CHEMICAL CLEANING AT MERCURY'S GEOTHERMAL POWER PLANTS

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ABSTRACT

Chemical cleaning is the use of chemicals to remove mineral scales and deposits from plant and equipment. Chemical cleaning is a practice used regularly in the geothermal industry and is often implemented when mechanical cleaning is either not practical and/or ineffective. Chemical cleaning techniques can be utilised on both surface equipment such as heat exchangers as well as downhole in production and injection wells to remove common geothermal deposits including silica, calcite and heavy metal sulphides such as stibnite.

This paper discusses the considerations that need to be made when planning chemical cleaning work, and assessing where chemical cleaning may be of benefit to geothermal plant operators. Case studies and examples are provided of typical chemical cleaning applications utilised at Mercury's geothermal power plants in New Zealand.

1. INTRODUCTION

Chemical cleaning is used throughout heavy industries, including the electricity generation industry to clean plant and equipment (particularly heat exchangers). Chemical cleaning can be undertaken to clean both new equipment (pre-service cleaning) as well as equipment that has become fouled during service (post-service cleaning). Chemical cleaning in the electricity generation industry often utilizes acidic solvents to remove mineral deposits and mill scale, while alkali solvents are typically used for the removal of organic material and some mineral deposits.

1.1 Examples of Chemical Cleaning

Common examples of chemical cleaning in the geothermal electricity generation industry include:

- Cleaning of shell and tube and plate and frame heat exchangers;
- Acid stimulation of geothermal wells

Mercury NZ has implemented chemical cleaning of heat exchangers and geothermal wells (both production and injection) in recent times.

1.2. Why Chemical Clean

Chemical cleaning is often not the first choice for cleaning equipment within Mercury's geothermal business due to the chemical handling and safety considerations. It is however a very important technique that is utilized when other cleaning methods (such as mechanical cleaning) are not suitable or are ineffective.

Chemical cleaning of heat exchangers is usually undertaken at Mercury for one of two reasons:

1. Other cleaning methods are not effective, for instance mechanical cleaning may not be sufficient to remove stubborn deposits of silica or metal sulphides. Alternatively, it may not be feasible to mechanically clean some equipment designs.
2. Chemical cleaning is the most effective cleaning method as a result of either better cleaning efficacy, or a reduction in time or cost compared to alternative options. Mercury has found this to be the case with some heat exchangers, where chemical cleaning can reduce unit down time by over 80% compared to mechanical cleaning

The chemical (typically acid) stimulation of geothermal wells is relatively common in the geothermal sector. Mercury utilize chemical stimulation of wells where well performance has declined significantly due to a reduction in near wellbore permeability. For a chemical clean to be selected for a given well, the cost/benefit of the restoration of this performance is always a key factor for consideration.

2. CONSIDERATIONS

When deciding whether chemical cleaning is the appropriate technique to remedy a plant or well issue, there are several factors to consider prior to the detailed design of the chemical cleaning operation itself.

2.1 Cleaning Approach

To assess whether chemical cleaning is the best approach, it is necessary to consider the alternative methods (e.g. pressure washing, steam cleaning, chiseling, grinding etc.). In some instances, it may be better (due to cost or reliability factors) to replace equipment, or components of equipment rather than cleaning them.

When determining the cleaning technique to be utilized some key points to consider are:

- Safety
- Likelihood of success,
- Complexity of the process,
- Risk to plant and equipment,
- Time (and any lost production) required,
- Cost
- Waste disposal

Figure 1 below shows how much equipment can be involved in an otherwise straight forward cleaning process.

Figure 1: Layout of a well pad for chemical cleaning, note the large amount of equipment required for this clean utilizing a CTU.

Once it has been ascertained that chemical cleaning is the best approach for a given situation, the design of the chemical cleaning process can begin. The design phase has two key categories: the chemical considerations and process considerations.

2.2 CHEMISTRY CONSIDERATIONS

Chemistry aspects of the clean are focused on determining the appropriate solvent (or mixture of solvents), corrosion inhibitor requirements and chemical volumes. The seven points below are used by Mercury when determining the appropriate solvent to use for a given chemical cleaning application.

2.2.1 Deposit/Material Composition

The most important factor in designing a chemical clean is understanding the composition of the material that is to be removed. While a basic understanding of the material can often be enough to prepare a chemical cleaning plan, the more information that can be gathered, the more effective and efficient a clean is likely to be. For example, when attempting to remove silica rich deposits or minerals in geothermal wells, a mixture of hydrochloric and hydrofluoric acid (mud acid) is often utilized. Given thorough understanding of the deposit (preferably by laboratory analysis of samples), the concentrations of the two acids can be adjusted to improve the result from the clean – i.e. solvent optimization.

In-depth material composition information can also be used to adjust the cleaning process design parameters such as contact time and temperature.

Laboratory testing of deposit samples is recommended when designing a chemical clean.

2.2.2 Corrosion Risk

Corrosion of equipment and well casings and liners is often one of the key concerns when undertaking chemical cleaning. The risk of corrosion is governed largely by materials of construction (of the equipment to be cleaned), the solvent selection, temperature and contact time. Other factors can also impact corrosion risk – for instance the partial pressure of carbon dioxide can adversely affect the efficacy of some corrosion inhibitors – something to be aware of when planning the chemical cleaning of calcite deposits.

Where the corrosion risk of a cleaning process is significant, corrosion inhibitors are typically employed to reduce corrosion to acceptable levels. It is recommended to undertake testing of corrosion inhibitors under the expected conditions of use, on the materials that will be exposed to the solvent. Corrosion inhibitors that are effective on one material, may be less effective on another – for example the efficacy of a particular corrosion inhibitor blend may be acceptable on L-80 well casing, but not acceptable on the HS80 or Q900 coil tubing used to place the solvent in the well. A similar challenge can exist in heat exchangers, where the tubing or plate material is often different to the shell and piping material.

2.2.3 Precipitation

The potential for the precipitation of reaction products, and the risks that such products pose should be studied. Reaction products from the reaction of the solvent and the target material are often straight forward to identify and have a large bearing on solvent selection (e.g. sulphuric acid is not typically used to remove calcite or carbonate bearing deposits due to the production of relatively insoluble calcium sulphate). However other possible reactions also need to be considered, especially when the material to be removed is not homogenous such as calcite rich silica deposits (hydrofluoric acid and calcite reacting to form relatively insoluble calcium fluoride).

2.2.4 Contact Time

The appropriate contact time required for the solvent to remove the desired material is influenced by several factors:

- deposit thickness,
- reaction kinetics,
- temperature,
- rate of agitation (if any),
- and in some cases, pressure.

Corrosion risk is another factor that is considered when determining contact time – typically the higher the corrosion risk the shorter the desired contact time. Typically for a given deposit, a higher temperature (and in some cases pressure) will reduce the required contact time. Turbulent flow at the solvent/solute interface will also reduce the required contact time compared to a static, or a poorly mixed solvent/solute system.

When cleaning surface equipment such as heat exchangers it is often possible to control contact time to achieve the best clean. When cleaning subsurface equipment such as geothermal wells, contact time will often be governed by the volume of chemicals to be used and the achievable pump rates. In the case of geothermal wells pump rates can be limited by both the need to keep the well temperature within specification (often minimum flows are required to keep the well cool enough), and the maximum capacity of the pumping system – especially when using coil tubing units that often restrict flow to ~30m^3/hr or less. A lack of flexibility in achievable contact times can mean that thick scales or deposits cannot be cost effectively removed through chemical cleaning alone, and physical methods may need to be used – potentially in combination with chemical methods.

2.2.5 Temperature

Temperature has a major influence on the both the required contact time, and also on the corrosion risk to plant and equipment.

Increasing the temperature of the chemical cleaning process increases the reaction rate and often increases solubility of the solute. This results in a decrease in the contact time required and can also result in a decreased requirement for the solvent. The increased reaction rate also increases the rate of corrosion reactions however, which can be a limiting factor when selecting a cleaning temperature. Many corrosion inhibitors for use with steels are useful at temperatures up to 80ºC, with corrosion inhibition at higher temperatures achievable with the use of higher inhibitor concentrations and addition of intensifiers. Corrosion inhibition systems become increasingly more expensive as the design temperature increases above 80ºC.

Materials of construction, safety concerns and practical/achievable temperatures are also taken into consideration when determining the cleaning temperature.

2.2.6 Safety

Once the list of suitable solvents has been narrowed down to what is technically suitable, the safety of the solvent and the process is reviewed. In cases where several solvents are suitable, safety can be the differentiating factor in solvent selection. In cases where a single solvent has been identified as suitable, a determination is made on whether this solvent can be applied safely – if it cannot be applied safely, then either the cleaning process needs to be redesigned such that it is safe, an alternative cleaning method devised or the cleaning abandoned. When considering the safety of a solvent, the concentration, quantity, temperature and pressure at which the solvent is used are considered along with the chemical hazards associated with the transport, storage, handling and mixing of the required chemicals.

The use of solvents such as hydrofluoric acid and its derivatives (eg ammonium fluoride, ammonium bifluoride etc) require careful safety planning including the procurement of specialized treatment products (eg calcium gluconate, hexafluorine®) in case of personnel contact.

2.2.7 Waste Disposal

Solvent selection can have a significant impact on how cleaning effluent can be treated and disposed of. This is typically not a significant consideration for well cleaning, where the spent fluid is usually lost to the reservoir (although the risk of reflow must be addressed for production wells), however cleaning effluent can be a significant complication for heat exchanger cleaning. Issues can be encountered with the use of organic acid solvents used for iron removal, that can result in a large volume of liquid waste that can be difficult and expensive to treat and dispose of when compared to mineral acids where the dissolved deposits can often be precipitated and separated post cleaning.

Effluent treatment and disposal can also be an issue when removing heavy metals such as antimony sulfides. If a suitable injection well is not available to return the material to the reservoir from which it was produced, it may be necessary to treat the effluent prior to disposal. In cases such as this often the solute can be precipitated from the cleaning solution and then filtered, so that the lower volume of solid material containing the heavy metal sulfides can be disposed of as a solid to a hazardous waste facility, and the remaining liquid (typically neutralized, saline water) can be disposed of as non-hazardous waste water.

2.3 PROCESS CONSIDERATIONS

Once the solvent has been selected, the cleaning process itself is designed to ensure the application of the solvent is done safely and effectively. Key factors considered by Mercury when designing the cleaning include:

2.3.1 Mass of Deposit/ Volume of Solvent

The total mass of deposit to be removed determines how much solvent will be required for the chemical clean. Typically, an excess of solvent will be used to remove the expected mass of deposit. This hedges against two common issues – namely that the deposit mass is higher than anticipated, and that the efficiency of the solvent-deposit reaction is likely to be significantly lower than 100% in most cases. In some cases, it may not be feasible to remove all of the deposition in a system, and in these cases the solvent requirement is estimated based on the degree of removal being targeted. Utilizing an excess of solvent will usually reduce the required contact time for deposit removal, as saturation, or consumption of the solvent is not completed.

The volume of solvent required is usually dictated by the mass of the deposit and expected efficiency of the solvent, however in some cases logistical and pragmatic considerations may dictate that a higher or lower volume of solvent is used.

2.3.2 Pressure and Temperature

The effects of temperature are discussed in section 2.2.5 above. Pressure is a key variable in the process considerations, particularly where gases may be evolved. For example, increasing pressure (up to a point) can increase the rate of reaction between hydrochloric acid and calcite, presumably a result of decreased interference of carbon dioxide gas which can restrict contact between the calcite and the acid solution. Increasing the solvent pressure will typically be restricted by the design of the equipment being cleaned, as well as the cleaning equipment used. In many cases increasing the pressure may not be an option.

2.3.3 Deposit thickness

The expected thickness of a deposit has a major bearing on the contact time and agitation (or solvent turnover) required to remove the deposit. Thin and relatively reactive deposits can typically be removed very quickly, while especially thick and slow reacting deposits may result in chemical cleaning not being a viable option.

2.3.4 Flow rate/Agitation/Recirculation

For a chemical clean to be successful it usually requires that there is some flow of the solvent across the material to be removed. If there is insufficient flow a removal of the deposit can be inhibited by a buildup of reaction products, or a static layer of saturated solvent. Flow of the solvent is usually achieved through either recirculation of the solvent or by pumping the solvent through the system for once-through cleans. If long contact times are required, and recirculation of the solvent is not practical, agitation of the solvent may be an option. Agitation may be achieved through the bubbling of an inert gas through the solvent if the equipment being cleaned does not provide other alternatives.

A wide range of flow rates can be used when chemically cleaning. Too low a flow rate may impair cleaning efficacy, while too high a flow rate can impair the function of corrosion inhibitors and result in increased corrosion rates. Flow rates from 1ft/s (0.3m/s) to 5ft/s (1.5m/s) have been suggested for cleaning boilers (EPRI, 2001), while some corrosion inhibitor suppliers suggest a maximum linear flow rate of 40ft/s.

2.3.5 Flow Path

Determining the flow path for a chemical clean can vary from the simple (eg geothermal wells) through to the complex (eg high pressure utility boilers). Typically, P&IDs (Piping and Instrumentation Diagrams) are used when mapping out the flow path. The P&IDs are used to identify locations for the solvent inlet to; and outlet from the equipment to be cleaned. At this stage, relevant isolations are determined to protect personnel and equipment from the solvent. A confirmation of the materials of construction for each part of the flow path is undertaken to confirm that there are no incompatible materials in the flow path (and not just the equipment to be cleaned). When determining the flow path, it is also important to note any dead legs that will need to be flushed at the completion of the cleaning process.

2.3.6 Multi-stage clean

Where the deposits or material to be removed during a chemical clean are of a mixed nature, it may be necessary to undertaken a multi-stage clean. This approach is common in geothermal injection wells, where a carbonate mineral removal stage is often undertaken prior to a silica removal stage to reduce the likelihood of forming insoluble reaction products. Multi-stage chemical cleaning is also common in heat exchanger cleaning, for example an alkali stage to remove oil and grease, followed by an acid stage to remove corrosion products and/or mill scale. Mercury are currently considering whether a multi-stage clean would be beneficial for some heat exchangers that appear to have both silica and antimony sulfide deposits (Lawson, Hoepfinger, Clark, Firth, & Richardson, 2018). In this case it is suspected that a alkali stage (sodium hydroxide) to remove antimony sulfide would precede a hydrofluoric acid stage to remove remaining silica deposits.

2.3.7 Gas Release

If the generation of gases is possible then the removal of the gas from the cleaning system needs to be considered. The generation of gas may interfere with the cleaning process and/or pose a risk to personnel and equipment. Carbon dioxide is released when carbonate minerals are dissolved in acid, this may be observed as a pressure buildup in a heat exchanger or wellhead, or a gas effervescing from a recirculation tank. As mentioned in section 2.2.2 carbon dioxide can impair the function of some corrosion inhibitors, it can also displace oxygen, interfere with the reaction between acid and carbonate as well as presenting a toxicity risk to personnel in high concentrations.

When chemically cleaning some deposits, there is a risk of releasing particularly toxic gases (e.g. arsine and stibine from the reaction of arsenic and antimony sulfides with strong acids). As such, a clear understanding of the expected deposits and the solvent chemistry is essential when planning chemical cleaning projects.

Where necessary a gas vent line may be installed to vent produced gases to a safe location, or to a gas scrubber if the gas cannot be safely and legally vented.

2.3.8 Post Cleaning Treatment

Post cleaning treatment typically involves the passivation of steel surfaces following a chemical clean. A variety of passivation agents are used for this purpose, and can include both oxidizing (e.g. hydrogen peroxide) and reducing agents (e.g. hydrazine). Passivation is not always undertaken, but is a prudent step to undertake, especially if the objective of the clean was to remove corrosion products.

Post cleaning treatment may also include the addition of another solvent to minimize the precipitation of reactions products from the cleaning process (e.g. the addition of an acidic post flush stage following mud acid injection into a geothermal well).

3. CHEMICAL CLEANING EXAMPLES

Mercury undertakes chemical cleaning activities for both surface and subsurface equipment at its geothermal power plants. Four examples of chemical cleaning operations undertaken at Mercury are described below.

3.1 Antimony Sulfide Removal

Antimony sulfide deposition is an issue experienced at Mercury's Ngatamariki geothermal power plant. The deposition occurs in the preheaters of the Ormat Energy Converter (OEC) units. Over time this deposition builds up to the point that it adversely affects heat transfer in the preheaters. If the deposition continues the output of the power plant can be impaired because of reduced heat transfer in the preheaters.

3.1.1 Background

Initially the preheaters where water blasted with high pressure water during annual plant maintenance shut downs to remove the deposits and restore heat exchanger performance. The water blasting process was time consuming (taking approximately 48 hours of cleaning time, plus disassembly and reassembly of the end caps), while treatment and disposal of the large volumes of cleaning effluent was also challenging. As a result of the time and challenges involved in water blasting the heat exchangers alternative cleaning processes were investigated.

Antimony sulfide deposits had been successfully removed from geothermal heat exchangers at the Ngawha geothermal field (Dorrington & Brown, 2000), so this approach was investigated for Ngatamariki. Mercury's experience with geothermal deposits has indicated that deposits of the same chemical composition can behave very differently, and this is evident in the differences in antimony sulfide deposits at the Rotokawa power plant (thick, sludge-like, easily removed physically) and the antimony sulfide deposits at Ngatamariki (thin, hard adherent deposits that are very difficult to remove physically). Due to these concerns bench-top testing was undertaken to determine if the chemical cleaning approach was likely to be successful at Ngatamariki. As no heat exchanger tubes were available for testing (none had been removed from the affected heat exchangers) several thermowells that were located between the affected heat exchangers were removed from the plant and utilized for testing as shown in **Figure 2** below (the thermowells were coated in the antimony sulfide deposits as a result of their location in the plant). The bench top testing consisted of attempting to chemically clean the thermowells under a variety of test conditions which including varying the solvent, temperature, contact time and agitation.

The results indicated that a solution of sodium hydroxide (10%) was an effective solvent and that the temperature of the solvent had the biggest influence on solvent efficacy – the hotter the solvent the better the deposit removal. Interestingly the solvent contact time was not a significant factor – even at lower temperatures increasing the contact time did not have a significant effect past the first hour and at temperatures above 60ºC no further benefit was gained after 30 minutes of contact time. Agitation did not appear to be a factor, with the use of an ultrasonic bath not achieving a better cleaning outcome than a static soak in hot caustic solution.

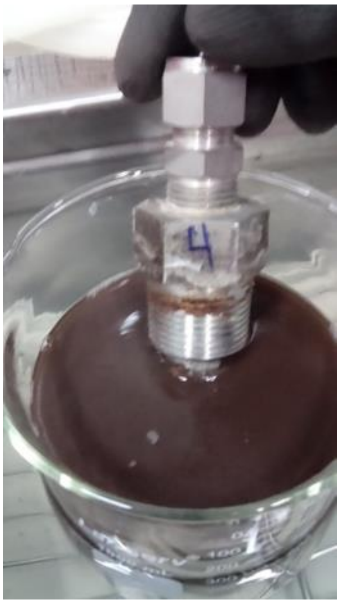

Figure 2: Bench top testing with a thermowell from the plant to inform solvent selection and cleaning design.

3.1.2 Design

With the solvent selected, the design of the chemical cleaning process was commenced. The plant P&IDs and a plant walk-down were used to identify the most appropriate flow path for the chemical clean, including the inlet and outlet points for the solvent.

The volume of solvent required was based on the volume required to fill the flow path for the solvent. This includes the heat exchangers, end caps, connecting pipework and the temporary pumping and piping system setup to recirculate the solvent. This decision was based on both logistical considerations (retaining heat in the solvent) and chemical storage and handling, as well as an estimation that this volume would be sufficient for an adequate chemical clean.

The design temperature became a compromise between solvent efficacy and corrosion risk. The bench testing had determined that a higher temperature would maximise the effectiveness of the clean, however a review of the plant materials showed a mix of materials in the flow path. The materials that would be exposed to the solvent included 2205 Duplex stainless steel, 316 stainless steel and carbon steel. At temperatures above 80ºC carbon steel can be at increased risk of corrosion damage (stress corrosion cracking) from 10% sodium hydroxide solutions. While the 2205 and 316 steels had a higher resistance to sodium hydroxide related damage, the temperature limit of the clean was set at 80ºC to protect the most susceptible material in the flow path.

As agitation was not a significant factor in the bench testing the cleaning solvent was recirculated through the heat exchangers with a target flow rate of between 1000 l/min and 1600 l/min, which would result in a solvent retention time of approximately 20-30 minutes. This would enable 2-3 passes of the solvent through the heat exchangers with a 1 hour recirculation time. The 1 hour recirculation time was longer than required based on the bench testing results, but this was used so that samples could be collected throughout the recirculation period to determine the optimal cleaning time in practice.

3.1.3 Results

The chemical cleaning process was successful in removing large amounts of deposits from the Ngatamariki preheaters and restoring heat exchanger performance. The cleaning results are discussed in depth in (Lawson, Hoepfinger, Clark, Firth, & Richardson, 2018). One of the key benefits of the chemical cleaning process was a reduction of the time taken to clean a unit – a unit can be shut down, chemically cleaned and restarted in approximately 6 hours, compared to in excess of 48 hours for water blasting. The costs of the cleaning methods were similar (materials and labor), however the reduced unit down time from chemical cleaning has significant financial benefits.

3.2 Silica Removal

Silica deposition in geothermal heat exchangers is a common issue experienced in the geothermal industry. Mercury has traditionally removed silica scale in heat exchangers through high pressure water blasting at its Rotokawa power plant. Over time the heat exchange capacity in one of the heat exchangers declined, and high-pressure washing was unable to restore the performance, or remove remaining silica deposits. This resulted in chemical cleaning being considered to remove the remaining silica deposition and restoring heat exchanger performance.

A relatively conventional chemical clean for silica removal was decided on and undertaken on the heat exchanger. A 10% hydrofluoric acid solution was used as the solvent with a corrosion inhibitor added to minimize corrosion of the heat exchanger and piping. The solvent was heated to 60ºC to improve reaction time, and decrease the contact time required for cleaning, while not being so hot as to significantly increases safety or corrosion risks. A 6-hour contact time was selected based on the cleaning contractor’s experience with similar cleans, and regular sampling was undertaken during the clean to confirm the required cleaning time for future cleans.

The result of this clean was increased heat transfer across the heat exchanger, which resulted in an increase in unit output of 1MW compared to the uncleaned condition.

3.3 Calcite Removal from a Well

The buildup of calcite in geothermal production wells is a relatively common issue in the geothermal industry

(Bloomer & Cottrell, 2001), (Richardson, Addison, & Lawson, 2015). Mercury observes calcite deposition in production wells at both the Ngatamariki and Kawerau geothermal fields.

Mercury typically utilize anti-scalant delivery systems to place anti-scalant chemicals into wells that are prone to scaling to minimize calcite wellbore scaling. Even so, it is occasionally necessary to undertake calcite removal operations in a production well, which may be done either mechanically or chemically depending on the situation (location and thickness of calcite).

Where the calcite is potentially located behind the perforated liner, or where the well can not be accessed with mechanical tools (or the tools are ineffective) chemical cleaning is typically employed for well clean outs.

Mercury have undertaken several chemical cleans to remove calcite from production wells. Typically, these cleans utilise 10-15% hydrochloric acid with the addition of corrosion inhibitors to minimize corrosion to the well casing and chemical pumping equipment. Temperature is a key consideration for production well chemical cleaning, as the corrosion risk to the well increases rapidly with temperature. Where practicable the well temperature is decreased to ~80ºC for these cleans – at this temperature corrosion inhibition is readily achievable with low concentrations of corrosion inhibitors, while the reaction kinetics between hydrochloric acid and calcite are still rapid. Maintaining a reduced well temperature in a hot geothermal reservoir can require the constant pumping of cool water into the well if the acid volume is not sufficient to keep the well cool. In these cases dilution of the acid mixture typically occurs, and should be considered in the cleaning design.

The acid may be placed in the well with a coil tubing unit (CTU) when it is desired to place the acid at a particular location within the well. The use of a CTU has the benefit of reducing contact between the well tubulars and the acid mixture, however use of a CTU comes with increased costs and a limitation on the available flow rates that can be achieved.

The volume of acid required is usually determined in one of two ways:

- An estimation of the amount of calcite to be removed (particularly if the scaling is inside the wellbore), with an allowance for the expected efficiency of the reaction.
- The use of industry guidelines for application rates (e.g. 75gal/ft for the treatment area). This approach is typically used for deposits that are located in the near well-bore area, rather than inside the casing.

During these well cleanouts the contact time of the acid with the calcite is a function of the acid volume and the pumping rate – as recirculation of the acid mixture is not possible. Once the acid has been placed in the well, the well is flushed with fresh water to displace the acid to the formation. Soaking of the acid mixture in the well is usually avoided due to the need to keep the well relatively cool to reduce the corrosion risk to the well casing.

The reaction of hydrochloric acid and calcite results in calcium chloride forming in the well and near well bore area. When production wells that have been chemically cleaned are reflowed it is necessary to confirm that the well chemistry has returned to normal prior to flowing the well to the power plant. This typically requires that a drilling pond or soakage pond accept the well fluid until the fluid chemistry has stabilized.

3.4 Silica Removal from a Well

Mercury has experienced silica deposition in the near well-bore area of some injection wells, which reduces the injection capacity of the well. As the deposition is outside of the casing and perforated liner, mechanical cleaning is not an option.

Mercury has undertaken several chemical cleans to remove silica deposition from injection wells, most recently in May 2017. During this clean out a mixture of hydrochloric (10%) and hydrofluoric acid (5%) (this mixture is often referred to as ‘mud acid’) was selected as the solvent to remove silica and silicate deposits from the near wellbore area. The well temperature was controlled to below 80ºC to minimize corrosion risks, although the acid system was designed to withstand higher temperatures in case they were encountered.

The acid volume was calculated using application rates found in literature which were confirmed with several other geothermal operators. The targeting of discrete zones within the well required to use of a CTU to place the solvent at the target locations. Each of the 6 target zones was given a nominal 50m thickness, which at an application rate of 75gal/ft gave a solvent volume of ~280,000L. Each application of solvent was preceded with a pre-flush of 10% hydrochloric acid to remove carbonate minerals that could form insoluble precipitates if reacted with the hydrofluoric acid. Each application of solvent was followed with a smaller application of 5% hydrochloric acid to ensure the pH remained low, to minimize the risk of reaction product precipitation that could adversely affect permeability in the near wellbore area.

This cleanout resulted in a significant recovery in injection well capacity. The details of this clean and the results are discussed in depth in (Coutts, Richardson, Quinao, & Goh, 2018).

4. CONCLUSION

Chemical cleaning has been used successfully at Mercury to remove a variety of geothermal deposits from both surface and subsurface equipment in its geothermal power plants. In some cases chemical cleaning is the only available option to clean equipment, while in other cases chemical cleaning is the most cost effective option to restore plant performance.

Each chemical cleaning application requires careful consideration to manage health & safety and corrosion risks, while also achieving an effective clean that does not result in unwanted adverse impacts.

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