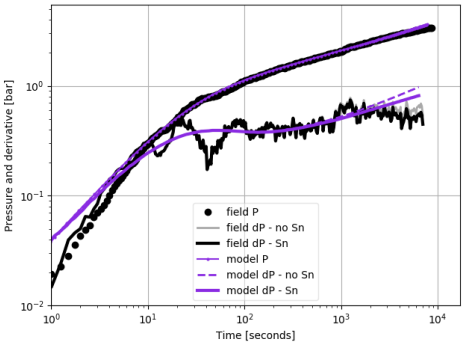

Figure 16: BR52 post-job PBU pressure derivative plot.

6. SUMMARY

Scaling in both geothermal production and reinjection wells is a major issue causing capacity decline. Formation scaling is worse than wellbore scaling because it is more difficult to both identify and remove. Chemical cleaning is currently the only method able to remove formation scaling. Because the cost of chemical cleaning is not trivial, it is necessary to diagnose formation scaling with the highest degree of certainty that is reasonably practicable, to decrease the risk of unsuccessful cleans.

There are several common steps used to infer the presence of formation scale indirectly: identifying capacity decline, ruling out reservoir conditions as the culprit, checking the flash point, checking the geochemical conditions, ruling out wellbore scale, development of cyclical behaviour. A Fishbone diagram is very useful to visualise the cause-and-effect analysis being undertaken:

If the indirect methods are insufficient there are several additional less-common methods available to increase certainty in the diagnosis of formation scale: analysis of the shape of output curves (for steam wells only), discharge of scale fragments during vertical discharge (production wells only), productivity/injectivity index decline, PTA methods (for production and reinjection wells) – changes in s and k with time or cleaning.

It is true that in some cases, there will be insufficient data to reach the maximum level of certainty. Also, the risk appetite of each operator is different, and the urgency of a job may outweigh the potential benefits of increased certainty. However, the steps and methods outlined in this paper are offered as a guide for consideration by operators of geothermal wells with formation scaling/chemical cleaning challenges, if increased certainty is of interest.

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