Geothermal Drilling Corrosion - Reducing Costs And Failures With Onsite Monitoring And Treatment

John D. Tuttle, Renan Listi and Ron Tate
Sinclair Well Products & Services, Inc.

Keywords
Drilling fluids, corrosion, mud, corrosion rings

ABSTRACT

This paper addresses the challenges associated with corrosion as it relates to geothermal drilling activities. Specifically, the common goal is to identify methods to measure the quantitative and qualitative aspects of drilling corrosion in these hostile environments so that appropriate action can be taken to proactively enhance the life of tubulars. Corrosion tendencies will affect drill pipe, downhole tools, surface piping and equipment, and can become a very costly consideration to the drilling contractor and geothermal operator.

Onsite testing and monitoring of corrosion can be implemented on a drilling operation. If effective treatment is implemented in a timely manner, then significant operational cost savings can be realized.

1. Corrosion Concerns While Drilling Geothermal Wells include:
   - Downhole tooling corrosion – Downhole pipe and tooling fatigue and failure might be observed as severe pitting of drill pipe, washouts, twist-offs at tool joints, catastrophic drill string failures, stress cracking of drill pipe, damage to directional tools and stabilizers, shortened working life expectancy of tooling and bits, and other drilling indicators. Excessive tubular and tooling wear are costly and could lead to catastrophic failure and excessive costs associated with non-productive time at the rig.
   - Surface corrosion – Surface corrosion is exacerbated by naturally occurring atmospheric Oxygen and poorly treated and maintained equipment, and might be observed in the form of deteriorating drill string and drill collar conditions when left unprotected in air or stored between wells, excessive surface equipment wear and repair requirements (pumps, pits, lines), badly rusted mud pits and mud cooler, and degradation of other surface equipment that may be exposed to geothermal drilling fluids or other potentially corrosive environments.
2. Brief History of Geothermal Corrosion Treatment

In the late 1970s and early 1980s, during the Arab oil embargo, renewable energy (and specifically the potential of deriving energy from geothermal sources) received a significant amount of interest and governmental subsidies. Hence, a drilling campaign was initiated by both major O&G companies and new geothermal startups to identify and develop sources in the western U.S. The high activity level of drilling with conventional rigs (in both geothermal and O&G) created a high demand on drilling tubulars, resulting in high cost and limited excess supply.

Included in the drilling contractor’s IADC contract was a consideration for the operator (both O&G and geothermal) to maintain a corrosion program to protect the contractor’s drill pipe, and a specific corrosion rate to be maintained (generally 2-4 lb/sqft/yr) through a proactive monitoring and treatment program, generally managed by the drilling fluids company servicing the project. Drill pipe corrosion rings were run and analyzed at laboratories, and on-site corrosion treatment programs were implemented in order to satisfy the required corrosion rates. Pipe was inspected before and after each project, and if any significant corrosion damage had occurred, it was often paid for by the operator. After the boom busted (in the mid-late 1980s), corrosion became less of an issue and this consideration was dropped from the contractor’s contracts.

Geothermal drilling is generally pursued in a very hostile drilling environment – high downhole temperatures, brackish/corrosive formation fluids, air or aerated drilling practices, use of brines or seawater as a drilling fluids base, hard formations, etc. All of these considerations increase the potential for corrosion of tubulars and surface equipment, and any combination of two or more of the above will greatly increase corrosion tendencies and lead to pipe failures. Therefore, corrosion control has become an important component in geothermal drilling activities to reduce overall drilling costs associated with fishing jobs, tool failures and extended time on wells.

2.1 A Corrosion Management Program should be an integral component of any Geothermal Drilling Fluids Program.

A corrosion management program is a necessary cost savings approach to protecting tubulars in the drilling process. The direct costs of excessive or untreated corrosion include fishing jobs, loss of tubulars down hole, downtime costs while dealing with corrosion related failures, and possible loss of wellbore stability. Untreated geothermal drill string life may be reduced by as much as 75% thereby decreasing the expected life expectancy of the pipe from 8 years to 2 years. Corrosion plays a major role in 74% of all drill pipe loss. A well thought out corrosion management program should be a part of every drilling program to save on costs and to aid in the successful completion of the well at hand.

2.2 Current Geothermal Drilling Operations and Drilling Fluids

Today’s geothermal drilling activities generally utilize conventional rotary drilling methods, incorporating state-of-the-art directional and hydraulic technologies and other innovations. Surface hole is drilled to (or near) the top of the target interval with a clay-based drilling fluid, (which generally exhibits acceptable/low corrosion rates), where protective surface casing is run in anticipation of drilling the production zone. Through the (12-¼” or 8-¾”) production interval, the goal is to provide good wellbore stability and inhibition while minimizing the possibility of
formation damage from conventional mud additives. Generally, the use of clay/bentonite is discontinued, and only temperature-degradable or acid-soluble materials are recommended in the designed ‘Drill-In’ fluid; it is often possible (and desirable) to drill a production interval underbalanced, using water/air/foam as the circulating medium, either in fresh water or an inhibited fluid base. Air is introduced via compressors, either injecting directly into the drill string or through a parasite string set at a predetermined depth. These non-damaging ‘Drill-In’ Fluids are inherently more corrosive than the clay-based muds, sometimes with corrosion rates well in excess of 10 lb/100 sqft/yr, which is unacceptable to an ongoing drilling operation.

![Figure 1: Examples of drill pipe corrosion](image)

Figure 1: Examples of drill pipe corrosion – holes in drill pipe near where slips and tongs are used to make connections (upper and lower left), pin/box corrosion that has caused a washout in the tool joint (upper middle and right), twist-off at tool joint (bottom right) are all examples of drill pipe failures resulting from corrosion.

The ‘Drill-In’ fluids phase of this operation is treated with pH adjusters and corrosion inhibitors to assist with corrosion protection, as well as with foamers to enhance cuttings removal from the wellbore. The use of the freshwater ‘Drill-In’ system with an appropriate (K-Sub) inhibitor will provide formation protection while also performing a secondary function as a high temp corrosion inhibitor, thereby minimizing corrosion treatment costs. Penetration rates are generally significantly increased when using this underbalanced drilling method, when compared to conventional drilling. However, corrosion tendencies can become excessive, often encountering corrosion rates well in excess of 10 lb/sqft/yr.
2.3 Factors Affecting Corrosion Rates

Numerous factors affect corrosion rates, and combinations of any of these factors can increase corrosion rates significantly:

- Drilling Fluids Selection and Properties – Corrosion should be considered as a variable cost when the drilling fluids selection is being made for a specific geothermal project, as different drilling fluids systems provide differing levels of inherent protection (or lack thereof) for drill pipe corrosion.
- Oxygen – Introduced through direct air injection, air entrapment in the active mud system, or through extended exposure of drilling tubulars to air while in storage – oxygen reacts with metal to form compounds of rust (Fe(OH)$_2$ and Fe(OH)$_3$).
- CO$_2$ – Generally encountered while drilling naturally occurring formations and through bacterial degradation – combines with water to form carbonic acid (H$_2$CO$_3$).
- Temperature – Corrosion rates increase directly with the elevated temperatures encountered in geothermal drilling operations.
- H$_2$S – Naturally occurring – reacts with metal to cause hydrogen embrittlement, severe pitting and stress fatigue cracking.
- Dissolved Salts – Encountered through naturally occurring formation brines and KCl/other salts added for fluid density or inhibition – increases conductivity/corrosion, especially in low brine concentrations.
- pH – From drilling fluid, formation fluids - Low pH levels increase pH, higher pH levels (>10) will reduce corrosion tendencies.
- Annular Velocity – Higher annular velocities of fluids while drilling will promote erosion, which in turn increases the potential for creating corrosion cell locations and increased corrosion rates.
• Bacteria – Introduced through drilling mud degradation, temperature – creates H₂S, CO₂ and SO₄, all of which promote increased corrosion rates, especially at elevated temperatures.
• Drilled Solids – Circulating (and recirculating) of abrasive drilled solids will physically remove corrosion coating and chemicals on drillpipe, increasing corrosion cell formation.

![Figure 3: Corrosion reactions and byproducts.](image)

2.4 Geothermal (Drilling-Related) Corrosion Tendencies, Effects, Impacts and Costs

Geothermal drilling encounters conditions that enhance the number and severity of corrosion opportunities. Some general observations related to geothermal drilling corrosion are as follows, all of which support the recommendation of a preemptive Corrosion Control Program:

• High temperatures, aerated drilling conditions, the presence of corrosive gases, and brine/saline fluids are the primary corrosion contributors in geothermal drilling operations.
• Corrosion in geothermal drilling operations is 4-10 times that encountered in conventional O&G drilling operations.
• Drill pipe and downhole tubulars/tools are the most damaged drilling equipment – extending the lifespan of downhole equipment can provide significant cost savings.
• O₂ levels of 1 ppm can cause corrosion at elevated temperatures. Although operations can be modified to minimize O₂, chemical treatment to remove O₂ in geothermal drilling operations is not generally practical (surface and downhole aeration, temperature considerations).
• Corrosion rates at the bit and bottom hole assembly are generally much higher than near the surface, due to elevated temperatures, pressures, dissolved gases, and other considerations. Therefore, corrosion rates should be monitored with rings placed at or near the bottom hole location, to identify any significant/ unacceptable downhole corrosion rates, and to prescribe any required corrosion chemical treatment.
• Bentonite/Clay-based mud systems are generally much less corrosive than ‘clay-free’ Drill-In systems; even 10 ppb bentonite can significantly reduce corrosion rates through mechanical coating of the downhole tubulars.
• Quantitative and qualitative corrosion analysis can be obtained by using in-string corrosion coupons/rings.
• Geothermal drilling corrosion is generally observed as anodic pitting or etching, which can become quite extensive and severe under downhole conditions.
• Corrosion rates increase with salinity, although lower salinity fluids (~5,000-40,000 ppm Cl⁻) are much more corrosive than higher salinity levels.
• Excessive/uncontrolled corrosion of drilling tubulars can lead to pipe and tool failures, as well as hole problems.
• Corrosion rates increase significantly with oxygen/aeration of the mud system.
• Corrosion rates are inversely proportional to pH levels; pH levels in excess of 10 will enhance protection against corrosion cell formation.
• The worst-case geothermal drilling scenario – high temperature environment, neutral pH, aerated clay-free system with 3% KCl brine for inhibition. Corrosion rates can easily exceed 50 lb/sqft/yr without treatment, and the cost of an effective treatment to reduce rates to acceptable levels is generally thousands of dollars per day.
• Corrosion rates in excess of ~10 lb/sqft/yr can devastate a drill string and downhole tubulars within weeks.

Figure 4: Corrosion Rates at pH levels and temperature.
2.5 Corrosion Control Program: Implementing at the Drill Site

In order to combat corrosion at the drill site we must minimize/reduce surface aeration of the active mud system. In addition, utilize in-string corrosion rings and test ‘real time, on-site to determine the quantitative and qualitative nature (rate and type) of any unacceptable corrosion. In order to correct or control any unacceptable corrosion rates and trends, implement an effective corrosion treatment using the correct combination of chemicals, and where appropriate use metering pumps to inject chemicals directly into the primary mud pumps. It is wise to wipe/dry drillpipe during trips out of the hole and to coat tubulars prior to storage (with an appropriate corrosion coating agent), when they will be subjected to a long time in the air. This will help to mitigate corrosion problems in the field.

2.6 Corrosion Control Program: On-Site Field Corrosion Testing Protocol

An on-site corrosion control program will include a testing method to determine current corrosion tendencies. This is accomplished by utilizing drill pipe corrosion rings and subsequently performing cleaning, weighing, and testing processes to determine the specific corrosion rate (lb/sqft/yr) and type of corrosion.

Drill pipe corrosion rings are made of Type 4130 machine-finish steel and are used as a standard for field testing to evaluate the corrosiveness of the drilling fluid on the drill string and other tubulars and surface equipment. Corrosion rings are available for each drill pipe or tooling size and generally two are run in the string on a continual basis. Corrosion rings are placed in the Kelly sub and crossover at the drill collars, then left in the string for ~100-120 hours (anything less than 40 hours exposure will not provide accurate results).

Corrosion rings are weighed accurately to ±0.001 grams, before and after exposure, to determine the amount of weight lost while in the string. This weight loss is converted to a standard corrosion rate (lb/sqft/yr or mils/yr). Qualitative analysis can be performed on-site, using specific testing methods, to determine the type of corrosion that is actively affecting the drill string.

Following the on-site quantitative and qualitative analysis of the corrosion coupons, the need for treatment chemicals can be assessed and implemented. If no excessive corrosion is indicated, then no formal treatment may be required (although pH and some precautionary treatment is generally recommended). If corrosion is indeed indicated, then an addition or adjustment daily addition levels of specific treatment chemicals may be recommended to reduce corrosion rates to industry accepted standards.

2.7 Corrosion Control Program: On-Site Treatment Protocol

The rig’s mud pit configuration and treatment chemicals are critical components of a successful corrosion control program. Prior to drilling, the active mud pit system should be viewed and modified as needed to reduce any potential for surface aeration. Circulating and centrifugal pumps and mud pumps should be free of leaks, with well-lubricated packing. ‘Cascading’ of fluid from pit to pit should be minimized to reduce direct air entrapment. Also, any discharge lines from SCE (mud cleaner, centrifuge) should extend to below the mud level. While drilling, the mixing hopper should only be used when adding material. The addition of defoamer may be recommended to minimize entrapment and recirculation of air. When adding corrosion treatment
chemicals, the method of addition, and the monitoring of additions will ensure a successful result.

![Corrosion Rates General Acceptance Levels]

Figure 5: Corrosion rates general acceptance levels.

An initial treatment program should include the adjustment of the drilling fluid pH to 10-10.5 using lime, caustic soda or other appropriate OH⁻ additive (note: higher pH levels may be required if CO₂ or H₂S are encountered or anticipated). In addition, a base prescribed addition of a corrosion inhibitor will provide initial protection while waiting for the initial corrosion ring results.

Field-proven geothermal corrosion inhibitors are available for removal of oxygen, passive inhibition at the corrosion sites on metal surfaces, coating of metal surfaces, and specific treatment for H₂S and other contaminants. Where possible, any treating chemical should be injected directly into the pump suction using diaphragm pumps and metered to obtain the desired treatment concentration. After an initial corrosion treatment is implemented, further additions will be based on general observations and corrosion ring analyses, with adjustments in daily corrosion treatment chemicals made to obtain targeted corrosion rates.

Observations of drill pipe and downhole tubulars should be performed on a continual basis while drilling, inspecting tool joints for irregular wear, pitting or corrosion cells. During trips, a wiper rubber should be used to dry the pipe as it is being pulled from the hole and, in serious environments, the pipe may be coated with spray or brushed-on film-forming protectant. Pipe and tubulars should be cleaned and coated prior to any long-term surface storage to arrest any serious ongoing corrosion issues.
Figure 6: Pictured above are corrosion rings in new and used conditions (left photos), laboratory analytical scale (middle) and testing kit (right) for quantitative and qualitative determination of corrosion issues. All equipment can be maintained and utilized at the drill site for ‘real-time’ corrosion analysis.

Figure 7: Corrosion mitigation at the drill site.

2.8 Solids Control Equipment and Use of Mud Cooler

Recirculation of drilled solids in the drilling fluid will exacerbate corrosion by mechanically eroding tubulars, as well as removing corrosion chemicals from the drill string. In addition, higher temperatures generally promote higher corrosion rates (especially on tubulars exposed to excessive bottom hole temperatures). Addressing these issues with current technology will mitigate the number and severity of corrosion-related problems, while also reducing the daily requirements and costs for corrosion and other mud treating chemicals.
An effective Solids Control Equipment (SCE) program will generally consist of a ‘closed-loop’ system using dual or triple high G-force linear shakers, followed by a hydrocyclone desilter/mud cleaner, and complemented with a high volume centrifuge to remove fine drill solids from the drilling fluid. This equipment should be monitored continually at the drillsite, to ensure drill solids are being removed effectively and efficiently.

In the closed-loop SCE configuration, a mud cooler will reduce the circulating temperature of the recirculated drilling fluid significantly, often as much as 25°-35°F. Reduced circulating temperatures will promote reduced corrosion rates and longer wear life for downhole tools such as mud motors, stabilizers, and bits.

Where acceptable and appropriate, the geothermal drilling fluid may be circulated through a high-volume surface reserve pit. This will allow for significantly more time for settling of drill solids and mud cooling prior to recirculation. In addition, an appropriate total flocculent may be used in the reserve pit, to enhance settling (and avoid recirculation) of low gravity fine drill solids. This enhanced cooling and settling time should effectively reduce corrosion, however the on-site testing protocol should still be utilized to validate corrosion trends and treatment requirements.

2.9 Conclusions

A formal corrosion control program should be an integral component of any geothermal drilling operation. This should include the on-site, real-time analysis of corrosion rings to determine rates, and the addition of field-proven corrosion inhibitors to the circulating mud system.

Considerations of specific well targets and goals, and corrosion expectations, should be important factors in geothermal drilling fluids selection. Designing a drilling fluids system that satisfies all goals while minimizing corrosion trends will provide cost-effective protection of drilling tubulars, and there are large variances in the general corrosiveness of the conventional geothermal drilling mud systems; temperature, fluid pH, aeration and salinity are all primary components that can drastically impact corrosive trends.

An effective SCE program and mud cooler should be implemented, and corrosion coupons/rings should be run regularly and analyzed both quantitatively and qualitatively on-site.

A prescribed corrosion control treatment should include the use of field-proven corrosion chemicals, implemented to maintain corrosion rates less than ~6 lb/sq/ft/yr. Various corrosion additives, including oxygen scavengers, polyphosphate and similar inhibitors, film-forming amine compounds and others are highly effective in controlling corrosion to acceptable levels. Actual treatment rates should be determined and adjusted based on field observations and rig-site corrosion coupon analysis. Treatment rates can vary widely based on actual conditions and operational considerations.

A successful Corrosion Control Program can extend the life of tubulars and other steel components, mitigate or eliminate costs associated with drill pipe failure and fishing jobs, and effectively reduce the risk and costs associated with ‘non-productive’ geothermal drilling operations.
REFERENCES


Weatherford: Technical Literature, D-134-11.