Understanding Material Selection Challenges in Geothermal Well and Systematic Qualification Approach

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Abstract. Geothermal wells are usually operated under High Temperature High Pressure (HTHP) conditions where corrosion is the major threat to the well integrity. As a result, high operation cost and production time loss due to a short life span of steel casing reported in less than two years. This paper describes a study of the casing problems and failures observed in geothermal wells and a possible approach to optimize material selection and qualification of geothermal wellhead system materials.

1. Introduction

Geothermal energy is essentially inexhaustible because it draws heat from the earth and its greenhouse gas emissions are negligible compared to fossil fuels. Several studies conducted by Keserovic and Bäßler (2013), Lichti et al. (2010), Mundhenk et al. (2013) and Sanada et al. (2000) have been said that geothermal fields around the world caused excessive corrosion in the wellbore and wellhead components made of standard carbon steel material [1][2][3]. Most of the studies give attention to two types of acidic geothermal fluid the acid chlorine + (sulphide) type and acid sulfate + (chloride) type (Nogara and Zarrouk, 2014) [4][5]. Its possible negative environmental consequences are negligible due to the removal of hydrogen sulphide from high-temperature steam and the disposal of spent geothermal fluids into the soil. As the Philippines is part of the "Pacific Ring of Fire," it is rich in geothermal resources. Dissolved CO₂, NH₃ and H₂S contain geothermal fluids and chloride ions, which can cause metallic material corrosion. Therefore, the safe use of geothermal systems depends on especially when choosing materials. Precautions and conscious selection of materials at the design stage play an important role in reducing corrosion effects. Optimal cost and safety are factors that affect material selection. Construction costs, operating assets, operation, lost production, repair, and maintenance directly impact materials selection [6].

Aikenawa et al. (2021) studied the use of nanobubbles as corrosion inhibitor in acidic geothermal fluid [7]. However Michailidi et al. (2020) has been said it can only exist for many hours, several days of only couple of months [8]. The cost of corrosion resistant material is relatively expensive and there are many studies have alternatively pursued to chemical solutions on the material surface for inhibiting corrosion. The main corrosion process stated by Tang (2019) includes anodic and cathodic reactions, corrosion inhibitors can usually be classified as anodic inhibitors, cathodic inhibitors, and mixed inhibitors [9]. In the Philippines, the NaOH solution was injected into the well with capillary Titanium or Alloy 625 tubing to neutralize the reservoir and zone insulation to mitigate the acidic source. Using steam collection and well-case acid resistant structural materials, acid wells marketing techniques would
involve high initial fixed costs that are not feasible in third-world countries such as the Philippines. In the same way, the cost of converting geothermal energy into power is high, which would make it less favorable than other sources of energy. In recent geothermal efforts of power generation companies to extract the injection assembly from the well, the commercial mitigation operation has to be stopped for safety considerations.

2. Corrosion in geothermal
The corrosiveness of geothermal fluids are attributed to many factors:

2.1. Influence corrosion in geothermal well.

2.1.1. Produced gases composition:
- Carbon Dioxide (CO2): CO2 increases general corrosion of plain carbon steel and acidification of well fluid.
- Hydrogen Sulphide (H2S): H2S causes cracking (Sulphide Stress Cracking or Stress Corrosion Cracking) in high strength steel and acidification of well fluid. H2S reacts with mild steel and form protective film. However, presence of other ions such as Chloride will disturb this process.
- Oxygen Contamination: Presence of O2 may be very low in geothermal well but intrusion or diffusion of O2 traces from geothermal installations will make the fluid highly corrosive.

2.1.2. Pressure
The deeper the well, the higher the pressure. Increased produced gases pressure will increase the amount of the corrosion gas ions in the system which will increase the corrosion of the steel.

2.1.3. Temperature:
High temperature in geothermal condition accelerates the corrosion process of carbon steel and is also one of essential environmental limits in selecting the alloys. Temperature change (expansion or contraction) usually happens when the cement sheath is incomplete, vertical expansion with failure at or near connection and expansion of trapped fluid between casings with bulge or collapse.

2.1.4. Well fluids composition:
- Chloride ion accelerates corrosion especially localized corrosion (e.g. pitting) as well as uniform corrosion. pH: Although some geothermal wells have alkali well (pH 8-10), extreme fluid conditions exist with pH as low as 2 which will accelerate the corrosion of mild/carbon steel and cause cracking in stainless steel.
- Sulphate is the primary aggressive ion in some geothermal fluids.
- Well Fluid Flow Rate, the higher the flow rate, the higher the corrosion rate.
- Chemistry of (shallow) formation fluids outside casing.
- Chemistry of produced fluids from the reservoir.

2.2. Service conditions and failure modes
There are several possible causes of casing failure in geothermal wells include formation loading, mechanical damage, corrosion and scaling, thermal stress, metal failure and entrapped fluid expansion [10]. In the actual service condition, it can be predicted hardly the temperature accurately and most of available casing steel grades and casing connections are designed and manufactured for petroleum service rather than geothermal service [11]. The below picture of 10-3/4” casing pipe collapse exposed area is an illustration of failure shows in Figure 1.
Table 1, as shown below reproduced from the paper of Southon (2005), describes the failure mechanisms common in geothermal wells.

Table 1. Production Casing Possible Failure[13]

| Casing Mechanism                  | Conditions                                      | Likely Depth                                |
|----------------------------------|-------------------------------------------------|---------------------------------------------|
| Casing implosion                 | $\Delta T$ and casing to casing entrapment of fluids | Anywhere above shoe of outer casing (s)    |
| Compression failure in casing and/or coupling | $\Delta T$ and rapid heat up. Also an added condition in severe doglegs | High temperature fields and shallow where $\Delta T$ is greatest |
| Sulfide stress cracking          | Temperature below 80°C and high stress areas.   | Shallow with cold shut in conditions        |
| Early (< 2 years) corrosion and or casing holing (internal). | Sections with worn (thinned) casing or wells with very aggressive (low pH) production fluids | For aggressive fluids the first sign of problems is corrosion at the wellhead. |
| Delayed corrosion (3-5 years) internal Corrosion evidence after 5 years (external) | Condensate level shut-in wells | At the water gas interface of shut in wells |
|                                  | Corrosive fluid penetrating along micro-fractures in casing cement | Any depth in production casing              |

3. Material selection

When it comes to preventing corrosion in equipment, the correct material selection is very important. Although it is difficult to find materials that are completely resistant to corrosive elements, careful material selection, especially when combining them in a product, can help decrease corrosion. Understanding the corrosion process in metals, as well as their mechanical properties and the metal strength required to withstand corrosion effects, helps a lot toward developing equipment withstand corrosion.

As defined by the ISO 9223 standard, corrosion categories are based on atmospheric wetness and pollution and the corrosion rate of metals in the atmosphere. This standard is a useful guide when deciding on materials for your equipment. Figure 2 shows the relationship factors in the selection of material considerations.
According to the Norsok Standard design principles in 1994, the materials used should be optimized based on investment and operating costs to minimize the life cycle cost (LCC) while ensuring acceptable safety and reliability. The main factors considered in selecting material are: (1) Material with good market availability and recorded manufacturing and service efficiency. (2) Reducing the number of materials considering the costs, interchangeability, and availability of the necessary spare parts. (3) Lifespan and service condition. (4) Capability with materials and corrosion protection techniques against related corrosion conditions. (5) Require system availability. (6) Applied maintenance system and the extent of machine redundancy. (7) Loss weight consideration. (8) Monitoring of corrosion. (9) Climate impact including the compatibility of different materials. (10) Assessment of the possibility of failure, criticalities, and effects. Consideration should be given to any adverse effects that material selection may have on human health, environment, protection, and material properties. (11) Environmental concerns associated with corrosion inhibitors and other chemical treatments [14].

Selection of a corrosion resistant material for the environment is a prerequisite to a good design. Materials and design are complimentary to each other and neither of the two can be ignored. The following factors influence the service life of equipment described in Figure 3.

For Carbon and Low Alloy Steels, high corrosion rates are observed in both brine and steam environments. In the case of 4130 steel, deep pits are found at the Heat Affected Zone (HAZ). The additions of Chromium, Molybdenum, Nickel, and Copper in various alloy families have no significant corrosion resistance effect.
Higher corrosion resistance can be achieved with Stainless Steels; however, varying Chromium, Molybdenum and Nickel contents did not significantly improve corrosion resistance. 316L suffers from trans-granular Stress Corrosion Cracking in steam and brine environments, while 410 SS suffers from crevice corrosion cracking. Both Alloy and Hastelloy C-22 have almost the same corrosion rate in brine and steam environments. They don’t suffer from Stress Corrosion Cracking. A few CRA (corrosion resistant alloys) in consideration are described in the following tables. These are chosen for their corrosion resistance and outstanding mechanical properties. They can either be solid but employing them as cladding material will prove to be more economical while maintaining its integrity during service [6].

Geothermal process environments are mainly under high temperature/high pressure ((HT/HP), conditions and special test vessels and equipment are manufactured to replicate these conditions in a laboratory environment (Nogara and Zarrouk, 2018) [4], [5]. The temperature of the geothermal brine is decreased, the pressure drops or is unstable when exposed to air, and the trace (but important) composition of the brine makes it difficult to simulate in the laboratory. Definitive corrosion testing must also be carried out in the field [15].

The below-gathered photos shown in Figure 4 and 5 from case study obtained from one of the geothermal power plants in the Philippines in 2014. The researcher previously visited the site to understand the corrosion issues encountered in the power plant.

![Figure 4](image1.png)  
**Figure 4.** Flow Accelerated Corrosion resulting in severe wall loss on Branchline Elbows

![Figure 5](image2.png)  
**Figure 5.** Erosion in Expansion Spool Wing Port Due to High TSS Well Discharged
Figure 6 shown the corrosion at 2” corrosion coupon tapping leaked on April 2014 after six (6) months of service due to severe pitting corrosion on the internal surface of the tapping assembly. The 2” tapping connection was replaced but without the 2” diameter spool between the weldolet and weldneck flange. The weldneck is directly welded to the weldolet to minimize exposure of the pipe (relatively thinner than flange and weldolet material) to the acidic fluid condition.

**Figure 6.** Pitting Corrosion on the Internal Surface of the Tapping Assembly

### 4. Methodology in selection and qualifications approach

The researcher theoretical framework outlined from an oil and gas industry approach as illustrated in Figure 7 below, where the first phase of the study started with the data collection and review of geothermal well and pipeline condition. Based on the data collected and established pre recognized guide for preliminary material selection. The standard material assessment and corrosion testing were according to the available and well-known international code & standards and recommended practices. The result's evaluation and analysis have elaborated to rank the material for selection for field testing.

| Step 1: Data collection and review |
|------------------------------------|
| • Gathered information on the current corrosion problems and common mitigation method practice |
| • Well and pipeline data collection and review |

| Step 2: Preliminary material selection |
|---------------------------------------|
| • Collect the data of chemical composition and the acidity of the geothermal fluid of most acidic well |
| • Assumed the worst-case scenario respective the corrosion |

| Step 3. Standard material assessment |
|-------------------------------------|
| • Shortlist material based on the limitations listed in international recognized standards, books or databases. |

| Step 4: Specimen Preparation and testing |
|-----------------------------------------|
| • Prepare test sample |
| • Metallurgical testing (chemical properties, micro-examination and corrosion testing) of selected CRA material |

| Step 5: Evaluation and analysis of result |
|------------------------------------------|
| • Materials are evaluated for their relative performance demonstrated from qualification test based on specific criteria (e.g. corrosion rate at defined pressure/temperature rating, cracking susceptibility at H2S concentration, etc). |

| Step 6. Field Testing |
|-----------------------|
| • In addition to comprehensive material qualifications and studies field tests may be necessary to assess additional corrosion hazards that are not considered. |

**Figure 7.** Material Selection & Qualification Approach
Shortlist material based on the limitations listed in internationally recognized standards, books or databases. The standard references for this research are: ISO standards, especially ISO 15156/NACE MR0175 - Petroleum and natural gas industries – Materials for use in H2S-containing environments in oil and gas production, ISO 21457 - Materials selection and corrosion control for oil and gas production systems; Materials database (e.g. Total Materials); ASM Handbook, especially volume 20 – Material Selection and Design [16][17]. In the table 2 show that nickel alloys in any combination of temperature and chloride content in the production environment are acceptable.

| CRA Grouping as per ISO 15156-3 | Max Temperature (°C) | Partial Pressure PH2S (psi) | Max Chloride (mg/L) | pH |
|---------------------------------|-----------------------|----------------------------|---------------------|----|
| Austenitic Stainless Steel      | 60                    | 15                         |                     |    |
| High Alloved Austenitic Stainless Steel | 121               | 100                        | 65000               | ≥3.5|
| Duplex Stainless Steel          | 232                   | 1.5                        |                     |    |
| Martensitic Stainless Steel     | d Acceptable          | 1.5                        |                      |    |
| Solid Solution Nickel Alloys    | CW: 230               | 30                         |                     |    |
| Titanium Alloys                 | Any combination of temperature, PH2S, chloride content and in-situ pH occurring in production environment is acceptable | | | |

a. General environmental limits for any equipment or components
b. Materials in solution annealed condition (A) or annealed and cold worked condition (C)
c. Any combination of chloride content and in-situ pH occurring in production is acceptable
d. Any combination of temp and chloride content occurring in production environment is acceptable
e. Material used without restriction on temperature, PH2S, chloride content and in-situ pH.
No limits on individual parameters are set, but some combinations of these values parameters might not be acceptable

**Figure 8.** Characterization of Sour Condition - Regions of environmental severity with respect to SSC of carbon and low alloy steel (NACE ISO 15156, 2015 [18])
The above figures 8, 9 and 10 show other materials selection guides for sour service environment that can be applied in geothermal settings. Thorhallsson stated in 2005 that "the change in the pH of the fluid by acid or caustic addition would have an impact on the precipitation rate of silica [20]. If you add acid, precipitation is slowed down so that a highly saturated solution can be handled. Likewise, you can add caustic, which can induce rapid precipitation if you try to separate the silica from a supersaturated solution that has been acidified."

Standard material assessment & tests act as QC for the shortlisted material regarding suppliers, incoming materials batches/heat, weldment, and traceability. Standard testing helps eliminate the substandard material and unsuitable alloy for the further selection process, reducing total material qualification & selection process duration and costing.

Mostly the laboratory test has performed for further assessment for material that is survived or accepted by standard material assessment. The test include mechanical test, chemical analysis, and corrosion testing, macro and micro examination. Customized testing is specially designed to simulate the actual operating condition, based on the data collection from the step 1 (with respect to H2S, CO2, pressure, temperature, pH, Chloride, acids, etc) [21]. In a typical HPHT test, the sample is loaded in autoclaves under simulated condition, followed by corrosion rate, pitting, and intergranular evaluation at the end of test duration. Depending on well condition and project need, dynamic testing in the lab such as a rotating cage and flow loops may be considered to include the effects of flow rate and shear stress.
Materials are evaluated testing reference to Table 3 for their relative performance demonstrated from qualification test based on specific criteria (e.g. corrosion rate at defined pressure/temperature rating, cracking susceptibility at H2S concentration, etc). For further optimization, cost of workover and stop production may also be included to evaluate the total life cycle cost.

Table 3. The Typical Testing to be conducted for Material Assessment [22]

| Mechanical Tests       | Chemical Analysis                      | Corrosion Test                                      | Microstructure Examination |
|------------------------|----------------------------------------|-----------------------------------------------------|-----------------------------|
| Tenile Strength        | Optical Emission Spectroscopy (OES)    | Determination of corrosion rate (ASTM G31)          | Grain size measurement (ASTM E112) |
| Charpy Impact (V-Notch)| Electron Dispersive X-ray Spectroscopy (EDX) | Pitting & crevice corrosion (ASTM G48)              | Ferrite count (ASTM E562)    |
| Bend Test              | Inductive Coupled Plasma (ICP) methods | Intergranular corrosion (ASTM G28 and A262)         | General microstructure examination (ASM Handbook Volume 9) |
| Hardness Test          | XRF (PMI)                              | H2S cracking (NACE TM 0177, TM0316, TM0284, EFC16/17) | Galvanic corrosion (ASTM G72) |
| Reference standard:    |                                        |                                                     |                             |
| ASTM A370              |                                        |                                                     |                             |

In addition to the comprehensive material qualification and studies, field test are necessary to evaluate other corrosion threats that are not accounted for. Field test can be carried out by inserting corrosion coupons in different locations with different environmental parameters. Corrosion trend can be plotted with different exposure duration based on the investigation of result coupled with different operation phases.

5. Conclusion

In conclusion, selection of appropriate wellhead materials, casing and connections designed for high thermal applications offers potential for enhanced well integrity. A systematic selection and qualification of materials can help reduce corrosion and associated failure risk, hence improve the safety and reliability of the geothermal plant. Use of qualified and fit-for-purpose materials can help reduce total life cycle cost of well operation i.e. both capital expenditure and operation expenditure. The establishment of industry-specific guidelines and standards is a critical enabler for improving the material selection and qualification process. To make this happen, close industry collaboration is required.

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Acknowledgments
The author would like to thank PT Cladtek Bi-Metal Manufacturing to support the plan to pursue the doctorate degree and provide valuable technical advices in completing the research.