PERFORM
Best practice for geothermal plants to minimize scaling and corrosion

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PERFORM is one of nine projects under the GEOTHERMICA – ERA NET. The overarching target of PERFORM is to improve geothermal system performance, lower operational expenses and extend the life-time of infrastructure by the concept of combining data collection, predictive modelling, innovative technology development and in-situ validation. The improvement of geothermal plant performance from the proposed work is expected to result in an increase of the energy output by 10 to 50%. In order to reach this goal PERFORM will establish a single and shared knowledge database, build predictive models and demonstrate new and improved, cost-effective technologies which will reduce or even eliminate flow-obstructive scaling, clogging, and resistance to fluid (re-)injection at eight geothermal plants across Europe.

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**About PERFORM**

Despite years of experience with geothermal systems, the geothermal sector still faces a significant number of underperforming doublets, posing a strong limitation on a region’s growth of geothermal energy utilization. A key operational challenge in geothermal energy production is restricted flow. Major obstacles for geothermal flow are scaling (mineral deposition), clogging (solid micro-particle deposition), corrosion and inefficient injection strategies. These issues result in high and mostly unforeseen costs for workovers, and additionally reduce production. In order to overcome these challenges, the consolidation and sharing of knowledge, including validated strategies for prevention and mitigation needs to be in place.

Therefore a consortium consisting of De Nationale Geologiske Undersøgelser for Danmark og Grønland (GEUS) and FORCE Technology from Denmark, Helmholtz Centre Potsdam German Research Centre for Geosciences (GFZ) and Hydroisotop GmbH from Germany and Ammerlaan Geothermie B.V., Greenwell Westland B.V., Wageningen Food & Biobased Research and ECN part of TNO from the Netherlands proposed a G EO THERMICA project PERFORM, which has been granted. The overarching target of PERFORM is to improve geothermal system performance, lower operational expenses and extend the life-time of infrastructure by the concept of combining data collection, predictive modelling, innovative technology development and in-situ validation. The improvement of geothermal plant performance from the proposed work is expected to result in an increase of the energy output by 10 to 50%. In order to reach this goal PERFORM will establish a single and shared knowledge database, build predictive models and demonstrate new and improved, cost-effective technologies which will reduce or even eliminate flow-obstructive scaling, clogging, and resistance to fluid (re-)injection at eight geothermal plants across Europe.

Based on experiences from operating geothermal sites within the EU, PERFORM will establish a single knowledge database containing information on operational, chemical and physical aspects of geothermal energy production. The database enables sharing experiences from operating geothermal doublets located in various countries and comparing the performance of the different geothermal reservoirs. PERFORM builds predictive models that allow for pinpointing the most likely sources and causes of failure, as well as the best options for injectivity improvement. The integrated models will provide forecasting for scaling, productivity, and injectivity on short- and long-time scales, supporting early warning and planning of mitigation measures. Coupled thermo-hydro-mechanical-chemical simulators will allow for evaluation of injection temperature that apart for increasing flow will also increase the energy output.

Data and knowledge gathering and technology demonstration is planned for eight geothermal plants across Europe. Demonstration of new and improved, cost-effective technologies will allow for the reduction or even elimination of flow-obstructive scaling, clogging, and resistance to fluid (re-)injection. The technologies include low-cost cation extraction filters, self-cleaning particle removal appliances, H₂S removal technology and soft-stimulating injection procedures (thermal and CO₂-injection). The goal is to provide a set of new and improved, low-cost and environmentally friendly technology alternatives.

PERFORM integrates the knowledge database, predictive modelling and advanced technologies into a design and operation toolbox, which will be tied to economical calculations. The toolbox will enable stakeholders and specifically geothermal operators to plan future operations, mitigate existing obstructions, and optimize production/injection procedures, thus ensuring maximum energy production when needed.

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Summary

This best practice is the result of Work Package 4 (WP4) in the GEOTHERMICA PERFORM project with the objective of addressing the operational problems in geothermal plants related to scaling and corrosion. Based on the new insights gained in the PERFORM project, through data collection, modelling, experimental measurements and interviews with operators, advice on mitigation strategies is given. The best practice reviews the typical plant designs and materials for Geothermal plants, and then introduces possible scaling and corrosion types that can occur in the saline geothermal water (brine).

Common types of scaling found in low enthalpy geothermal sites are reviewed. This includes carbonates, sulphates and heavy metal scales. The general approach for predicting the scaling potential is introduced. Instead of using simple index equations, a geochemical model should preferably be used as illustrated by a 6-step approach. The possibilities for scaling monitoring often include indirect observations on flow rate, filters and water chemistry rather than direct measurements. Scaling mitigations may involve strict control of dissolved gasses, use of inhibitors or installation of filters. Since most plants are made from non-coated steel tubing the potential for release of rust debris is enormous unless corrosion is controlled strictly. Such particles will, over time, lead to pressure build-up in the wells, and it is only possible to remove the clogging again by costly well operations (such as acid jobs).

Corrosion of steel tubing in the wells and surface plant can occur as a result of oxygen ingress, gases in the reservoir (especially CO₂) or metal ions in the water. In particular, dissolved metal ions can lead to considerable corrosion, which is demonstrated by calculations. Oxygen ingress affects both steel and Corrosion Resistant Alloys (CRAs), and it must be monitored and prevented in the plant. Corrosion caused by the geothermal fluid composition is usually prevented by injection of corrosion inhibitor into the production well. Here it is also necessary to constantly monitor the chemical dosage and the impact of inhibitors on the production and thus the corrosion monitoring is an important part of this best practice. All techniques from simple corrosion coupons to advanced on-line measurement are reviewed and evaluated. Based on the corrosion types introduced, a brief guide on how to select the right materials for casing and top-side facilities is given.

Water sampling is an important step to understand and prevent both scaling and corrosion. Samples should be collected both during start-up and during geothermal operation and corrections are necessary based on the method and depth of sampling. The basic requirements are introduced. Practical input has been collected from the operators of geothermal systems in Netherlands, Germany and Denmark. The main challenges in operating a geothermal plant are 1) corrosion 2) increased reliability and lifetime the ESP and 3) guidelines on water sampling and NORM waste disposal. This is followed by statements and advice about the operational phases including start-up, operation, shutdown, standstill and well-head and heat exchanger service. The feedback helps to identify or shed light on issues that have been overlooked or require a closer attention.
1 Introduction

The best-practice covers issues related to scaling and corrosion in geothermal plants. The content is based on the knowledge of all partners in the PERFORM project. In addition, experiences from geothermal plants in Denmark, Netherlands and Germany have been included. This information was obtained by a questionnaire and interviews.

Much of the information presented in the current best-practice is also available on the project site as brief introductions, maps, interactive toolboxes etc. [https://www.geothermperform.eu/](https://www.geothermperform.eu/). Along this, the intention of the best-practice is to provide an easily accessible and concise introduction to the most important topics affecting scaling and corrosion as well advice on mitigation strategies. This includes practices for shutdown and start-up, possible need for chemical treatments as well as requirements to monitoring and associated action points to minimize corrosion and scaling. Moreover, advice on water and gas sampling is provided. Selecting the right materials for wells, tubing, pumps and surface installations is also of key importance to minimize corrosion, scaling and operational issues. The main observation points to be addressed when selecting the material are covered in this practice is based on the new insights gained in the PERFORM project.

Compared with oil and gas production, geothermal energy is still a young industry. Thus, there are yet no recognised international standards or guidelines about design and operation of the geothermal plant. A wide range of national guidelines exists. As an example, the geothermal plants in Paris must comply with national guidelines to maintain their insurance policy and financial support (BRGM, 2018). The plants in Paris produce from carbonated reservoirs so the conditions are not the same as those found in the Danish, Dutch and German sandstone reservoirs. Denmark has its own extensive guideline covering everything from planning and legislation to operation of a geothermal plant for district heat production (Drejebog, 2014). In Netherlands, there is an extensive guide about corrosion and materials selection, based on the same principles applied for oil and gas exploration (Wood, 2017). The approach for the PERFORM best practice is to share the knowledge across the consortium partners with focus on the doublet-type geothermal plants, present in Denmark, Netherlands and Germany. The reservoir types are typically sandstone and carbonate rocks.
2 Layout and materials of geothermal plants

- What is the common layout?
- Which materials are used?
- Can experience be gained from other installations?

A conceptual sketch of a geothermal plant is shown in Figure 1. This type of plant is known as a doublet having two wells, a producer (1) and an injector (8). Apart from that, six other elements make up the basic design and operation of the plant (2-7, Figure 1). Additional equipment is found in the loop and vary from plant to plant (a-e, Figure 1), such as degassing (b), inhibitor injection (a) and corrosion monitoring (e). The use of the produced heat also varies from district heating in Denmark and heat for greenhouses in Netherlands to electrical power production in Germany.

![Conceptual sketch of a geothermal plant including the main elements (1-8) and additional components found in some plants (a-e). Typical materials used in geothermal plants in Denmark, Netherlands and Germany are shown.](image_url)

<table>
<thead>
<tr>
<th>No</th>
<th>Main components</th>
<th>Materials in contact with brine, typical</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Producer, lower completion</td>
<td>Carbon steel, stainless steel EN 1.4401, duplex casing</td>
</tr>
<tr>
<td>2</td>
<td>Producer (well bore)</td>
<td>Carbon steel, composite (GRE)</td>
</tr>
<tr>
<td>3</td>
<td>Production Electrical Submersible Pump (pESP)</td>
<td>Abrasion and corrosion resistant alloys (CRAs)</td>
</tr>
<tr>
<td>4</td>
<td>Filtration</td>
<td>Coated steel, stainless-steel canisters</td>
</tr>
<tr>
<td>5</td>
<td>Heat exchanger</td>
<td>Titanium, stainless steel, 17Cr stainless steel tubing</td>
</tr>
<tr>
<td>6</td>
<td>Injection Pump (iP)</td>
<td>Corrosion resistant alloys (CRAs)</td>
</tr>
<tr>
<td>7</td>
<td>Injector (well bore)</td>
<td>Carbon steel, composite (GRE)</td>
</tr>
<tr>
<td>8</td>
<td>Injector, Lower completion</td>
<td>Carbon steel, stainless steel EN 1.4401</td>
</tr>
<tr>
<td>a</td>
<td>Chemical injection</td>
<td></td>
</tr>
<tr>
<td>b</td>
<td>Degasser or oil separator</td>
<td></td>
</tr>
<tr>
<td>c</td>
<td>Corrosion protection, anodes</td>
<td></td>
</tr>
<tr>
<td>d</td>
<td>Booster pump</td>
<td></td>
</tr>
<tr>
<td>e</td>
<td>Corrosion monitoring</td>
<td></td>
</tr>
</tbody>
</table>
The interviewed geothermal plants are comparable with that in Figure 1 with some differences in formation type, plant design and operation. For example, the well depth ranges from 1.1 km to 4 km.

The typical materials used in geothermal plants in Denmark, Netherlands and Germany are shown in Figure 1. Most plants use non-coated steel tubing for the wells, such as the API 50 CT L80 alloy. As an example, the internal surface area of 4 km 9” tubing amounts to roughly 3000 m². Thus, the potential for release of rust particles is enormous unless corrosion is controlled very strictly. In some plants, composite (GRE) is used for tubing or lining instead of bare steel tubing, minimizing the potential for both corrosion and scaling. Still, corrosion from the outside must be considered, why duplex stainless steel sometimes is used for the casing.

The other major components account for less surface area in the plant, and they are usually made from corrosion resistant alloys (CRAs). The electrical submersible pump, ESP (3), in the production well feeds the surface installation with warm brine from the sandstone reservoir. The brine is filtered in bag filters in stainless steel or steel canisters (4) before reaching the heat exchangers or the absorption heat pump that usually are made from titanium. Compact cartridge filters (4) remove particles before the brine finally is reinjected into the formation again, sometimes using an injection pump (6).

The brine solution is potentially very corrosive due to the high salt concentration (10-27 %, Na-Ca-Cl). As discussed later, strict precautions such as nitrogen or argon blanketing during standstill periods are applied to avoid ingress of air/oxygen, thereby removing the driving force for corrosion. Other substances may also affect corrosion such as dissolved metal ions (Pb²⁺ or Cu²⁺) or dissolved CO₂ gas. The use of dissimilar metals (carbon steel, stainless steel and titanium) may in addition present a risk of galvanic corrosion.

During normal operation 100-400 m³ warm brine (50-110 °C) is circulated through the plant every hour. The known causes for unscheduled stops or interruptions include break-down of the ESP, injection well plugging, filter replacement, wear in pump due to sand production and heat pump failure (LiBr brine corrosion). In many cases, scaling or corrosion is the cause for such incidents. Thus, this best practice focusses on the conditions in the main circuit in contact with the geothermal brine, being the most important one to secure the injection well and provide uninterrupted service for +30 years.

Valuable experience can be gained from literature, guidelines and standards about water injection systems in oil and gas production (NACE, 2012). Such systems are comparable with geothermal injection system as to materials, corrosion, operation and requirements for monitoring. The injected water for oil production is often a mixture of seawater and produced water from the reservoir. Seawater contains a wide range of microbiologic organisms and nutrients, while the geothermal brine usually is free from such constituents. If not present in the geothermal reservoir, contamination with bacteria may, however, still occur during shutdowns, maintenance or well
workovers in the geothermal facility. In the oil and gas industry it is also well known that bacteria in the injected seawater may cause souring (H₂S production) of the reservoir leading to complications in the producing wells. Such scenarios are yet not known for geothermal energy, but efforts must still be made to control bacteria.

For the geothermal producers, the experience on CO₂ corrosion from oil and gas production is useful, although the low content of hydrocarbons in the geothermal water is a major difference.
3 Scaling and mineral precipitations

The changes in conditions that the geothermal fluid will be subjected to, from subsurface to the surface and injected back to the aquifer, will lead to changes in the brine properties and the potential risk of mineral deposition and scaling. The list of some of the common changes in the conditions are (but not limited to):

- Temperature decrease during the production and heat extraction of the geothermal brine
- Pressure decrease of the geothermal brine in the production casing and surface facilities
- Temperature and pressure increase in the injection wells of the geothermal brine with a new equilibrium (filtered or partially precipitated brine)
- Depressurization of the brine in the separator or degasser

Scaling precipitation could impact the production and injection by increasing the hydraulic resistance, i.e. the resistance to flow. Additionally, it can reduce the heat transfer rate in the heat exchangers and reduce the overall COP (Coefficient of performance) of the system.

3.1 Scaling types

- Which type of scaling are observed in European low enthalpy geothermal sites?
- What are the critical ions/minerals which triggers this mineral precipitation?
- What are the mechanisms and where do they occur in the plant?
- How can scaling potentials be predicted?

3.1.1 Carbonate scales

Carbonate scales occur both, in low- and high enthalpy geothermal systems (Schreiber et al., 2016). Carbonate scaling is primarily related to (partial) outgassing of CO₂ from the produced geothermal water during geothermal production. The naturally dissolved gas in geothermal water comes out of solution if the pressure is decreased sufficiently at the surface. The pressure at which the dissolved gas is released is called the bubble point and depends on the reservoir gas content and composition, pressure, temperature and salinity and hence is specific for each doublet. The gas in low-enthalpy geothermal doublets mainly contains CO₂, CH₄ and N₂ (e.g. Dutch doublets are dominantly CH₄, but CO₂ typically makes up 5-10% of the total gas pressure (Schreiber et al., 2016). The process of carbonate scaling is governed by CO₂ release from the water causing a pH increase, which reduces the solubility of carbonates. The reduced solubility causes carbonate precipitation, forming scales in the surface installation. Depending on the water composition, any carbonate can precipitate but for the calcium rich waters of the Delft sandstones, mainly calcite and minor siderite is observed. Although the main pH change of the water will already occur in the gas-liquid separator, calcite scaling has often been observed further downstream of the system such as in the filters. This is most probably related to the availability of particles/sites for nucleation of carbonate crystals. Carbonate scaling is highly unlikely in the system after the temperature drop at the heat exchanger since carbonate solubility, unlike most minerals, increases with decreasing temperatures. Note that, besides the pressure dependence, calcite scaling can also occur due to temperature increase such as in high temperature storage. The pressure or pH dependence and the influence of temperature on carbonate scaling can be predicted with geochemical modelling software (more information is provided in the section 3.1.4).
### 3.1.2 Sulphate scales

Barite (BaSO$_4$) or other sulphate scales in the production wells can significantly reduce the flow diameter of the tube in oil and gas wells. The solubility of BaSO$_4$ reduces with decreasing temperature or pressure and increases with increasing salinity. Since the pH dependency is negligible between 2 and 6.5 (only at pH of 9 to 10 the solubility decreases, Zhen-Wu, 2016), the pH effect is not relevant for most geothermal systems. The main trigger for BaSO$_4$ precipitation in geothermal systems will be the temperature decrease. As a result, BaSO$_4$ scales often occur in the heat exchanger, injection well and near injection well area. BaSO$_4$ has been observed in filters, but major issues with barite have not yet been encountered in geothermal operation. Numerical simulations do indicate that barite slowly forms in the reservoir due to its slow reaction rate and delayed precipitation. However, it has also been argued that barite only precipitates and causes injectivity issues when the saturation index (SI) approaches values over 1 or even over 3 (van der Hulst, 2019). Experience with geothermal systems indicates that the saturation threshold for nucleation is rarely exceeded to a degree that allows barite scale formation. At Groß Schönebeck, however, substantial amounts of BaSO$_4$ scales were observed in the production well despite calculated supersaturation for pure BaSO$_4$ being modest. The formation water at this site is hot, very Ca rich and possesses high ionic strength, which challenges determination of saturation state. Thus, barite may be more saturated than indicated by calculation because i) phases form with solid solution of Ba, Sr, Ca sulphates or ii) the calculations underestimate the decrease of the stability of the CaSO$_4$ ion pair with decreasing temperature (PERFORM, 2020). Predictions of sulphate scaling can be done with geochemical modelling software, but the models do require assumptions on the saturation threshold for precipitation.

### 3.1.3 Heavy metal scales

Heavy metal scaling is a well-known problem in geothermal systems. Heavy metal (e.g. lead, copper or mercury) can form scales due to salt oversaturation or electrochemical reaction with the steel casing, i.e. galvanic corrosion (Regenspurg et al., 2015, Schreiber et al., 2016). Examples of heavy metal scaling are lead carbonate, elemental lead, lead hydroxochlorides, or iron scales such as pyrite or magnetite. Heavy metal scales are common for geothermal systems targeting the Rotliegend Formation and mainly the lead and copper originating can cause issues during geothermal production. The high heavy metal content of Rotliegend waters originates from the overlying Kupferschiefer formation or underlying volcanic rocks or Carboniferous coals. For example, Dutch geothermal systems in the Rotliegend Formation are prone to lead scaling due to the relatively high lead concentration of the formation water (Bressers and Wilschut, 2014). Corrosion of steel can cause elemental lead deposition by the reduction of lead ions using electrons released by the oxidation of iron from the steel components of the wells or surface installations. Hartog (2015) identified lead scales as cerussite (PbCO$_3$) instead of elemental lead with no sign of corrosion enhanced lead scaling. Cerussite is a carbonate mineral which, in contrast to calcite, dolomite and siderite, has a lower solubility at lower temperatures. The heat exchanger, injection well and near-well area are therefore more prone to this type of scale than other carbonate scales. Pyrite and magnetite scaling can be caused by dissolved H$_2$S corrosion of...
the carbon steel casing, as has been observed in geothermal systems in the Molasse Basin. Fe(III) oxides or hydroxides are generally induced by increased dissolved oxygen concentrations. Heavy metal scaling may occur by different processes depending on the targeted reservoir and the doublet material use but corrosion related scaling appears dominant. Compositional analyses of the formation water and the scales are required to identify which type of heavy metal scale is occurring and what inhibitor or operational/material changes are advisable to solve the scaling issue.

3.1.4 Scaling potential prediction

Determination of the scaling potential is not straightforward. Firstly, some scaling materials contain a gas component (e.g., CO\(_2\) in calcite). For such solids, the gas content of the waters must be accurately accounted for. Secondly, water samples taken at the surface often represent solutions after potential scaling, corrosion and degassing reactions have taken place in the well and possible oxygenation reactions upon sampling. Thus, the composition of such samples is not necessarily representative of those entering the geothermal doublet system. Thirdly, the solubility of solids depends significantly on the composition of the water because the charge of dissolved ions screens the charges of reactive ions, lowering their activity (the "effective concentration"). Finally, solubility also depends on temperature and pressure, which would have to be known for accurate assessment of scaling potential.

Here, we outline several ways to estimate the potential, some of which are simple but less accurate and others, which are complex and detailed but much more accurate if conducted properly.

Two of the simple methods to estimate the scaling potential of Calcium Carbonate is by means of Langelier Saturation Index (LSI) and Ryzner Stability Index (RSI) which estimate the saturation degree of the brine. The saturation index is calculated using pH, total dissolved solid (TDS), calcium and alkalinity concentrations (note that these two can be affected in response to degassing by the precipitation of CaCO\(_3\), see more details in the water sampling section) and temperature. The details of the calculation procedures for these indicators are further described in Annex I. Such simplified models are not sufficient to give a full overview of potential scaling problems in geothermal brine.

To provide a more detailed and potentially more accurate measure of the scaling potential or the rate of scaling, geochemical modelling can be performed with a variety of software. Programs include MINTEQ (Felmy et al., 1984), PHREEQC (Parkhurst and Appelo, 2013), and Geochemist Workbench, Bethke and Yeakel (2015), as well as codes capable of also modelling subsurface flow, such as CrunchFlow (Steefel and Molins, 2016), TOUGHREACT (Xu et al., 2011), and PHREEQC coupled with PHAST (Charlton and Parkhurst, 2013). An overview of commonly used software can be found in Steefel et al. (2015) and reactive transport modelling was the subject of a recent publication in the series Reviews in Mineralogy and Geochemistry (Druhan and Tournassat, 2019).
The modelling relies on calculation of the activity coefficients for dissolved ions and description of the saturation state of solutions with respect to solids and gasses based on thermodynamic databases that include reactions in the aqueous phase (aqueous speciation) and the solubility product of phases as a function of temperature and pressure. Many of the software allow the use of reaction kinetics if the aim is to estimate the scale growth rate. Geochemical modelling can certainly be a powerful tool to estimate the scaling potential and rate. However, there are numerous pitfalls. In the hands of a less experienced user, unfamiliar with interpreting the modelling results, they are very much a “black box”. The list of common errors is long and include use of equilibrium concepts for reactions that are at disequilibrium because of slow reaction kinetics, solution salinity being beyond what the databases/software were designed for and use of simplifying assumptions that are unreasonable. To enable the calculations, the user should:

1) Define a conceptual model of the problem at hand, i.e., does calculation of the degree of supersaturation suffice? Is reaction kinetics required? Does the modelling involve reactive transport? If so, at what spatial dimensions? A conceptual model should include all the steps required to account for recalculation of the composition of imperfect samples, include the changes in conditions to be simulated and include the relevant mineral and gas phases selected from a thermodynamic database.

2) Evaluate that the modelling software is capable of performing the type of calculations wanted. This includes checking if calculations have already been conducted with the software of similar systems, if solubility most likely can be adequately described at the required conditions, that the required phases exist in the database, that the required processes can be described by the software and the database.

3) Become familiar with how the modelling is conducted with the chosen software and how the model output is presented. This includes verification that the reactions entailed in the calculations are reasonable for the system, i.e., that equilibrium conditions are not set for redox reactions that are much slower than the time frame of interest. The selection of mineral phases to include or exclude in the simulation can be done based on experience in the field and literature.

4) Conduct simpler versions of the modelling, that are testable. At this stage, it should be checked that the chosen software and database are capable of modelling the equilibrium state of the processes of interest by comparing experimental data at similar conditions with calculated values. If calculations entail reaction rates, it would be prudent to test if a simple model can reproduce the experimental data that formed the basis for the rate expression.

5) If the rates of chemical reactions are calculated, the calculation time may become impractically long. In this case, simplifying assumptions could be made about what phases are likely to be at equilibrium, based perhaps on comparison of short-duration calculations with and without the simplifying assumption.

6) If uncertainties are of importance, a sensitivity analysis of the modelling should be conducted using reasonable uncertainties of input parameters. This becomes increasingly important for more complex models, where results of processes can be convoluted and complicated to disentangle and understand.
3.2 Scaling Monitoring

- What indications can be used to monitor the scaling deposits and growth?
- Are there different methods to monitor the different type of scaling?

(Direct) monitoring of scaling is not commonly done. However, below there are some common practices presented to monitor or analyse the precipitated minerals;

- Changes in flow rate or pressure may be caused by flow obstruction which could originate from precipitation. It is important to mention that a detailed analysis is required to determine whether scaling was the main cause of the decline in pressure, flow rate or increase in the pressure drops or not. In addition, a proper pressure analysis (e.g. nodal analysis) is required to determine the location of the scaling, in case it occurs in the subsurface, along the production/injection tubing or inside the downhole pump.
- Material captured in the filters can be analysed to check for precipitates
- Water chemistry may be monitored, but changes may not be within the accuracy. pH could be measured to monitor calcite scaling potential.

For detailed in-situ fluid monitoring at harsh geothermal conditions, a mobile fluid-monitoring device ("FluMo") was developed by GFZ engineers and researchers (Milsch et al., 2013; Feldbusch et al., 2013). This device allows measuring and fluid sampling at up to 150 °C and 20 bars. The fluid-contacting parts are made of corrosion resistant materials and the electrodes for pH, electrical conductivity, dissolved oxygen, and redox potential as well as a density measurement device are also selected specifically to measure and withstand these extreme geothermal conditions.

3.3 Scaling Mitigations

- What are the methods to mitigate each of these scaling precipitations?
- Use of scaling inhibitors (e.g. barite)
- Change of pH value prevention of calcite scaling
- Use of materials (for pipes and casing) that do not undergo galvanic reactions
- Temperature and pressure control

There are several methods to mitigate and control scaling. A suitable method to mitigate scaling depends on an accurate prediction and characterization of the brine chemistry, type, location and amount of the scaling and considering operational limitations, such as possibility to deploy the most effective mitigation measure in the field. In this section several candidates for mitigating different type of scaling, namely carbonate, sulphate and heavy metals scales are provided. In general, the mitigation techniques could be a change in the operating conditions (e.g. controlling pressure and/or temperature), use of chemical additive and inhibitors or filtering of the minerals. It is important to note that the development of new cost effective and efficient scaling mitigation technologies is still in progress which some of them were further researched in GEOTHERMICA PERFORM project (Wasch et al. 2019).
3.3.1 Carbonate scales

- Avoid or limit CO₂ outgassing by maintaining a sufficiently high operation pressure in the surface installation. A pressure is required that keeps enough CO₂ in solution to prevent carbonate precipitation. In general, this pressure may be lower than the bubble point and partial outgassing should not be a problem. The bubble point may very well be estimated by application of numerical geochemical calculations.
- Use inhibitors to keep Calcium in solution.
- Use cation filters to remove Ca²⁺. Such filters could e.g. be based on seeded crystallization (FACT filter).
- Add acid or CO₂ to the brine to prevent decrease the pH and increase carbonate solubility.

3.3.2 Sulphate scales

- Use scaling inhibitors.
- Use cation filters with adsorption materials for e.g. barium removal (e.g. chitosan or zeolite) prior to re-injecting cooled water.

3.3.3 Heavy metal scales

- Use corrosion inhibitors
- Use corrosion resistant materials
- Use cation filters with adsorption materials for heavy metal removal prior to re-injecting cooled water.
4 Corrosion in geothermal assets

4.1 The need for corrosion control

- Why is corrosion important to control?
- What kind of secondary damage may corrosion cause?

It is important to control corrosion damage in the tubing pipework for several reasons: Perhaps most obviously is the need to reduce the amount of particles in the system, because it can cause blockage of the injection well and result in formation damage. It is known from seawater injection wells in oil and gas industry that corrosion products (e.g. iron oxide and iron sulphide) and bacterial biomass have caused considerable damage, even in formations with high permeability, (NACE, 2012).

Great efforts are already applied in the surface plant design to reduce such particles by filtering, but the injection line and well include several kilometres of steel tubing where the problems might reoccur. Since a geothermal plant is intended to work well for at least 30 years, control of corrosion and selection of the right material shall be taken very seriously already before installing the wells.

Corrosion damage also involves a risk for the projected lifetime and integrity of the equipment. Since the majority of the installations is subsurface, maintenance and repair are complicated and very costly, requiring specialized contractors. The installations in the surface plant are easier to access, but any interruption in service is still undesirable due to the costs of loss in production, repair as well as laborious operations for shutdown and resuming service.

Other concerns of corrosion include reduced efficiency of the heat exchangers, if corrosion leads to scaling and loss in heat transfer.

Finally, and equally important is the risk of penetrating corrosion in well tubing, since this could potentially contaminate upper fresh water reservoirs with salts and metals of the geothermal brine or with chemicals (if inhibitor is used).

4.2 Corrosion types

- What is the difference between pitting and uniform corrosion?
- What are the most corrosive elements in the brine?
- To what extent does corrosion release particles?

The geothermal brine, having a salinity of 10-27 % (w/w), makes it potentially very corrosive to most metals. For comparison, the salinity of seawater is just 3.5 % (w/w).

The dissolved salts (mainly Na⁺, Ca²⁺ and Cl⁻), are not the main driving force for corrosion, but they provide the possibility of the long-range galvanic elements due to the high electrical conductivity of the geothermal brine (approx. 150 mS/cm). This is obvious from the character of aqueous corrosion of iron (or steel), being an electrochemical reaction that involves release of electrons according to equation (1):
Fe → Fe^{++} + 2e^{-} \quad (1)

Corrosion only occurs if this reaction (anode) is balanced by an electron consuming reaction (cathode), such as oxygen reduction (2) or hydrogen reduction (3):

\[
\frac{1}{2}O_2 + H_2O + 2e^- \rightarrow 4OH^- \quad (2)
\]

\[
2H^+ + 2e^- \rightarrow H_2(g) \quad (3)
\]

Both reactions are known to occur in geothermal brines. However, corrosion due to oxygen would usually imply unintended ingress of oxygen to the closed system, because the geothermal brine is completely free from oxygen in the reservoir. Corrosion due to acid (H^+) may arise from dissolved gasses in the brine such as CO_2 and H_2S, both being weak acids. Acid (H^+) may also come from the natural dissociation of water (anoxic corrosion), but usually the amount is so small in pH-neutral brine that this type of corrosion is negligible.

Deposition of dissolved metal ions, such as lead (4), is also known to cause corrosion in certain brine types:

\[
Pb^{++} + 2e^- \rightarrow Pb(s) \quad (4)
\]

\[
Cu^{++} + 2e^- \rightarrow Cu(s) \quad (5)
\]

Carbon steel usually accounts for the majority of the installations in well tubing and pipework in the surface plant, and therefore provides the source for Fe(II) in many geothermal plants. The dissolved Fe(II) quickly forms insoluble corrosion products such as magnetite (Fe_3O_4) with the risk of plugging the wells.

Corrosion resistant alloys (CRA) are used for various equipment and instrumentation, e.g. titanium is used for plate heat exchangers and stainless-steel type EN 1.4401 is used for instrument tubing and canisters for filters. As discussed below, the CRAs are only susceptible to oxygen ingress whereas carbon steel is susceptible to all corrosion mechanisms shown in Figure 2.
4.2.1 Uniform corrosion

Uniform corrosion is only possible for carbon steel in the brine solution, Figure 2a. Several cathode reactions may facilitate this reaction including oxygen reduction and hydrogen reduction. High flow conditions or elevated temperature conditions may favour rapid corrosion in some areas while other areas may be partly covered by rust products (iron oxide), slowing down the process here.

4.2.2 Pitting and localised corrosion

Pitting corrosion is mainly a problem for corrosion resistant alloys (CRAs) that are protected by a passive oxide layer. Even trace levels of oxygen (>10-20 ppb) may cause pitting, especially for low alloy grades like 17Cr or EN 1.4401 stainless steel. Corrosion becomes very localised in the pit because the majority of the surface remains passive, at the same time facilitating the cathode reaction. Moreover, the metal-rich and low-pH solution formed in the pit makes the corrosion self-catalytic, Figure 2b.

If stainless steel components are coupled to carbon steel, no corrosion will take place because the less noble carbon steel provides cathodic protection at the cost of faster corrosion of this steel. Thus, the risk of severe pitting is only relevant if larger sections of stainless steel (pipework, heat exchangers or pumps) are installed. This is also the reason why highly resistant titanium is preferably used in the plate heat exchangers.

Pitting corrosion and localised corrosion may also occur on carbon steel, if the steel is partly covered by electrically conductive scales such as iron sulphide.
4.2.3 Crevice corrosion

Crevice corrosion has many similarities with pitting, because it is promoted by an oxygen concentration cell between passive and active areas, and by the trapping of an aggressive solution inside the crevice, Figure 2c. It is mainly a problem for low alloy CRAs, provided oxygen is present in the brine. Common areas to find crevice corrosion include flange joints, threaded joints or small cavities filled with brine.

4.2.4 Galvanic corrosion – dissimilar metals

Galvanic corrosion occurs when two dissimilar metals are in contact, and at the same time having a liquid connection between the two metals. In geothermal systems, oxygen reduction is the only likely cathode reaction for driving this process. Thus, galvanic corrosion with dissimilar metals is only considered if oxygen ingress happens. CO₂ may also give galvanic effects on dissimilar metals, but usually the effect is small when compared with the CO₂ corrosion already occurring on the steel.

The principle of galvanic corrosion is comparable with a battery cell. If the metals are more than 0.1-0.2 V apart in the galvanic series, there is a considerable risk of corrosion of the less noble metal on behalf of the more noble metal, Figure 2d. Stainless steel is ~0.6 V more noble than carbon steel in geothermal brine, thereby presenting a risk of galvanic corrosion. If the surface area of the noble metal is much larger than that of the less noble metal, the unfavourable area ratio will lead to extremely rapid corrosion. Due to the high electrical conductivity of the brine, the galvanic element includes surfaces over long distances, making this mechanism dangerous in geothermal plants.

For the same reasons, care must be taken when defining the welding procedure for steel tubing in geothermal plants to avoid galvanic differences between the weld metal and the parent pipe metal. Usually, weld metal is added small amounts of nickel and chromium to optimise the mechanical properties. The addition of such noble elements would typically imply higher corrosion resistance of the weld than the parent metal, but in some situations the effect is opposite leading to a phenomenon known as Preferential Weld Corrosion (PWC). It is always advised to make a prequalification corrosion testing of the welding procedure to avoid this problem before building the plant.

4.2.5 Galvanic corrosion – noble metal ions

A special form of galvanic corrosion, involving noble metal deposition, can happen in geothermal plants. In certain reservoir types, the brine contains dissolved metal ions. Lead (Pb²⁺) is present in the Bunter reservoirs in Denmark, where it has caused galvanic corrosion in one plant. And in Germany, dissolved copper ions (Cu²⁺) in a Rotliegend sandstone reservoir have caused galvanic corrosion at the Groß Schönebeck geothermal site (Regenspurg et al., 2015).
Since lead and copper are more noble than iron, the mechanism shown in Figure 2e can run. The tendency to lead deposition increases with increasing temperature and flow rate. Consequently, the production well and tubing are more vulnerable to this form of corrosion than the other sections.

Again, due to the high electrical conductivity of the brine, the galvanic element includes surfaces over long distances, making this mechanism particular dangerous in geothermal plants. Guiding calculations have shown that the corrosion current may travel a length equaling 30-35 pipe diameters in geothermal water.

4.2.6 CO₂ corrosion
Carbon dioxide (CO₂) is a weak acid when dissolved in water and thereby potentially corrosive to steel. The corrosion rate mainly depends on the partial pressure of CO₂, which can be high in pressurized systems like geothermal wells. By this, CO₂ becomes almost an inexhaustible source for the cathode reaction. There is vast experience from oil and gas production, where CO₂ dissolved in the produced water is known to cause considerable corrosion. In the Danish geothermal wells only a small fraction of the gas from the production well is CO₂ (0.5-3.6%), whereas methane (CH₄) and especially nitrogen (N₂) make up the majority of dissolved gasses. However, much higher CO₂ levels are known from some Dutch and German plants, i.e., up to 92%.

The mechanism of CO₂ corrosion is shown in Figure 2f. When CO₂ is dissolved in water, carbonic acid is formed that acts as cathode for the corrosion process. It also involves formation of a partly protecting iron carbonate film, leading to localised corrosion of the steel. Usually, the corrosion rate increases with temperature up to a maximum at about 70-80°C. At higher temperature, the carbonate film becomes more stable leading to slower corrosion. Thus, the conditions in the production well (high temperature, high pressure) represent the greatest risk for CO₂ corrosion. Flow rate and buffer capacity of the brine are also decisive for the stability of the carbonate film and the resulting pH at the surface.

4.2.7 Other types of corrosion
Other types of corrosion than the above could potentially occur and are being introduced briefly below.

Local high flowrates causing turbulence usually increases the corrosion rate of especially unalloyed steel by constantly removing the formed rust layer from the surface. This will happen if pipe bends are too sharp, and in extreme cases, erosion occurs too on the surface. Likewise, sudden pressure changes due to reduced sections in the pipework can lead to cavitation from the impact of collapsing gas bubbles on the surface. Supersaturation with dissolved gasses accelerate this mechanism further. However, usually the design of the plant is made to avoid such flow related degradation mechanisms by following well-established rules for hydrodynamic engineering.

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Handling warm chloride solutions (>50°C) always presents a risk of stress corrosion cracking (SCC) for low-alloy stainless steel types such as EN 1.4401. This form of corrosion is particularly dangerous because the combined effect of mechanical stress and chemical attack can lead to rapid cracking. Since oxygen is needed for the reaction to occur, the exterior surfaces of hot equipment are most vulnerable, provided there is a continuous spill (i.e. wetting) of chloride solution.

In line with this, the risk of corrosion under insulation (CUI) must also be considered for all types of equipment. Continuous wetting of the insulation from e.g. small leakages, rain etc. can cause severe corrosion of the hot metal surface due to the well-aerated conditions.

As mentioned previously, microbiologically induced corrosion (MIC) is well known in the oil and gas industry. No incidents of MIC have yet been reported for the geothermal plants although one Dutch plant have experienced heavy clogging due to bacteria that also potentially can cause corrosion. Bi-products from bacterial activity in the reservoirs are also known to cause corrosion, such as H₂S occurring in the Bavarian Molasse basin.

4.3 Potential corrosion rates and release of rust particles

The amount of iron dissolved from either oxygen corrosion or deposition of metal ions can be calculated using stochiometric calculations based on equations (1) to (4). Possible worst-case scenarios are given below to give an impression of the impact corrosion may cause on particle release. This is calculated as release per year at continuous operation. In practice, lower corrosion rates are observed due to mass transport limitations and/or formation of protective layers, but still the calculations give an impression of the available driving force for corrosion. It is assumed that iron forms magnetite (Fe₃O₄) which is the normal corrosion product in water with almost no oxygen. For CO₂ calcite (FeCO₃) is formed.

**Oxygen**

Ingress of oxygen could potentially dissolve 2 mg/l O₂ in the high-saline brine at 25 °C, which is much lower than that of tap water (8-9 mg/l). At higher temperature the solubility is even lower. On-site measurements indicate that the dissolved oxygen (DO) level during excursions is about 0.2 mg/l. Assuming all oxygen is consumed by corrosion and the oxygen ingress continues all year, the amount of Fe₃O₄ can be calculated as:

\[
\text{Dissolved oxygen: } 0.2 \text{ mg/l} \\
\text{Flow rate: } 200 \text{ m}^3/\text{hr} \\
\text{Fe₃O₄ formed: } 190 \text{ g/hr} = 1.7 \text{ t/yr} = 0.34 \text{ m}^3/\text{yr} \\
\text{Corrosion rate*: } 0.2 \text{ mm/yr}
\]

*assuming uniform corrosion in 1.2 km 9 5/8” tubing
Presence of mill scale in the well tubing, as seen in one plant, may cause even higher release rates of the particles due to subsurface corrosion and flaking-off of the mill scale (Mathiesen, 2019).

**Lead**
A similar calculation can be made for dissolved lead ions as the driving force for corrosion of steel. Assuming 200 mg/l as in Groß Schönebeck sums up to 3 mm/year:

- \( \text{Pb}^{2+} \) concentration: 200 mg/l
- Flow rate: 200 m\(^3\)/hr
- \( \text{Fe}_3\text{O}_4 \) formed: 30 kg/hr = 260 t/yr = 52 m\(^3\)/yr
- Corrosion rate*: 29 mm/yr

*assuming uniform corrosion in 1.2 km 9 5/8” tubing

**CO\(_2\)**
Calculation example, NORSOK M-506 model:

- \( \text{CO}_2 \) concentration: 7 mol%
- Well head pressure: 10 bar
- Temperature: 73 °C
- Bicarbonate: 100 mg/l
- TDS: 200,000 mg/l
- Flow rate: 200 m\(^3\)/hr
- Tubing ID: 220 mm
- Corrosion rate: 3.6 mm/yr
- \( \text{FeCO}_3 \) formed*: 3.5 kg/hr = 14 t/yr = 3.6 m\(^3\)/yr

*assuming uniform corrosion in 1.2 km 9 5/8” tubing

**Anoxic corrosion**
Corrosion due to the dissociation of water (6) without presence of oxygen should also be considered.

\[
2\text{H}_2\text{O} + 2\text{e}^- \rightarrow 2\text{OH}^- + \text{H}_2 \quad (6)
\]

Corrosion rate measurements in the laboratory in deaerated brine (pH 7) predicts a corrosion rate of 25 \( \mu \text{m}/\text{yr} \) in the temperature range from 25 to 70 °C on a fresh metallic surface (Mathiesen et al, 2019). However, experience from completely deaerated locations like ship wrecks in cold seawater in the seabed show an anoxic corrosion of steel in the range of 0.1-1 \( \mu \text{m}/\text{yr} \) (DNV, 2008). This is further supported by examination of a 30-year old pipe sample from a geothermal plant that had maintained ideal oxygen-free conditions in the cold brine (Mathiesen et al, 2019). Studies in hot brine have identified \( \text{Fe(OH)}_2 \) as product of steel corrosion in saline solutions (Nagies and Heusler,
1997). It could also form directly by the oxidation of steel and simultaneous reduction of water to hydrogen ($H_2$) under reducing conditions (Schon and Heidendael, 1996):

$$FeO + 2H_2O \rightarrow Fe(OH)_2 + H_2 \quad (7)$$

Confirmation for this reaction happening at the GrSk production well was obtained by measuring the gas composition over time of fluid circulation tests at the release of the gas separator. Hydrogen content ranged between 0.2 and 20 vol% with highest $H_2$ concentrations released during shut-in periods (Regenspurg et al, 2013).

Precise corrosion rate data for anoxic corrosion in brine is lacking, and the effects of composition and temperature are unknown. However, when we assume that anoxic corrosion is roughly 20 times smaller than that of the 200 ppb $O_2$ scenario, and it mainly occurs in the hot brine, the corrosion rate is in the order of:

$$Corrosion \ rate: \ 0.010 \ mm/yr$$
$$Fe_3O_4 \ formed*: \ 10 \ g/hr = 0.090 \ t/yr = 0.02 \ m^3/yr$$

*assuming uniform corrosion in 1.2 km 9 5/8" tubing

4.4 Corrosion monitoring

Why is side-stream loop preferred over intrusive probes?
What are the pros and cons of the different probe types?
What decides layout and configuration of a corrosion monitoring strategy?

Due to the potential impact on the injection well and equipment, corrosion should ideally be monitored in the geothermal plant. Corrosion monitoring can in many cases prevent unscheduled stops or at least indicate when forthcoming interventions are needed. Based on the experiences obtained in the PERFORM project, various corrosion monitoring techniques are introduced below. The final configuration depends on the challenges met in the specific geothermal plant, i.e. whether it is oxygen ingress, $CO_2$ corrosion or dosage of corrosion inhibitor that needs to be controlled. Corrosion monitoring should be regarded as a mandatory part of the overall supervision and maintenance strategy for the geothermal plant alongside with procedures for regular inspection equipment, water sampling and review of process performance etc.

4.4.1 Corrosion probes and safety

Part of the geothermal plant operates at high pressure and high temperature, so safety is a key concern. Ideally, the corrosion probes should be installed in a side-stream loop that can be disconnected without interfering operation of the geothermal plant, Figure 3. In this way, any of the below mentioned probes can be serviced without pressure in the lines. Otherwise, the probes may be installed directly in the pipework in sections that are depressurized during standstill, but this option limits service of the probes to the standstill periods.

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Replaceable corrosion probes for direct installation (intrusive) and retrieval in pressurized pipework are available from several suppliers, and they are commonly used in oil and gas industry. However, we advise against this option due to the safety concerns and the extra training needed for using such probes and the special retrieval tools. If this path is chosen anyway, it is important to learn about the safety and installation options (Johnstone, 2014).

![Side-stream loop for corrosion monitoring in pressurized line downstream the injection pump.](image)

**4.4.2 Weight loss coupons**

The simplest way of corrosion monitoring is obtained by installing metal coupons in the same material as the pipework, Figure 4. Other configurations such as flush disc-probes are also available, giving a better resemblance of the flow conditions along the pipe wall. The pre-weighted coupons are exposed in pairs for several months and then retrieved for inspection, cleaning and weighing. By this, the accumulated corrosion rate for the exposure period is determined. Exposure should be at least one month to accommodate for the high initial corrosion rate of the metallic clean coupons.

The mounting direction of the coupons and flowrate in a side-stream loop should be considered closely to obtain flow conditions resembling the pipework. High flowrate causing turbulent conditions may give too high corrosion rates due to erosion and cavitation effects on the coupons.

The visual inspection of the coupon does at the same time provide essential information about corrosion type (uniform or pitting) and tendency to scaling. Scrape-off samples of the scale or products on surface can be analysed chemically to identify the mechanism for corrosion.
Additionally, corrosion coupons may be coupled in pairs of dissimilar metals to evaluate the risk of galvanic corrosion.

Corrosion coupons give a precise and direct measure of corrosion, but short-lived excursions in operation of the plant are not identified. This includes sudden oxygen ingress, variations in corrosion inhibitor dosage or effects from changing service conditions (flow, temperature, pressure). Consequently, it is always advised to install one of the real-time monitoring techniques mentioned below together with corrosion coupons.

4.4.3 Galvanic probe

The galvanic probe consists of two dissimilar metals that are electrically isolated from each other to facilitate measurement of the electrical current using a high-resolution amperemeter. Usually, the metal pair include the pipework metal (steel) and a noble metal (brass), Figure 5.

In case of oxygen ingress, galvanic current will instantly run between the noble metal (cathode) and the steel (anode). If the brine on the other hand is completely deaerated, no current is measured. It is not possible to translate the measurement to the exact concentration of dissolved oxygen (DO), but since the system ideally should be deaerated, this semi-quantitative measure still provides valuable information.

While the galvanic probe is very sensitive to oxygen ingress (or oxidizing agents), it has limitations on other types of corrosion, such as CO₂-corrosion, metal deposition or inhibitor dosage.

The galvanic probe should be inspected at half year intervals or when the geothermal plant is shut down for service. If scaling is observed on the brass coupon (such as iron sulphide) it should be considered replacing it with another noble metal.
4.4.4 ER probe

The ER probe (electrical resistance) measures the corrosion rate by detecting the gradual increase in electrical resistance of a metal element having a well-defined cross-sectional area. Any loss of metal due to corrosion will lead to an increased electrical resistance. The metal probe may be configured in several ways, as thin metal foil or a wire loop as shown in Figure 6.

Since the change in electrical resistance is extremely small and at the same time temperature dependent, the measurement is always accompanied by measurement on a fully enclosed and unexposed element in the probe. Today, high-resolution instruments are available so changes in corrosion rate over a day can be detected, provided the metal element has a sufficiently low cross-sectional area.

Corrosion rate can be calculated as mm/yr assuming uniform corrosion. If pitting occurs, this value may be slightly misleading but to the conservative side, still providing essential information. Readings from ER probes may also be interfered by formation of a conductive layer on the metal (e.g. iron sulphide), giving too optimistic values. Consequently, it is advised to inspect the probe at half year intervals or when the geothermal plant is shut down for service. The examination should assess type of corrosion (uniform or pitting) and whether conductive scales are present on the probe.
4.4.5 Electrochemical probe

Electrochemical probes are available in different configurations, including either two or three identical metal probes. However, the principle for measurement is basically the same. By applying a small electrical current amplitude on one probe using another passive probe, a rough measure for the electrode resistance is obtained. In this case, high resistance means a poor ability of the corrosion reaction to occur, previously introduced as eq. (1).

Using electrochemical principles such as LPR (linear polarisation resistance), the measured resistance can be transformed to an instantaneous corrosion rate (e.g. mm/yr). The obtained precision is usually within a factor 2-3 provided the measurement is not disturbed by e.g. deposition of conductive scales. The design of the probe is comparable with the galvanic probe in Figure 5.

4.4.6 Dissolved oxygen (DO) probe

The DO probe provides a precise and instantaneous measure of the dissolved oxygen content in the brine. Since the expected levels in brine are in the range of 0 to 200 ppb (part per billion), high-sensitive sensors must be used. Such sensors are either based on galvanic measurement in a glass probe or optical measurement.

Due to the delicate sensing electronics, DO probes have limitations to temperature and pressure, and require frequent recalibration as opposed to the robust corrosion probes, mentioned above. For the same reason the DO probe is installed in special rig, providing depressurizing and cooling of the brine before measurement, Figure 7. The advantage of this rig is the possibility of connecting it to outlets of hot brine from the product well as well as the high-pressure lines downstream the injector pump.

As discussed above, ingress of oxygen has a tremendous impact on corrosion and possible particle release. This applies not only to unalloyed steel but also low-alloy stainless steel types such as 17Cr and 1.4401. Consequently, the installation of a DO probe is strongly recommended.

4.4.7 pH probe

The pH probe should be installed in the same rig as the DO probe because it has the same limitations to temperature and pressure as the DO probe as well as the need for frequent recalibration.

Acidification of the brine may occur due to dissolved gasses (e.g. CO₂) thereby presenting a risk of corrosion of especially unalloyed steel. Thus, pH should ideally be measured in the pressurized brine to include the effect of all dissolved gasses. However, such measurements require probes that are too complicated for continuous on-line monitoring. Therefore, the readings obtained from
the rig in Figure 7 should be interpreted with care, because it can only show undesirable effects from e.g. chemical dosage or acid producing bacteria.

4.4.8 ORP probe

The oxidation reduction potential (ORP) probe monitors the redox potential of the brine. It may be installed in the same rig as the DO probe and pH probe. Assuming fully deaerated conditions the reading from the ORP probe will show a constant low potential. On the other hand, unintended presence of oxygen or oxidizing agent will show an increase in potential that should attended immediately because of the risk of corrosion.

Thus, the ORP probe provides largely the same information as the DO probe and galvanic probe. But the quantitative reading (mV) obtained with the ORP probe provides advantages in evaluating the risk of corrosion of passive metals, such stainless steel. Since the stability of the protective oxide layer on stainless steel is very sensitive to the potential in the brine, it is possible to define critical threshold levels that require immediate attention in the operation of the geothermal plant.

The ORP probe requires maintenance and recalibration at prescribed intervals like the pH probe.

Figure 6. Wire-loop for corrosion rate measurement by ER technique.

Figure 7. Automated water sampler for measuring DO, pH and ORP in cooled and depressurized brine.
### 4.4.9 Other options for corrosion monitoring

Apart from the above techniques, other options for monitoring may be considered in the geothermal plant, like the ones described below.

Iron count is frequently used in oil and gas installations to quantify corrosion. It involves regular sampling of the brine at one specific sampling-point, followed by measurement of the iron content in the water sample using chemical analysis. Ideally, the measured iron content should be correlated with a base-line sample taken downhole at the production well to account for any iron in the reservoir. By this, any increase in iron content in the surface plant indicates corrosion of steel tubing.

The installed iron anodes in stainless steel canisters for filtering may also be useful to monitor corrosion. Logging the consumption rate is here recommended as indicative measure for corrosion. Additionally, installing a zero-resistance ampere meter between the anode and stainless steel can provide even more detailed information, similar to that obtained with the galvanic probe.

Non-destructive testing (NDT) may also be applied directly on the pipework to detect changes in the wall thickness. The applicable techniques include manual ultrasonic testing (UT), automated UT (T-scan) and radiography (RT). NDT performed at 1-2 year intervals in the exact same location provides an accurate measure for wall thickness and thereby corrosion rate of the pipework. Pipe bends and areas having turbulent flow conditions should be included in such inspection campaigns. These NDT techniques can be performed from the outside of the pipes while the plant is in operation, without any lost production.

Multi finger caliper measurements give indication about increase or decrease of the wall thickness of a geothermal well. This detects both, the location of scaling (decrease of the well diameter) and that of corrosion (increase of the well diameter can be detected and localized). This logging tool is typically offered by wells service companies. It is important to repeat occasionally those measurements to monitor changes over time.

Analysis of the particles collected in the filters may be considered too, as described in the section on water sampling. An increasing amount of rust (iron oxides, hydroxides) is here a direct measure for corrosion, but the analysis may also reveal other effects related to scaling (e.g. Ba, Ca), sand production, oily matter, bacteria or stability issues of the brine.

### 4.4.10 Layout and configuration of corrosion monitoring

The layout and configuration of the corrosion monitoring strategy should be based on a detailed review of the potential threats for each specific geothermal plant. A corrosion specialist should be consulted to undertake this task.
If steel is used as the main tubing material, the need for corrosion monitoring is greater than that in plants having composite tubing installed. Likewise, the brine chemistry is decisive for corrosion, depending on presence of dissolved gases (e.g. CO₂), metallic ions (e.g. Pb) and whether corrosion inhibitor is injected.

As a basis, we recommend one of the following configurations for different scenarios.

**Steel tubing for injection well**

Oxygen ingress in the surface plan is considered as the main risk.
- Install a side-stream loop downstream the injection pump
- Include corrosion coupons of steel
- Include at least one real-time corrosion monitoring technique connected with the SRO/Scada system, e.g. galvanic probe, ER probe, DO sensor or ORP sensor
- Define alert levels and follow-up procedures

**Dissolved metal ions or CO₂-gas in brine potentially requiring corrosion inhibitor dosage**

Corrosion inhibitor is injected in the production well to deal with corrosion of steel caused by metal ions or CO₂-gas in brine. In this case it is important to monitor corrosion to ensure correct inhibitor dosage at all times.
- Install a side-stream loop close to the production well manifold
- Include corrosion coupons of steel
- Include at least one real-time corrosion monitoring technique connected with the SRO/Scada system, e.g. ER probe or electrochemical probe
- Define alert levels and follow-up procedures

### 4.4.11 Interpretation of monitoring data

Interpretation of corrosion monitoring data requires insight in plant design and operation as well as metals corrosion and scaling. During the first years of operation, it is advised to include a corrosion specialist for data analysis and interpretation due to the complexity of corrosion and geochemistry. At a later stage, when baseline levels are defined and possible improvements have been implemented, interpretation and follow-up may be handed over to the staff operating the geothermal plant. At this stage, detailed documentation should cover probe maintenance, alert levels and follow-up procedures on how to minimize corrosion in the geothermal plant.

### 4.5 Corrosion control

**How can oxygen enter the system?**
**Can CO₂ corrosion be stopped?**
**Are dissolved noble metals a risk for corrosion?**

Corrosion in geothermal systems is usually caused by one of the mechanisms described in section 4.2, i.e. air ingress, noble metal ions or dissolved gases from the well, and to a smaller extent by
anoxic corrosion or bacteria. In the following paragraphs it will be described what possible measures are to prevent corrosion.

4.5.1 Deaeration

It is always of outmost importance to keep the system deaerated, including start-up, operation, shutdown and standstill periods. Air entering the waterfilled system will lead to corrosion of carbon steel and possibly also low-alloy stainless steel. The calculations in section 4.3 indicate the release of iron that will form iron oxides or particles that could block the well. Moreover, ingress of oxygen could destabilise the brine and form other mineral precipitates.

As a basis, the brine from the reservoir is completely free from oxygen. Thus, possible ingress of air is related to operations in the plant (draining, repair, filter replacement etc.) or faulty and inadequate maintenance of equipment (leaking seals in pumps etc.). Efforts should constantly be applied to minimize the air entering the system from such sources.

During start-up, rock-the-well operations are sometimes made to stimulate the injection well. This involves a pressure build-up with nitrogen followed by a rapid pressure-release. Pure nitrogen or other inert gasses like argon should be used for such operations. Compressed air should not be used for such well operations due to its high content of oxygen.

Typically, a technical grade nitrogen gas containing less than 100 ppm (v/v) oxygen is considered sufficiently pure. The heavier argon gas is recommended for blanketing above the water level in wells, if work at the well head leads to oxygen ingress here.

During normal operation, the risk of oxygen ingress is usually very small, especially if the system is pressurized. The injection pump represents a potential risk area for air-intake at the seal for the pump shaft due the suction forces. Usually, a special device prevents this from happening by applying a pressure of liquid and nitrogen on the outside of the seal. However, if not operated correctly, oxygen ingress could occur at this location while the pump is running. If the surface plant operates at slight under-pressure, the risk of oxygen ingress is even higher and strict procedures should be established, e.g. continuous dissolved oxygen monitoring.

During shut-down for maintenance, special precautions are also required to minimize air, entering the system. In most cases the system remains water-filled without circulation. Some equipment may by disconnected and opened, e.g. filters and heat exchangers. When refilling and reconnecting such equipment, air will inevitably enter the system. Blanketing and pressurizing with inert nitrogen gas are commonly used to displace air as a good practice.

Dosage of oxygen scavengers may be considered to limit the effect of oxygen during shutdown and standstill depending on the amount of oxygen entering the system. Sodium sulfite, ammonium bisulfite or sodium bisulfite are frequently used in systems such as water injection systems,
comparable with the geothermal circuit. Sometimes a catalyst is added in ppb concentration (e.g. cobalt) to speed up the reaction. However, before applying oxygen scavengers the potential risks and side-effects should be evaluated closely. As an example, sulfate and perhaps H$_2$S formed by the reaction with sulfite could promote growth of sulfate reducing bacteria (SRB). Thus, it may be beneficial to add a biocide simultaneously together with the oxygen scavenger.

The operation of the geothermal plant should be planned to reduce the number of start/stop situations due to the possibility of air ingress, as mentioned above.

4.5.2 Corrosion inhibitors

Metal ions in the brine, such as lead, can contribute considerably to the corrosion of carbon steel. Since such metal ions come from the reservoir, only a slow decrease in concentration can be expected throughout the entire lifetime of the plant. The decrease rate will depend on the exchange of brine between the interconnected formations.

Yet, there are no mature ways of removing such ions before the brine goes back into the injection well, although promising techniques are being developed (see Annex II). Consequently, the only way to prevent this type of corrosion is adding corrosion inhibitors. Corrosion inhibitors form an organic film on the metal surface, thereby obstructing the metal deposition and galvanic reactions from occurring. The efficiency depends on dosage concentration, flow, temperature and surface finish of the steel. It is advisable to conduct corrosion testing in a laboratory before deciding on the inhibitor type and dosage. Continuous corrosion monitoring in the operating plant is also recommended as discussed before.

Apart from chemical dosage, it may be considered to redesign critical details in the plant, where deposition of the metal ions is most likely. Turbulent flow is known to promote metal deposition, so it is advisable to avoid sharp pipe bends or sudden reductions in the pipe diameter. Likewise, elevated temperature promotes metal deposition of e.g. lead, so circulation with no cooling should be prevented in order to limit the problem to equipment upstream the heat exchangers.

4.5.3 Degassing

Dissolved CO$_2$ gas from the reservoir is a main concern for corrosion of carbon steel. The concentration may change from the production well to the surface and change depending on the pressure in the gas separator tank, so correct sampling is crucial to determine a reliable value. A significant change in concentration in the fluid from the reservoir is not expected over time.

Depending on the concentration, it may be considered to inject a corrosion inhibitor in the production well through a chemical injection line. This will reduce corrosion in the production well tubing to the surface and downstream equipment.
In the surface plant, where the pressure is relieved, CO₂ may come out as a separate gas phase. Removing the CO₂ gas from the brine in a de-gasser will be beneficial to avoid corrosion of downstream equipment. However, the resulting increase in pH could on the other hand affect the stability of the brine, leading to scale formation (e.g. calcite). Consequently, a geochemist should be consulted before installing a de-gasser.

Although degassing can reduce CO₂ corrosion in the surface plant and injection well, dosage of corrosion inhibitor seems to be the most feasible method to prevent CO₂ corrosion of the entire plant. However, it is recommended to perform prequalification by corrosion testing in the laboratory as well as continuous corrosion monitoring in the operating plant to ensure high efficiency.

### 4.5.4 Treatment with biocide

Bacteria are mainly considered a potential problem during well standstill periods. Water sampling and analysis (e.g. DNA extraction) can show whether there is a tendency to bacteria growth. Depending on this, it may be considered to treat the water with biocide. Oxidizing biocides such as chlorine (Cl₂) or hypochlorite (NaOCl) are not applicable for the deaerated water system because they accelerate corrosion. Their effect on corrosion is the same as dissolved oxygen. Instead organic biocides to control anaerobic bacteria should be considered.

Care should be taken when selecting suitable biocides. Incorrect selection of biocide can cause compatibility issues with brine stability or other chemicals, particularly oxygen scavengers. Experienced chemical treatment companies with appropriate documented testing should be consulted to ensure full compatibility.

### 4.5.5 Stable operation

Operating the geothermal plant requires fully educated and dedicated staff, similar to running any other power plant. Any deviations in operation recorded by the SRO/SCADA system should immediately be attended and evaluated for follow-up actions in accordance with predefined procedures. Even small excursions in operation could potentially cause increased corrosion or scaling, and in the end require costly work-over of the wells as a worst-case scenario. As discussed in the previous section, on-line corrosion monitoring should preferably be part of this supervisory strategy for better corrosion control.

Observations from the equipment during operation, shutdown or maintenance should also be included in the daily procedures to control corrosion. Things to look for and keep a journal on include:

- Spill or leakages. Indicates corrosion from the inside. Furthermore, any leakage may cause even faster corrosion on the outside surface due to the contact with air.
- Characteristics of surfaces. Perform visual inspection of the inside surfaces whenever the equipment is opened. Look for anomalies such as pitting, preferential weld corrosion, scaling, metal deposition etc.

- Anode consumption in filters. Iron anodes are often used to protect the stainless steel canisters in filters. Record the consumption. A sudden increase indicates air-ingress in the system.

- Filter replacement intervals. The need for frequent filter replacement or increasing pressure drop over the filters indicates a problem with particle release, potentially rust.
4.6 Selecting the right materials

What are the basic steps for material selection?

Which materials are used and what are their corrosion risks?

Selecting the right materials is of course an important prerequisite to minimize scaling and corrosion in the geothermal plant. The material selection is usually done by the engineering company, designing the geothermal plant. Often, the principles known from oil and gas are applied, especially when selecting the well materials accounting for most of the installation (Wood, 2017). This includes a systematic process including a review of operating scenarios, material threats, material selection according to standards or need qualification, life cycle cost etc. As an operator, it is useful to have some insight in this process in case of problems necessitating replacement of components.

The basic steps for selecting the right material in corrosive media usually include:

1. Defining the corrosive environment and operation scenarios
2. Identifying the life-determining corrosion mechanism (see sect. 4.2).
3. Collecting corrosion data
   a. Experience or references from similar sites
   b. Literature and databases
   c. Corrosion testing
4. Overall evaluation of corrosive conditions
5. Evaluation of cost and supply issues
6. Final selection of material

Great efforts should be made getting reliable water and gas samples from the bottom hole when designing the geothermal plant. When considering carbon steel for the well and pipework it is important to measure the potential drivers for corrosion:

- dissolved gases: CO₂, H₂S, (O₂)
- dissolved metal ions, e.g. Pb²⁺ and Cu²⁺
- acidic components, pH

In some cases, unforeseen components have later been identified even though the above was analysed. As an example, the small amounts of dissolved lead leading to galvanic corrosion were not foreseen in several projects. Therefore, when using the carbon steel, the well should always be prepared for chemical injection.

If a corrosion inhibitor is needed, a prequalification test should be made to prove its efficiency. Such tests can be performed in autoclaves simulating the temperature, pressure, flow and dissolved gasses in the producer well.

Test loops with corrosion coupons during trial drilling has successfully been applied in at least one plant to ensure correct material selection. This plant has operated in 35 years without any
corrosion problems, using carbon steel as the well materials. If possible, this approach is strongly recommended.

Material selection is a complex science going beyond the scope of this best practice for a detailed review. Ideally, a corrosion engineer should be involved in the early stages of the planning. Based on the interviews and new insights of the PERFORM project, the table below summarises common materials used for the different components together with the main observation points to be addressed when selecting the material.

Table 1. Common materials in contact with brine, and main considerations and concerns about their use regarding risk of corrosion.

<table>
<thead>
<tr>
<th>Component</th>
<th>Materials</th>
<th>Considerations / main concerns rg corrosion</th>
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</table>
| Producer, lower completion and producer (well bore) | Carbon steel for tubing | • Susceptible to corrosion driven by CO₂ or acidic components.  
• Susceptible to corrosion driven by dissolved noble metals (e.g. Pb, Cu).  
• Susceptible to corrosion by oxygen but it is hardly present in well.  
• If H₂S is present, special requirements apply to the steel material to avoid sulphide cracking.  
• Microbial activity (bacteria and archaea), but yet no reported cases of corrosion.  
• Be aware of surface condition. Mill scale should be removed because it otherwise can release large amounts of particles.  
• Consider adding a corrosion inhibitor to avoid above. |
| Stainless steel EN1.4401, 316L for sand control screens |  | • Oxygen is the main risk, but hardly present in producer well.  
• Contact to carbon steel provides cathodic protection of the stainless steel.  
• If acids jobs or well workovers are performed, the potential damaging effects of the acid must be evaluated in advance. |
| Composite (GRE) |  | • Corrosion resistant, but lower pressure rating and temperature rating than steel. |
| Production Electrical Submersible Pump (pESP) | Abrasion and corrosion resistant alloys (CRAs) | • Oxygen is the main risk, but hardly present in producer well.  
• Frequent corrosion failures have been reported, possibly related to electrical stray currents from leaking seals.  
• Abrasion from produced particles can be severe.  
• If pump fails, a complete failure investigation should be undertaken to identify cause. |
| Pipework surface plant | Carbon steel | • Same risks as for carbon steel in well  
• Corrosion under insulation (CUI) on external surfaces should be considered |
<table>
<thead>
<tr>
<th>Component</th>
<th>Materials</th>
<th>Considerations / main concerns re corrosion</th>
</tr>
</thead>
</table>
| Filtration canisters and vessels | Coated steel | - Same risks as for carbon steel in well  
- Corrosion under insulation (CUI) on external surfaces should be considered |
| Stainless steel EN1.4401, 316L | | - Oxygen ingress is the main risk that can cause pitting and crevice corrosion. Additionally, stress corrosion cracking (SCC) can occur in hot equipment (>50°C).  
- Cathodic protection by e.g. iron anodes may be installed to avoid corrosion.  
- Risk of external stress corrosion cracking (SCC) on hot equipment in case of salt spills. |
| Heat exchanger | 17Cr stainless steel | - Oxygen ingress is the main risk that can cause pitting and crevice corrosion.  
- Possibility of cathodic protection depends on heat exchanger design. |
| Stainless steel EN1.4401, 316L | | - Oxygen ingress is the main risk that can cause pitting and crevice corrosion. Additionally, stress corrosion cracking (SCC) can occur in hot equipment (>50°C).  
- Possibility of cathodic protection depends on heat exchanger design.  
- Trend to replace EN 1.4404 plates with titanium due to corrosion. |
| Titanium | | - High resistance to saline solutions. No corrosion failures reported. |
| Injection Pump (iP) | Corrosion resistant alloys (CRAs) | - Oxygen ingress is the main risk that can cause pitting and crevice corrosion, depending on alloy grade.  
- Note, the injection pump is a possible source for oxygen ingress. |
| Injector (well bore) and Injector, Lower completion | Carbon steel | - Same risks as for carbon steel in the producer well, but corrosion is less likely due to lower temperature.  
- Corrosion due to oxygen ingress in the surface plant (as opposed to producer)  
- If corrosion inhibitor is added in the producer, reassure residual level, and re-inject if necessary. |
| Stainless steel EN1.4401, 316L for sand control screens | | - Oxygen ingress in surface plant is the main risk that can cause pitting and crevice corrosion, unless there is contact to carbon steel.  
- Contact to carbon steel provides cathodic protection of the stainless steel.  
- If acids jobs or well workovers are performed, the potential damaging effects of the acid must be evaluated in advance. |
| Composite (GRE) | | - Corrosion resistant, but lower pressure rating and temperature rating than steel. |
5 Water sampling

The collection of samples of geothermal fluids presents a series of challenges not encountered when sampling surface water or groundwater. In particular, special considerations should be taken to obtain water samples that adequately represents the chemical composition of the geothermal fluids. For example, the elevated temperature and pressure of the formation water means that chemical reactions can occur during sampling, sample storage and analysis, which would modify the composition of the fluids. Ideally, a sampling technique should be selected to avoid or minimize such reactions. If this is not possible, awareness of the range of possible reactions is crucial to define what the determined chemical composition actually represents.

The elevated temperature of the fluids necessitates cooling of the sample prior to analysis. Because the solubility of many minerals (except carbonates) decreases with decreasing temperature, their saturation state may be exceeded upon cooling. This may result in precipitation and a decrease in aqueous concentrations of certain solutes. Additionally, the depressurization of the sample during ascent of the fluid from reservoir to surface (or prior to analysis) may lead to degassing if the pressure becomes lower than the bubble point. The degassing of CO₂, for example, will not only affect the gas composition of the sample but would also increase the pH and could easily result in precipitation of carbonate minerals. Furthermore, the concentration and oxidation state of redox sensitive elements such as iron, arsenic and sulphur may be altered if the water sample is exposed to atmospheric oxygen. For example, oxidation of ferrous iron (Fe(II)) to ferric iron (Fe(III)) is accompanied by precipitation of Fe(III) hydroxide and a decrease in the water pH. Therefore, contact of the water sample with the atmosphere during sampling, storage and analysis should be minimized to avoid degassing and changes in the concentration of oxygen sensitive components upon exposure to air. Thus, it is suggested that some components to be directly measured in the field such Fe(II), Si or Sulphide which can be done by a field photometer. Preferably, samples of geothermal fluids should be collected in a container at the bottom of the borehole that can be sealed in situ to retain pressure and withdrawn without substantial decrease in temperature. The subsequent degassing and cooling of the sample in the container at the surface allow determination of any degassed gasses and characterization of precipitated minerals. This sampling technique may, however, not be possible during operation of the geothermal plant, in which case the samples must be collected at the surface. When doing so, the possibility that degassing and precipitation of minerals may have occurred prior to sampling should be taken into account and possible modifications of the chemical composition of the sample identified.

Samples should be collected and analyzed at start up after drilling of a new well and during geothermal operation e.g., every half year. For new wells, water samples should be continuously collected until the concentration of drilling fluid additives (e.g. potassium) reaches a constant level as an indication of complete cleaning of the well. Subsequent downhole samples may be considered representative of the formation water and may form the base line for subsequent evaluation of potential changes to the water and gas composition during geothermal operation. Because the future changes to composition almost always cannot be predicted, the analytical program should include a number of aqueous components, i.e., major cations, anions, trace
metals, pH, alkalinity and gas composition. From the chemical composition of the samples, potential geochemical threats to the operation can then be defined and form the basis for development of a sensible analysis program. Such a program could be reduced in scope to include only components relevant for evaluation and monitoring of the challenges specific to the geothermal plant in question. Any particles captured during the sampling procedure or geothermal operation could advantageously be quantified and identified to help evaluate the risk of mineral precipitation. Note that during the initial sampling campaign after completion, the presence of barite and clay minerals may represent drilling mud.

Most aqueous components in the collected water can be preserved for later analysis in the laboratory if samples are correctly treated. Anionic samples may be stored as long as they are frozen to avoid microbial activity. For organic analyses as well as trace element analysis, it is highly recommended to use acid washed equipment. Other parameters such as pH, may change because of reactions during storage, and the best results are obtained by analysis on site. Parameters that should always be measured on site include pH, temperature, flow rate, electric conductivity and redox potential as well as dissolved O₂ concentration (this parameter if of interest). Even if measured on site, some degassing may still take place - which increases the pH - and for further use in e.g. modelling this should be corrected for. To prevent inaccuracies due to (partial) degassing, the pH could also be measured under pressure with a monitoring device connected to the flowline. Accurate measurement of pH is critical for reliable data interpretation, since many minerals have a pH dependent solubility. The pH is a measure of the activity of H⁺ in the solution and since the dissociation constants for acids and bases are temperature dependent, the pH varies with the temperature of the solution. It is therefore important to report the temperature at which the pH is measured and to calibrate the pH-meter with standard buffer solutions at the temperature at which the pH of the samples is measured. Sample treatment for preservation depends on the analytical method to be used. It is therefore essential to identify the character of components in the analytical program and the methods with which their concentration will be quantified before sample collection.
6 Lessons learned from operation

6.1 Feedback from operators
What are the operational challenges in geothermal assets?
What are the 3 top headaches?
What are the current best practices in the operation of geothermal systems, e.g. during start-up, shut-in, etc.?

In this section, an overview of the practical inputs from the operators of geothermal systems is presented. Information provided by operators in Netherlands, Germany and Denmark have been gathered about experiences on operating their geothermal plants. Below is a summary and individual statements about the most critical equipment types and phases during the operation. The statements should be considered as a guidance because the conditions and design vary from plant to plant. But ideally the feedback helps to identify or shed light on issues that have been overlooked or require a closer evaluation. Firstly, an overview of the operational challenges in their sites with the operators wishes on further research and developments are provided. The top three operational challenges were asked in terms of their impact on the operation, reliability of the system and cost. In the final section, the lessons learned from their operational practices are provided.

6.1.1 Overview of operational challenges and operator wishes
Several operators agreed on the top 3 headaches regarding costs related to the operation (OPEX), i.e.:

1. Corrosion. Why/where does it happen?
2. ESP. How to increase the reliability/lifetime?

Additionally, other issues have been covered such as wear, clogging, scaling, etc. Almost all insights and experiences are gained by means of trial and error in the first phase of the exploitation. For all the mentioned challenges, operators shared their wishes in having more proactive guidelines/best-practices for the operation of their systems, rather than a reactive operation. Specific proactive operational guidelines need to be developed over time, especially concerning corrosion and scaling, as these two phenomena are the most difficult to predict.

Corrosion
Corrosion appears to be the biggest operational challenge when reviewing the feedbacks.

- Corrosion is a main issue, especially subsurface corrosion. It is unpredictable as well: for some wells no major problems arise with corrosion, but it is present more often.
- In one plant a well collapsed in 6 months, also causing leaking pipes and ESP failures. Using slightly higher alloyed steel grades did not solve the problem, and apparently the corrosion
inhibitors attach better to the unalloyed steel grades. It is suspected that dissolved lead is causing the corrosion, mainly affecting the casing upstream the ESP.

- At the surface where iron is in contact with glass fibres, it seems that there is a higher chance of corrosion and leakage.
- Corrosion is monitored by direct measurement from water samples. The water samples are collected at the wellhead on a monthly basis and between the heat exchanger and injector pump on a quarterly basis. Still, this gives no clear view of the situation in the subsurface.
- In some cases coupon measurements in surface facilities are performed to monitor corrosion. However, selection of the coupon type and location for monitoring is dependent on an accurate estimation of the type of corrosion.
- Corrosion occurs but corrosion monitoring is not applied as standard. Some tests have been performed just after commissioning or as part of research projects. A long-term mitigation strategy is still sought.

**ESP failures**

- Common failures with a lifetime of 2-3 years and a significant cost component.
- Unscheduled repair and replacement twice. Shaft coupling damaged and water ingress in motor due to corroded bolts.
- Production Electrical Submersible Pump (pESP) was pulled 11 times in 10 years in one of the assets. In this well, the pump was pulled within a year, due to a flooded power plug. No mechanical failures of the ESP's were recorded.
- The ESP failures are either due to a design and installation failure or caused by the operation of ESP in a harsh environment (corrosive and high volumetric flow rate). The main cause of common ESP failures in geothermal systems are often unknown.
- ESP failure due to a design failure needs attention and must be eliminated.
- If the ESP lifetime could be increased, it has a significant impact on the reliability and OPEX of the system.
- Further research and root-cause analysis are required to better understand and detect different failure mechanisms.

**Guidelines. Water sampling and NORM legislation regarding waste disposal.**

- Water sampling
  - Water sampling is performed in different asset on a regular basis from monthly to yearly periods.
  - There are still uncertainties in the location of the water sampling and potential chemistry changes of the collected brine during the sampling, storage and analysis
  - Another challenge was in terms which information can be acquired from the sample analysis and how it can be translated into operational actions
- NORM
  - Scales are NORM classified, a costly and demanding disposal strategy is required; a further reduction of scales is therefore mandatory
NORM is an issue. The disposal of waste collected by the filters is a quite expensive process, due to the strict rules regarding this subject. Perhaps an inhibitor could be added to decrease the (toxicity of the) waste, captured by the filters.

Guidelines on the addition of inhibitors/ treatment of filters regarding NORM legislation are strongly required.

In addition to the top three operational challenges, some other topics were raised by operators. The summary of the described challenges have been summarized below;

Wear and tear
- Wear and tear has been observed in several locations:
  - In pESP
  - Primarily in heat exchangers
  - Not observed as of yet, might be an issue at the inlet of the ESP.
- In some cases the mechanical failures of the ESP’s were recorded due to the wear and tear.
- In case the wear and tear are caused by sand production, a suitable sand control technique needs to be employed.

Scaling
- Scaling occurs, mitigation by using inhibitors; costs ~ 70 k EUR p.y.
- Carbonate scaling was an issue in at the start of several assets – noticed in filters and heat exchangers -, but by increasing the top side pressure, the issue was resolved. No further monitoring was necessary. In the new wells, no scaling issue was observed so far.

Clogging
- Clay-like deposits (lead) have been observed. Pre-filtering was installed.
- Minor clogging effects in the injection well
- It was a problem in the beginning when oil was present. The plant was rebuilt, and now it is not a problem anymore. Use good filters to avoid clogging.

Surface facilities failing/clogging
- Only utility systems such as heat pump, not in contact with brine.
- Filters are changed every month (1st half after 2 weeks, 2nd half 2 weeks after that, to keep the plant running). Pressure drop is an indicator for the filter changes.
- There are clogging observed in the filters and sometimes in the degassing unit.

6.1.2 Operational lessons learned
In this section, an overview of different operational procedures at different operation stages which are critical to the performance and reliability of the geothermal plant operation are discussed. The different operational stages which are described are start-up, operation, shut-down, standstill and during the maintenance.
6.1.2.1 Start-up
The start-up procedure is a critical operation that takes between ½ and 3 hours. Some of the challenges during the start-up are avoiding sudden release of particles, ingress of oxygen and improving ESP reliability.

- The ESP frequency is increased automatically until optimum frequency is achieved (takes around an hour). In one plant, this procedure especially for the injector pump is important to minimize the risk of induced seismicity.
- In two instances, the water volume of the producer and surface plant is led to sewer before initiating operation to get rid of particles formed during standstill.
- Water samples are collected at different sampling points in the surface plant. The water samples filtered to check for particles. The details of water sampling best practices are provided in chapter 5.
- For plants having a separator, it is important to fill and pressurize it correctly before opening valves and injection pumps.
- Nitrogen purging of the filters is used to prevent oxygen ingress.

6.1.2.2 Operation
The main requirements during normal operation are running the pump correctly as well as monitoring the corrosion and the effects of chemical dosage.

- It is important to maintain the producing pump’s working window to avoid pump damage or lower performance.
- A certain counter-pressure is always needed to avoid wear and cavitation in the pump.
- The flow rate is regularly adjusted manually to comply with the need for heating. The changes in the production settings should be monitored to avoid problems such as scaling (due to a lower tank pressure), corrosion or ESP operating outside its defined frequency and rpm ranges.
- The barrier liquid at the injection pump shaft (according to API plan 52/53) is carefully checked to avoid ingress of air.
- Pressure in system is carefully controlled and monitored to avoid degassing and potential pH-increase that could lead to supersaturation or carbonate scaling. Pressure must always be above bubble-point.
- The frequency of water sampling ranges from monthly to yearly, while gas samples typically are taken at yearly intervals. Often, a service company advises the operators about the locations of water sampling and frequency and analyses of the samples as well (more details in chapter 5). Sampling points during the operation may include:
  - Just above well head.
  - Before the separator.
  - After the separator.
  - Before bag filters.
Most of doublets are using corrosion inhibitors. The corrosion inhibitors are injected in the production well to minimize corrosion. The dosage level is typically 10 ppm, which needs to be consulted with the service provider. At the same time, corrosion monitoring is applied to tackle the problems in the surface plant.

6.1.2.3 Shutdown
The shutdown procedure usually aims at minimizing the ingress of oxygen, precipitations, pump failures and induced seismicity.

- Gradual reduction of the ESP pump rate, avoiding a sudden stop while keeping the surface pressure high.
- Valves in surface plant are closed, separating the system into isolated hydraulic sections.
- In some cases, the surface plant is pressurised with pure nitrogen to 0.4 bar to avoid air ingress.
- Chemicals are seldomly injected. In one plant, biocide and oxygen scavenger were added to the surface facilities.

6.1.2.4 Standstill
The usual practice is to keep the surface plant separated in isolated hydraulic sections, sealed and left as-is. Thus, circulation is not applied, and the brine stays in the equipment.

- Flushing with fresh water has been attempted in one plant, whereas other strongly advises against it due to risk of damaging the heat exchangers (possibly because of air ingress).
- Heat exchangers during a service at winter time needs to be kept at a high temperature.
- In some cases, the surface plant is pressurised with pure nitrogen to 0.4 bar to avoid air ingress.
- Other operators prefer to lower the pressure, knowing that the vapor pressure will prevent precipitation.
- In case of using line shaft pumps (LSP), a continuous lubrication of the driving shaft is recommended.
- Chemicals are seldomly injected during standstills. In one plant, biocide and oxygen scavenger were added to surface plant.

6.1.2.5 Well-head service
Well-head service is required when the Production Electrical Submersible Pump (pESP) has to be replaced. The replacement interval ranges from 2 to 7 years.
• Most plants have a redundant pump for an unforeseen failure and replacement.
• In some plants, maintenance on the well heads is done yearly during the annual shutdown.
• It is important to avoid precipitation and air ingress from the open well-head. For this purpose, argon is used as a blanketing gas. Argon is heavier than nitrogen and thereby provides a better protection of the well.
• For wells with a considerable gas content in the brine, the dissolved gas will act as a blanket and prevent precipitation.

6.1.2.6 Heat exchanger and heat pump service
Dismantling and cleaning of plate heat exchangers or heat pump evaporators is only performed if scaling, leakages or other issues dictates this.

• It is stated that titanium alloys perform better at higher temperatures (around 80 – 90 °C), so whenever stainless steel plates need replacement, titanium plates are added.
• Heat pump service is performed once a year, by a third party company. During the year, no work on the heat pump is performed, unless leakages occur.
7 References


Mathiesen, T. et al. Results of on-site monitoring campaign and parametric laboratory testing. GEOTHERM Milestone Report M5.4. 2019


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Annex I. Calculation procedure for LSI and RSI

Two mathematical formulations to estimate the calcium carbonate scaling tendency of the brine are:

- Langelier Saturation Index (LSI)
- Ryzner Stability Index (RSI)

Both of these methods can be described by having the following input parameters from the geothermal brine compositions:

- pH
- Temperature (in C)
- Total dissolved solid (TDS) in mg/L
- Calcium hardness in mg/L
- Total alkalinity in mg/L

For estimating LSI and RSI, the saturation pH needs to be estimated, known as $pH_s$ which is calculated as follows:

$$pH_s = (9.3 + A + B) - (C + D)$$

$$A = \frac{\log_{10}(TDS) - 1}{10}$$

$$B = -13.12 \times \log_{10}(Temperature + 273.15) + 34.55$$

$$C = \log_{10}(Calcium hardness) - 0.4$$

$$D = \log_{10}(Total alkalinity)$$

- From these equation the pH of the brine at saturated conditions will be estimated which will be used to calculate LSI and RSI: $LSI = pH - pH_s$
- $RSI = 2(pH_s) - pH$

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<th>Brine activity</th>
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<tbody>
<tr>
<td>LSI</td>
<td>RSI</td>
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<tr>
<td>3</td>
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Scaling Forming
Scaling dissolving
### Annex II. Summary of Problems and Learnings

<table>
<thead>
<tr>
<th>Identified problems linked to geothermal operations. Problems to be considered (and solved)</th>
<th>Suggested solutions – and methods developed for potential solutions through the PERFORM study work</th>
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</thead>
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| **Operational problems as consequence of improper design and dimensioning of the sub-surface facilities (like gravel packs, screens and casings/tubings).** | ▪ Conduct workover operations.  
▪ Replace gravel packs and screens, if possible. | Sønderborg and other plants. |
| **Clogging of pores, perforations etc. by particles.** | ▪ Use a self-cleaning particle filter or another type of particle filter. | Grünwald, Oberlaa and Insheim.  
▪ Particle filters have been tested at these sites |
| **Calcite scaling. Precipitation** of calcite is a common problem. Calcite scaling is primarily related to CO\textsubscript{2} de-gassing or temperature increase. The solubility of calcite decreases as the temperature increases. Supersaturation with calcite indicates a potential risk of calcite scaling. A high downhole Saturation Index (SI) for calcite (SI > c. 0.3) points to potential scaling problems. | ▪ Avoid CO\textsubscript{2} de-gassing by maintaining a high operation (injection) pressure that exceeds the bubbling point.  
▪ Use inhibitors to keep Ca in solution.  
▪ Use cation filters to remove Ca\textsuperscript{2+}. Such filters could e.g., be based on seeded crystallization (FACT filter*). The formed carbonate crystals are to be removed by filtration.  
▪ Add CO\textsubscript{2} to the brine to prevent de-gassing (CO\textsubscript{2} control). | Generally, a challenge in plants with high CO\textsubscript{2} and Ca\textsuperscript{2+} content, for example Pijnacker-Noordorp, Insheim, and Ammerlaan.  
▪ Further lab. and field tests are needed for examining the FACT filter performance.  
▪ Usually, the operators can handle this problem by pressurizing the system. |
| **Barite scaling** in the injection wells, the plant components or in the pores of the reservoir rocks. Pronounced barite scaling is observed at sites producing from hot, saline brines. Scaling with respect to barite is particularly a problem if the thermal water is super-saturated with barite, i.e., if the Saturation Index is high (> c. 0.5). The greatest risk occurs at the surface due to cooling (lower temp.) | ▪ Use scaling inhibitors.  
▪ Use cation filters with adsorption materials for barium removal (e.g., chitosan or zeolite) prior to re-injecting cooled water.  
▪ Avoid site-locations with Ba-rich brines in the system, if possible.  
▪ Avoid sites with CaSO\textsubscript{4}-rich brines, as the stability of the CaSO\textsubscript{4} ion pair decreases significantly when the temp. is lowered, leading to Ba\textsuperscript{2+} + SO\textsubscript{4}\textsuperscript{2-} → BaSO\textsubscript{4}. | Margretheholm, Insheim, Horstberg, Den Haag, and Groß Schönebeck.  
▪ Further lab. and field tests are needed for examining the effect and performance of the cation removal filters. |
| **Corrosion due to oxygen ingress. May cause destruction of materials and formation of Fe-oxides that again could lead to clogging of screens and gravel packs in the injection wells.** | ▪ Avoid (or limit) the amount of oxygen ingress, e.g., by maintaining a high operation pressure.  
▪ Use casings of composite material. | Corrosion due to oxygen ingress observed at Sønderborg, Lund and other plants. |
| **H\textsubscript{2}S-induced corrosion. H\textsubscript{2}S in the geothermal fluids - or formed by reduction of sulphates caused by bacterial activity - may lead to formation of corrosion products such as sulphides (e.g., FeS). The sulphides may clog sub-surface facilities, cause** | ▪ Remove H\textsubscript{2}S by adding iron-based additives (iron hydroxide (granulate) or FeCl\textsubscript{3} (liquid)).  
▪ Usually, this process leads to precipitation of Fe-sulphide particles. The generated particles can then be removed by filtering (cf. Regenspur et al., 2020). | Sønderborg, Pyrzyce and Oberlaa.  
▪ Especially a problem at strongly reducing conditions. May also be a problem in presence of |
material corrosion and/or result in bad smell.

| Galvanic corrosion due to dissolved Pb^{2+} and Cu^{2+} in the formation brine. Especially pronounced if the chloride concentration > 100,000 mg/L. May lead to generation of metallic lead (Pb(0)) and copper (Cu(0)) in the geothermal wells. | • Use particle filters for removal of metallic Pb and Cu.
• Use cation filters with adsorption materials for removing Pb^{2+} and Cu^{2+} from the geothermal water (materials could be chitosan, Fe-oxide, and zeolite).
• Use corrosion inhibitors.
• Use tubings and casings made of corrosion-resistant material, e.g., casings of composite material.
• Use corrosion-resistant alloys to prevent (or limit) galvanic corrosion, e.g., stainless steels. | Margretheholm (Pb), Sønderborg (Pb) and Gross Schönebeck (Cu).
• Cation filters have been successfully tested in the laboratory – a field test is still needed.
• Carbon steel and several higher alloyed steels were tested in the lab. in order to examine/control the corrosion processes. |
| CO\textsubscript{2}-induced corrosion Corrosion due to presence of CO\textsubscript{2} | Use corrosion-resistant alloys to prevent (or limit) CO\textsubscript{2}-induced corrosion.
• Or use a suitable corrosion inhibitor. | The selection of right materials for both the surface and downhole installations is essential. To be considered at an early stage in plant history. Alternatively, injection of an inhibitor should be considered. |
| Reduced flow | Temperature optimization is used to soft-stimulate the reservoir and/or to determine the best flow properties of the fluid with respect to the operational cost and energy output. | Ammerlaan. |

*) FACT: Filtration Assisted Crystallization Technology