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Corrosion Review and Materials Selection for Geothermal Wells

Prepared for: Kennisagenda Aardwarmte

Doc Ref: WGI 5099A

Rev: 2

Date: June 2017

Report

Client	
Kennisagenda Aardwarmte	
Document Title	
Corrosion Review and Materials Selection for Geothermal Wells	
WG Reference Number	Client Reference Number (if applicable)
WGI 5099A	
Contact	
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Revision	Date	Reason for Issue	Prepared	Checked	Approved
2	09/06/2017	Final	PW	MB	LS
1	02/05/2017	For approval	PW	MB	LS
0	17/01/2017	For review	PW	MB	LS

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Executive Summary

The Dutch Geothermal Energy sector makes use of low enthalpy geothermal heat as a renewable energy. The heat extraction scheme typically combines a production well including an electric submersible pump (ESP) lifting the hot fluid to a surface heat exchanger and an injection well pumping the heat depleted fluid back into the source reservoir. The first geothermal wells in the Netherlands were completed in 2007 and as of January 2016 there are fourteen geothermal installations in the Netherlands. All geothermal wells in the Netherlands require the use of ESP's to lift the hot fluid to the surface. The depths of the wells investigated in this report lie between 1,500 meters to 3,000 meters.

Studies and Operator experience have identified corrosion and scaling as major potential challenges for the geothermal wells. Assessment of the material degradation threats (corrosion) to ensure appropriate materials selection at the design stage is identified as a key element in achieving effective asset management in the geothermal systems.

This report provides a full analysis of relevant corrosion and scaling threats and their mitigation in geothermal assets and practical guidance on materials selection including the use of life-cycle costing so that cost-effective material choices can be made for wells at the design stage. It defines the process for material selection decisions and provides example material selections for all well components. The necessary chemical treatment, monitoring and inspection regimes are described. Guidance on is provided on the use of life-cycle costing in the materials selection for geothermal well components. Guidance is provided on corrosion risks for surface facilities, with mitigation options.

A second stage of the project (Comprehensive Asset Management) will develop the further the practical operating measures to control and manage corrosion in low enthalpy geothermal operations.

Corrosion Threats

Relatively high levels of CO₂ are present in the four reservoirs currently exploited for geothermal projects and this is the most significant corrosive species. There is a large variation in CO₂ levels from location to location even within the same reservoir. Carbon dioxide (CO₂) corrosion and scaling are the major internal corrosion and integrity threats.

The critical factors influencing CO₂ corrosion rates in the geothermal situation are:

1. CO₂ concentration
2. Fluid velocity and flow conditions
3. Temperature
4. Water chemistry (especially presence of further acid or alkaline species)

Methods for assessing and predicting corrosion rates for CO₂ corrosion are described. In general, the service conditions are within the range that has been thoroughly studied for oil and gas production and other applications, and there are several corrosion prediction

models and approaches that are expected to be reliable.

All other potential corrosion threats are analysed in detail with their application to the Dutch Geothermal situation and mitigation options are explained.

Materials selection

The corrosion rates in the majority of waters do not allow the use of unprotected carbon steel. There are essentially two design options, namely Carbon Steel plus Inhibition or Corrosion Resistant Materials. The minimum acceptable corrosion resistant alloy (CRA) for downhole tubulars is 13Cr martensitic stainless steel, which is the most economical of the commercially available CRA materials. The most significant limitation of 13Cr martensitic stainless steels in Dutch low enthalpy geothermal conditions is their lack of resistance to pitting corrosion in the presence of even trace oxygen levels.

To date, the default choice for well construction has been Carbon Steel plus Inhibition. However, the life-cycle costing examples suggest that capital cost is probably not the most important factor in material selection for these wells if considered on the basis of full life-cycle cost. The tubing material cost is a relatively small proportion of the whole well capital cost, and there is relatively little impact of the different materials on the cost of a geothermal well.

The use of corrosion resistant downhole materials should be considered at the design stage for new projects.

Detailed materials selections for all well components are presented for both Carbon Steel and the CRA design options.

Safe Operating Windows

Example Safe Operating Windows for corrosion and materials related parameters are provided. Both Carbon Steel and CRA design options have tolerance to the range of conditions in low enthalpy geothermal operations. Maintaining high availability of inhibition is an important operating requirement for the Carbon Steel design approach.

Monitoring and Inspection

Recommendations for the basic minimum monitoring are presented.

Both corrosion coupons and probes are used for corrosion monitoring purposes and these should be analysed according to a regular schedule with the results from each data retrieval being compared to previous to determine long term trends. In addition, relevant related parameters should be monitored for trending and to confirm the system continues to operate within the Safe Operating Window. A key reason for monitoring is to ensure and confirm the effectiveness of inhibition, therefore one or more fast response, on-line

measurements are strongly recommended, for example LPR corrosion probes.

Caliper surveys of the casing are advised for carbon steel tubulars inspection, typically on a 5-yearly cycle. Ultrasonic inspection of wellheads at specific datum locations is recommended for carbon / low alloy equipment on an annual basis.

Revision History		
Revision	Date	Comments
0	17/01/17	For review
1	02/05/17	For review
2	09/06/2017	Final

HOLDS		
No.	Section	Comment

Signatory Legend		
Revision	Role	Comments
2	Prepared Checked Approved	Paul Wood, Senior Integrity Engineer Mike Billingham, Engineering Manager Liane Smith, Managing Director



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1.0 Introduction

1.1 Objectives of the Study

The Dutch Geothermal Energy sector makes use of geothermal heat as a renewable energy. The heat extraction scheme typically combines a production well including an electric submersible pump (ESP) lifting the hot fluid to a surface heat exchanger, and an injection well pumping the heat depleted fluid back into the source reservoir.

The first geothermal wells in the Netherlands were completed in 2007 and as of January 2016 there are fourteen geothermal installations in the Netherlands (www.NLOG.nl).

Various studies undertaken by this sector have identified corrosion and scaling as major potential challenges for the geothermal wells. Assessment of the material degradation threats (corrosion) to ensure appropriate materials selection at the design stage is identified as a key element in achieving effective asset management in the geothermal systems. Included within this topic are the impacts of scaling and the impacts of the measures used to control scaling on the materials.

This report provides a full analysis of relevant corrosion and scaling threats and their mitigation in geothermal assets and practical guidance on materials selection including the use of life-cycle costing so that cost-effective material choices can be made for wells at the design stage.

1.2 A Guide to the Report

Chapter 2 describes a generalised materials engineering design approach for well facilities. This is then applied to the conditions in the Dutch Geothermal operations in the following Chapters. Detailed information is presented in the Appendices.

Introduction to the corrosion assessment and materials engineering design process	Chapter 2
Typical facilities design for Dutch Geothermal Operations	Chapter 3
Review of operating conditions for Dutch Geothermal wells as they affect corrosion and materials	Chapter 4
An analysis of potential corrosion risks and scaling problems identifying the key threats.	Chapter 5 and Appendix A
Materials selection for Wells and detailed recommendations of materials grades for all well components.	Chapter 6
Monitoring and Inspection Methods applicable to Dutch Geothermal Wells.	Chapter 7
Life cycle costing	Chapter 8 and Appendix D
Well operating envelopes due to corrosion /materials issues	Chapter 9
Corrosion risks for surface facilities	Chapter 10
Comprehensive review of all degradation threat mechanisms and their mitigation	(Appendix A)
Survey of the commercially available and technically applicable material options available for use for downhole components and wellheads	(Appendix B)
Comprehensive literature review of the corrosion and scaling experiences in comparable low enthalpy wells	(Appendix C)
Examples of life cycle costing applied to a geothermal well	(Appendix D)



1.3 Abbreviations

Abbreviations used throughout the report are included in Table 1.

Table 1: Abbreviations

Abbreviation	Meaning
API	American Petroleum Institute
CAPEX	Capital Expenditure
CFD	Computational Fluid Dynamic
Cl-SCC	Chloride Stress Corrosion Cracking
CRA	Corrosion Resistant Alloy
CS	Carbon Steel
CUI	Corrosion Under Insulation
DAGO	Dutch Association of Geothermal Operators
ECE	Electronic Corrosion Engineer®
EDX	Energy Dispersive X-Ray Analysis
ESP	Electrical Submersible Pump
GLR	Gas Liquid Ratio
GRE	Glass Reinforced Epoxy
GRP	Glass Reinforced Polyester
HDPE	High Density Polyethylene
IOW	Integrity Operating Window
ISO	International Standards Organisation
Kennisagenda	Dutch Knowledge / Research Agenda
LCC	Life Cycle Cost
MFL	Magnetic Flux Leakage
MIC	Microbiologically Influenced Corrosion
MOC	Management of Change

Abbreviation	Meaning
MPN	Most Probable Number
NACE	National Association of Corrosion Engineers
NPV	Net Present Value
OPEX	Operational Expenditure
PEEK	Polyetheretherketone
PPB	Parts Per Billion
PPM	Parts Per Million
PPS	Polyphenylene sulphide
PReN	Pitting Resistance Number
RT	Radiographic Testing
TDS	Total Dissolved Solids
UNS	Unified Numbering System
UT	Ultrasonic Testing
VT	Visual Inspection
WAG	Water Alternating Gas
WHT	Well Head Temperature

2.0 Materials Design for Wells

2.1 Material Engineering Design Process for Wells

Figure 1 shows the key steps in a generalised materials engineering process for wells. This process is applicable in principle both to individual components and to the complete well.

The extent and depth of detail at each step will depend on factors such as the criticality of the well and its individual components, experience of similar situations and the maturity of the overall well design.

The design steps may be repeated at different lifecycle stages as required, for example for replacement or upgrade components or in due to a major change in operating conditions.

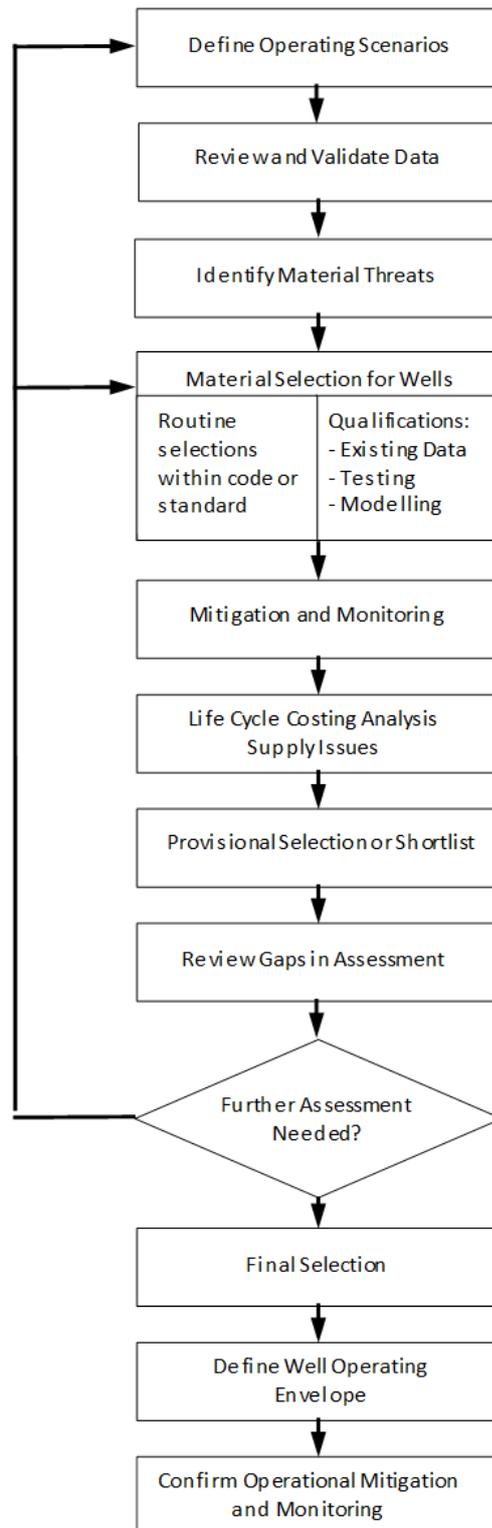


Figure 1: Flow Chart for the Materials Design Process



2.2 Define the Operating Scenarios

2.2.1 Initial Design

The minimum set of information for a useful concept stage materials selection for Geothermal wells is:

- Water production and injection capacity
- Basic mechanical design (well depth, tubing and casing sizes and material strength)
- Maximum acid gas concentration (CO₂ and H₂S)
- Reservoir water composition, as a minimum salinity, bicarbonate and organic acid levels
- Design temperatures and pressures, at bottom-hole, bubble point and at well-head, both flowing and shut-in
- Design life

2.2.2 Detailed Design

For detailed or final design, all operating cases and corrosion threats for the well should be identified so that the appropriate data for materials selection or corrosion mitigation of the environment can be collected. Critical design cases may not be the normal operating conditions or maximum temperature conditions; transient or upset conditions may be decisive.

Table 2 provides a non-exhaustive checklist of possible scenarios relevant to corrosion management activities. Note that not all Scenarios listed in Table 2 will apply for any one specific well and some may be classed as “not applicable”.

The potential failure of well barrier components and the consequences of exposing outer barrier elements to the leaking fluid should be considered. For example the secondary barrier components should be able to survive failure of the primary barrier, at least until remedial action can be taken.

Table 2: Check List of Possible Operating Scenarios for Materials Design

Scenario	Notes
Operating (producing or injecting) conditions	Consider conditions over the whole life-time, including changes in production rates.
Any special mechanical design requirements	e.g. a need for high strength
Environments on both sides of tubular components	e.g. packer fluids
Direction of flow and pressure	e.g. reverse flow and pressure on a component may expose materials to different fluids which needs consideration
Suspension conditions	For example some geothermal facilities may have seasonal demand and may be shut-in for some periods with stagnant instead of flowing conditions. Long term shut-in with a suspension fluid in the well
Other intervention activities and frequency	Fluids which may be aggressive or may be contaminated (e.g. with oxygen) Mechanical damage or wear
Consequences from failure of primary well barriers	e.g. leakage of geothermal fluids into the annuli
Realistic sources of contamination	e.g. oxygen ingress
Extended residence time for short-term treatment fluids	e.g. acidisation treatments used to increase the injectivity of the well
Failure of inhibitor injection or other chemical treatments such as scale treatments	

In general, corrosion threats may be mitigated by materials selection or by operational controls, or a combination of both. It is not necessary that materials selection alone should deal with all threats.

2.2.3 Changes in Operating Conditions

There may be variation in fluid compositions, temperatures, pressures and flow rates over the design life. There may be potential compatibility issues between materials and treatments added to fluids in order to control souring.

In addition, ground movement can alter the loads on the well components and thermal cycling associated with shut-in and start-up cycles and changing production rates may cause



fatigue or even sudden collapse.

2.3 Review and Validate Data

The environmental data for the primary environment the material is exposed to and, if necessary, data for transient and secondary environments should all be checked. Often data has not been obtained with use for materials selection in mind and may need interpretation or conversion to another format.

- Cross-reference different sources if possible to confirm that the data is reliable, such as multiple well tests, tests on different dates, analogous data from the same or similar reservoirs.
- Consider the validity of the fluid sampling methods i.e. pH readings from field usually refer to the degassed fluid and may not be reliable. It may be appropriate to consider duplicate sample analysis at different laboratories or with different analytical methods.
- Most corrosion models and materials selection guidelines use the CO₂ and H₂S content of gas phase samples as inputs, not the concentrations in water.
- H₂S concentration is critical to the performance of many materials, therefore it is important to challenge input design data indicating zero H₂S. It is possible to underestimate H₂S due to sampling or measurement issues.
- While H₂S is not currently present, the potential for a future rise in H₂S concentration should be considered.
- Consider the validity of water analysis samples.
- Consider the validity of production flow rate data - is it the maximum possible or normal sustained operation? Production rates may change significantly over the well lifecycle and this may impact on the corrosivity (either positively or negatively).
- Pay attention to minor constituents such as lead, mercury, organic acids, elemental sulphur, other scale forming elements
- Do not assume a constituent is not present if not quoted as it may have not been sampled or analysed.



2.4 Identify Material Threats

Based on the operating scenarios, the realistic degradation mechanisms can be identified. Further guidance is provided in Chapter 5 and Appendix A.

A desktop research study can be done on material failures for relevant existing and historical in-house projects and publically available sources.

For CO₂ corrosion rate estimation Table 4 can be used for an estimation of the potential corrosion rate for two example Dutch geothermal sources. Corrosion modelling of other specific well conditions using dedicated software will provide predication of the corrosion rate for individual water chemistries.

2.5 Materials Selection for Wells

Material selection is typically based on choosing the production tubing material first as this is generally exposed to the most critical service environment and then selecting compatible materials for the remainder of the wellbore equipment and wellhead equipment.

Material design can be simple: many threats are well defined and material selections can be made within existing industry codes or from in-house guidance. Experience from existing wells in the same reservoirs is also extremely valuable. However, one reason for clearly defining the operating scenarios and threats, is to confirm that the scope of Codes or existing experience actually cover all the identified threats.

Where routine selections are not possible, then a more detailed assessment is required and, depending upon the particular threats, this could be based on:

- Validated field experience including failure cases
- Existing test data
- Corrosion modelling
- Qualification testing

Careful consideration should be given to the anticipated corrosion mechanisms when extrapolating from limited datasets to predict materials performance in new conditions as some degradation processes can be strongly temperature dependent.

2.6 Mitigation and Monitoring

Corrosion mitigation, such as inhibitor treatment, may be an appropriate option for mitigating the identified threats. Monitoring of service conditions and inspection of corrosion damage may be required to maintain the selected well materials within the defined well operating envelope. The necessary mitigation and monitoring requirements associated with each materials option should be determined and documented to inform the final selection.

Whilst corrosion mitigation and inspection is an established option for corrosion control in general, it is a less convenient approach for downhole equipment than for surface equipment



which is why there is more emphasis on material selection for corrosion control.

2.7 Life Cycle Costing Analysis and Supply Issues

The capital costs of downhole tubulars and completion equipment in different materials can be a significant factor between different design options.

Availability of materials may be limited in some diameter and length ranges. Some special materials may have very restricted supply. High alloy materials and cold-drawn tubulars can have limits on total piece weight and therefore limited maximum length in larger diameters. This results in more connections and higher cost per overall length of tubular.

Life cycle cost analysis can be performed to refine selections, including both capital and operating costs such as mitigation and monitoring, replacement and work-over costs.

Note that there may be valid reasons not to choose the lowest life cycle cost option for example, for availability or standardisation issues.

2.8 Provisional Selection and Short List

It is often useful to provide several technically acceptable options before the final materials selection. Where further qualification is required on the preferred material, a fall-back option can be defined. Where there are several technically acceptable options this can help with supply and avoid having to deal with numerous technical queries or deviation requests from suppliers at a later stage: for example, for downhole equipment, the manufacturer may wish to use a variety of different alloys for different sub-components, perhaps for processing or availability reasons, rather than rationalise every part to the minimum acceptable alloy grade.

Candidate materials for well tubulars are discussed in Appendix B.

2.9 Review Gaps in Assessment

Gaps in the assessment may be of various types, for example incomplete environmental data, performance requirements, well design details and operating scenarios that are not finalised and confirmed, or gaps in knowledge of materials performance in specific conditions. Some gaps are inevitable in the earlier stages of design.

It is useful to define and document what these limitations and gaps are, so that the next round(s) of assessment can tackle these in a focused and effective manner. For example, this might include planning for the qualification testing of materials.

If there are no significant gaps, then materials selection can be regarded as final.

2.10 Define Well Operating Envelope

Materials selected may not be suitable for all conceivable operating conditions, or the consequence of corrosion may be tolerable if properly managed. In all cases, the limits need to be understood and clearly documented, along with relevant corrosion management requirements.



3.0 Typical Facilities Design

3.1 Production and Injection Wells

The typical geothermal facility has one or more production well and injection well doublets.

The well is constructed with a conductor casing and surface casing which are usually cemented to the surface. Liners may be installed to reach reservoir depth with, finally, a slotted liner or wire wrapped screen over the reservoir section. Except for the final production liner over the reservoir, all liners are cemented from shoe to the liner hanger assembly.

The production well is completed with a tubing and downhole pump, typically an electrical submersible pump (ESP), with a simple wellhead and Christmas tree assembly of valves.

The tubing and casing materials are carbon and low alloy steel in all existing wells.

The typical injection well is essentially similar but without the downhole pump.

A schematic of such a typical low enthalpy producer well is depicted in Figure 2. The exact design may vary with different reservoir, for example depth.



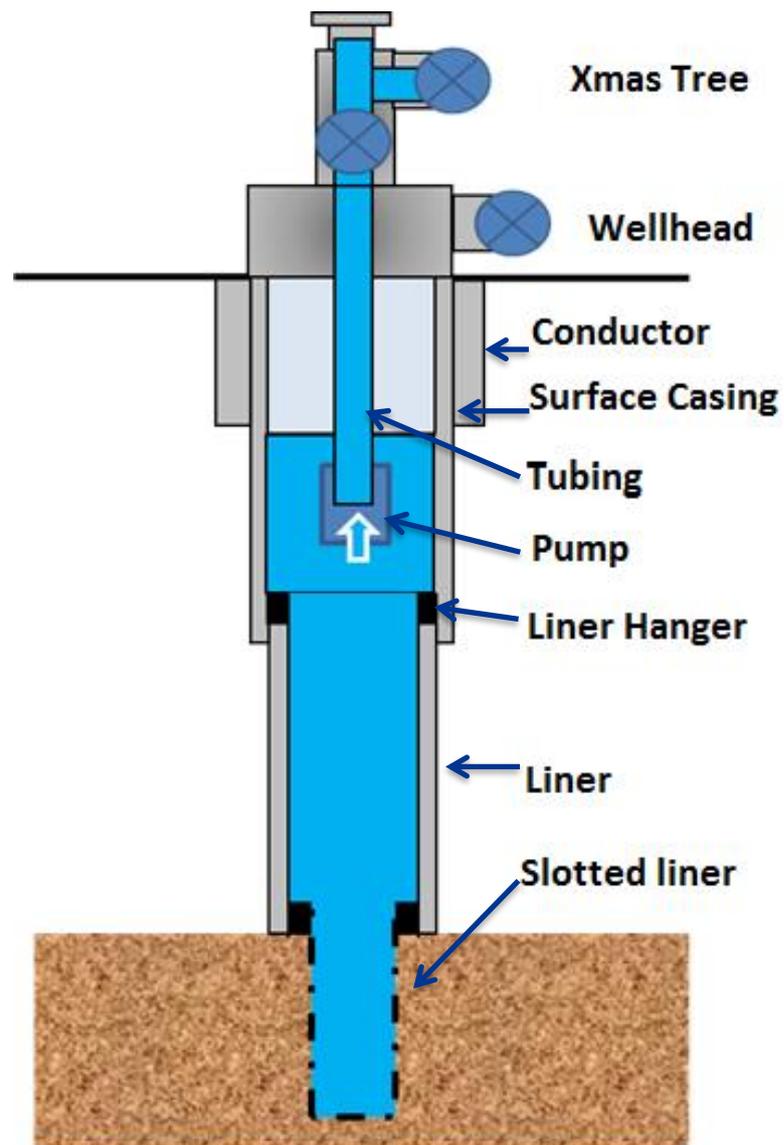


Figure 2: Diagram of Typical Low Enthalpy Geothermal Well

3.1.1 Typical Surface Facilities

The primary circuit on the surface typically includes

- Production separator (not present in all facilities)
- Filters
- Heat exchangers, typically plate -type
- Injection Pumps, typically centrifugal type
- Monitoring and chemical treatment equipment

Some units degas the produced water, and the off-gas may be suitable for heating fuel. Other units do not have the separation stage. Water must be filtered to protect the heat exchangers and the injectivity of the injection well formation.

4.0 Operating Conditions

4.1 Water and Gas Analysis

Operating conditions have been categorised by geothermal reservoir. Within the Dutch Geothermal context there are four low enthalpy reservoirs being exploited. The reservoirs are:

- Delft Sandstone
- Slochteren / Bunt Sandstein
- Carboniferous Limestone
- Triassic

DAGO provided full details on the reservoir types including operating and reservoir parameters based on the current geothermal operations. Typical conditions for each of the reservoirs are summarised in Table 3.

Table 3: Key Reservoir Parameters affecting Corrosion

Parameter	Reservoir			
	Delft Sandstone (6 wells)	Slochteren / Bunt Sandstein (4 wells)	Carboniferous Limestone (2 wells)	Triassic (1 well)
Typical Production Volume (m ³ /hr)	120 - 275	100 - 218	230 - 390	300
Producer Flowing Wellhead Temperature (°C)	60 - 87	74 - 100	80 - 88	82
Producer Flowing Wellhead Pressure (bar)	4.5 - 12	5 - 23	3.5 - 16	16
Degassing	Degassing / No Degassing	Degassing / No Degassing	No Degassing	Degassing
Chloride (mg/l)	6,1330 – 84,000	91,000 – 160,000	37,000 – 56,000	75,000
Bicarbonate (mg/l)	43 - 200	20 - 160	200 - 320	130
pH @ 25°C	5.62 - 6.4	5.3 - 6.2	6.2 - 6.4	6.34 - 6.7
Total Dissolved Solids @180°C (mg/l)	130,000 – 160,000	140,000 – 240,000	81,000 – 91,000	130,000
Hydrogen Sulphide (mol%)	Nil	<0.001 - 0.065	Nil	<0.001
Oxygen (mol%)	Nil	<0.001	Not determined	<0.001
Carbon Dioxide (mol%)	0.24 - 56.717	5.637 - 39.496	34.347 - 36.573	2.100 - 3.412

Note 1: The values given are derived from data collected by DAGO (10/04/2017). Each reservoir and well may have more than one analysis therefore the range from highest to lowest is quoted in the table.

Note 2: The analyses cover a period of three years.

Note 3: H₂S , CO₂ and oxygen values are all from the gas phase



Further points to note from Table 3 include:

- Surface flowing wellhead pressures are generally below 20 bar. The geothermal reservoirs do not have sufficient pressure to flow without pumping, so the flowing wellhead pressure operating pressures are determined by the ESP. The natural (unpumped) water level is typically more than 100m below surface level.
- Oxygen is not present in any analysis and is either reported as Nil or the lower detection limit.
- The pH values are from analyses at surface. They may not reflect process conditions accurately due to degassing and change of temperature.
- The CO₂ analyses are mostly based on sampling at surface conditions, for example from Separator vessel (where present).

4.2 CO₂ Content of Geothermal Water

The level of CO₂ associated with the geothermal water shows considerable variation within both the Delft Sandstone and Slochteren / Bunt Sandstein reservoirs.

The Carboniferous Limestone and Triassic reservoirs do not show significant variation within each reservoir, but this is based on data from a much smaller number of different sites. It is not known if greater variation from site to site (similar to that for Delft and for Slochteren reservoirs) will be encountered as further wells are developed.

At present, it must be assumed that a wide range of CO₂ content is possible in any new geothermal wells, but probably relatively high, i.e. 5 – 50 mol% in the gas phase.

The importance of CO₂ for corrosion behaviours is discussed in detail in the following section.



5.0 Key Material Threats

5.1 Introduction

Operator experience, analysis of the Netherlands geothermal source water environments and review of available literature identifies that the most significant corrosion and integrity threats are CO₂ corrosion and scaling.

This section of the report focuses on these specific threats. There are, however, other degradation mechanisms which exist and the full range of theoretically possible corrosion threats in the Dutch geothermal wells and surface equipment are therefore explained in Appendix A, with each mechanism described along with mitigation measures.

The final section of this Chapter summarises some “lessons learned” related to corrosion reported by Operators in the Dutch Geothermal industry.

5.2 CO₂ Corrosion

CO₂ is the principal corrodent in many geothermal reservoir fluids. When CO₂ dissolves in water it forms carbonic acid (H₂CO₃). The acid lowers the pH of the water and sufficient quantities promote general corrosion and / or pitting corrosion of carbon steel and low alloy steels.

5.2.1 Critical Factors

The critical factors influencing CO₂ corrosion are

1. CO₂ concentration
2. Fluid velocity and flow conditions
3. Temperature
4. Water chemistry (especially presence of further acid or alkaline species)

These parameters must be known in order to assess probable CO₂ corrosion rates.

Factors that are less important and generally only have a minor impact include

1. Differences in composition and metallurgy between different low alloy and carbon steel grades.
2. Neutral salts such as chlorides

5.2.2 Morphology of Attack

Depending on the flow conditions, the morphology of CO₂ corrosion can vary greatly. Corrosion may be relatively uniform, or more localised in the form of pitting. Distinct areas of corroded and essentially uncorroded material with a clear boundary can occur (mesa-corrosion). There may also be attack related to turbulence and flow conditions, for example near pumps or flow restrictions or uneven surface profiles such as weld beads.



Preferential attack at welds due to CO₂ corrosion (preferential weld corrosion) can occur in specific circumstances, see below.

5.2.3 Preferential Weld Corrosion

Preferential weld corrosion (PWC) is a form of attack that is localised in the weld metal or adjacent to the weld metal, for example in the heat affected zone of the parent metal. In the context of Dutch Geothermal operations, the main corrosive species is CO₂ and therefore PWC is treated as a morphology of CO₂ corrosion.

Appendix A contains details of the factors involved, high risk locations and mitigation options.

5.2.4 Flow Assisted Corrosion

Localised high corrosion rates in locations of high velocity and shear or turbulent flow are common in CO₂ containing environments.

Appendix A contains details of high risk locations and mitigation options.

5.2.5 Defining the CO₂ Content

The active species in CO₂ corrosion is of course the CO₂ dissolved in the water phase. However, CO₂ content is normally expressed as mol% or partial pressure in the separated gas phase in corrosion engineering usage. Measuring the gas composition is typically the most convenient and reliable field measurement: a field measurement with gas analysis tubes (Draeger ® tubes) is often adequate for corrosion assessment. In contrast it is often difficult to analyse dissolved CO₂ in the water phase at the process conditions, CO₂ will rapidly degas from the water if the pressure of the sample that is removed is lower than the process pressure, giving a misleading analysis for both CO₂ and also for pH.

Towards the surface facilities the pressure drops below the bubble point in nearly all Dutch wells. However, the operating conditions deeper in the geothermal wells frequently are above the bubble point pressure and there is no separate gas phase for sampling and measurement. Where the operating pressure is above the bubble point, further increase of pressure has little impact on CO₂ corrosion, because the concentration of dissolved CO₂ in the water phase cannot increase further (there is no source of additional CO₂). In these conditions, the critical data defining the corrosivity due to CO₂ is:

- Bubble point pressure and temperature
- Mol% CO₂ in the gas at the bubble point

For corrosion modelling, it is strictly correct to use the bubble point data for assessment. Conditions at the bubble-point are ideally determined by taking a pressured downhole liquid sample, depressurising this in controlled conditions in the laboratory and making analyses of the off-gas (a "PVT" analysis). Some estimate of bubble point pressure is required for the process design of the system, because the ESP inlet pressure should normally be above the bubble point pressure by a safe margin to minimise the possibility of two-phase flow in the

pump. Therefore, the bubble–point pressure (although not necessarily the associated gas composition) ought to be known for every producing well.

In absence of gas analyses taken at the bubble point, and as an approximation, the composition of off-gas from the Separator is often used as the reference point in practice.

Using the CO₂ mol% measured at surface and combining this with the higher pressures at the reservoir conditions or downstream of the injection pumps and in the injection well etc. will over-estimate the true levels of CO₂ and is likely to result in a serious over-estimate of corrosion rates.

Systems Without a Separator

Ideally, these systems operate fully above the bubble point pressure and gas presence is undesirable in the wells or surface facilities. No CO₂ containing gas is removed from the system. Ideally, the conditions defining the CO₂ level throughout the whole system (production and injection side) are the bubble point conditions:

- Bubble point pressure and temperature
- Mol% CO₂ in the gas at the bubble point

The dissolved CO₂ content remains essentially the same throughout the system, regardless of changes in pressure and temperature provided there is no gas phase at any point.

Systems With a Separator – Upstream of Separator

In the production well and upstream of the separator while the fluid is single phase, the CO₂ partial pressure is ideally defined by bubble point conditions of the reservoir water as described above.

In practice, the fluid stream may reach the bubble point before entering the Separator and start to degas CO₂ to some extent. However the residence time is short in the piping (before the Separator) and this effect can be ignored.

Systems With a Separator – Downstream of Separator

The separator conditions of pressure, temperature and mol% CO₂ in the gas phase define the CO₂ partial pressure for the separator and for the downstream system, including heat exchangers, pumps and injection well. The increase in pressure through the injection pumps does not increase the CO₂ content or corrosivity from the separator conditions.

Therefore, typically the CO₂ level and the potential corrosivity on the injection side will be less than on the production side in this scenario.



5.2.6 Information Required to Estimate CO₂ Corrosion Rates

The basic set of information required for estimating the CO₂ corrosion rate for geothermal wells is:

- Bubble point pressure or Separator pressure
- CO₂ mol% (and H₂S if present) in the gas phase (at the bubble point or at separator as applicable)
- Formation water composition - as a minimum the salinity and bicarbonate
- Flow rates
- Tubing, casing or piping dimensions (to calculate flow velocities)
- Operating temperatures and pressures

5.2.7 Assessment and Prediction of Corrosion Rates

The API 6A standard for wellhead equipment gives a very approximate rule of thumb for corrosivity of CO₂ environments in oil and gas production (API 6A Table A.1).

- “Non-corrosive”, less than 0.05MPa (0.5 bar) partial pressure of CO₂
- “Slightly corrosive”, 0.05 to 0.21 MPa (0.5-21 bar) partial pressure of CO₂
- “Moderately to highly corrosive”, above 0.21 MPa (2.1 bar) partial pressure of CO₂

This ranking is NOT recommended as a sound basis for design or materials selection, but is mentioned just to compare with the Dutch geothermal conditions where several bar CO₂ partial pressure is typical. In traditional oilfield practice, these are therefore “moderately to highly corrosive” conditions.

CO₂ corrosion is important in many hydrocarbon production systems and prediction of corrosion rates in CO₂ dominated environments has been studied intensively for many years. There are several proven methods and models available to predict corrosion rates; some of these are described below.

De Waard Corrosion Model

The original de Waard corrosion model was largely based on experimental flow loop data produced at IFE (Institut For Energiteknikk) in Norway, where test conditions and environments were strictly controlled (de Waard, Lotz, Milliams, 1991). This model forms the basis for several corrosion software models, both commercial and proprietary, which are significant in the oil and gas industry. The de Waard model is semi-empirical, fitted to experimental data rather than assuming a particular chemical reaction scheme.

The basic equations in the de Waard model are explained below (Smith, De Waard 2005):



$$\log(V_r) = 4.84 - \frac{1119}{t + 273} + 0.58 \log(f_{CO_2}) - 0.34 (pH_{actual} - pH_{CO_2})$$

$$V_m = 2.8 \frac{U^{0.8}}{d^{0.2}} f_{CO_2}$$

where t is the temperature (°C), U is the liquid velocity, d the pipe internal diameter, and f_{CO_2} is the fugacity of the CO_2 :

$$\log(f_{CO_2}) = \log(pCO_2) + (0.0031 - \frac{1.4}{t + 273})P$$

pCO_2 being the partial pressure of the CO_2 (=mol% x total pressure P).

pH_{actual} and pH_{CO_2} are the actual pH and the pH of pure water with CO_2 , respectively. All units are expressed in the S.I. system (kg, m, sec etc). The actual constants to be used in the above equations are slightly dependent on steel composition i.e. carbon content.

The resulting corrosion rate V_{cor} can be expressed by means of the "resistance model":

$$F_{out} = F_{out} + F_{out}$$

Implementations of the de Waard model modify and extend the CO_2 model with additional factors to consider protective scale, oil, H_2S and so on which are not necessarily needed for the geothermal situation. The low enthalpy geothermal conditions are in the range where the de Waard model is relatively well proven.

Norsok Corrosion Model

NORSOK standard M-506 "CO₂ Corrosion Rate Calculation Model" and spreadsheet-based software model is available online (<https://www.standard.no>). This model has a different calculation basis to the de Waard model but was originally based on some of the same experimental data. For simple cases, the NORSOK and de Waard based models are often in reasonable agreement.

The low enthalpy geothermal conditions are largely within the range of parameters covered by the NORSOK model. One exception is the salinity, which is higher in some of the geothermal reservoirs than is allowed in the NORSOK model (maximum 175 g/l). However modelling results are not highly sensitive to salinity, and in that case if the maximum allowed salinity is entered, the potential error introduced will be small compared with the overall accuracy of the model.



As it is well-documented and readily available, use of the NORSOK model is suggested as the first step for corrosion modelling of low enthalpy geothermal wells.

Limitations of Modelling

Corrosion behaviour is often quite variable in practice, one factor of course being the impact of normal process variations (flow rates, temperatures etc.). Also models do not consider all the minor factors that could impact corrosion. As a rule of thumb, a margin of at least +/- 25% should generally be applied to corrosion modelling predictions. It is possible to improve this greatly over limited ranges of service conditions by bench marking and calibration of models against specific field data.

One issue in the low enthalpy geothermal conditions is that temperatures are in a range where a transition between protective and non-protective scaling is often seen. Therefore the modelled and the actual corrosion behaviour may both be quite sensitive to temperature variations and scaling behaviour.

All models depend on accurate input data. The problems of determining the appropriate CO₂ input values have been mentioned. Models can only estimate behaviour at special locations with high flow velocities for example if those local conditions are reflected in the input data.

5.2.8 Example of CO₂ Corrosion Rate Calculation

Example corrosion rate calculations for the geothermal reservoir conditions have been carried out using Wood Group Intetech “Electronic Corrosion Engineer” (ECE ®) software, which is a commercial software package widely used in the Oil and Gas and process industries worldwide. The CO₂ corrosion model in ECE is an implementation of the De Waard Corrosion model, which has been developed and calibrated with field data over many years. As well as CO₂ corrosion, the ECE model takes account of additional factors including

- H₂S
- Carbonate filming
- Oil-wetting
- Organic acids
- Inhibition
- Top of line corrosion
- Flow regime
- Tubing (well) deviation

Table 4: Example Corrosion Rate Calculations



Parameter	Reservoir	
	Delft Sandstone	Slochteren / Bunt Sandstein
Volume (m ³ /hr)	120	125
Temperature (°C)	69.5	74
Wellhead / Separator Pressure (bar)	4.5	7
Tubing OD (in)	4.1/2"	4.1/2"
Chloride (mg/l)	75,000	130,000
Bicarbonate (mg/l)	160	100
Total Dissolved Solids @ 180°C (mg/l)	130,000	230,000
Hydrogen Sulphide (mol%)	0.000	0.000
Oxygen (mol%)	0.000	0.000
Carbon Dioxide (mol%)	4.5	5.6
Corrosion Rate (without inhibitor)	1.4 mm/yr	2.2 mm/yr

Comparison of the above rates may be made with observed corrosion in some wells from the literature review. Actual corrosion rates quoted from German research (Appendix C.4.2) include maximum short-term penetration rates in carbon steel of 2.4mm/y. For those same conditions, ECE modelled corrosion rates were about 1.6 mm/y. It is normal for short-term corrosion rates to be higher than long-term corrosion rates. The data they publish for corrosion of metals in a by-pass loop at the wellhead are, however, much lower (below 0.2mm/y); in this case scales were formed on the surfaces that were relatively protective.

Clearly, the potential corrosion rates without mitigation are unacceptable in these two examples. CO₂ levels and other significant factors are similar or more demanding in many Dutch Geothermal operations. The use of unprotected carbon steel will not be realistic in most cases, and mitigation options must be considered.

5.2.9 Corrosion in the Geothermal Wells

Potential “hot-spots” for CO₂ corrosion in the well system include

- Pump, pump inlet & outlet in producers
- Perforations and sandscreens
- Below (upstream) of corrosion inhibitor injection point in producers (if applicable)
- Wellhead and tree (due to bends, flow restrictions)

The flow velocity is greater in the tubing than in the casing and (other factors being equal),



the CO₂ corrosion rate will be substantially greater in the tubing, both for producer and injector wells.

There will normally be a gas head space between the production tubing and the casing at the top of the well. Some corrosion will occur in the area due to water condensation from the water-saturated acid gas. The rate of condensation in the well situation is relatively low (compared for example with that in subsea pipelines carrying hot wet gas) and condensing phase corrosion is typically less than the corrosion in the flowing parts of the well.

5.2.10 Mitigation - Corrosion Allowance

The current default material for the Dutch Geothermal systems is carbon steel or low alloy steel (strictly speaking low alloy steels are used for many downhole tubulars, but they behave as a carbon steel from a corrosion viewpoint). If a corrosion rate can be estimated then the total wall thickness loss over the life of the equipment can be estimated by multiplying the corrosion rate by the design life.

For surface equipment, additional wall thickness can be added to the piping and vessels as a sacrificial corrosion allowance. This can be consumed over time by corrosion and so extend the equipment life. Corrosion allowance values are typically standardised for surface equipment to be 3 mm or 6mm etc.

Corrosion allowance is far less frequently selected for downhole tubing because it adds to the weight of the tubulars and to their cost. CO₂ corrosion is generally not uniform, and failures due to corrosion in downhole tubulars often first occur as leakage due to localised corrosion through the wall thickness, rather than as mechanical failure due to general loss of thickness. However, deliberate selection of a slightly heavier weight tubing or casing may be considered, and has been tried in Denmark with up to 5mm of extra wall thickness in geothermal wells (Veldkamp et al, 2016).

Corrosion allowance is not normally considered for plate heat exchangers as the efficiency of heat transfer is impacted. Thus, these are normally constructed of a corrosion resistant material so that the wall thickness can be kept as thin as possible.

5.2.11 Mitigation - Corrosion Inhibitor Treatment

A corrosion inhibitor is a chemical compound (typically amine-based) that decreases the corrosion rate of a metal or alloy. Inhibitors work by forming a layer which prevents access of the corrosive substance to the metal surface and or otherwise interferes with the chemical reactions or mass transport processes involved in corrosion. The effectiveness of a corrosion inhibitor depends on the particular fluid composition and the flow regime. According to DAGO (2016), corrosion inhibitor is used by about 75% of all geothermal operators.

The efficiency of inhibitors is typically better than 95% (i.e. corrosion rates are reduced by at least a factor 20). However, that depends upon the inhibitor being deployed continuously above the correct minimum concentration, i.e. its availability. In practice, the availability is the critical factor in corrosion control using inhibitors.

Whilst it is possible to achieve higher availability, it is normal to assume there is some downtime, and an overall effectiveness (=efficiency x availability) of inhibitor of about 90%, is a typical design figure: reducing the corrosion rate to about 10% of the uninhibited value. For example if a corrosion rate was calculated as 1.5mm/yr then the use of corrosion inhibitor could realistically reduce the rate to about 0.15mm/yr and with good management of the inhibition system to minimise down-time, the corrosion rate could be reduced further.

If the uninhibited corrosion rates are sufficiently high, then the damage caused in even short periods of down-time will eventually be great enough to make use of carbon steel and inhibition impractical. Even if corrosion inhibition is planned, it is important to have an estimate of the uninhibited corrosion rate in order to set the targets (Key Performance Indicators, KPI's) for inhibitor availability.

Inhibitor can only protect steel downstream of the injection point. It is relatively easy to inject inhibitor immediately below the inlet to the ESP or immediately above the outlet and so protect the tubing string and any downhole equipment in the tubing string. It is, however, also possible to inject inhibitor at the bottom of the well to protect the entire production casing and the lower well: this is now the default option in Dutch wells and is considered best practice.

Laboratory experiments are advised to determine the most suitable inhibitor after initial screening based on the service conditions.

5.2.12 Mitigation - Corrosion Resistant Materials

Potential corrosion resistant materials for downhole geothermal service are considered in detail in Appendix B.

In the surface facilities, stainless steels are commonly used for equipment (pumps, heat exchangers, instrumentation etc.). Some operators are replacing or have replaced carbon steel piping with GRE, due to experiences of localised corrosion in piping systems despite inhibitor treatment.

5.3 Scaling

5.3.1 Scale Formation

All geothermal fluids contain amounts of dissolved minerals and gases under conditions of elevated temperature and pressure. When the geothermal fluid is brought to the surface and the temperature, pressure and chemical properties change, the potential for deposition of scale on the casing walls and within the heat exchanger and topsides facilities exists. Key changes leading to solids precipitation are:

- Temperature decrease during geothermal heat extraction
- Pressure decrease as the geothermal fluid is pumped from depths at higher hydrostatic pressures
- Degassing of CO₂ as the pressure decreases leading to increase in pH (becoming more alkaline). Precipitation of calcium carbonate (CaCO₃) is caused by the increase



of brine pH during degassing; under more acidic conditions the calcium carbonate does not precipitate out.

Simulations carried out by Wasch (2014) on Dutch formation water compositions indicated that the scaling potential of current operations is already significant and that further temperature reduction than is carried out at present would cause worse scaling and is not advisable without a scaling prevention strategy. Wasch stresses that the model would require verification.

Calcium carbonate forms a dense, extremely adherent deposit. It is by far the most common scale problem in low and medium temperature geothermal systems. There are other potential scales, depending upon the concentration of dissolved ions in the water, including Barium Sulphate and in some cases, (though not reported in the Netherlands) silica scales. For many scaling compounds, the kinetics of solid precipitation is often slow and thus even when a solution is oversaturated, precipitation may not occur. However, the presence of solid surfaces or microorganisms can strongly catalyse precipitation reactions (Regensburger et al, 2011).

Scale can precipitate and coat the surfaces of plant components which can cause blocking of flow and reduction of heat transfer capability. Even if the scale does not precipitate out on surfaces, nevertheless small, colloidal, particles which can remain suspended in the fluid, can be transported over large distances in the well and they can accumulate and cause clogging elsewhere in the system or impact injectivity in the reservoir at the re-injection well. The GPC Injectivity Report (2015) looked into severe injectivity decline noticed on several injector wells in the Netherlands (Californië (Grubbenvorst), Berkel, Bleiswijk, Pijnacker, Honselersdijk, Middenmeer, Koekoekspolder, Heemskerk) as a consequence of Calcium Carbonate precipitation.

Prediction of scaling can be attempted experimentally or by modelling simulation.

5.3.2 Tests for Scaling Tendency

Scaling testing can be carried out in laboratories by means of simple jar-type tests or by high-pressure, high-temperature flow loops tests simulating actual temperatures and pressures. Unfortunately, the test procedures are not standardised to the same degree as chemical analyses or mechanical tests; specialist laboratories generally have in-house procedures. Scaling tests can also be carried out to determine the most appropriate scale inhibitor for a particular application and the Minimum Scale Inhibitor Concentration level required to prevent scaling. Scaling tendency tests are not tests that can be performed on site as a check to determine if scaling will occur.

Factors which can affect the scaling tendency tests include:

- Using actual formation water or mixing the correct formulation using chemicals in the laboratory.
- How to achieve the correct pH:



- Saturation with CO₂ (difficult to achieve in practice).
- Using acid - need to ensure the acid does not itself form a scale e.g. sulphuric acid would form calcium sulphate scale.
- Use buffers – e.g. acetic acid and sodium acetate.

5.3.3 Modelling of Scaling Potential

Simple equations exist for scaling potential in specific conditions, for example the Langelier Saturation index or Ryznar index. These only consider certain possible scaling types and limited service conditions and are not expected to be reliable for geothermal waters in general.

Thermodynamic simulation of scaling can also be carried out by software models; in principle these can consider all species present and all possible reactions, although particular models may have different lists of species that they actually cover. These models are usually based on chemical equilibria and do not necessarily provide information on scaling rates or on non-equilibrium conditions. There are commercial scale prediction packages available and these are widely used in the oil and gas industry in similar situations¹.

Geothermal Operators have reported that scale simulation modelling has not correlated well with their actual experience in certain cases.

5.3.4 Scale Mitigation

Scale formation can be controlled by careful adjustment of the temperature (and pressure) to stay within solubility limits, and minimise degassing, but this can be difficult with the additional constraint of optimising the heat loss.

Other scale-control options are the addition of scaling inhibitors to the fluid or the acidification of the fluid to increase mineral solubility. Furthermore, biocides or disinfectants may be added to the fluids to prevent microbiologically catalysed mineral precipitation.

Provided that the scaling seen in the field can be simulated in the laboratory, the same procedures can be used to study treatment options.

5.3.5 Scale Inhibitors

Effective scale prevention in geothermal operations is critical to the success of a project. Unfortunately, scale prevention methods must be designed to the very site-specific conditions in the field (Papic, 1991; Perez, 2000). These conditions dictate the type of scale prevention method that will be feasible.

Calcium carbonate scaling may be prevented by

- Control of carbon dioxide partial pressure
- Control of the pH of the solution and

¹ OLI Systems “Scale-Chem” software is widely used in the Oil & Gas industry.



- Using chemical additives (scale inhibitors)

Pressure and temperature manipulations of the geothermal fluid can be achieved quite easily when pumping a geothermal well.

Another potential scale prevention method entails lowering or maintaining a low pH by artificially maintaining a high carbon dioxide partial pressure by reinjecting some of the produced carbon dioxide back into the producing well, but it appears to work only for fluids with low carbon dioxide partial pressures. CO₂ partial pressure control would either involve a reduction of well discharge or to inject CO₂ downhole.

Manipulation of the chemical composition of the geothermal fluid, particularly its pH, is another way to avoid scaling. Adding HCl to the geothermal fluid in order to decrease the pH below a certain value at which no calcite scaling can form is technically possible but expensive and requires precise process control.

The utilisation of scale inhibitors is the most common method of combatting scaling problems. The most suitable inhibitor is selected to match the water chemistry, considering the chemical binding capability of the specific range of ions and surface adsorption properties. A wide range of chemistries are available amongst commercial inhibitors but they tend to be surface active polyamine compounds. Perez (2000) describes problems with scale inhibitors in that some of them can break down due to thermal decomposition. This has the combined effect of rendering them ineffective to prevent scaling but also creates decomposition products which can themselves form deposits or be corrosive to metal surfaces.

It would always be recommended to test potential candidate inhibitors for the specific site conditions to identify the optimum inhibitor and its required dosing concentration.

5.3.6 Scale Chemical Treatment, Mitigation and Monitoring

The flow chart below summarises the scaling risk estimation and corresponding chemical treatment, as well as the monitoring programme for geothermal wells.

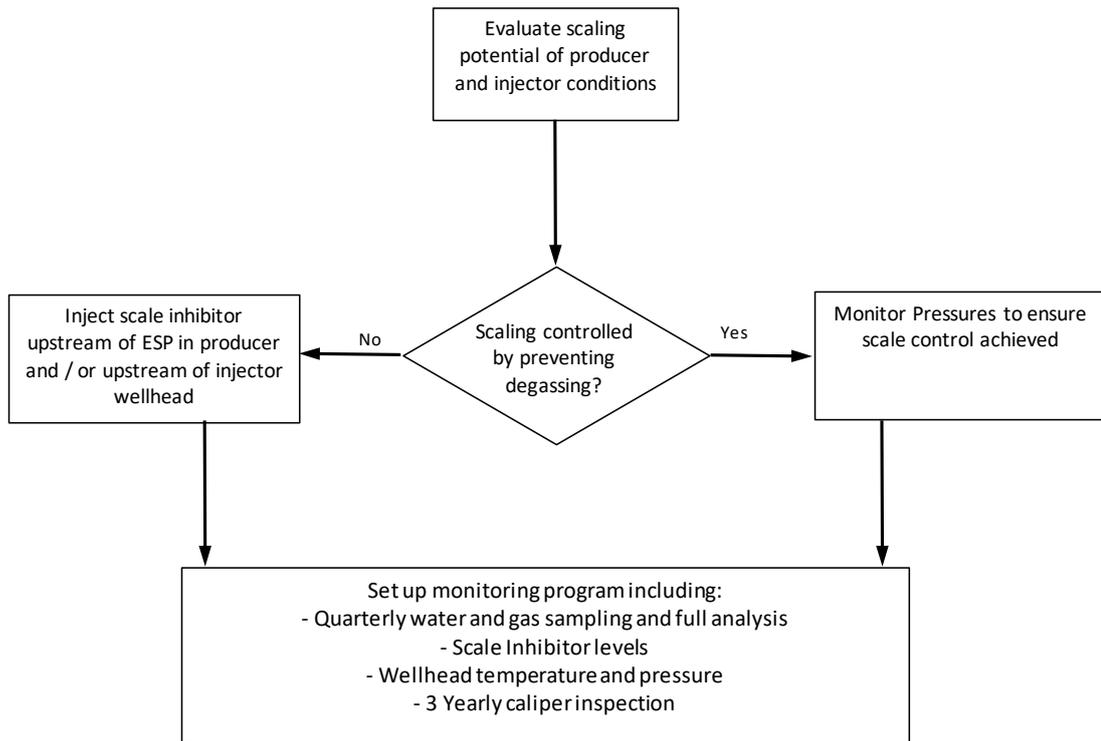


Figure 3: Flow Chart for Scaling Estimation and Monitoring Programme

The monitoring programme should capture all parameters in the well operating envelopes which depend upon the materials selection (See Section 2.0).



5.4 Lessons Learned from Existing Operations

This section summarises some “lessons learned” collated by DAGO.

- In general, corrosion inhibition is necessary with carbon steel well components.
- Instances of flow-related downhole corrosion have occurred, for example: near ESP inlet / outlet; at restrictions in the casing string.
- Increased attack has occurred at tubing joints where these are not flush type on the internal bore (i.e. premium or semi-premium joints are preferred).
- Instances of preferential weld corrosion have occurred in surface facilities.
- Instances of corrosion around bends and expanders at the inlet to Separators and to other surface equipment have occurred (flow related corrosion).
- Instances of leaks have occurred in plate heat exchangers related to the polymer seal.
- Instances of corrosion have occurred in carbon steel small-bore threaded connectors (instrumentation type fittings).
- Pb deposition can occur in the Bundstein water; Pb is main contribution to radioactivity.



6.0 Materials Selection for Geothermal Wells

6.1 Outline of Process

The flow chart shown in Figure 4 expands the detail of the corrosion rate prediction and materials selection step. Selection based on successful experience is the most simple option and therefore considered first; however, the conditions in the reference system MUST be at least as demanding as in the proposed system in all respects.

Where a detailed design assessment is required, the maximum allowable corrosion rate will be defined by the design life set by the Operator.

In principle, a separate assessment should be made for the producer and the injector in the doublet due to the different temperature and other conditions.

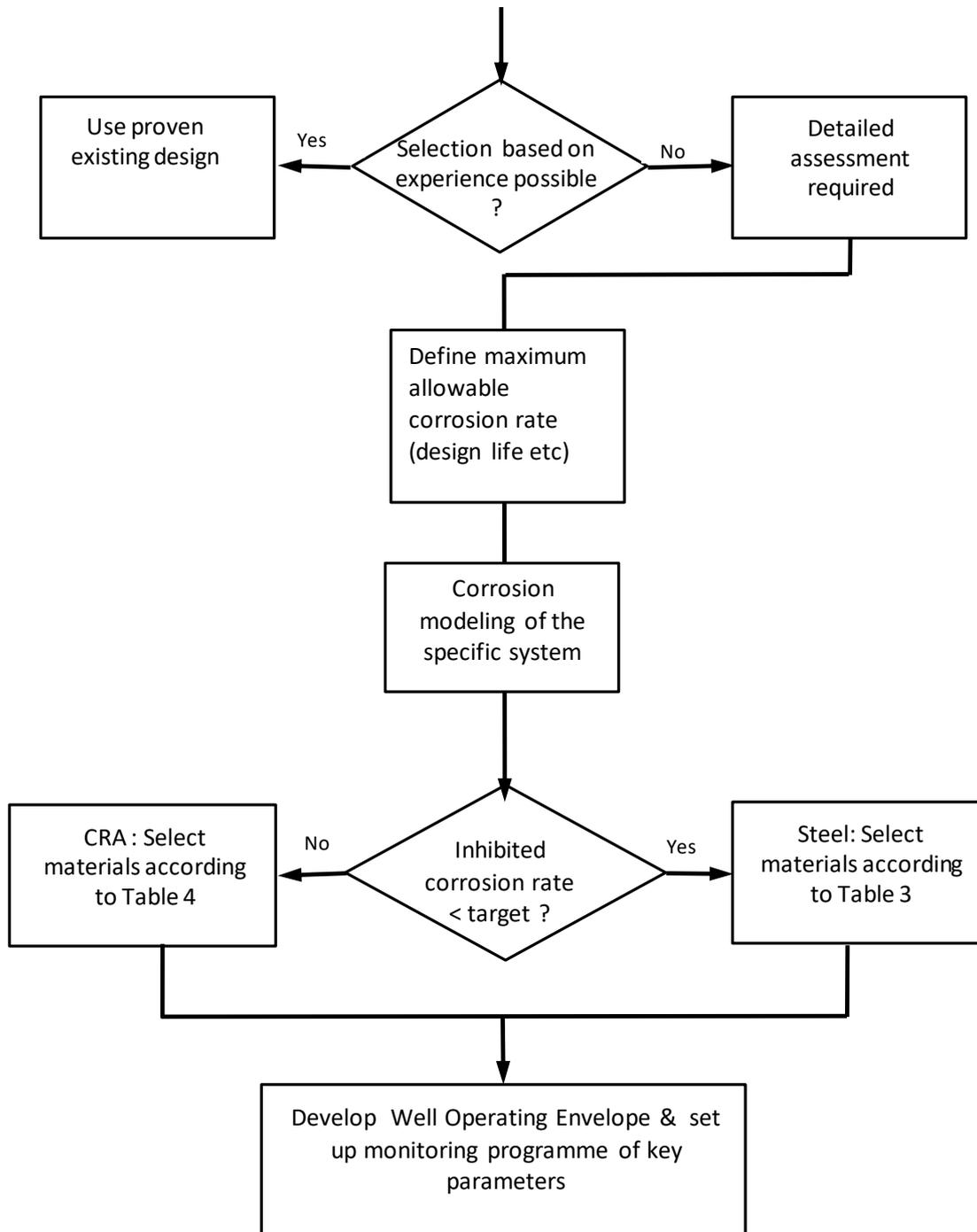


Figure 4: Flow Chart for Corrosion Estimation and Material Selection

6.2 Materials Selection Tables

Material selection for wells is typically based on choosing the casing material and the tubing material first as these are generally exposed to the most critical service environments, and then selecting compatible materials for the remainder of the wellbore equipment and surface facilities.

Essentially, there are two main technically acceptable options, namely Carbon Steel with inhibition treatment and corrosion resistant materials. The minimum suitable corrosion resistant material in the Dutch geothermal conditions is 13Cr martensitic stainless steel. If following the Carbon Steel option, corrosion resistant materials are still necessary for some critical components.

The Tables give minimum recommended materials and alternate materials. Where there are several technically acceptable options this can help with supply and avoid having to deal with numerous technical queries or deviation requests from suppliers at a later stage: for example, for downhole equipment, the manufacturer may wish to use a variety of higher grade alloys for different sub-components for manufacturing reasons.

6.3 Notes on Specific Components

6.3.1 Tubing and Casing

The production tubing has to be pulled at intervals to service and/or replace the ESP, so a planned replacement of the tubing and therefore a limited design life is a realistic strategy (slot-in wireline retrievable ESP's are not used due to the high flow capacity required).

Casing is not replaceable, and the design life is the full well life.

6.3.2 Tubing Joints

Operators have experienced enhanced corrosion at non-flush joints in alloy steel tubing. Although gas-tight premium joints are not normally necessary for liquid service, flush premium or semi-premium joint designs are recommended for the carbon steel tubulars.

If using CRA material, there is no issue with corrosion at joints and non-flush joints can be used.

6.3.3 Special Locations in Tubing

Flow assisted corrosion may occur at the inlet / outlet of ESP even where inhibited corrosion rates are acceptable for the normal run of tubing. A pup-piece in CRA (13 Cr or 316L) is recommended above and below the pump.

The same applies at other possible flow restrictions, for example if a check valve is fitted above the pump.



6.3.4 Sandscreens

Inhibition is unlikely to be effective immediately at the inhibitor injection point. Also, sand screens have very little tolerance for corrosion. Sand screens should be CRA therefore. The bodies may be 13Cr MSS or another suitable CRA. Wire mesh elements are normally austenitic alloy (stainless steel or nickel alloy) for manufacturing reasons.

6.3.5 Polymers

Service conditions are relatively mild for non-metallic materials in terms of temperature pressure and CO₂ concentration. HNBR is suitable for elastomer components. Conditions are well within limits commonly recommended for HNBR (maximum 120-150°C for continuous operation. NBR is not recommended generally because it is marginal in long-term service at about 80°C in demanding applications; however, NBR may be suitable for specific developments with lower service temperatures or for the injection well side.

For valve seats, stem seals etc., PTFE and other fluoro-polymer grades are acceptable. Nylon (PA-11, PA-12 etc.) is not acceptable due to swelling in high temperature water.

Table 5: Well Materials – Low Alloy Steel + Inhibition Option

Well Component	Minimum Material	Alternate Materials	Notes
Casing	CS / Low alloy steel		Any API 5CT grade
Production Tubing	CS / low alloy steel		Any API 5CT grade Inlet / outlet to pump in CRA
Downhole equipment	Low alloy steel (AISI 4130, 4140, ASTM A182 gr F22 etc.)	13Cr & S13Cr MSS Precipitation hardened MSS (17-4PH, Custom 450, 15-5 PH)	
Downhole equipment with active seals	13Cr MSS		
Downhole equipment trim & sub-components	13Cr MSS 316L	Other stainless steels and nickel-base alloys	
Downhole Pump	13Cr MSS 316L	Other stainless steels and nickel-base and Ni-Cu alloys	
Wellhead	Low alloy steel (AISI 8360, 4130, or ASTM A182 gr F22)	13Cr (e.g. AISI 410), S13Cr (e.g. F6NM)	
Wellhead trim, valve stems and internal components	13Cr MSS	Higher alloy stainless steels and nickel base alloys. Precipitation hardened MSS (17-4PH, Custom 450, 15-5 PH).	API 6A Class "BB"
Tubing Hanger & Casing Hanger	13Cr MSS	Precipitation hardened MSS (17-4PH, Custom 450, 15-5 PH).	
Control / injection lines	316/316L		
Polymers	HNBR	(NBR - note)	Maximum continuous operating temperature of NBR may be circa 80°C in mechanically demanding applications.
There is NO requirement for sour service materials or for compliance with NACE MR0175 / ISO 15156			

Table 6: Well Materials – CRA Approach

Well Component	Minimum Material	Alternate Materials	Notes
Casing	CS / low alloy steel 13Cr MSS		CS / low alloy if corrosion rate is acceptable.
Tubing	13Cr MSS		Any strength level
Downhole equipment	13Cr MSS	S13Cr MSS Precipitation hardened MSS (17-4PH, Custom 450, 15-5 PH)	
Downhole equipment trim & sub-components	13Cr MSS 316L	Other stainless steels and nickel-base alloys	
Downhole Pump	13Cr MSS 316 / 316L	Other stainless steels and nickel-base and Ni-Cu alloys	
Wellhead	13Cr MSS (AISI 410)	S13Cr MSS (F6NM)	
Wellhead trim, valve stems and internal components	13Cr MSS	Higher alloy stainless steels and nickel base alloys. Precipitation hardened MSS (17-4PH, Custom 450, 15-5 PH).	API 6A Class "CC"
Tubing Hanger & Casing Hanger	13Cr MSS	Precipitation hardened MSS (17-4PH, Custom 450, 15-5 PH).	
Control / injection lines	316/316L		
Polymers	HNBR (NBR – note)		Maximum continuous operating temperature of NBR may be circa 80°C in mechanically demanding applications.
There is NO requirement for sour service materials or for compliance with NACE MR0175 / ISO 15156			



7.0 Monitoring and Inspection Methods for Corrosion

7.1 Introduction

Any system that has equipment that is exposed to a corrosive environment requires some level of monitoring. Corrosion monitoring is an essential element of corrosion management. The basic objectives of corrosion monitoring are:

- To provide essential information on condition, continuously or at regular intervals
- To give advance warning of possible corrosion problems to avoid unexpected failures as a result of corrosion
- To establish relations between operating parameters and corrosion behaviour
- To measure and confirm the effectiveness of the corrosion mitigation measures (such as corrosion inhibition)
- To inform the planning of inspection and maintenance programmes

Monitoring include measurements of corrosion as well as process measurement, for example pH, temperature, chemical residual or bacteriological monitoring.

Corrosion probes and on-line process measurements can provide instant or near-instant data which is useful for the control of chemical inhibition systems and for detecting other changes in process conditions.

Corrosion Monitoring and Inspection are complementary and can help achieve the same objectives. Inspection can provide a second measurement technique and confirmation of monitoring data. Advantages of corrosion monitoring are that it can provide rapid feedback and frequent data, without interruption to the process and without heavy demand on resources. However, corrosion monitoring does not indicate the actual state of the well equipment (wall thickness) directly. Monitoring is usually at a surface location and under conditions that are different from the well environment. In contrast, inspection methods measure the wall thickness of the equipment; especially for wells, inspection data is much less frequent than monitoring data.

7.2 Corrosion Coupons and Probes

Corrosion monitoring in the form of intrusive corrosion coupons or probes provide a useful means to determine the extent of degradation over time and therefore give an estimate of the remaining lifetime of facilities.

7.2.1 Corrosion Coupons

Coupons are small pieces of metal, usually of a rectangular or circular shape, which are inserted in the process stream and removed after a period of time for assessment. The most common and basic use of coupons is to determine average corrosion rate over the period of exposure. The average corrosion rate can easily be calculated from the weight loss, the



initial surface area of the coupon and the time exposed.

It is advisable to leave a coupon exposed for at least 30 days to obtain valid corrosion rate information, and a longer period (e.g. 6 months) is typical. There are two reasons for this recommended practice. First, a clean coupon generally corrodes much faster than one which has reached equilibrium with its environment. This will cause a higher corrosion rate to be reported on the coupon than is actually being experienced on the pipe or vessel. Second, there is an unavoidable potential for error as a result of the cleaning operation.

Another benefit of coupons is to provide information about the type of corrosion. Unlike electrochemical probes, which only detect the corrosion rate, coupons can be examined for evidence of scaling, pitting and other localized forms of attack.

NACE RP0497 / ASTM G4-01 provide general guidance for the use of corrosion coupons in field applications.

Richter and Thorarinsdottir (2013) describe corrosion coupons for low temperature geothermal water installations. Usually associated with carbon steel installations, weight loss coupons are made from a similar material to the material being monitored. Corrosion coupons are used in pairs for averaging purposes. Prior to exposure the coupons are cleaned and weighed to an accuracy of 0.1mg. They are then exposed in the process stream (or a side loop from the process stream) for a period not less than 3 months and usually for 6 or 12 months. After exposure the coupons are weighed and then repeatedly chemically cleaned and weighed using appropriate techniques until the weight change stabilises meaning that all the corrosion product has been removed. The coupons final weight is recorded and the weight loss over the exposure period determined to imply a corrosion rate of the exposed facilities.

Coupons are generally installed in the surface installation; downhole installation is also possible but less easily inspected and / or replaced. Special fittings are available to allow change over of coupons from pressurised lines². In the geothermal situation there are typically several parallel filter sets which are regularly off-line to change or clean filters: this allows retrieval and change of corrosion coupons from the de-pressured line without special fittings.

7.2.2 Corrosion Probes

The major advantage of probes compared to coupons is that measurements can be obtained on a far more frequent basis - essentially continuous. Also, readings do not require removal of the probe.

Electrical resistance (ER) systems work by measuring the electrical resistance of a thin metal probe. As corrosion causes metal to be removed from the probe, its resistance increases.

Electrochemical probes consist of several individual electrodes and allow one or more electrochemical methods to be used to measure corrosion rate. Typical methods include

² For example "Cosasco" ® fittings



Linear Polarisation Resistance (LPR), Electrochemical Noise and Electrochemical Impedance. In favourable conditions, electrochemical probes can provide detailed and rapid information.

The advantages and disadvantages of common corrosion monitoring techniques are summarised below.

Table 7: Corrosion Monitoring Techniques in Geothermal Context

Technique	Advantages	Disadvantages
Corrosion (weight-loss) Coupons	Simple Suitable for any service condition, Indication of pitting or localised attack, or of scaling & fouling.	Long term, delay to results Time averaged – do not give rate at a specific time and therefore difficult to relate to process changes
Electrical resistance (ER) probe	Continuous measurement (but with a delayed response time depending on probe model): can detect the influence of process changes quickly Reliable in a wide range of service conditions	Can be unreliable where pitting occurs Trade-off between sensitivity and probe life
Electrochemical Probes (LPR, Noise, Impedance)	Instantaneous corrosion rates Some ability to detect pitting or changes in pitting behaviour	May be affected by scaling
Fixed UT probes (“UT mat”)	Non-intrusive (safety) Measures wall thickness directly	Low sensitivity and long response time compared with ER or LPR probes

Electrochemical (LPR) probes are a standard technology for water systems generally, and are suitable for geothermal applications.

Richter and Thorarinsdottir (2013) also describe corrosion probes in geothermal conditions.

According to DAGO (2016), several operators use continuous inline measurements in the brine flow, either in the main flow, or through a bypass with a comparable flow rate. Measurements techniques include both LPR and ER.

7.3 On-site Corrosion Loop / Skid

A corrosion loop or skid is a section of bypass tubing that allows some of the process stream to pass through pipework running parallel to the production or the injection pipework. The material of construction of the bypass should be the same as the well tubing and as such it would then act as a small-scale version of the well which is then more easily monitored for



corrosion and scale deposition.

A corrosion loop provides a long-term monitoring solution. In addition to using the loop as a small scale version of the well (albeit not at the same temperature and pressure), corrosion probes can be installed in the loop to provide facilities for on-line investigation of the use of new inhibitors or process parameters. The advantage of a bypass is that it can be readily isolated for maintenance etc.

Several Dutch operators have installed corrosion loops in collaboration with chemical suppliers for the purposes of on-line monitoring of inhibitor performance.

7.4 Inspection (well logging)

A multifinger caliper measures the internal radius of the well casing in several directions through the use of multifinger feeler arms (typically 40-finger calipers). The multifinger caliper survey can measure anomalies only on the inner surfaces of the tubing or casing. Output reports can provide the average wall thickness loss and also some indication of the maximum local wall thickness loss. A caliper can also identify regions where the tubing or casing diameter is reduced, which may be as a consequence of scale deposition.

Magnetic flux logs make use of magnetic flux leakage (MFL) technology to determine the location, extent and severity of corrosion and other metal loss defects in the inner tubular string.

Electromagnetic (eddy current) logs can give information on the total wall thickness of up to three strings, with some indication as to whether loss of thickness is on the inner or outer strings.

Ultrasonic corrosion logs employ a very high transducer frequency to measure anomalies in the tubing or casing. The emitter sends out sound waves and the detector measures the reflected response. It is able to provide information about casing thickness, surface condition and small defects on both internal and external casing surfaces.

Combinations of different techniques may help distinguish wall thickness loss on outer casing strings and inner casing strings.

7.5 Application to Geothermal Operations

7.5.1 Monitoring

The following monitoring regime is recommended as a basic minimum for managing corrosion in the wells, assuming that carbon steel with corrosion inhibitor treatment is the design option. For reliable trending of data, consistency in procedures, sampling location and analysis techniques is critical. The Asset Integrity part of this Study will provide more detailed recommendations.



Table 8: Basic Corrosion Monitoring Regime

Technique	Notes
Corrosion Monitoring	
LPR corrosion probe pH monitoring	At a convenient location in the surface piping or on a bypass loop. Ideally, real-time connection to control room. Otherwise, manual reading or download of data daily. Acts as an alert for problems with the inhibition system.
Corrosion coupon	At a convenient location in the surface piping. Typically retrieved 6-monthly.
Process measurements (pressure, flow rates , temperature)	Standard process measurements
Sampling	
Inhibitor residuals (biocide residual, scale inhibitor residuals etc if applicable)	Measure at commissioning of the system to set correct dose rates. Thereafter at 6 or 12 monthly intervals. Sampling point should be as far downstream as practical, e.g. at injection wellhead.
CO ₂	For systems with Separator, measure the off-gas. May be on-line monitor or by sampling (e.g. 6-monthly). It is important that a consistent sampling location and technique is used.
Water chemistry	Sampling and laboratory analysis, e.g. 6 or 12 monthly
Bacteriological sampling and analysis	Only required as routine with lower salinity waters able to support microbial activity.
Monitoring of Inhibition systems	
Check level of chemical in the storage tank	Record daily, confirms that inhibitor is being used, ensures re-supply on time etc.
Pumps and equipment operational	Check and record daily. On-line alerts may be used , but manual check should still be made.
Chemical dose rate	Daily. Check versus target and record. Adjust or re-set rate if necessary.



7.5.2 Inspection

Assuming carbon steel design option, the probable corrosion damage is on the tubing and on the inner bore of the first casing string. This is ideal for conventional caliper surveys. Other corrosion log techniques are not necessary as a routine, but may be performed if there are particular reasons to suspect corrosion problems on the outer casing strings.

If CRA tubulars are used, routine logging is not necessary as not corrosion attack is expected in normal operation.

Inspection of the Producer well is practical when the ESP is retrieved; a multi-finger caliper tool can be run in the casing string while the tubing is out. The tubing can be inspected visually at the surface. A suggested inspection interval is approximately 5-yearly, depending on the ESP retrieval schedule. Longer intervals may be appropriate for systems with very low CO₂ and very mildly corrosive conditions. The interval can be adjusted based on experience or on any indication of corrosion problems from the monitoring data.

The injection well should be inspected on a similar frequency.

Ultrasonic inspection of wellheads at specific datum locations is recommended for carbon / low alloy wellheads on an annual basis. Wellhead components are continually subjected to corrosion and erosion via the internal environment. The gradual thinning of the metalwork caused by these corrosive / erosive environments can lead to cracks or holes and potentially catastrophic failure. Caliper logging of the casing strings is only practical at long intervals and so the more frequent inspection of wellheads can give a first indication of potential corrosion problems in the system as a whole, and an indirect pointer to problems in the well. .

The possibility of failure can be greatly reduced through a programme of planned monitoring of general wellhead conditions and well maintenance. Inspection initially on an annual basis is suggested due to the criticality of the wellheads. This frequency can be modified based on experience using a risk-based approach.

8.0 Life Cycle Costing

Detailed life cycle cost analysis (Appendix D) shows the relatively small impact of different materials on the cost of a geothermal well over the full life cycle. The tubing material cost is also a relatively small proportion of the whole well capital cost which is dominated by the drilling and completion time element. So the extra expense of selecting a corrosion resistant alloy tubular rather than carbon steel + inhibitor is negligible in the context of the complete well cost.

DAGO noted that small quantities of GRE-lined tubulars (for single wells or doublets) are not available commercially, so the practical choice is between carbon steel and martensitic 13Cr tubing.

Carbon steel protected by inhibitor may possibly fail in the design life of the project and in that case this “cheapest” capital expenditure material then becomes the most costly on a total life cycle basis.

The conclusion of the study suggests that material capital cost is probably not the most important factor in material selection for these wells on a full life cycle basis. Different conclusions may be reached for different developments depending on the cost of capital for each project. More critical concerns are the technical preference (from both corrosion and mechanical viewpoint) and the commercial availability of materials.

9.0 Well Operating Envelope

9.1 Introduction

Materials selected may not be suitable for all conceivable operating conditions, or the consequence of corrosion may be tolerable if properly managed. In all cases, the limits need to be understood and clearly documented, along with relevant corrosion management requirements.

The Well Integrity Study completed for the Dutch Geothermal Operators included an example Well Operating Envelope.

Table 9: Example Well Integrity Operating Window

Validation date		Well Schematic Attached	
Well name		Wellhead and Xmas tree rating, dimension, service trim	
Well Type (Function)		Identify any leaking or failed barrier components	
Reservoir name		Additional Notes:	
Original Completion date		Any limitation on acceptable kill and completion fluids?	
Latest Completion date		Any special monitoring requirements?	
Well design Life		Any other comments?	
Operational Limits (enter value or NA)		Min/Max	
H ₂ S (ppm in gas phase)			
CO ₂ (mol% in gas phase)			
O ₂ in Water Injection (ppb Oxygen equivalent)			
Maximum Injection Pressure (psi)			
GWR (scf/bbl)			
Reservoir Pressure (Bar)			
Reservoir Temperature (C)			
SITHP (Bar)			
Maximum design production rate (m ³ /hr)			
Maximum design injection rate (m ³ /hr)			
ESP design rate (m ³ /hr)			
Fluid Additives			
Corrosion inhibitor			
Scale inhibitor (continuous/intermittent)			
Bactericide / Biocide (continuous/intermittent)			
Oxygen Scavenger (Residual O ₂ concentration)			
H ₂ S Scavenger (Residual H ₂ S Concentration)			



Well Operating Envelopes are based on the data drawn from Appendix B and are provided for the materials listed in Table 5 and Table 6:

- Carbon and low Alloy Steels
- 13Cr Martensitic Steels

Typical operating conditions are given in Table 3 and are considered in this analysis.

Note that the Well Operating Envelopes are advised in respect of material limits, scaling tendency is not considered.

9.1.1 Carbon Steel Design Option

The Well Operating Envelope for Carbon Steel Design Option is given in Table 10.

Table 10: Well Operating Envelope for Carbon Steel Tubulars

Parameter	Limits Due to Materials and Corrosion
H ₂ S (ppm in gas phase)	Nil (H ₂ S is not recorded in most reservoirs - H ₂ S presence will require reassessment)
CO ₂ (mol% in gas phase)	Calculate per Facility based on corrosion modelling and/or measured corrosion rates.
O ₂ in Water Injection (ppb Oxygen equivalent)	20 ppb (dissolved); (water in the source reservoir will normally have nil oxygen)
Maximum Injection Pressure (psi)	No restriction
GWR (scf/bbl)	No restriction
Reservoir Pressure (Bar)	No restriction
Reservoir Temperature (°C)	No restriction within low enthalpy geothermal maximum reservoir temperature (120°C)
SITHP (Bar)	No restriction
Maximum production rate (m ³ /hr)	No restriction within the maximum design flow rates as long-term average. Short-term higher excursions are acceptable
Maximum injection rate (m ³ /hr)	
ESP rate (m ³ /hr)	
Fluid Additives	Minimum up-time (availability) of 95% should be targeted as good practice for continuous treatment. (Other values may be defined for specific wells based on the corrosion assessment.) Note: Biocide is not usually required.
Corrosion inhibitor	
Scale inhibitor (continuous/intermittent)	
Bacteriocide/Biocide (continuous/intermittent)	
Oxygen Scavenger	Not required
H ₂ S Scavenger	Not required
There may be limits due to other reasons (mechanical, process etc.)	



9.1.2 Corrosion Resistant Alloy Design Option

The Well Operating Envelope for the corrosion resistant alloy (13Cr MSS) design option is given in Table 11.

Table 11: Well Operating Envelope for Corrosion Resistant Alloy (13Cr MSS) Tubulars

Parameter	Limits Due to Materials and Corrosion
H ₂ S (ppm in gas phase)	Nil (H ₂ S is not recorded in most reservoirs - H ₂ S presence will require reassessment)
CO ₂ (mol% in gas phase)	No restriction
O ₂ in Water Injection (ppb Oxygen equivalent)	Nil (i.e. below measurement threshold) Short term excursion to 10 ppb maximum
Maximum Injection Pressure (psi)	No restriction
GWR (scf/bbl)	No restriction
Reservoir Pressure (Bar)	No restriction
Reservoir Temperature (°C)	No restriction within low enthalpy geothermal maximum reservoir temperature (120°C)
SITHP (Bar)	No restriction
Maximum production rate (m ³ /hr)	No restriction
Maximum injection rate (m ³ /hr)	
ESP rate (m ³ /hr)	
Fluid Additives:	
Corrosion inhibitor	Not required
Scale inhibitor (continuous/intermittent)	Minimum up-time (availability) of 95% should be targeted as good practice for continuous treatment.
Bactericide/Biocide (continuous/intermittent)	Not required
Oxygen Scavenger	Not normally required
H ₂ S Scavenger (Residual H ₂ S Concentration)	Not normally required
There may be limits due to other reasons (mechanical, process etc)	



10.0 Surface Facilities

10.1 Corrosion Risks in the Surface Facilities

The surface facilities are continuous with the wells; CO₂ is the main corrosive species and forms of CO₂ corrosion are the major internal corrosion threat in the surface facilities. Due to the nature of the surface equipment, preferential weld corrosion and galvanic corrosion are both more significant than downhole. Enhanced corrosion due to flow conditions is possible at several locations.

Externally, the systems operate in the temperature range where corrosion under insulation is a significant threat.

Geothermal waters are often highly saline, and even small leaks will create salt deposits on the external of equipment. Combined with the temperature, this creates potential conditions for pitting corrosion and/or chloride stress corrosion cracking of austenitic stainless steels. This is particularly an issue with plate heat exchangers due to the thin plate thickness and the greater potential for leaks. The same situation applies when stainless steel equipment is opened, for example at filter changes.

Scaling is a threat, especially after Separators, and scale could affect the heat exchangers and filters operation in particular.

Table 12: Summary of Corrosion Threats and Mitigation for Surface Equipment

Equipment	Threats	Mitigation Options
All piping and equipment	Scaling	Scale inhibitor; pH control (controlling outgassing of CO ₂)
Piping	CO ₂ Corrosion (including preferential weld corrosion, flow assisted corrosion)	Steel piping with corrosion allowance + inhibitor treatment Or GRE piping
	Galvanic corrosion (to major stainless steel equipment)	Isolation joints or flange isolation kits at key locations Or GRE piping
	Atmospheric corrosion	External coating; inspection and maintenance regime Or GRE piping
	Corrosion under insulation	



Equipment	Threats	Mitigation Options
All stainless steel equipment	Internal pitting and/or CI-SCC	Operating procedures for shut-downs to avoid exposure to hot saline water + oxygen (air)
Vessels (separator , filters)	CO ₂ corrosion	Stainless steel (minimum 316 / 316L)
Pumps	CO ₂ corrosion (flow assisted corrosion)	Stainless steel (minimum 316 / 316L)
Heat exchangers (plate type)	CO ₂ Corrosion	Stainless steel
	External pitting and/or CI-SCC	Higher grade stainless steel, e.g. 22Cr duplex (e.g. UNS S31803), or 6Mo stainless steel (e.g. UNS S31254) Design details to minimise leaks
Instrumentation tubing and equipment	CO ₂ Corrosion	Stainless steel (316 / 316L minimum)
	Crevice corrosion	Avoid threaded small bore connections in carbon steel. Use welded or flange connections for preference.
Chemical treatment equipment	Chemicals (corrosion inhibitor, scale inhibitor, biocide)	Stainless steel (316 / 316L) and non-metallics are standard for cleanliness. Check Supplier's recommendations. Note that neat chemicals (including corrosion inhibitors) can be corrosive to carbon steel.

10.2 GRE Piping

GRE is an excellent material for handling corrosive saline water and eliminates the major internal and external corrosion threats.

The quality of the joints is critical to the success of GRE piping installations, and several Operators in the process industries generally have suffered large expense due to leaks at poorly quality adhesive joints. Use of a specialist contractor with GRE experience and a high level of QA / QC controls during installation are recommended.



GRE requires more frequent piping support than steel piping. It has much less ductility than carbon steel, and therefore is much less tolerant of poor fit-up and of thermal strains that would be no issue with steel construction. The piping layout and supports should be designed with these characteristics in mind.

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Appendix A Corrosion Risks and Scaling Problems



A.1 Overview of Corrosion Threats

This section summarises the most common forms of corrosion and metallurgical degradation mechanisms that are potential threats applicable to geothermal wells in the Netherlands. As a starting point, the analysis deliberately considers a wide range of threats drawn from experience in the wider geothermal and oil and gas industries. Some of these threats are unlikely or have not been experienced in practice in Dutch Geothermal wells, and the risk from each specific threat in the Dutch Geothermal well conditions is analysed.

The applicability of the degradation mechanisms is based on the data derived from the well fluid reports, International Standards, industry codes and Wood Group experience. Industry standards including ISO 21457, API 571 and Energy Institute Guidelines have been used as reference to the potential damage mechanisms. The damage mechanisms are described in line with these codes and standards. The descriptions also include the critical factors that affect the mechanism, appearance of the damage, how the mechanism is relevant to Dutch geothermal wells, and typical mitigation approaches.

Considering all materials of construction, the potential internal corrosion mechanisms include:

- Carbon Dioxide Corrosion
- Thermal Stress and Thermal Fatigue
- Sour (H₂S) Corrosion
- Erosion and Erosion-Corrosion
- Microbiologically Influenced Corrosion (MIC)
- Galvanic Corrosion
- Crevice Corrosion
- Under Deposit Corrosion
- Pitting Corrosion
- Oxygen Corrosion
- Stress-Corrosion Cracking

The potential external corrosion mechanisms include:

- External Chloride Stress Corrosion Cracking
- Atmospheric Corrosion
- Soil-side Corrosion
- Corrosion Under Insulation



A.2 CO₂ Corrosion

When CO₂ dissolves in water it forms carbonic acid, H₂CO₃. This is a weak acid, in other words it is not fully dissociated into its ions, unlike a strong acid such as HCl, which dissociates nearly entirely to H⁺ and Cl⁻ ions.



The mechanism of CO₂ corrosion of carbon steel differs in one major aspect from corrosion by strong acids like HCl. Corrosion by acids generally involves reactions such as:



The rate of this corrosion reaction is highly dependent on the concentration of hydrogen ions, H⁺, which is measured by the pH. Although this reaction does happen with carbonic acid, there is also an additional mechanism:



Here the carbonic acid is directly reduced, with a rate which also depends on the amount of dissolved but undissociated carbonic acid and not directly on pH. It follows that, for the same pH, the weak carbonic acid is more corrosive than a strong, fully dissociated acid.

The acid may lower the pH and sufficient quantities may promote general corrosion and / or pitting corrosion of carbon steel. Carbon steel and low alloy steels are affected by CO₂ corrosion.

CO₂ is the principal corrodent in many reservoir fluids and modelling and prediction of CO₂ corrosion has been extensively studied since the 1970s.

A.2.1 Critical Factors

- The CO₂ concentration is of course critical with increasing partial pressure of CO₂ resulting in higher rates of corrosion. As a very approximate guide only, API 6A standard for wellhead equipment defines service classes for hydrocarbon producer wells based on CO₂ partial pressure:

“Non –corrosive” < 0.05 MPa (7 psi) partial pressure of CO₂

“Slightly corrosive” 0.05-0.21 MPa (7 - 30 psi)

“Moderately to highly corrosive” above 0.21 MPa (30 psi)

- But note there are many other factors that can make these broad guidelines invalid.
- Higher flow velocity typically results in faster corrosion as the process is partly controlled by the rate of transport of reactants to and from the steel surface.
- Temperature has a complex effect. Generally, reaction rates and therefore corrosion rates increase with temperature. However, above a certain temperature the iron carbonate corrosion products can form protective scales and reduce the corrosion rate substantially. Based on field experience, the highest corrosion rates can often occur in the range 80-100°C.



- Water chemistry can have an impact, in particular species which affect the pH such as bicarbonates and carbonates or organic acids.

A.2.2 Appearance of Damage

Depending on the flow conditions, the morphology of CO₂ corrosion can vary. Corrosion may be relatively uniform, or more localised in the form of pitting. Distinct areas of corroded and essentially uncorroded material with a clear boundary can occur (sometimes referred to as mesa-corrosion). There may also be attack related to turbulence and flow conditions, for example near pumps or flow restrictions.

A.2.3 Preferential Weld Corrosion

Preferential weld corrosion (PWC) is a form of attack that is localised in the weld metal or adjacent to the weld metal, for example in the heat affected zone of the parent metal. In the context of Dutch Geothermal operations, the main corrosive species is CO₂ and therefore PWC is treated as a morphology of CO₂ corrosion. Joint industry projects in the O&G industry have investigated this subject in detail (Turgoose et al, Lee et al, 2005). PWC can involve various contributing factors.

1. Deliberate Ni additions are often made to weld consumables as a reliable and simple method to improve the toughness of the weld deposit. The inherent corrosion rate of steels containing small nickel additions in some CO₂ containing environments can be higher than for the parent steel without deliberate nickel additions.
2. Galvanic differences between weld metal, HAZ and parent inevitably exist due to composition differences or micro-structural differences or both. These can drive galvanic corrosion of the weld, HAZ or parent material depending on the particular circumstances.
3. Corrosion inhibitors can perform differently on the different materials, for example protecting the parent steel but not protecting the weld metal. In particular, specific corrosion inhibitors have been documented as failing to protect welds containing nickel at about 0.5-1wt%, or to protect the welds less efficiently than (nickel-free) carbon steel.

The first two factors are unlikely to lead to local corrosion rates that are very much greater than the background rate for the parent steel; acceleration of 1.5-2 times is typically the maximum. The third factor can potentially cause hugely accelerated attack, with the relatively small area unprotected by inhibitor being the anode and the normal parent material providing a large cathode area.

In the current Dutch geothermal systems, the potential corrosion rates without corrosion inhibition are high (this may not be the case for future shallow reservoir developments). Therefore the situation for severe PWC exists if inhibitor performance is not adequate to protect the welds.

Mitigation can involve



- Testing and selection of inhibitor that perform well with the actual welds used in service
- Minimising composition differences between weld metal and parent steel, especially Ni
- Increase in the inhibitor dose rate to compensate for possible reduced performance on the weld areas.

A.2.4 Flow Assisted Corrosion

Flow conditions have a large impact on CO₂ corrosion rates. Factors include transport of reactants and corrosion product to and from the surfaces, the removal of protective corrosion products and of corrosion inhibitor films. Inhibitors will eventually become ineffective in high shear conditions, the limits depending on the product and to some extent the dose rate. Localised high corrosion rates in locations of high velocity and shear or turbulent flow are common in CO₂ containing environments. Locations may include

- Pumps, and pump inlet / outlet piping
- Tubing perforations and sand-screens etc
- Any variations in the tubing or piping profile, such as welds beads, non-flush threaded connections etc.
- Valves and other restrictions
- Bends
- Locations where there is pressure drop and gas starts to flash off from the liquid with increase in the volume flow and therefore increased velocity; for example after a choke valve or at entry nozzle to a vessel.

Mitigation may include: minimising tight bends, restrictions, and uneven surface profiles; use of corrosion resistant materials (stainless steel or non-metallic) at high risk locations for sand-screens, pumps, valves, heat-exchangers etc.

A.2.5 Prevention / Mitigation

Corrosion inhibitors can reduce corrosion of carbon steel due to CO₂ in liquid environments.

Stainless steels with more than 12% chromium are highly resistant to CO₂ corrosion in most applications as are higher grades of corrosion resistant alloys.

In carbon steels, caliper logs for wells and VT, UT and RT inspection techniques for surface equipment, can be used to identify general and local loss in wall thickness where CO₂ corrosion damage is anticipated. In addition, monitoring water analyses (pH, Fe²⁺, etc.) to determine changes in operating conditions can give an indication that attack is occurring.



A.2.6 Relevance to Geothermal Wells

CO₂ corrosion is particularly relevant to the current geothermal wells as the well water contains dissolved CO₂. For corrosion engineering the amount of dissolved CO₂ is typically expressed by the CO₂ content in the gas in equilibrium with the water (e.g. the CO₂ content of the gas in the separator). Carbon dioxide levels ranging from 0.24 to 56.7 mol (Table 3) have been recorded % with a number of wells having over 10 mol%, and there is therefore potential for significant carbon dioxide corrosion.



A.3 Thermal Stresses and Thermal Fatigue

Thermal stresses arise when components are restrained from expansion or contraction in response to temperature variation. Thermal fatigue is the result of cyclic stresses caused by variations in temperature. Damage is in the form of cracking that may occur where relative movement or differential expansion is constrained, particularly under repeated thermal cycling. All materials of construction are potentially affected.

In this sort of system, the major cycles of thermal stress are expected to be due to the difference between the flowing and non-flowing temperatures. Thermal expansion and static thermal stresses can be significant in wells and should be considered in the well's mechanical design. In surface piping and for equipment such as heat exchangers, thermal expansion effects are covered by standard design codes.

A.3.1 Critical Factors

- Key factors affecting thermal fatigue are the magnitude of the temperature swing and the frequency (number of cycles).
- Time to failure is a function of the magnitude of the stress and the number of cycles and decreases with increasing stress and increasing cycles.
- Startup and shutdown of equipment increase the susceptibility to thermal fatigue. There is no set limit on temperature swings; however, as a practical rule, cracking may be suspected if the temperature swings exceeds about 200°F (93°C).
- Damage is also promoted by rapid changes in surface temperature that result in a thermal gradient through the thickness or along the length of a component. For example: cold water on a hot tube (thermal shock); rigid attachments; inflexibility to accommodate differential expansion.
- Notches and sharp corners or any other stress concentrations may serve as initiation sites.
- Thermal fatigue is not a common failure mechanism in wells because the number of heating and cooling cycles (flowing / non-flowing) is normally low in terms of fatigue.

A.3.2 Appearance of Damage

Thermal fatigue cracks usually initiate on the surface of the component. They are generally wide and often filled with corrosion product in surface equipment. Cracks may occur as single or multiple cracks and can often start at the end of an attachment. If there is a bending moment as a result of the constraint, they will develop into circumferential cracks into the tube.

A.3.3 Mitigation

Thermal fatigue is best prevented through design and operation to minimise thermal stresses and thermal cycling.

Since cracking is usually surface connected, visual examination, Magnetic Particle Testing



and Dye Penetrant Testing are effective methods of inspection for surface equipment.

A.3.4 Relevance to Geothermal Wells

The mechanism is not considered to be significant for the Dutch geothermal wells due to the moderate temperature range and small number of on-off cycles.

A.4 Sour Corrosion

Sour corrosion is corrosion due to water containing H₂S. Carbon dioxide (CO₂) may also be present and very often corrosion involves both species. The presence of H₂S (i.e. a sour environment) modifies the CO₂ corrosion behaviour. H₂S is an acid gas, and hence affects the pH of the water; H₂S also reacts with dissolved iron ions, removing them from solution and increasing the acidity of the water phase. Both these effects tend to increase the carbon steel corrosion rate. On the other hand, with sufficient H₂S, an insoluble iron sulphide film may form on the steel surface, which can greatly reduce the rate of general corrosion (Smith and Joosten 2006). However, in some circumstances the protective sulphide film can break down and localised corrosion attack occurs, i.e. pitting corrosion. The occurrence of pitting is sensitive to several factors, including the flow regime, the presence of solids and deposits and the presence of oxygen, sulphur or high levels of chloride ions.

Stainless steels and nickel base alloys are usually resistant at the low concentrations of H₂S found in geothermal waters. Stainless steel can be susceptible to pitting attack in sufficiently severe conditions of temperature, H₂S and chloride concentration.

Copper is very reactive with H₂S. Some copper base alloys (such as Monel, UNS N04400) can have useful resistance to sour corrosion in a limited range of service conditions, but great care should always be taken if intending to use copper-base alloys in the presence of H₂S.

A.4.1 Critical Factors

- H₂S concentration, pH, temperature and velocity of flow are all critical factors.
- Other species can have a significant effect on behaviour; in particular high chloride concentrations are associated with increased tendency to pitting attack.
- The presence of air or oxidants may drastically increase corrosion because the H₂S is oxidised to elemental Sulphur and sulphur-acids which are extremely corrosive.

A.4.2 Relevance to Geothermal Wells

Sour water corrosion is a concern in systems with H₂S above trace levels. As H₂S has only recently been reported in Dutch geothermal waters and is at very low levels, it is not at present considered to be a significant damage mechanism in geothermal wells. If the levels of H₂S increase over time then this mechanism may then become relevant.

A.5 Erosion and Erosion-Corrosion

Erosion is the accelerated mechanical removal of surface material as a result of relative movement between, or impact from, solids, liquids, or vapour. Particle erosion due to solids in the process stream is a concern in some wells and surface systems. The solids may be from the reservoir (sand) or in some cases may be scale and corrosion products.

Erosion-corrosion describes the situation where both corrosion and erosion contribute to material damage. For example, erosion can mechanically erode protective oxide layers or remove corrosion inhibitors or corrosion product, thus allowing enhanced corrosion of the exposed material underneath.

A.5.1 Prediction

For simple geometries such as pipe bends, pure particle erosion can be modelled using the DNV RP O501 code or other models and these are reasonably well validated by field data (Barton et al, 2016). Computational fluid dynamic (CFD) modelling is necessary for accurate assessment of complex geometries, for example valves.

A.5.2 Critical Factors

Other factors being equal, particle erosion rates are proportional to the quantity of particles and the velocity to the power of about 2-3. For example, in DNV RP O501, the velocity exponent $n = 2.6$ for steel.

$$\text{erosion rate} \propto \text{sand production rate} \cdot (\text{fluid velocity})^n$$

Therefore, erosion is very sensitive to velocity.

The angle of impingement is also very important in particle erosion, for example at bends and other changes in flow direction.

There is very little practical difference in the resistance of most metals to pure particle erosion (although this is contrary to common belief, this is well documented and is confirmed in the DNV RP O501 code). For particle erosion resistance, there is often little or no benefit in using high alloy metals. Tungsten carbide and other high hardness, non-metallic materials can be considerably more resistant to particle erosion, in the range of 10-100 times in different conditions. These materials are typically used for “hard-facing” of items such as valve seats and components in flow control (choke) valves.

The passive films on high alloy stainless steel and nickel-base alloys are extremely adherent. The passive films on standard 13Cr stainless steel are less adherent and synergistic erosion-corrosion has been reported for 13Cr stainless steel in production type conditions that are both corrosive and highly erosive.

A.5.3 Appearance of Damage

Erosion and erosion-corrosion are characterised by a localised loss in thickness in the form of pits, grooves, gullies, waves, rounded holes and valleys. These losses often exhibit a directional pattern.

A.5.4 Prevention / Mitigation

Mitigation of particle erosion is ideally achieved in design by correct sizing of equipment to avoid excessive velocities and by measures to prevent presence of solids: for example sand-screens in the well. Because of the extreme sensitivity to velocity, even a small reduction in flow rate can have a substantial benefit.

For resistance to pure particle erosion, there is often little or no benefit in using high alloy metals or harder metals. High hardness, non-metallic materials such as Tungsten Carbide are typically used for “hard-facing” of critical locations such as components in flow control (choke) valves or in pumps.

Higher alloy steels, stainless steels and corrosion resistant alloys do have possible benefits with respect to erosion-corrosion. In production conditions, BP recommend using higher alloy materials to avoid possible erosion-corrosion effects if the predicted erosion rate is greater than 0.1 mm/yr (Martin, 2006).

Use of chemical corrosion inhibitors may be unsuccessful in erosive conditions, or may require higher dose rates than for non-erosive conditions.

Visual examination of suspected or troublesome areas, as well as Ultrasonic Testing checks or Radiographic Testing can be used to detect the extent of metal loss. Specialised corrosion coupons and on-line corrosion monitoring probes can also be used. Probes are also available to measure the rate of solids production.

A.5.5 Relevance to Geothermal Wells

Erosion should always be considered as a possibility, either due to sand production or due to scale and corrosion products.

Particle erosion is typically most severe in wellhead and surface equipment where there are tight bends and flow restrictions, while straight tubing and piping runs are at much lower risk. Subsurface pumps and associated equipment may also be at risk.

The possibility of sand production should therefore be assessed at an early stage and included as a factor in the design if necessary. Increased flow rates above design values, achieved by increased drawdown, may endanger reservoir integrity and thereby enhance sand production. Where there is concern, sand production and erosion rates should be measured and monitored.

The control of erosion and erosion-corrosion is ideally achieved in design by measures to prevent production of solids: for example sand-screens in the well. For particle-free conditions, velocities and pipe sizing can be based on standard codes such as API 14E so far as erosion risk is concerned (CO₂ corrosion or other factors such as pump characteristics



may also limit the maximum velocity).

If solids are present, then DNV RP O501 can be used for assessment and design. Because of the extreme sensitivity to velocity, even a small reduction in flow rate can have a substantial benefit.

For resistance to pure particle erosion, there is often little or no benefit in using high alloy metals or harder metals. High hardness, non-metallic materials such as Tungsten Carbide are typically used for “hard-facing” of critical locations such as components in flow control (choke) valves or in pumps.

A.6 Microbiologically Influenced Corrosion (MIC)

Microbially influenced corrosion (MIC) is defined as any interaction between microorganisms and solid materials that results in the loss of part of the solid. Most common materials of well construction including carbon and low alloy steels, stainless steels and some nickel base alloys can potentially be affected, although in practical experience, damage to stainless steels with higher alloy content than 316/316L is extremely unusual. In wells, MIC has most often been found in shut-in wells (particularly water injectors), or wells with incorrect chemical treatment of the packer fluids. In the latter case, MIC is possible in the non-process locations such as the outer annulus spaces.

In surface equipment, MIC is most often found in stagnant and low flow locations, such as the bottom of storage tanks and vessels, or piping dead-legs. MIC can also occur on the external side in contact with some soils or under damaged coatings.

A.6.1 Critical Factors

- Stagnant or low-flow conditions are much greater risk as micro-organisms can then settle and establish colonies on the metal surfaces. Based on general industry experience, the critical velocity is between 1 to 2 m/s. Shut-in and non-flowing conditions are generally higher risk.
- Different types of organisms can grow under severe conditions including with / without oxygen, light or dark, high salinity, wide pH and temperature range. Depending on species, active growth is possible over ranges of about pH 5 to 9.5 and temperature from 4°C to 100°C and up to about 18% salinity (Energy Institute, 2014). Organisms can generally survive even more extreme conditions and then become active again if conditions become more favourable.
- Micro-organisms are ubiquitous in the external environment and process systems can easily become contaminated by organisms that then multiply and spread.
- All micro-organisms requires a food source to allow them to grow and proliferate and different organisms thrive on different nutrients including inorganic substances (e.g. sulphur, ammonia, sulphate ions) and inorganic substances (e.g. hydrocarbons, organic acids). In addition, all organisms require a source of carbon, nitrogen and phosphorous for growth.
- Scale and corrosion products can provide protection for micro-organisms underneath and are generally adverse factors for MIC.



Parameter	Range	Comment
pH	pH 5.0 – 9.5	
Temperature	0 - 80°C	Psychro-, meso- and thermo-philic
Salinity	1% - < 11%	Non-, mild and moderate halophiles
Sulphate	> 10 mg/L	In excess of Ks value
Organic carbon	> 1 mg/L	
C:N:P	In balance	Conducive to bacterial growth

Table 2. Physicochemical ranges within which SRB activity could be expected.

Figure 5: From Maxwell, NACE Corrosion 2006, Paper 06662

Although microorganisms can survive extreme conditions, significant corrosion activity is limited to certain environmental ranges. The Table above summarises experience of the conditions needed for MIC in service. Note that the salinity of the Slochteren, Triassic, and Delft reservoirs is above the range where SRB activity is expected. The Carboniferous reservoir water is towards the high salinity end of the active range. The operating temperatures in some parts of the systems may also be above the dangerous range for MIC (i.e. > 80°C); the injection side of the process is at great risk in this respect.

In summary, MIC is considered unlikely in the Slochteren, Triassic, and Delft waters under geothermal conditions. MIC may be possible in the Carboniferous waters in lower temperature sections.

A.6.2 Appearance of Damage

MIC is usually observed as localised pitting under deposits or tubercles that shield the organisms from the shear effect of the flowing fluids. Damage is often characterised by cup-shaped pits in carbon steel or subsurface cavities in stainless steel. The presence of sulphur (yellow deposits) or sulphides (rotten egg smell) is characteristic of specific types of MIC.

A.6.3 Prevention / Mitigation

Proper application of biocides will control micro-organisms, but generally will not eliminate them completely. Repeat or continued treatment is necessary. Sessile colonies can be very resistant to biocide treatment because the scale or corrosion products provide protection to the micro-organisms underneath. Effective control of established MIC may require physical removal of deposits or chemical cleaning (descaling) in combination with biocide treatment.

Maintain flow velocities above minimum levels (typically at least 1m/s) to reduce the tendency for solids to drop out which encourages microbial growth and avoid design features with low flow or stagnant zones.

The presence of micro-organisms can be monitored by sampling and laboratory analysis (MPN – most probable number method). Sampling from the water stream only measures planktonic organisms, which may not reflect the numbers of sessile colonies on the metal surfaces, but it is useful for trending purposes. When possible, sampling from solids or



deposits on the metal surfaces can also be informative.

Biocide treatment can also be monitored by measuring the biocide residual concentration, typically at the most downstream part of the system.

A.6.4 Relevance to Geothermal Wells

Micro-organisms were recently discovered in one of the geothermal wells (DAGO, 2016, KO meeting).

From wider industry experience, contamination of surface systems with MIC often occurs. Even if there is no biological activity in the water source reservoir there is a real possibility of biological activity in the surface system and in the injection wells. This could realistically introduce micro-organisms into the reservoir and the producer wells.

A.7 Galvanic Corrosion

Galvanic corrosion is a form of corrosion that can occur at the junction of dissimilar materials when they are joined together in a suitable electrolyte, such as an aqueous environment, or soils containing moisture. All metals can be affected. Although usually involving two metals, galvanic corrosion is also possible between graphite and metals. Galvanic corrosion between graphite gaskets and stainless steel flange faces is a classic example. One material acts as the cathode and is protected from corrosion by sacrificial corrosion of the more active material – the anode. The anode corrodes at a higher rate than it would if it were not connected to the cathode.

Galvanic corrosion is usually most severe in oxygen-containing environments. In fluids with low oxygen content the threat of galvanic corrosion is often over-rated. For example, extended tests by Statoil – BP found no noticeable acceleration of the corrosion rate of carbon steel tubulars joined to various corrosion resistant alloy tubulars in deaerated injection water – an environment very similar to the low enthalpy geothermal conditions (Evans, 2004). Experience in production environments shows that the local acceleration of corrosion rates due to galvanic coupling between different materials is often minimal (Francis, 2001). The effect on corrosion rates is usually less in flowing conditions than in static conditions.

A.7.1 Critical Factors

Three conditions must be met for the mechanism to be viable:

- Presence of an electrolyte (a fluid that can conduct a current), for example the well water.
- Two different materials to act as the anode (corroding) and the cathode (protected) both in contact with the electrolyte.
- An electrical connection must exist between the anode and the cathode.

The electrochemical potentials of different carbon steel and low alloy steel grades are usually NOT sufficiently different to cause galvanic corrosion in practice. Likewise, galvanic corrosion will not normally occur between different grades of stainless steels.

The relative exposed surface areas between anodic material and the cathodic material has a significant affect.

- Penetration rates of the anode can be high, if there is a small anode area and large cathode area.
- Corrosion rates of the anode will be less affected if there is a large anode area and small cathode area. For example small stainless steel trim components in valves in contact with carbon steel valve bodies rarely cause problems.

The same metal or alloy may act as both an anode and a cathode at different locations due to surface films, scale and / or local environment (for example, old steel pipe connected to new steel pipe).



A.7.2 Metallic deposits

Another galvanic effect reported in geothermal water systems is the deposition of a noble metal (lead, arsenic, antimony, copper) from the water onto the surface of the well tubular. This situation is specific to particular water chemistries. Similar behaviour is also known in other handling water systems (NALCO, 2016). The primary concern in the geothermal cases is scaling and blockages due to the deposits and also the unwelcome deposition of radioactive species on surface equipment (Lichti, 2016) and (Bressers, 2014). In so far as the deposition of metal ions provides an additional cathodic reaction mechanism it theoretically could increase the carbon steel corrosion rate. The concentrations of the metal ions involved are usually rather low which limits the possible impact. Galvanic corrosion between the deposited metal and carbon steel is also a possibility, but unless there is a rapid cathodic reaction mechanism available (such as oxygen reduction), the practical impact will not be significant. Examples of galvanic corrosion between copper deposits (cathodic) and aluminium equipment (anodic) are also known in other systems. Aluminium is generally not used in downhole or wellhead equipment, but might possibly be used in geothermal systems for surface equipment such as heat exchangers.

A.7.3 Appearance of Damage

The anode material can suffer generalised loss in wall thickness or may have the appearance of a crevice, groove or pitting corrosion. Corrosion of the anode may be significantly higher immediately adjacent to the connection to the cathode, depending on the solution conductivity.

A.7.4 Prevention / Mitigation

Very often, no mitigation is necessary.

The best method for prevention / mitigation is through correct design; different classes of alloys should not be in contact with each other in conductive environments unless the anode / cathode surface area ratio is favourable (i.e. the anode is a large area compared to the cathode). In wells it is common to select any completion equipment in materials that match the well tubulars or are cathodic to the tubing materials (higher Cr for example), thus avoiding galvanic corrosion issues because the anode area is very large and cathode area small.

Normally, no mitigation is needed

- At interfaces between different carbon steel and low alloy steel grades
- At interfaces between different stainless steel grades
- At interfaces between metals and non-metallic materials (except graphite, as noted above)

Controlling the environment and minimising the general corrosivity, especially by removing oxygen or by using corrosion inhibitors, can be very effective. Galvanic effects basically accelerate the underlying corrosion rate and if the underlying corrosion rate is very low then



the locally increased rate may still not be significant.

For surface equipment, isolation kits can be used at flange connections to electrically isolate mixed materials. Although this is often done, there are problems:

- Very often the isolation is ineffective because both sides are electrically connected by another path, for example through the piping and vessel supports or through instrumentation.
- Bolting sleeves, isolating washers and gaskets can be easily damaged

An isolating spool, for example GRE piping, can be used. This does not require perfect electrical isolation of the two items to be effective, as it also introduces a resistance in the water side of the electrical circuit due to the distance between the two materials.

If coating is used as mitigation, then cathode material (non-corroding) should always be coated (the anode material may be coated also). If only the anode material were coated, this creates a large cathode area to anode area and can hugely accelerate corrosion of the anode at any breaks in the coating. Coating is impractical for pumps and heat exchangers.

Internal sacrificial anodes provide a third material that is anodic to both the construction materials and in theory protects both. There are possible disadvantages

- Operators have reported adverse impact on scaling behaviour due to the corrosion products from the anodes changing the water chemistry. The additional corrosion products that must be filtered before the injection wells
- There is a need to monitor and replace anodes
- Successful design to ensure protection is not simple, especially if both flowing and non-flowing periods have to be considered.

A.7.5 Relevance to Geothermal Systems

The scope for galvanic corrosion exists due to the uninsulated connection between dissimilar metals in the presence of the highly conductive geothermal water. However, as described above, the actual risk of galvanic corrosion is minimal in many situations or can be eliminated by simple design choices.

Normally, there is no significant risk with

- Interfaces between different grades of low alloy and carbon steel, for example API 5CT K55 / API 5CT L80 / AISI 4130 and normal piping material grades etc.
- Non-metallic (polymer) to steel or stainless steel (exception: graphite, as in graphite gaskets, can be extremely cathodic to all metals, and graphite gaskets should be avoided)
- Valve trim, instrumentation and chemical injection fittings etc with small area relative to the area of steel
- Downhole equipment and single tubing pup-pieces in higher alloy materials, again



small area in relation to the steel tubing

- Conditions where corrosion rates are low due to effective inhibition

Mitigation can be considered at major items of stainless steel equipment (heat exchangers, filters, vessels, surface pumps etc), although very often it will not be necessary. If required as a precaution, the preferred options are

- Isolation spools
- Flange isolation kits

For surface facilities, if steel piping is eliminated by use of GRE, then no galvanic corrosion issue arises.

Conventional inspection methods can be used for detecting galvanic corrosion (visual inspection, RT, UT). However, it is important to check the critical locations, usually next to the interface between the two materials.

A.8 Crevice Corrosion

Crevice corrosion is a localised form of corrosion most commonly experienced in aerated waters. Crevice Corrosion is usually associated with a stagnant solution on the micro-environmental level. In surface equipment, these microenvironments tend to occur in crevices for example those formed beneath gaskets, washers, insulation material, fastener heads, surface deposits, threads and lap joints.

Crevice corrosion is initiated by changes in local chemistry within the crevice for example by:

- Depletion of oxygen in the crevice
- A shift to acid conditions in the crevice
- Build-up of aggressive ion species (chloride ions) in the crevice

For a crevice exposed to an aerated liquid, oxygen diffusion into the crevice is restricted, being present at the outer edge of the crevice but depleted within the crevice. A differential aeration cell is then set up between crevice (microenvironment) and the external surface (bulk environment) which provides the driving force for the corrosion to occur. Carbon steel and stainless steel are susceptible, particularly where chlorides are present.

The lack of oxygen in most well environments minimises the risk of crevice corrosion.

A.8.1 Critical Factors

- An aerated aqueous environment e.g. injection water if it has been aerated at the surface and not treated with oxygen scavenger.
- A suitable crevice containing an electrolyte for example, flange / gasket interfaces, under clamps on instrument tubing and bolt / flange interfaces.
- Presence of chlorides (in practice, any non-zero level)

A.8.2 Prevention / Mitigation

The potential for crevice corrosion can be reduced through use of oxygen scavenger (in the re-injected water) to remove the cathodic reagent.

If conditions are likely to promote crevice corrosion, the selection of materials and design details at crevice locations can help prevent corrosion. For example, overlays in resistant high alloy materials on flange faces. For external equipment such as fasteners and pipes support, preservatives such as wax or grease can be used to minimise water ingress to crevices on fasteners and piping clamps.

Inspection and monitoring is inherently difficult and typically relies on visual inspection, particularly during maintenance.

A.8.3 Relevance to Geothermal Wells

Crevices are unavoidable at the well tubular connections and at other locations. As explained above, these features generally do not cause crevice corrosion problems in oxygen-free production environments. The injection side of the geothermal system is at greater risk if



there is oxygen ingress to the water at the surface (for example through pump seals).

A.9 Under Deposit Corrosion

Under deposit corrosion essentially refers to accelerated corrosion processes that develop underneath deposits. Under deposit corrosion can occur in surface and downhole systems where sand deposition or scaling is possible. In downhole conditions, settlement of solids or scale formation is more likely at large deviation angles and at low velocities or at locations where the fluid conditions are suited to scale formation.

The mechanisms involved in under deposit corrosion may include MIC, crevice corrosion, carbon dioxide corrosion etc. Deposits can hinder the access of inhibitor to the metal surface but if they are porous or incomplete then corrosive elements can still access the metal surface.

A.9.1 Critical Factors

- Locations where solids (scale, sand or corrosion products), settle out in low flow or stagnant areas.
- Deposits that are compact and adherent enough to prevent corrosion inhibitor reaching the steel beneath the deposit.
- Development of a difference between the chemical environment under the deposit and the bulk fluid.

A.9.2 Prevention / Mitigation

Systems should be designed to be free-flowing, avoiding dead legs and low spots so far as practical. Flow should have sufficient velocity that water and solids remain suspended in the flow and cannot become trapped in low spots in the system. Techniques discussed in Section 2.2 for scale prevention should be employed.

A.9.3 Relevance to Geothermal Wells

As discussed in Appendix C geothermal fluids are prone to scaling and therefore particularly prone to forms of under deposit corrosion.



A.10 Pitting Corrosion

“Pitting” has use as a descriptive term, without implying a particular corrosion mechanism (for example, “pits” might be caused by MIC).

Pitting Corrosion as a *damage mechanism* is a specific form of localised attack. Typically this requires a passive alloy for example stainless steel or a nickel-base alloy and operating conditions that can cause break-down of the passive (oxide) film that is present on the surface of these materials and responsible for their normally good resistance to corrosion. The presence of halides, primarily chlorides in the environment is the main aggravating factor. Once the attack has started, the rate of penetration at the pit location can be extremely high, driven by a large surrounding cathode area. The depth to area ratio of the pit is typically high, and the material can be completely penetrated within a short time.

The starting point for pitting corrosion can be some surface defect or surface profile feature, or mechanical damage to the protective layer (e.g. from wireline operations). Poor quality oxide films associated with welding are also a common location for pitting. In stainless steels, surface contamination by ferrous material can be a cause of pitting.

Pitting corrosion can also occur in carbon steel when there is partial but not complete protection of the surface due to (for example) an inefficient inhibitor, or partial filming by sulphide corrosion products.

A.10.1 Critical Factors

- The primary requirement for pitting corrosion to occur is to have a material such as stainless steel that is protected by a passive surface film that can be locally depassivated.
- The chloride content, pH, oxygen content and temperature are key environmental factors. Stainless steels are much more susceptible to pitting corrosion with oxygen present than in oxygen-free conditions.
- Other aggressive species include S, H₂S and organic acids.
- Once pitting has started, the process to some extent becomes independent of the bulk environment. Even if the general service conditions become less aggressive, pitting may still continue.

A.10.2 Appearance of Damage

Pitting corrosion is distinguished by dark spots or pits over the surface of the metal under attack. Corrosion product can be present at the mouth of the pit and when removed a small pit may be visible. The depth and size of the pit is usually not apparent from the surface aspect, with pits extending into the depth of the metal and sometimes spreading sideways, undercutting the surface. Pitting corrosion is often much more serious than the surface appearance would suggest.



A.10.3 Prevention / Mitigation

Pitting corrosion is difficult to mitigate if the material is susceptible in the particular environmental conditions. Prevention through correct material choice is the best option. The resistance of stainless steels to pitting in oxygen containing environments can be ranked in terms of the “pitting resistance number” or PReN. The PReN is not applicable to oxygen-free conditions.

Due to the poor resistance of some stainless steels to pitting corrosion with oxygen present, preventing oxygen ingress into the process system or removing oxygen if present can be critical.

Contact with carbon steel equipment or ferrous contamination can dramatically reduce the corrosion resistance of stainless steel. Ferrous contamination on the surface, or worse, pressed into the surface, can act as a site for pit initiation in conditions that would not normally cause any attack to a clean surface. As good practice, stainless steel tubing and equipment should be transported, stored and handled separately from carbon steel items. Any tools, thread-protectors, grip-faces, storage racks etc. in contact with stainless steel should be dedicated to stainless steel and not used for carbon steel. Using equipment with both material types risks transferring ferrous contamination.

Proper welding procedures for stainless steels are necessary to avoid damaged oxide films which are highly susceptible to pitting attack (typically indicated by “heat-tint” colours adjacent to the weld). Physical cleaning or chemical passivation steps after welding can help restore the corrosion resistance of the weld area.

Stainless steel tubing and equipment pulled from a well must be assumed to be at risk of severe pitting corrosion if left wetted with saline reservoir water while exposed to the atmosphere. Pulled stainless tubing and equipment should be washed with fresh water as soon as practical and ideally dried with compressed air.

As pitting corrosion is associated with materials of a much higher cost than carbon steel, correct selection or testing of potential materials prior to purchase under fully representative conditions is advised.

A.10.4 Relevance to Geothermal Wells

Pitting corrosion of stainless steels and nickel-base alloys is relevant for the geothermal situation due to the elevated temperatures and the presence of chlorides and the potential for other aggressive species including oxygen or H₂S.

The precautions outlined above concerning materials handling and welding should be regarded.



A.11 Oxygen Corrosion

Oxygen corrosion refers to corrosion of steel due to the dissolved oxygen content in water. The cathodic reaction mechanism is reduction of dissolved oxygen:



Oxygen corrosion of carbon steel is often relatively predictable. There are several corrosion prediction models based on mass transport of oxygen to the steel surface as the rate controlling step, for example the Berger-Hau and Oldfield - Todd models. These corrosion models are claimed to be reliable up to at least 120°C (Andijani and Turgoose, 2004). The models do not take into account any beneficial influence of scales or surface films on the steel, and can therefore be understood as upper bound limits.

Oxygen corrosion typically appears as general corrosion often with shallow, wide pit features. There may be enhanced attack related to local flow conditions.

A.11.1 Critical Factors

The key factors are dissolved oxygen content, flow velocity and temperature. Even ppb levels of oxygen can cause significant rates of attack on carbon steel at the temperatures of geothermal systems.

A.11.2 Prevention / Mitigation

The systems and practices should be designed to minimise oxygen ingress. Chemical treatment (oxygen scavenger injection) can be used for extra security to remove oxygen before reinjecting.

A.11.3 Relevance to Geothermal Wells

Geothermal well water is generally oxygen free from the producing well.

Experience from similar systems in oil and gas production shows that it is surprisingly easy for trace levels of oxygen to enter surface systems even if they are closed systems. ISO 21457 notes that although the internal system pressure exceeds the external pressure, this does not alleviate the risk of oxygen ingress, because the concentration of oxygen in the atmosphere greatly exceeds the concentration internally. Hence, there is a concentration gradient from outside to inside and a driving force for oxygen ingress exists in spite of the pressure difference.

This is a relevant threat especially for the injection side of the system.

A.12 Chloride Stress Corrosion Cracking

Chloride Stress Corrosion Cracking (CI-SCC) is characterised by surface initiated cracks under the combined action of tensile stress, temperature and an aqueous chloride environment. The presence of dissolved oxygen greatly increases the threat of cracking.

The common 300-series austenitic stainless steels (grades 304, 316 etc) are among the most susceptible materials to this form of cracking. Higher alloy austenitic stainless steels, duplex stainless steels and nickel-base alloys are more resistant, but not immune. Note that martensitic stainless steels are not susceptible (e.g. 13Cr alloys, F6NM etc).

Chloride stress corrosion cracking is often an external damage mechanism, especially in piping and equipment operating at temperatures above ambient. However, internal CI-SCC is also possible.

A.12.1 Critical Factors

- Chloride content, temperature, stress and a susceptible alloy composition are the critical factors.
- Oxygen is involved in the majority of cases of CI-SCC, but is not absolutely necessary: field cases are known in extreme conditions without oxygen (extremely high chloride concentrations, high temperature).
- The nickel content of the stainless steel or nickel-base alloy has a major effect on resistance. The greatest susceptibility is at a nickel content of 8% to 12%. Alloys with nickel contents above 35% are highly resistant and alloys above 45% are nearly immune.
- Carbon steels, low alloy steels and 400-series stainless steels are not susceptible to CI-SCC.
- The presence of external insulation on a sensitive material can increase the risk of external chloride stress corrosion cracking. Likewise, any poor design features for supports etc that allow wetting / drying cycles and concentration of chlorides.

A.12.2 Appearance of Damage

Because the cracks are very fine the material may show no visible signs of corrosion. The first indication may be by leakage. Surface breaking cracks can occur from the process side or (more commonly) the external side. Heat affected zones near welds often are the first locations to show cracking.

A.12.3 Prevention / Mitigation

The mechanism is best prevented through design:

- Use of resistant materials based on temperature and other environmental conditions.
- Properly applied coatings and insulation to mitigate external CI-SCC.
- Design details for supports, clamps etc.



As good practice, oxygen ingress to Wells should be avoided, either in the process stream or in any fluids introduced in the well. If halide brines are used in the Well as annulus fluids etc, the brine should normally be treated with oxygen scavenger and in some cases with additives to control the pH (requirements differ with different brine types – supplier recommendations should be followed).

In principle, cracks can be detected by dye penetrant inspection and by UT techniques. Practically, inspection cannot be relied on to detect cracking in advance of failure. One issue is that cracking can be fast once it has initiated.

A.12.4 Relevance to Geothermal Wells

External CI-SCC may be a threat for specific wellhead and surface equipment.

CI-SCC is very unlikely in the internal environment with normal design features and under normal operating conditions.



A.13 Atmospheric Corrosion

Atmospheric corrosion is a form of corrosion that occurs from moisture associated with atmospheric conditions. Marine environments and moist polluted industrial environments with airborne contaminants are most severe. Dry rural environments cause very little corrosion. Carbon steel and low alloy steels are affected. Lower grade stainless steels and other materials such as aluminium and copper-base alloys may also be affected to varying degrees.

A.13.1 Critical Factors

- Critical factors include the physical location (industrial, marine, rural); moisture (humidity), particularly designs that trap moisture, presence of salts, sulphur compounds and dirt.
- Corrosion rates increase with the process-side temperature up to about 120°C. For process temperatures above about 120°C, the exposed surfaces are usually too dry for corrosion to occur.

A.13.2 Appearance of Damage

The attack is general over all exposed surfaces, but in practice, exposure is often limited to local coating flaws or coating damage. In carbon steels, atmospheric corrosion is often characterised by red rust corrosion products (hydrated iron hydroxide).

A.13.3 Prevention / Mitigation

Coating is the most commonly used method.

A.14 Corrosion Under Insulation (CUI)

Corrosion under Insulation (CUI) describes corrosion that is associated with insulation or fireproofing. The insulation can trap water and prevent surfaces from drying-out naturally, while also maintaining higher temperature than on bare surfaces which tends to increase corrosion rates. Insulation may also be a source of chlorides. CUI includes atmospheric corrosion of carbon steel and low alloy steels, and also CI-SCC of stainless steels.

A.14.1 Critical Factors

- Corrosion rates increase with increasing process temperature up to the point where the water evaporates quickly and surfaces are permanently dry, approximately 120°C. So geothermal systems are operating within the temperature range for CUI.
- Design of the insulation system, insulation type, temperature and environment are critical factors; poor design and / or installations that allow water to become trapped will increase the threat of CUI.
- Cyclic thermal operation or intermittent service can increase corrosion.
- Early detection is difficult due to the presence of insulation shielding the metal surface.

A.14.2 Appearance of Damage

Appearance is generally as for atmospheric corrosion or CI-SCC as applicable.

A.14.3 Prevention / Mitigation

Mitigation is primarily based on using high quality coatings (often immersion grade). Maintaining the insulation, sealing and vapour barriers to minimise water ingress under the insulation is important, although experience suggests that it is almost impossible to prevent water ingress completely.

Where practical, insulation for personal safety can be avoided and replaced by screens or cages.

Inspection is problematic without stripping the insulation. Thermography (detecting cold-spots associated with water presence) can be effective for larger facilities. Otherwise, inspection usually is concentrated on high risk locations such as low points, locations with damaged insulation etc. There are special probes that can be installed under insulation to detect wetness.

A.14.4 Relevance to Geothermal Wells

CUI is relevant to topside equipment that will often be insulated for heat retention and/or personal safety.

A.15 Scaling

All geothermal fluids contain dissolved solids and chemicals, the amount of which varies considerably between the geothermal facilities around the world and even within wells from the same reservoir. These materials are dissolved in the formation water under conditions of elevated temperature and pressure. When use is made of low enthalpy geothermal resources, the formation water is brought to the surface and the heat is transferred to a second working fluid in a heat exchanger.

As the geothermal fluid rises in the well the physical (temperature and pressure) and chemical properties (due to degassing) change and this can lead to the deposition of a scale on the casing walls. In addition, the solubility of most compounds in the fluid is lower at lower temperatures and as the geothermal fluid is cooled in the heat exchanger there is the possibility of depositing some of the dissolved species as a scale within the heat exchanger and downstream equipment and injector well.

The effects of scaling on corrosion can be both detrimental and beneficial. Scaling itself is not necessarily a corrosion process but the deposition of a semi-adherent or incomplete scale can lead to some of the mechanisms already discussed including; Under Deposit Corrosion, Crevice Corrosion and Galvanic Corrosion (due not actually to scaling but from lead or copper deposition). If, however, an adherent and complete scale is formed then it can act as a barrier to corrosion processes and limit degradation of the metal substrate, in which case it can be considered a beneficial process - providing that the scale does not limit flow by growing so thick as to restrict or prevent liquid flow.

The process of scaling is discussed in further detail in the Literature Review.

Appendix B Material Options for Well Tubulars



B.1 Introduction

This section concentrates on the materials used for well tubulars, as this is the major material selection decision for the geothermal well design. Typically, the same materials are used for joints, pup-pieces and other well equipment manufactured from tubular stock. Materials for other equipment items are normally chosen based on compatibility with the tubing material. Therefore reference is made to some materials used only for equipment components.

The primary standards for tubular components are API 5CT / ISO 11960 and API 5CRA / ISO 13680, which define standard material grades, manufacturing requirements and dimensions.

Various material options are available for well tubulars. The application requires that the material used for the tubulars is of sufficient strength and is amenable to forming threaded connections. The material options include the following types:

- Carbon and Low Alloy Steel
- 13Cr Super Martensitic Steels
- Duplex Stainless Steels
- Nickel Alloys
- Weld-Overlaid / Clad and Alloy Lined Carbon Steel
- Non-Metallic Materials

The material options are detailed in the following subsections.



B.2 Carbon and Low Alloy Steels

Carbon steel is the base case tubing material and lowest capital cost option but may require the use of chemical inhibition to reduce corrosion rates to acceptable levels. Although there are variations in the chemical composition, microstructure and other properties of different carbon steels, the impact on their corrosion behaviour is usually small in comparison with the effect of external environmental factors.

Low alloy steels contain up to 5wt% of deliberate alloying additions such as Cr, Ni, Mo. Examples include AISI 4130 and ASTM A182 F22. These steels are widely used for equipment items primarily for their high strength and toughness. Although the corrosion resistance is better than carbon steel, this is not usually the determining factor in selection.

Because API 5CT tubing grades K55 and N80 have no limits specified for Ni, Cr, Mo, it is possible that these grades can be supplied as carbon steel or as low alloy steel depending on the manufacturer's preference.

Steels with low chromium additions in the range 1-5% Cr have been developed for use as tubing, primarily for improved corrosion resistance compared with carbon steel.

B.2.1 1%Cr Tubing

Tubing with 1%Cr has a niche application for water injection service due to the improved resistance to oxygen corrosion compared with carbon steel. Some operators have found lower corrosion rates and longer lifetimes for 1%Cr steel compared against carbon steel by factors of 2-4 times and recommend 1%Cr as the standard material for deaerated water injection. At higher temperatures typical of geothermal systems, the relative difference versus carbon steel may be even greater.

However, when corrosion inhibitors are the primary means of mitigation there is no evidence that 1Cr alloys provide any advantage over standard tubing grades. This is the case in the Dutch Geothermal wells. Therefore, 1%Cr alloys are not recommended as a default choice.

Downhole tubing with 1%Cr is available from several tubing suppliers.

B.2.2 3-5% Cr Tubing

Steels with around 3% Cr have been developed for tubing grades with the intention of achieving a worthwhile improvement in resistance to CO₂ corrosion compared with carbon steel to compensate for the additional alloy cost. These 3-5% Cr grades typically show the most favourable comparisons with standard carbon steels in sweet conditions and at moderate to high flowrates. WGI experience during materials selection exercises (both field and laboratory tests) is that 3Cr alloys had good performance in wellhead flowing conditions, but had worse performance than standard carbon steel tubing in static conditions, in particular displaying lower general corrosion rates but more severe pitting compared with carbon steel.

The practical window of application for these alloys in production service is therefore with relatively low CO₂ partial pressures, up to about 1-2 bar CO₂. A case by case analysis is

necessary to determine if there is a genuine advantage. In the typical geothermal case with small numbers of wells, the extra cost and the procurement overheads in using proprietary, non-standard materials will make these materials less attractive.

There is no benefit with 3%Cr steel if using chemical inhibition.

B.2.3 Higher Alloy Steels

9Cr-1Mo alloy steel has some limited use for equipment items, primarily based on mechanical properties. API 5CT includes a 9Cr-1Mo steel, grade L80-9Cr but this is rarely used for tubing or casing. The martensitic 13Cr grades (see below) offer a more cost-effective option for most applications.

Higher alloy steels such as 3%Cr and 9Cr-1Mo are all prone to pitting and crevice corrosion in saline waters with trace oxygen content.



B.3 Martensitic Stainless Steels

B.3.1 Standard 13Cr steels

The basic martensitic stainless steel tubing grade is API 5CT L80-13Cr which contains 11.5-13.5wt% Cr and no other alloying elements. Some manufacturers also offer higher strength versions (and occasionally lower strength versions), although only the 80 ksi strength grade is included in API 5CT. Similar grades used for other product forms are include AISI 410 or AISI 420.

Like low alloy steels, martensitic stainless steels are manufactured by a quenching and tempering process, which allows relatively high strength. The processing and handling requirements are more similar to those for low alloy steels than those for higher alloy stainless steels, which keeps the manufacturing costs relatively low. Coupled with the lean alloy composition, the standard 13Cr grades are usually a significantly lower cost material than other stainless steels or corrosion resistant alloys.

The standard 13Cr grades are widely applied for downhole tubing and the limitations of their use are well defined. 13Cr martensitic stainless steels are highly resistant to CO₂ corrosion in oxygen-free conditions, Figure B.1. As can be seen, the salinity has a strong effect on the maximum allowable temperature, while the sensitivity to CO₂ content is less marked (Craig and Smith, 2011).

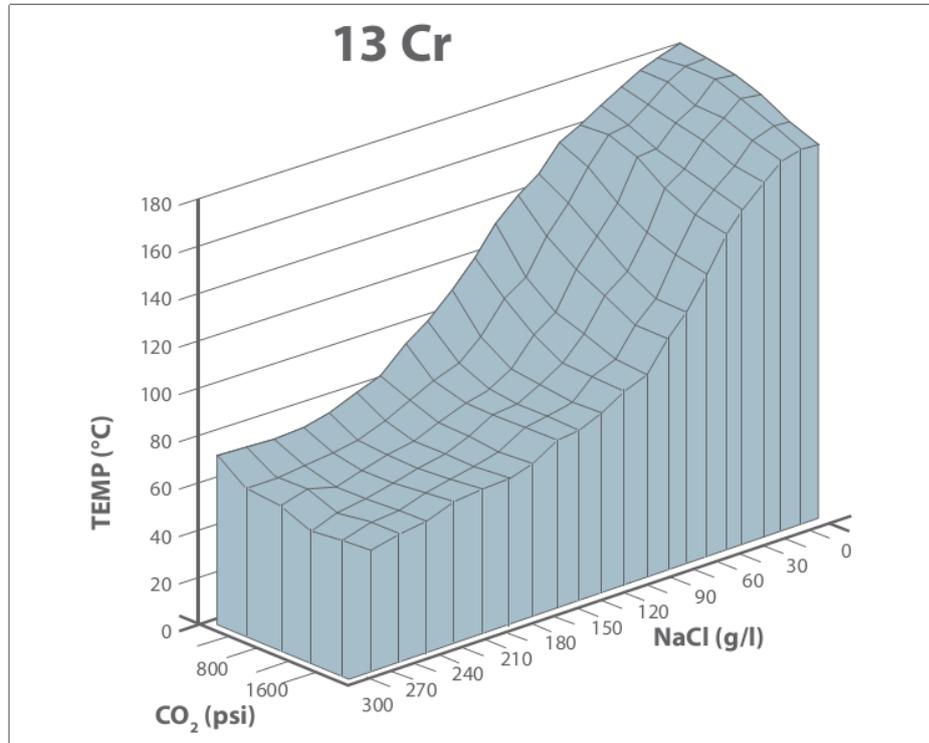


Figure B.1 Service limits for 13Cr Martensitic Stainless Steels in Oxygen-free Service

B.3.2 Other Martensitic Stainless Steels

In addition to the standard 13Cr MSS, there are a variety of more higher alloyed 13Cr martensitic stainless steel grades, often these are referred to as “super-martensitic stainless steels” (SMSS) or S13Cr. All have lower carbon content compared with L80-13Cr, typically 0.03wt% or less, and there are additions of Ni and Mo, and in some cases smaller amounts of other elements such as Nb, V and N. It is possible to distinguish two broad classes used for well tubing and equipment:

- “Modified grades”, about 13Cr-4Ni-1Mo
- Higher alloy grades with about 13Cr-5Ni-2Mo

Tubing grades are generally proprietary materials with minor differences in composition from different suppliers.

The S13Cr grades offer higher yield strength and improved toughness compared with standard 13Cr material. The higher Cr and Mo content in the material provides improved corrosion resistance in sweet conditions and a higher maximum temperature limit, perhaps 20-30°C higher temperature than shown for standard 13Cr in Figure B.1.

The martensitic stainless steels have been developed further with the introduction of steels with higher levels of Cr (nominally 15wt% or 17wt% Cr). Although loosely referred to as “martensitic”, the microstructures of these alloys may have substantial fractions of ferrite, and they can be regarded as dual-phase or duplex materials. The principal benefit of the higher chromium content alloys is that they can provide higher yield strength (125 ksi) with further improved corrosion resistance at high temperatures compared with S13Cr; the temperature limit could be as high as 200°C in suitable environments. The 15%Cr and 17%Cr alloys are relatively new and service experience is very limited to date. These materials are unlikely to be required for low enthalpy geothermal applications.

Equipment items may use precipitation-hardened martensitic stainless steels, such as 17-4PH (UNS S17400). These are typically selected where higher mechanical strength is needed, with reasonable toughness and corrosion resistance. One example application of 17-4PH is for valve stems. The corrosion resistance is broadly similar to S13Cr grades.

B.4 Austenitic Stainless Steels

The basic austenitic stainless steels such as grades 304 and 316 have relatively low strength and are not used for well casing, tubing or major well components. However, they are common candidate materials for internal trim and accessory items. Small diameter tubing for chemical injection, instrumentation and control lines is often in austenitic stainless steel, as are the wire-mesh parts of sandscreens.

The Mo content is important in austenitic stainless steels to give resistance to pitting attack especially in saline environments. Therefore the grade 304 (UNS S30400) and similar grades without Mo addition should be avoided for handling saline water. The minimum grades that should be considered for geothermal service are 316 / 316L type (UNS S31600 / S31603).

The service limits for Grade 316 in oxygen-free conditions are shown in Figure B.2.

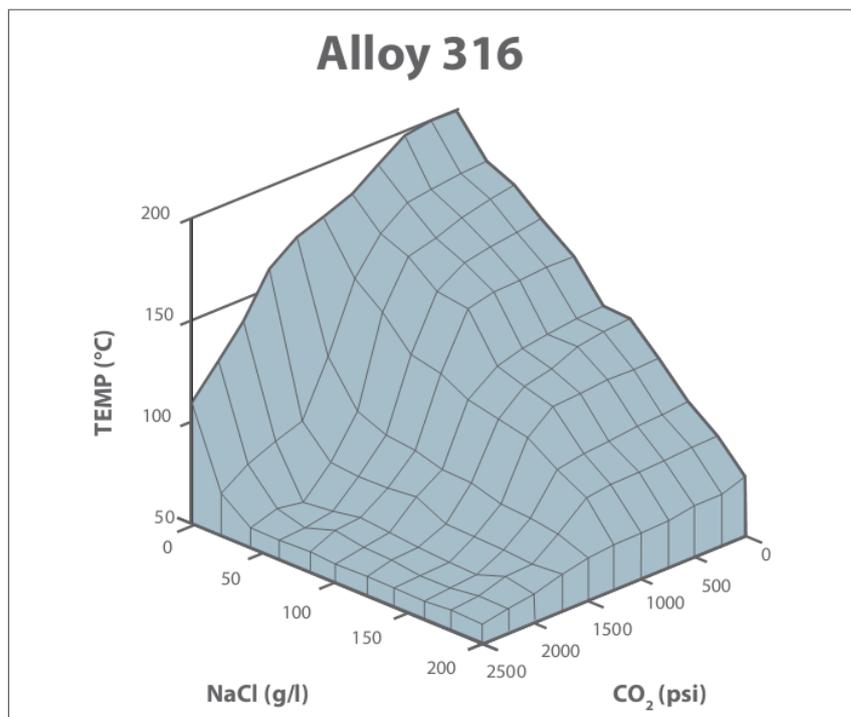


Figure B.2 Service limits for 316 Stainless Steel in Oxygen-free Service

B.5 Duplex Stainless Steels

The main duplex stainless steels used for downhole tubulars are “22Cr” alloys (S31803 type) and a variety of “25Cr” or super-duplex alloys (for example S31260, S32750, S32760, S32550). 22Cr and 25Cr Duplex Stainless Steels are highly resistant to corrosion in sweet environments and show little sensitivity to the partial pressure of CO₂. The service envelope for 22Cr duplex in sweet, oxygen-free conditions is beyond the Dutch Geothermal conditions by comfortable margins. The service limits for 22Cr in oxygen-free conditions are shown in Figure B.3.

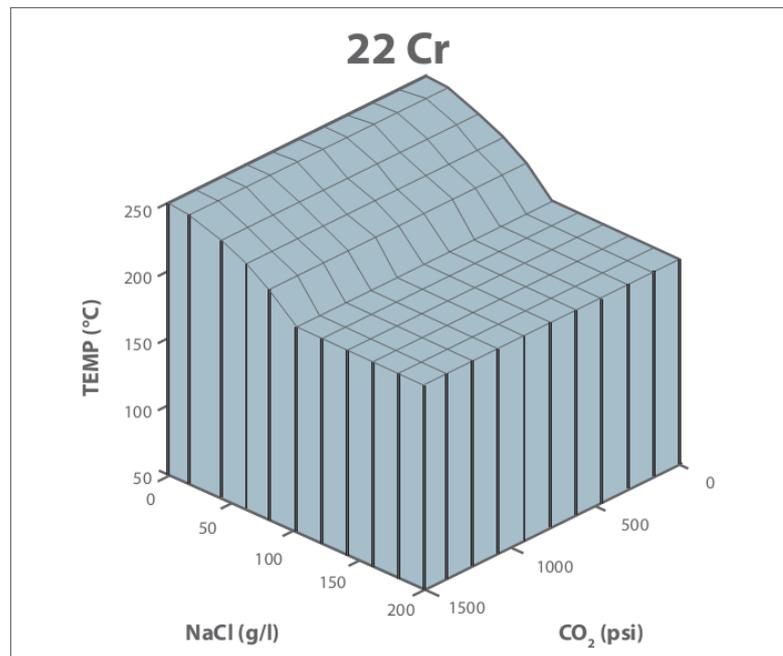


Figure B.3 Service limits for 22Cr Stainless Steel in Oxygen-free Service

B.6 Higher Alloy Materials

More highly alloyed stainless steels (e.g. Alloy 28, N08028) and nickel alloys such as alloy 825 (N08825) or Alloy 625 (N06625) are used for extreme conditions with high temperature and / or high H₂S levels. These are not relevant for the Dutch low enthalpy geothermal wells. Equipment suppliers may specify high alloy materials for sub-components or trim in some cases.

There is some use of titanium tubulars in geothermal wells but these tend to be high temperature steam producing wells rather than the low enthalpy wells such as those in the Netherlands. Titanium is extremely unlikely to be cost-effective for low-enthalpy geothermal production.

B.7 Stainless Steels and Nickel Base Alloys in Oxygen-containing Conditions

Although the geothermal water system is not open to atmosphere, trace oxygen levels are reported in some water analyses, and ingress of oxygen is a possibility in the surface system. This section therefore considers behaviour in saline waters and with oxygen levels well below saturation. Reference is made to behaviour in seawater (salinity about 3.5wt %, pH about 8.0) which is well documented for many materials. Geothermal waters will be more or less aggressive depending on salinity, pH, temperature and oxygen content.

The resistance of different stainless steels to pitting or crevice corrosion in oxygen containing conditions can be ranked by the pitting resistance number (PREN). It is calculated from the composition of the alloy:

$$\text{PREN} = \%Cr + 3.3\%Mo + 16\%N + 1.65\%W \quad (\text{ISO 21457 definition})$$

Standard 13Cr martensitic stainless steels (PREN ~ 12) are extremely prone to pitting and crevice corrosion in saline water with almost any trace level of oxygen even at ambient temperature: several ppb (parts per billion) dissolved oxygen is enough to cause pitting corrosion. S13Cr martensitic stainless steels (PREN ~ 15-18) are not much better in practice. Local penetration rates can be extremely rapid and there is practically no safe limit for these materials. The only exception is that single equipment items or single tubing joints in 13Cr attached to carbon steel tubing are galvanically protected by the carbon steel and may not suffer pitting.

Evans et al. (2004) studied several materials in seawater with low oxygen contents, the diagram below summarises their data.



TABLE 3. SUMMARY OF RESULTS BY TEST MATERIAL.

Test Condition	30°C (pH ~7.5)				60°C (pH 5.5-6)			
	20 ppb Oxygen		200 ppb Oxygen		20 ppb Oxygen		200 ppb Oxygen	
	Flow	Static	Flow	Static	Flow	Static	Flow	Static
Carbon steel	G	NT	G	NT	G	NT	G&F	NT
Electroless nickel plated steel	U	U	U	U	U	U	U	U
1%Cr low alloy steel	G	NT		NT	M	NT	M	NT
3%Cr low alloy steel	P	P&D	P	P	P	P	P	P
13%Cr	P&C	P&C	P&C	P&C&D	P&C	P&C	P&C	P&C&D
13%Cr alloy-1	P&C	P&C	P&C	P&C	P&C	P&C	P&C	P&C
13%Cr alloy-2	NT	P&C	NT	P&C	NT	P&C	NT	P&C
316L	C	C	C	C	C	C	C	C
22%Cr duplex							C	
25%Cr superduplex								
17-4PH	P		P&C	P&C	C	C	P&C	P&C
Alloy 718		NT		NT		NT		NT

Notes:

- All results relate to uncoupled specimens.
- Black fill indicates any pitting or a corrosion rate on bore surfaces in excess of 1 mm/year.
- Light grey fill indicates no pitting and a corrosion rate on bore surfaces less than 0.1 mm/year
- Dark grey fill indicates borderline behaviour.
- NT denotes no test conducted.
- U denotes undercutting beneath nickel plate.
- G denotes general corrosion.
- M denotes mesa-style corrosion.
- P denotes pitting corrosion.
- C denotes crevice corrosion.
- D denotes under deposit corrosion.

Figure B.4 Materials Behaviour in Seawater with Low Oxygen Contents (Evans, 2004)

22Cr duplex stainless steel (PReN ~ 34) is the minimum material usually applied in deaerated seawater injection systems, which may have a target 10-20 ppb dissolved oxygen. Alloys with PReN of more than 40 such as super-duplex and super-austenitic stainless steels are used in more corrosive conditions, including with raw seawater within strict temperature limits.



B.8 Non-Metallic Materials

B.8.1 Solid Glass Reinforced Polymer (Fibreglass) Tubing

At moderate temperature, glass reinforced epoxy (GRE) is very resistant to both water and to chlorides, oxygen and CO₂. There are a large number of onshore wells worldwide completed with fibreglass tubing, mostly for shallow water source and water injection wells, but also some wells handling high concentrations of CO₂. There is some use for casings and casing repair, for example where the ground waters are especially aggressive.

The main drawbacks relate to the mechanical properties. GRE tubing has very limited strength, low stiffness and low strain to fracture (i.e. poor ductility) compared with steel tubing. Compatibility with metallic downhole equipment can be a problem, for example the local sealing forces developed by conventional packers. At high pressures such as at contact points and seals, GRE tubing is prone to creep to a much greater extent than metallic materials. This is especially true in higher temperature applications.

Although the corrosion properties are very attractive, there are some particular limitations to use as downhole tubing for geothermal wells:

- Low mechanical strength and stiffness.
- Limited temperature envelope (especially when load-bearing).
- Long-term creep affecting the integrity of packers and other sealing elements in the well.

The applications of Glass Reinforced Epoxy materials in central geothermal heat systems are increasing for surface piping more than for downhole tubing due to their high corrosion resistance, ease of installation and short assembly times, longer service life and low operating costs (Kaya et al, 2005). In surface applications, the low mechanical strength and stiffness can be managed to some extent by appropriate pipe supports and there are suitable flange joint systems to make transitions from GRP to metal equipment.

B.8.2 Internal Organic Coatings

Coatings are generally thinner than linings and typically applied by spray, or by powder coating. Organic coatings can be applied to improve flow or to mitigate scaling or waxing, indeed some coating suppliers promote them primarily for these purposes rather than for corrosion prevention. Epoxy-novolac coatings are available which are chemically resistant to H₂S and other well environments, with maximum service temperatures of around 200°C. There are a variety of other formulations with different degrees of chemical and temperature resistance. Fluoropolymer-based coatings have low friction and smooth surface properties, but are relatively soft and therefore more susceptible to mechanical damage.

There are some potential limitations that should be considered in selecting coatings:

- There is a possibility of holidays in the coating, resulting in localised corrosion.
- Coatings are easily damaged at the pin-ends and connections on installation.



- Intervention tools tend to damage coatings.

In practical use, coated carbon steel tubing has generally proved unsatisfactory in corrosive services. The lifetime is limited by pitting corrosion at the inevitable coating holidays or at handling damage. Many Operators who have tried coatings, consider that they provide no extension to life-time in practice. In one example, analysis of historic data for water injector wells by WGI, there was no difference in the proportion of failures comparing wells with coated tubulars and with uncoated tubulars.

Coatings may have a use in mitigating scaling, and occasional coating defects are less critical for this purpose.

B.8.3 Thermoplastic Liners

Thermoplastic liners can be inserted in tubulars by swage-lining processes: in the simplest form of the process, a polymer tube is pulled through a die or fed through rollers into the steel tubing and expands to fit the tubing more or less tightly once the tension is released³.

HDPE (high density polyethylene) is the most common material and this has a limited maximum service temperature of about 60-80°C. The process is also possible, although more difficult, with higher performance polymers, and liner products are marketed based on polyphenylene sulphide (PPS) and polyetheretherketone (PEEK). Maximum service temperatures as high as 170°C (PPS) and 260°C (PEEK) are claimed for these products, based on the “continuous service temperature” of the polymers. In practice, the service window is likely to be limited by other considerations such as the performance of joint fittings. PPS and PEEK are much more expensive than HDPE and more difficult to process as liners.

The main applications for HDPE liners are in low pressure and low temperature wells, which could include the injection side of geothermal systems at circa 40°C. Liners can be useful in rod-pumped wells to reduce tubing wear and extend tubing life. They are also widely used in on-shore water injection or water-alternating-gas (WAG) injection wells. Often the lined tubing is competing with bare CS tubing, with the aim to reduce the frequency of tubing replacement. In the simplest applications where the main issue is abrasive wear rather than corrosion, a special connection design is not always used, a butt-fit of the liner at the each tubing joint is adequate. For corrosive services coated couplings are offered as well as coupling insert rings.

Polymer linings may also be advantageous in mitigating scale formation.

There are potential limitations that should be considered in selecting thermoplastic liners:

- Lining is relatively thick, reducing the bore area (although the low friction properties of polymer mitigates the effect on well production to some extent).
- Polymer liners are permeable to both gases and water. Especially in higher pressure wells, gas permeation behind the liner is a potential threat, resulting in delamination and the risk of internal collapse if there is a sudden drop in pressure. This risk will be

³ Suppliers include Western Falcon (www.westernfalcon.com) and Swagelining Ltd (www.swagelining.com).



greater at higher temperatures due to the lower mechanical strength and stiffness of the polymer and the higher permeation rates of gas.

- In the long term, some corrosion may occur behind the liner.
- Lack of proven high integrity fittings for connections.
- Equipment and fittings are not protected - liners only protect the inner bore.

B.8.4 Glass Reinforced Epoxy (Fibreglass) Liners

GRE liner systems consist of a rigid GRE tube, bonded to the steel tubing. Various designs of insert rings are available to protect the connection area, or alternatively coated or CRA clad pin-ends and couplings have also been used. Suppliers include Tuboscope NOV (TK – liner), Composite Lining Systems (GlassBore), and Duoline Technologies (Duoline).

Typically GRE liners have been applied at service temperature of up to about 120°C. Systems with specially designed epoxy resins can tolerate higher temperatures up to about 170-180°C, although the higher temperature epoxy resins tend to be more brittle at ambient temperature and therefore more susceptible to handling and installation damage.

The most frequent application is in water source, water injection and WAG services, as GRE is good at handling saline, poorly deaerated and corrosive waters that would otherwise require very expensive high alloy stainless steels or nickel-base alloys. GRE liners have proved very successful in these applications, which are broadly similar to the geothermal well producers or injectors. Historically there were issues with the connections, but these are now resolved with improved connection designs. There is some limited use in production conditions. H₂S concentrations of several mol% have been handled successfully, although the maximum operating temperature may be reduced because H₂S chemically attacks the resin at high temperature.

Haarman and van Strien (1999) document the use of GRE-lined tubulars used in geothermal applications in France since 1989, identifying that despite the higher cost, the overall life cycle cost was reduced because of the lack of corrosion control needed. They note that it carries the downhole pump. Longer term performance is not known. The excellent flow characteristics cause an increase in the flow capacity and the pump-efficiency and diminish the scale build-up.

The GRE liners have reasonable tolerance to wireline operations and intervention tools, more so than thin organic coatings. Asiri et al (2014) remark that the installation of GRE lined tubing stopped scale build up. Carbon steel wells had built up corrosion product scales, so the combination of the lack of corrosion and good smoothness of the GRE surface reduce, and potentially prevent, scaling accumulation.

Limitations that should be considered in selecting GRE liner systems are:

- The liner reduces the tubing bore area, although the low friction properties of the liner mitigate the effect on flow to some extent.
- Equipment and fittings are not protected. The liner only protects the inner bore of the



tubing.

- The potential for damage during installation or during well interventions (e.g. pulling and replacing ESP's).

B.8.5 Thermoplastic-Fibre Composite

Thermoplastic composite tubing consists of a polymer inner sheath, and layer of fibreglass carbon-fibre or Kevlar tapes for strength and an outer protective sheath, all fused together. Advantages are: good chemical resistance, especially for water, oxygen, chlorides; high strength to weight ratio and good fatigue properties; good toughness; the ability to manufacture continuous lengths which could dramatically simplify running well completions. Thermoplastic composite is much more flexible and tough, resistant to impact damage etc., than GRE. Thermoplastic composite tubing is under development for some oil and gas applications, including surface piping and coiled tubing for well interventions⁴.

Although the corrosion properties are very attractive, especially for handling saline water, there are some particular limitations to use as downhole tubing:

- Joint designs and terminations are problematic; there can be problems with interfaces to other well equipment.
- If not jointed, there are practical limits to the transport of continuous lengths on reels at normal tubing and casing diameters.
- Long-term creep affecting the integrity of packers and other sealing elements in the well.
- Lack of track record.

The capital cost is likely to be high compared with carbon steel.

⁴ For example Airborne (www.airborne-oilandgas.com) and Magma (www.magmaglobal.com)



B.9 Weld-Overlaid, Clad and Alloy Lined Carbon Steel

There are many techniques for weld overlaying, cladding or lining carbon steel with a corrosion resistant alloy material but all of them involve the bonding together of dissimilar metals to produce a composite pipe material that has the benefit of significantly improved internal corrosion resistance of the high alloy CRA with strength being provided by the cheaper carbon steel outer material. The use of carbon steel reduces the overall requirement for the more expensive CRA, especially for very high pressure systems and large diameter piping or vessels.

There are no manufacturers of downhole tubing which is internally clad as it has not proven to be cost effective to produce relative to solid 13Cr or other stainless steel tubing materials.

Schnaut et al, 2011, describe the use of CRA lined pipe at California's superheated brine Salton Sea geothermal power plant where CRA lined pipe was used to replace carbon steel that had experienced corrosion rates of 10-15 mm/y in the environment of dissolved CO₂ up to 4,800 ppm, H₂S up to 50 ppm, 300°C and 4MPa pressure. Similarly, clad and weld overlaid piping have been used for transporting high pressure produced fluids in the oil and gas industry. However, for low pressure systems, the cost of producing and welding them is higher than solid alloys and so they would not be a cost effective option for a low pressure geothermal installation relative to use of a conventional solid metallic CRA or carbon steel options.

This materials selection option is not considered to be commercially viable for the Netherlands low enthalpy geothermal industry. The only exception is the use of small amounts of weld overlay on sealing surfaces of flanges or valves etc., where the CRA material is deposited precisely where it brings technical benefit.

Appendix C Literature Review

C.1 Geothermal Energy in the Netherlands

Geothermal energy is energy that is derived from the heat of the earth usually by means of either hot water or steam. Hot groundwater at depth in the subsurface of the Earth is a source of energy that is exploited in numerous countries, including the Netherlands, for the production of heat supplies to businesses and homes. In the Netherlands geothermal water is at a temperature of 45-120°C, at aquifers depths of between 1.5 to 4 kilometres. This type of geothermal energy is classed as low enthalpy as opposed to high enthalpy geothermal which is associated with dry steam at temperatures up to 450°C in locations such as Iceland and New Zealand.

According to www.NLOG.nl as of January 2016 there are fourteen geothermal installations classified in the Netherlands, with one of these installation, Heerlerheide, being a heat / cold storage facility.

Geothermal installations are termed doublets as they consist of two wells, a production well producing the hot water from the aquifer and an injection well pumping the cooled water back into the aquifer; heat extraction takes place between the wells. Most of these installations are located in the southwest of the Netherlands. The heat produced by the installations is predominantly used for heating commercial greenhouses.

Small amounts of hydrocarbons can sometimes be co-produced with the formation water. In most installations the hydrocarbon is gas but oil is produced in one installation as well. In addition to hydrocarbon gas, carbon dioxide gas can also be produced. Gases are usually dissolved in the formation water and released when the pressure of the production water in the production installation falls below the 'bubble point'. According to NLOG, five installations have reported the production of hydrocarbon gas. Carbon dioxide is produced in all installations and represents the biggest corrosion threats to the integrity of the doublets. In many locations the water is highly saturated with dissolved solids and so there is also a risk of scale formation.



C.2 Formation Water and Gas Chemistry

Formation water chemistry is a complex variable. Formation water chemistry can vary over short distances due to the geology of the well. Wells within the same reservoir can show different water chemistries. In addition there is a tendency for salinity to increase with depth. It should be considered that each geothermal doublet and installation is unique in respect of formation water composition, temperature and pressure.

Adding further to the complexity of the well fluids is the gas that is associated with the formation water. Gas chemistry also differs between wells due to varying geological circumstances.

Figures C.1 and C.2 are laboratory analyses of water chemistry and gas composition produced for a well in the Slochteren reservoir in January and March 2016 respectively. They are provided here for information purposes as an example of formation water composition.

Degassing is the term given to the thermodynamic process involving a drop in gas pressure from that at reservoir depth (due to hydrostatic pressure), to the lower pressure at which the surface system operates. Degassing occurs only if the gas solubility of the fluid is lower than the existing gas content - Frick et al (2011).

During degassing the dissolved gas separates from solution and creates a gas phase. Once a gas phase exists, degassing / evaporation or dissolution / condensation continues towards an equilibrium of partial pressures and saturation pressures. Due to the different densities of the phases, even the degassing of small amounts of gas can cause a significant increase of the volume gas fraction. The presence of a gas phase in liquid flow lowers the effective density of the medium which will lead to an increase of the fluids mean velocity and therefore an increased wall friction.

Degassing raises the pH and therefore decreases the corrosion rate but conversely causes the precipitation of carbonate minerals (scaling).

Analytical Report

This sample was analyzed as received, the results being as follows:

Sampling point: Geothermo Well Geothermal 1

Water

thod: AMW0013		Total
Aluminum (Al)		<0.5 mg/L
Antimony (Sb)		<0.5 mg/L
Barium (Ba)		4.6 mg/L
Boron (B)		28 mg/L
Cadmium (Cd)		<0.1 mg/L
Calcium (Ca)		9400 mg/L
<i>Calcium (CaCO3)</i>		23000 mg/L
Chromium (Cr)		0.1 mg/L
Copper (Cu)		<0.1 mg/L
Iron (Fe)		55 mg/L
Lead (Pb)		0.7 mg/L
Lithium (Li)		<1 mg/L
Magnesium (Mg)		1000 mg/L
<i>Magnesium (CaCO3)</i>		4300 mg/L
Manganese (Mn)		1.9 mg/L
Molybdenum (Mo)		<0.5 mg/L
Nickel (Ni)		0.2 mg/L
Phosphorus (P)		<1 mg/L
Potassium (K)		820 mg/L
Silicon (Si)		13 mg/L
<i>Silica (SiO2)</i>		27 mg/L
Sodium (Na)		47000 mg/L
<i>Sodium (CaCO3)</i>		100000 mg/L
Strontium (Sr)		500 mg/L
Vanadium (V)		1.2 mg/L
Zinc (Zn)		6.5 mg/L

Anions	Test Method: AMW0002	Filtered
Chloride (Cl)		110000 mg/L
Nitrite (NO2)		<200 mg/L
Bromide (Br)		250 mg/L
Nitrate (NO3)		<200 mg/L
Sulfate (SO4)		600 mg/L

Quality System Certified to ISO 9001



Authorized by Jan Roukema
Research Scientist

Figure C.1 Water Chemistry Analytical Report



Resultaat

De analysesresultaten en de berekende fysische grootheden uit de samenstelling hebben de onderstaande waarden. De m³ wordt gedefinieerd bij 0°C (meetcondities) en 1013.25 mbar. De energie in MJ is herleid van de thermodynamische waarden van 25°C (verbrandingscondities) tot 0°C en bij 1013.25 mbar volgens ISO 6976.

Component	Molprocenten	Onzekerheid (mol%)	
Helium	0.228	0.002	
Argon	0.069	0.001	
Waterstof	0.11	0.01	
			19
Stikstof	14.71	0.07	
Kooldioxide	8.16	0.03	
Koolmonoxide	-	-	
Methaan	75.06	0.07	
Ethaan	0.986	0.005	
Propaan	0.0821	0.0004	
Isobutaan	0.00540	0.00008	
Butaan	0.00497	0.00009	
neo-Pentaaan	-	-	
isoPentaaan	-	-	
n-Pentaaan	-	-	
cyclopentaaan + 2,3-dimethylbutaan	-	-	
2,2-dimethylbutaan	-	-	
2-methylpentaaan	-	-	
3-methylpentaaan	-	-	
n-Hexaan	-	-	
C7-KWS	-	-	
C8-KWS	-	-	
Benzeen	0.0093	0.0001	
Tolueen	0.00105	0.00002	
Fysische grootheden:			
Calorische onderwaarde	27.69	0.03	MJ/m ³
Calorische bovenwaarde	30.71	0.02	MJ/m ³
Wobbe-index (inf.)	33.03	0.03	MJ/m ³
Wobbe-index (sup.)	36.63	0.03	MJ/m ³
Dichtheid t.o.v. lucht	0.7029	0.0003	-
Soortelijke massa	0.9088	0.0004	kg/m ³
- < 0,001 mol%			
De fysische grootheden hebben een onzekerheid van maximaal 0.2 % relatief (k=2).			
Controle Kaarten volgens Kiwa Technology W1403.			
Datum laatste kalibratie: maart 2016. Primair Referentie Materiaal: NPL2013100302-01/-09			

Figure C.2 Gas Chemistry Analytical Report

To summarise the example formation fluid conditions from Figures C.1 and C.2:

- Chloride - 110,00mg/l
- CO₂ - 8.16 mol%
- H₂S - 0 mol%
- O₂ - 0.566 mol%
- N₂ - 14.71 mol%

It should be noted that O₂ is, in principle, absent from Dutch geothermal reservoirs and



producing wells so the presence of oxygen in this analysis suggests that the sample is taken at the surface and has had some air contamination. It is also possible that the oxygen content is indicative of contamination of the sample itself.



C.3 Corrosion Experience in Geothermal Installations in the Netherlands

This section of the report contains a brief summary of the corrosion experience in geothermal wells in the Netherlands.

Carbon dioxide and dissolved solids are the critical elements that cause corrosion and scaling issues in geothermal installations in the Netherlands. The general formation water conditions are:

- The temperature is generally quite low (between 65 and 100°C)
- Moderate to high salinity and total dissolved solids (80 - 190g/l)
- An appreciable amount of carbon dioxide (up to 8mol%)
- Hydrogen sulphide is not present
- pH range of 5 to 8 (note that the high pH value is probably due to degassing)

The predominant corrosion mechanism is CO₂ corrosion and the rate of this mechanism depends on a number of variables including pressure, temperature, the presence and quality of well cement, salts and chemicals in the brine, pH etc. For geothermal wells it is often observed that an initial high corrosion rate tends to decrease over time due to the formation of a passivating iron carbonate layer (corrosion product film). The formation of a protective, adherent iron carbonate layer tends to increase at temperatures above 65°C which tends to reduce the corrosion rate to an increasing extent for increasingly high temperature conditions. So the well may show lower corrosion rates with depth because of the increasingly adherent iron carbonate corrosion product film in the higher temperature bottom of the well.

Notable damage mechanisms in addition to CO₂ corrosion are discussed in the following sub-sections.

Damage to the 4½” Liner in the Honselersdijk System

Veldkamp (2016) describes a case of damage in the Honselersdijk system in which the well was blocked. The source of the blockage material came from damage to the 4½” liner in the depths between 2470 to 2500m, at a casing connector (BTC coupling).

Investigation of the failure initially suggested that it was erosion related, being caused by high local flow velocities in combination with vortices created as a result of the irregular internal surface of the BTC couplings. It was believed that such vortices could potentially lead to pipe erosion, especially in combination with solids or gasses in the fluid.

Veldkamp offers an alternative mechanism, that of crevice corrosion and considered it unlikely that flow rate induced erosion caused the damage to the production tubing based on a consideration of the estimated average flow velocity (5.7 m/s) being only marginally more than the API RP 14E value (5.5 m/s). Instead, crevice, galvanic or stress corrosion cracking on or near a connector (especially between connector and casing), enhanced by the

presence of CO₂, is suggested as a more likely cause of the damage.

From the limited information available, our view is that it is not bulk fluid flow erosion (which is what API RP14E focusses on) that has caused the failure but is, as first evaluated, local turbulence at the thread run-out of the connection. This is sufficient to remove iron carbonate scaling, exposing fresh steel to corrosion without any of the passivating effect of the corrosion product build-up. That is, this is an example of erosion corrosion.

Pijnacker-Nootdorp Zuid

Veldkamp (2016) also describes an issue in the doublet in Pijnacker-Nootdorp Zuid. In this case the ESP motor reportedly broke off the pump. Initially the cause of this failure was attributed to flow rate induced erosion which does seem to be a very plausible cause, but Veldkamp suggests that the failure was not erosion related but was actually caused by the low grade of the steel applied in the pump inlet; this corroded and led to the failure.

The mitigation was use of a higher grade steel (stated as 1410 chromium steel, assumed to be AISI 410 (1410 chromium) steel with Monel coating) and an improved high-flow inlet design.

There is reference to there being CO₂ corrosion elsewhere in the well. CO₂ corrosion is very influenced by flow velocity or shear conditions because it is often limited by mass transport of the reactants and the inlet and outlet regions of pumps are high risk locations for enhanced corrosion rates without a fundamentally different corrosion mechanism being involved. The detailed mechanism may involve enhanced removal of corrosion products or surface films and therefore could be described in the category of erosion-corrosion. Whether this is described as CO₂ corrosion, flow-influenced corrosion or erosion-corrosion is to some extent a matter of terminology.

Whatever the detailed damage mechanism may be, corrosion resistant alloys are more resistant to both corrosion and erosion-corrosion mechanisms than carbon steel and are highly recommended for pump inlet and outlet locations in our experience.

Lead Deposition

The deposition of lead in one of the Dutch geothermal doublets prompted research into the nature of lead deposition. Bressers and Wilschut (2014) investigated the electrochemical reactions between the metal parts of a geothermal installation and the formation water which could result in the deposition of lead. The study focused on the doublets in the Slochteren formation where significant lead concentrations are found in the formation water.

Corrosion of carbon steel and deposition of a more noble metal from solution is a standard electrochemical process. Similar behaviour is known to occur in other water handling systems given the right situation, i.e. ions of a noble metal such as Pb or Cu dissolved in the water and in contact with steel, aluminium or another less noble metal.



The metal deposition reaction is an additional cathode reaction and to that extent may increase the scope for corrosion of the carbon steel. The impact will, however, be limited by the concentration of ions in the water (typically rather low, see, for example Figure C.1 water analysis) and mass transport limitations. As discussed earlier, galvanic corrosion between the deposited metal and carbon steel is also a possibility, but unless there is another rapid cathodic reaction mechanism available (such as oxygen reduction), the practical impact on corrosion will not be significant.

In the electron exchange reaction, the initial stage of the process is considered to be carbon dioxide corrosion of the steel casing producing Fe^{2+} ions, bicarbonate and hydrogen. The ferrous ions and bicarbonate then react to form an iron carbonate scale. It is speculated, at an appropriate temperature and pH, that lead ions can oxidise metallic iron to form Fe^{2+} and elemental lead. The elemental lead can subsequently deposit on the steel casings and then cause galvanic corrosion of those steel casings. Note that a similar process is mentioned by Regenspurg et al (2013) at the Groß Schönebeck facility but in that case it is suggested that Cu^{2+} is reduced to elemental copper.



C.4 Corrosion Experience in Low Enthalpy Geothermal Wells Outside of the Netherlands

The following sub-sections of the report look at some of the low enthalpy geothermal locations in France and Germany that are the most similar to those in the Netherlands. The final sub-section considers some of the other locations around the world where low enthalpy geothermal energy is becoming of more importance.

This part of the report is meant as a general overview of experience around the world to illustrate that the issues facing geothermal operators in the Netherlands are not unique but have been encountered by many operators over the last 30 years. In particular and common to all are the issues of corrosion and particularly scaling as described in Section 2.

C.4.1 France

French and German low enthalpy geothermal sites offer the most comparable sources of information for the geothermal installations in the Netherlands due to the similarity of the geology, formation water and operating temperature.

Paris Basin

The central part of the Paris Basin was one of the world's largest developed hot water resources in the late 1980's, used for district heating purposes (Ungemach and Turon, 1988). Depths and temperatures of the geothermal wells range from 1,600 to 2,000m and 50 to 85°C respectively. Production technology is based on the doublet concept, with a production well, a heat exchanger transferring the geothermal heat to a distribution network and an injection well conveying the heat depleted brine into the source reservoir.

During the early stages of energy production it was estimated that up to one third of the production wells were undergoing severe exploitation problems stemming from well damage which usually affected the injection well first and then the production well.

The damage originated from the formation fluid which is a hot, slightly acid brine with a fairly low gas / liquid ratio and with some amount of H₂S gas dissolved. Damage effects included casing corrosion and scaling by iron sulphide deposits which were noted to increase the corrosion rate by providing a part of the casing surface that supported the cathodic reaction (Ignatiadis and Abou Akar (Joule II project)). It is now more widely understood that iron sulphide forms readily on the steel surface, but at any breaks in the sulphide scale there is a tendency for pitting because the exposed steel acts as an anode with the surrounding iron sulphide supporting the cathodic reaction, thus accelerating attack.

Chemical injection and well workover using drilling and jetting are generally employed to restore productivity and injectivity. The project included attempts to control sulphide formation, but it is now recognised that inhibition is better focussed on allowing the sulphide scale to form, as it is very protective, and preventing its breakdown. Most difficulties due to scaling and corrosion had been overcome by the end of the 1980's.

By 2008, 31 doublets were remaining in operation, which is about half the total amount of

active doublets in France. Lopez et al. (2010) remark that the costs of preventive measures are high, but still lower than the costs repairing and replacing corroded casings, and temporarily or permanent shutdown. Within the Paris Basin, forty-two wells have been abandoned for technical or economic reasons (Veldkamp et al, 2015).

Soultz-sous-Forêts – Upper Rhine, Graben

Mundhenk et al (2014) describe the corrosion and scaling issues encountered in Soultz-sous-Forêts. Geothermal wells in this region have been operational for over 20 years and are therefore in a long-term operational phase.

In this region the produced brines contain high amounts of dissolved solids (100,000mg/l). There are large amounts of dissolved CO₂ and the pH is below 5. Brine extraction takes place at approximately 160°C and cools to approximately 70°C prior to reinjection. Tests of different materials in the brine at 80 and 160°C were carried out. The formation water chemistry causes uniform corrosion of carbon steel (at about 0.15mm/y at 80°C and only 0.01 mm/y at 160°C, as a consequence of the formation of a protective iron carbonate deposit) while 316 Stainless Steel and Duplex Stainless Steel did not corrode but at 160°C pitting was noted on occasional samples. In this region, to avoid corrosion problems, it is considered necessary to select higher alloyed materials, or to use highly resistant organic coatings.

Scaling is also a serious problem in this region; the scales formed include barite-celestine and galena. Some of the scales are toxic and / or radioactive and removal and disposal is expensive and time consuming. In Soultz, scale formation is mainly related to the cold side of the geothermal loop due to the significant temperature drop - from 160°C to 70°C. Within the heat exchanger, scales form an insulating layer which causes a decrease in the heat transfer from the geothermal brine. The scale buildup is so severe that shutdown periods are required every 6 to 8 weeks for scale removal in order to retain energy efficiency.

C.4.2 Germany

Germany can be divided into three geothermal areas, the Molasse basin in the south, the Rhine Valley Graben in the west (which includes the Soultz-sous-Fôrets location in France) and the North German Basin (Regenspurg (2012)).

The Molasse Basin is characterised by low salinity < 1 g/L TDS which increases from north to south. Sulphate is found in the north while sulphide is found in the south, H₂S is therefore present along with CO₂. Typical depths are 3,500m with temperatures of 122°C.

The Upper Rhine Valley is characterised by high salinity, mainly NaCl (14-74g/Kg TDS), the salinity increases with depth, there is a high CO₂ content and there is scaling due to the precipitation of scales containing calcite, lead, barite and silicates.

The North German Basin has a high TDS, 265g/l, a temperature of 150°C and very low CO₂



levels (0.3%).

Groß Schönebeck, is the central site for geothermal research at the German Research Centre for Geosciences (GFZ). The reservoir at this facility is about 4400m deep with a fluid temperature of about 150°C and a reservoir pressure of 450bar. The reservoir fluid contains about 265g/l TDS and so much of the research activity is concerned with fluid property changes over time leading to scaling (Regenspurg et al, 2009).

According to Frick et al (2011) the salinity of a geothermal fluid increases with depth in the reservoir and also with age - how long the water has been in the reservoir. Temperature and pressure also change with depth, with both decreasing from the reservoir towards the surface. Pressure and temperature both strongly influence the fluid properties and a decrease or change in gas composition (for example by degassing) can result in a change in the mineral saturation and result in precipitation of minerals (scaling).

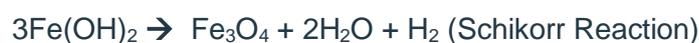
The gas composition in the North German Basin consists mainly of nitrogen and methane. CO₂ levels are quite low, 0.3%, but even these small amounts can contribute to corrosion processes and could represent a problem when degassing is carried out as the pH of the solution will be shifted to higher values and induce mineral oversaturation and scale formation.

Considering the other elements in the water, chloride ions can contribute to pitting corrosion in stainless steel if the water becomes oxygenated. Iron and manganese are present as well as heavy metals (e.g. Ba, Pb and Zn), all of which could contribute to the precipitation of scales. Scales are commonly formed by the precipitation of carbonates when the water exceeds the solubility limit.

Being a research facility, various types of experiments are carried out at Groß Schönebeck aimed at improving efficiency and longevity of geothermal wells. One aspect of the research has involved the development of a corrosion test rack that uses hot geothermal liquid to carry out exposure testing of different metallic materials to determine their compatibility for use in the facilities. In addition some components can also be tested under service conditions in the test rack.

Regenspurg et al (2013) carried out laboratory analysis of the fluids collected from the well at Groß Schönebeck and solids from filters in the surface facilities. They suggest that two different corrosion processes were taking place in the production well casing:

1. A process attributed to anaerobic steel corrosion as evidenced, they say, by hydrogen evolution in the gas phase (up to 8% in one sample) and the formation of magnetite in the solid phase, suggesting that the Schikorr Reaction is taking place.



We believe that this proposed mechanism is incorrect as it is far more likely that the



magnetite is derived from some residual mill scale which is routinely present on casings and that the hydrogen has a natural source.

2. Electrochemical copper reduction; Cu^{2+} is reduced by the oxidation of iron from the well casing to form elemental copper. The copper becomes a sediment in the borehole while the iron passes into solution.

Regenspurg et al also concluded that the selection of the most suitable material for the well casing is essential for the long term operation. They concluded that while a corrosion resistant material would be the optimum choice it may be more cost-effective to accept a material like carbon steel that will show some corrosion within economic limits.

Stainless Steels and CRA's

Research conducted by Bäßler et al (2013) and Bäßler et al (2014) adds to this concept. The research was aimed at increasing the knowledge base of construction materials in highly saline service conditions at temperatures up to 150°C , specifically looking at highly alloyed materials. duplex steel, super duplex steel, UNS S31603 ("316") austenitic stainless steel and a nickel alloy were evaluated at 100°C and 150°C in an artificial geothermal fluid deaerated by Argon bubbling. The conclusion of the research was that the nickel alloy showed an excellent resistance to pitting corrosion and was a good alternative for geothermal facilities but may be limited due to its cost. The cheaper materials, 316 Stainless and duplex steels showed some pitting and crevice corrosion in static conditions. Similar results for this range of materials were quoted by Mundhenk (2013, Chapter 9) in in-situ and autoclave testing in Soultz brines with CO_2 bubbling to deaerate the solution.

These materials would normally be excellent at these temperatures in the absence of oxygen, so the experiments must have included some oxygen despite effort to deaerate the test solution. From hard experience, researchers in the Oil and Gas field have realised the critical importance of eliminating oxygen in any tests involving stainless steels. Even the analytical grade CO_2 used by Mundhenk may contain oxygen at levels of several ppm, Accounting for the increased test pressure; this alone will give several 10's ppb of dissolved oxygen. Best practices have evolved to include measures such as having all test equipment in secondary test chambers that are also purged with nitrogen, equipment in metal or glass and with metal-metal seals, no use of plastic tubing, polymer seals etc, confirmation measurements to confirm lack of oxygen at ppb levels. These precautions are not mentioned in the above research and do not appear to be normal practice outside the Oil and Gas industry.

In our view, the validity of much of the reported laboratory data on stainless steel materials in geothermal type conditions is questionable.

However, these results do illustrate the risk of using these materials in any high temperature brine if trace oxygen ingress is possible.

Carbon Steel

In addition to research into corrosion resistant alloys, considerable research into corrosion of carbon steels has been conducted, the most comprehensive by Mundhenk (2013). Gas compositions from several sampling campaigns in Soultz are reported in Sanjuan et al. (2010). For instance, the gas liquid ratio (GLR) of one producing well (GPK2) can reach 40 vol%, at other sites even considerably higher. The gas composition is strongly dominated by CO₂ with minor fractions of N₂, CH₄, H₂, and He. The presence of CO₂ increases the acidity and most waters have a pH of 5 to 7. The water has TDS of about 100g/l, with the main ions being Na⁺, Ca²⁺ and Cl⁻. This well produces at 165°C. Comparable fluids are produced at another well (GB2) but at a lower temperature, 125°C.

In situ experiments were performed using a by-pass loop (once-through flow) with pressure conditions controlled to prevent degassing and scale formation.

*Tab. 2 Relevant technical and experimental parameters in the on-site bypass Soultz; * measured parameters, ** Sanjuan (2010), ***Baticci (2009).*

On-site bypass Soultz		
Temperature	≈ 60 – 80*	°C
Pressure	Max. 20	bar
CO ₂ fraction in the incondensable gases	50 – 90**	%
pH	≈ 4.6 – 4.8	-
Flow rate	≈ 4***	m ³ h ⁻¹
Flow velocity	≈ 0.3	m s ⁻¹
Exposure time	1 - 5	months

Figure C.3 Test Parameters used by Mundhenk

The mean (weight-loss) corrosion rates observed from these in situ tests were between 0.13 and 0.19 mm/y for typical casing steels N80 and P110. Scales were formed on the surfaces and appeared to be relatively protective at the in-situ conditions. However, the maximum local penetration rates (presumably with imperfect protection from scaling) were considerably higher, possibly as much as 2.4 mm/yr in short-term tests. Mundhenk gives information to estimate that the dissolved CO₂ content in the water equates to the reservoir conditions of about 6 bar CO₂ at 200-230°C. The surface pressure is deliberately maintained above the bubble point to avoid problems with gas evolution.

Laboratory tests in broadly similar conditions showed the corrosion rates were higher at 80°C than at 20°C or 160°C (Figure C.4). The actual corrosion rates in the laboratory tests cannot be taken as reliable for field experience due to unavoidable differences between autoclave tests and continuous flowing field conditions.



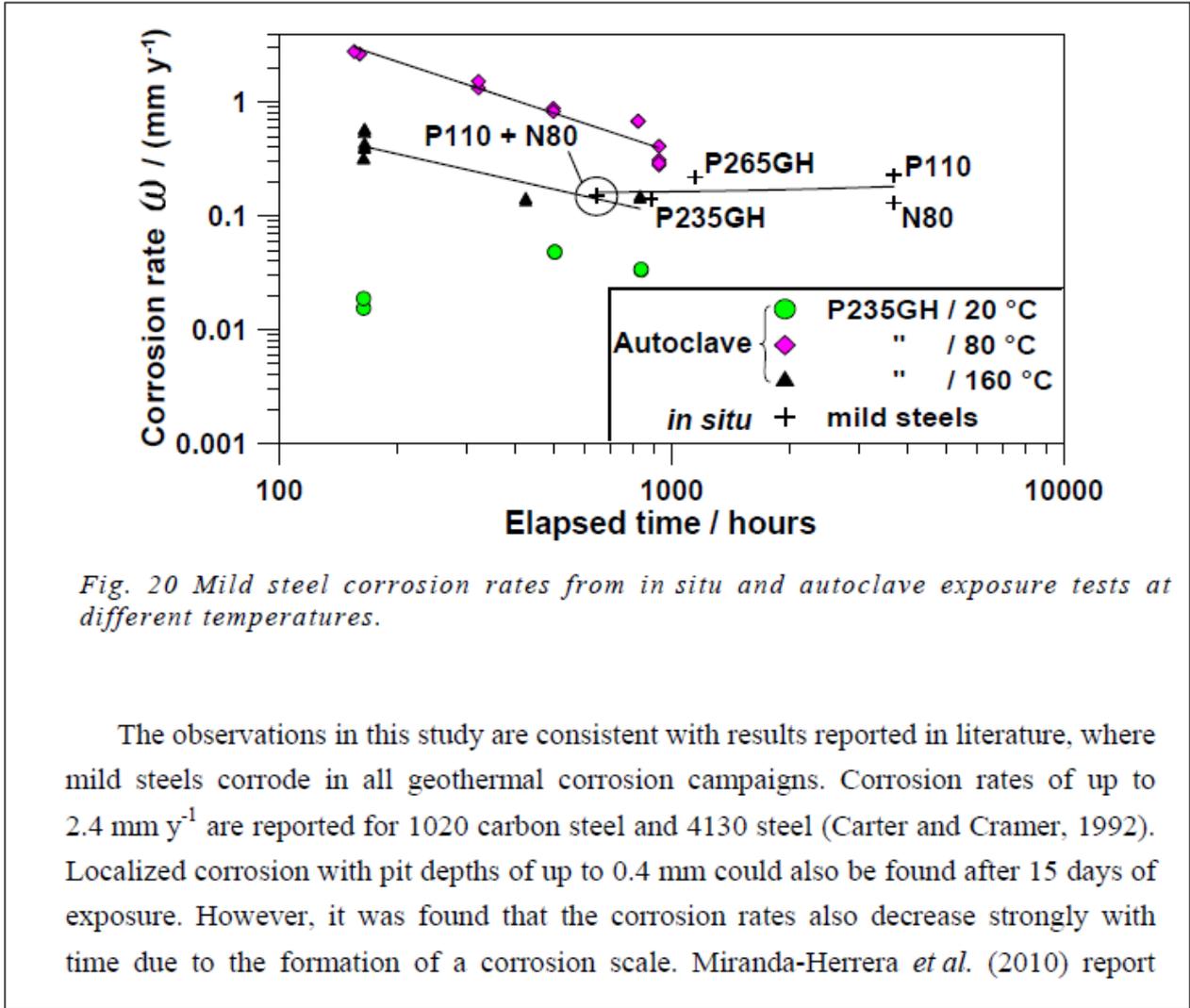


Fig. 20 Mild steel corrosion rates from in situ and autoclave exposure tests at different temperatures.

The observations in this study are consistent with results reported in literature, where mild steels corrode in all geothermal corrosion campaigns. Corrosion rates of up to 2.4 mm y⁻¹ are reported for 1020 carbon steel and 4130 steel (Carter and Cramer, 1992). Localized corrosion with pit depths of up to 0.4 mm could also be found after 15 days of exposure. However, it was found that the corrosion rates also decrease strongly with time due to the formation of a corrosion scale. Miranda-Herrera *et al.* (2010) report

Figure C.4 Test Results Produced by Mundhenk

ECE Tubing Corrosion Report

tubing diameter at wellhead	0.178 m	7.000 inch
wall thickness at wellhead	6.50 mm	0.256 inch
tubing diameter at bottomhole	0.178 m	7.000 inch
wall thickness at bottomhole	6.50 mm	0.256 inch
total length (measured depth)	3,000.0 m	9,842.5 ft
heat treatment condition	QT	
chromium content	0.01 %	
wellhead temperature	60.0 °C	140 °F
bottomhole temperature	60.0 °C	140 °F
wellhead pressure	3.0 bara	44 psia
bottomhole pressure	3.0 bara	44 psia
CO ₂	50.000 mol%	
H ₂ S	0.000 mol%	0 ppm
Bicarbonate	0 mg/L	
acetic acid	0 mg/L	
NaCl	100.0 g/L	60,660 ppmCl ⁻
crude/condensate flowrate	0.0 m ³ /d	0 StdBOPD
crude API gravity (stock tank conditions)	47.0 °API	
gas flowrate	0.000 MMSm ³ /d	0.000 MMSCFD
water flowrate (at wellhead)	570.81 Sm ³ /d	3,590.29 StdBPD
liquid holdup change parameter	2.000 %	
deviation angle at bottomhole	40 °	
Inhibition	none	
continuous inhibition availability	N/A %	
continuous inhibition efficiency	N/A %	
squeeze inhibitor frequency, every	N/A months	
erosional Velocity Factor	122 (kg/m) ^{0.5} /s	100 (lbs/ft) ^{0.5} /s
dissolved Fe at bottom-hole	Yes	
max. corrosion rate	1.57 mm/y	62 mpy
max. pitting corrosion rate	N/A mm/y	N/A mpy
corrosion rate wellhead	1.57 mm/y	62 mpy
corrosion rate bottomhole	1.57 mm/y	62 mpy
pH at bottomhole	5.68	
pH at wellhead	5.68	
liquid holdup	99.90 %	
GOR	N/A Sm ³ /m ³	N/A SCF/BBL
Watercut	100.000 %	
gas velocity	0.00 m/s	0.00 ft/s
liquid velocity	0.31 m/s	1.02 ft/s
API erosional velocity	0.0 m/s	0.0 ft/s
sour to ISO15156	NO	

Figure C.5 ECE Calculation of Corrosion Rate for Mundhenk's In-situ Test Conditions (60°C)

The scale formed on the samples was checked by EDX. An iron-rich carbonate with variable



amounts of Na, Al, Si, S, Cl and Ca formed an inner layer of variable thickness; this was regarded as the corrosion product scale. An outer layer containing Ba / Sr sulphates and other minor elements was found, but was fragile and not considered to be protective, with respect to corrosion damage.

Tests at higher temperature (160°C) produced lower corrosion rates overall as the faster reaction rate is offset by the formation of a less soluble, more dense and adherent iron carbonate scale which protects the surface from continuing corrosion.

Generally the Soultz brine found in both France and Germany causes corrosion rates in carbon steel below 0.2mm/y – which generates a wall loss of 4mm over a 20 year service life. Note that if a 40 year design life is required this corrosion rate would be unacceptable. A corrosion scale builds up on carbon steel, mainly composed of Siderite (FeCO_3) and this can act as a partially protective barrier to corrosion, although it only slows corrosion rates and does not completely arrest corrosion. The work carried out by Mundhenk et al is one of the most comprehensive studies. They identify that a key parameter not included in the work to date, is the flow condition. Based on oil industry experience, higher flow rates would result in higher corrosion rates.

In 1994 the application of corrosion inhibitor was started in the GPK-2 well. The chosen inhibitor, Mexel 432/0, in a 3-5 (in 1994-1995) and 4 ppm dose (in 1997, 8 kg/day at a flow rate of 2000 m³/d) reduced the corrosion to virtually nothing when applied at the production pump.

C.4.3 Other Low Enthalpy Examples

This section is intended to give a brief overview of the use of low enthalpy geothermal energy in a selection of countries around the world. Examples are given in terms of corrosion issues, material selections and geothermal energy usage. The list is not intended to be exhaustive but rather to indicate that low enthalpy geothermal energy is becoming increasingly important on a worldwide scale and as such the issues relating to its efficient use are receiving more attention.

Serbia

Oudech and Djokic, (2015) advise that the economic blockade (1991-2000) of Serbia stopped large geothermal heating projects. In recent years, however, investment has been made and since 2010, 3 new hydrogeothermal drillholes have been drilled and one rehabilitated. These sources are utilised for heating, aqua parks, bottling and wellness centres. The Republic of Serbia has also defined the development strategy for the energetic sector in order to increase total share of use of all renewable energy sources by the end of 2020 to 27% of gross final energy consumption.

Papic (1991), conducted a study of scaling and corrosion potential in selected geothermal waters in Serbia. Concern was raised at the time over scaling in the reinjection well. The geothermal waters existed at temperatures between 25 and 94°C and mainly contained



sodium bicarbonate and dissolved CO₂. In contrast to wells in the Netherlands the Serbian wells contained appreciable amounts of O₂.

Hungary

According to the Biocentrum report, Hungary has a significant potential for Low-enthalpy geothermal energy. Geothermal water resources are underused at present but the National Renewable Energy Action Plan (NREAP) for 2020 states that the planned use of geothermal energy should be increased, the required amount is a 24 times increase between 2010 and 2020.

At present approximately 420 acres (200 ha) of glass and plastic covered greenhouses are heated with geothermal energy. In addition, 2,500 acres (1,000 ha) of temporarily covered plastic tents of “tunnels” are also heated. Vegetables are grown in about 25% of the greenhouses covered by glass and in 95% of those covered with plastic. The most important vegetables grown are peppers, tomatoes and cucumbers.

Turkey

Yildirim et al, (2005) investigated geothermal energy utilisation in Turkey. There are approximately 1000 thermal and mineral water spring groups throughout the country, which vary in temperature from 30-242°C. The moderate-low geothermal fields are found in the western part of the country. Most of the experience concerns the higher temperature waters (>100°C), and particularly the presence of up to 10ppm oxygen in the water which results in the highest wall thickness loss corrosion rates.

The low temperature geothermal fluids in this region contain from 500 to 15,000mg/l of TDS, with a pH range of 6 to 9. There is a high percentage of bicarbonate (40%) of the TDS. CO₂ represents 3% of the aquifer fluid. The water can cause scaling problems as well as corrosion issues. Of particular interest in this region is the issue of oxygen ingress. Oxygen levels can reach 10ppm when the geothermal fluid contacts atmospheric air in the pumping station and surface flow lines and it is given as the major corrosive constituent.

Indonesia

Keserović and Bäßler (2013) conducted a material evaluation program for geothermal systems in Indonesia. Indonesia is considered to be the country with the largest estimated geothermal energy reserves in the world (40% of the global total). Commonly Indonesia utilises dry steam for energy production (for example Ekasari and Marbrun describe highly corrosive conditions in one well (320°C and acidity as low as pH=1 which resulted in very fast corrosion/erosion rates of both carbon steel and the cement phase), but future development plans include the utilisation of hot geothermal brine.

Research conducted by Bäßler et al confirmed previous findings (2009) that the most



common types of corrosion in geothermal applications included pitting and crevice corrosion, with effects related to oxygen also being of concern because excluding oxygen from the test solutions proved to be exceedingly difficult. Research into the corrosion behaviour of alternatives to carbon steel were carried including low alloy steel and 316 stainless steel as alternative for exploitation of the hot geothermal brine.

The results from an experimental program indicated that at a temperature of 100°C, 316 Stainless Steel represented an option as it showed good corrosion resistance compared to low alloy steel. However at higher temperatures (in this research 175°C), higher alloyed corrosion resistant alloys are required due to attack in the form of pitting corrosion.

316 stainless steel would be appropriate for surface piping and facilities, but is not available or suitable for downhole tubulars because of its low yield strength.

Canadian Prairies

Writing in 1988, Epstein et al described geothermal brines from the Canadian Prairies as potential sources of low-grade energy, at well-head temperatures in the vicinity of 60°C. The brine produced in the geothermal wells was very saline with dissolved solids concentrations up to 30% and, as seen frequently elsewhere, the heat recovery from those brines was adversely affected by the scale deposited on the heat transfer surfaces.

China

Geothermal energy for district heating schemes is growing in importance in China in recent years, often for the replacement of coal powered boilers and the consequent decrease in CO₂ released to the environment.

Jialing et al (2008) describe guidelines for geothermal heating system design in China. They describe iron removal from the geothermal water as an anti-corrosion and anti-scaling / clogging process. This is stated to involve an oxidation process where ferrous iron is converted to ferric iron by an oxidant and then removed. The process used is actually a natural-oxidation process where oxygen is deliberately dissolved in the geothermal water to remove iron. This technique is not considered viable as a corrosion control system due to the introduction of oxygen into the system. Very careful operation and monitoring would be required to ensure that no free oxygen is available for corrosion processes in the geothermal installation.

Iceland

Iceland has geothermal resources with a range of temperatures, the low temperature (<150°C) sources being used primarily for space heating (Gunnlaugsson et al). They experience corrosion in most geothermal installations, using material selection to mitigate the problems. As the majority of the experience is “dry” steam operation it is the condensate that

tends to be the major concern (which has conditions more comparable to the Netherlands systems) as it is often acidic and stainless steels or fibreglass are often required. Copper alloys are inappropriate as they are corroded by H₂S, a common contaminant in the fluid.

Denmark

In Denmark operational doublets exist in Thisted (1984), Copenhagen (2005) and Sønderborg (2013) (Veldkamp et al 2016). All doublets are operated by DONG (Dansk Naturgas and Dansk Olie og Naturgas). The depth and temperature ranges are roughly comparable to those encountered in the Netherlands: 1.2 – 2.6 kilometres, 48 – 74°C. The salinity is between 15 and 21%. All brines are devoid of hydrogen sulphide. The flow rates are very high (200 – 350 m³/hr). Some of the wells are closed in during the summer because of the low heat demand. The system is then protected by nitrogen blanketing to prevent corrosion. Corrosion inhibitors are only used when acidizing the injection well for clean-up.

The Thisted doublet has a corrosion rate of only 0.06 mm/year. In Copenhagen the rate is 0.2 mm/year. This higher rate is probably due to the fact that the CO₂ content is higher: (7 vol%, N₂ 84-88%, CH₄ 3-7%, GWR 0.14, pH 6.1, TDS 213-215 g/L).

Corrosion is apparently controlled by selecting heavy wall thickness casings to add corrosion allowance, up to 5 mm in Copenhagen. The doublet in Sønderborg has been in operation for only a short period. Therefore the corrosion rate is yet uncertain, but Veldkamp reports it to be about 0.2 mm/year (pers. comm.). This is in accordance with the reservoir brine and gas compositions: CO₂ 86-99 vol%, N₂ 0-13, CH₄ 0-1, GWR 0.16, pH 6.8, TDS 160 g/L). Although the CO₂ content of the gas is high, the pH is nearly neutral, possibly due to the low GWR.

C.5 Scaling in Low Enthalpy Geothermal Wells

The presence of solid surfaces or microorganisms can strongly catalyse precipitation reactions (Regensburger et al, 2011). Scale formation can be controlled by careful adjustment of the temperature (and pressure) to stay within solubility limits, but this can be difficult with the additional constraint of optimising the heat loss.

According to Frick et al (2011), scaling effects can precipitate on heat transfer surfaces or pipe walls causing clogging of the pipes and limiting fluid flow. Besides direct precipitation and coating of plant components, small, colloidal, particles which can remain suspended in the fluid, can be transported over large distances in the well and the fluid loop where they can accumulate and cause clogging elsewhere in the system or impact injectivity in the reservoir at the re-injection well.

Gill (2008) describes the main types of scale associated with geothermal fluids, these are Calcium Carbonate Scale and Silica Scale.

Carbonate Scale

Calcium carbonate scale has been found in low, medium and high enthalpy geothermal systems. Although the rate of scale formation depends upon the degree of supersaturation at the production well, some well water is supersaturated enough to completely obstruct the well flow in a few weeks.

Scaling occurs in the production well and / or in the surface equipment as degassing also takes place in the production separator. Even a small amount of dissolved calcium in formation water can precipitate enough calcium carbonate to cause scale up of geothermal production wells. Stapleton (2016) describes the same effect but also advises that not only do pressure drops occur in the flash vessels but also, for example, at well pumps or elbows in surface piping.

Calcium carbonate deposits can be also encountered in heat pump systems (Rafferty, 2000).

Calcium carbonate can exist in three different polymorphs, namely calcite, aragonite and vaterite, in order of increasing solubility. All three polymorphs have been identified in scales, although vaterite is rather rare. Thermodynamics predicts that calcite, the least soluble polymorph, should be the phase favoured in the precipitation process. Aragonite is also encountered in geothermal systems, forming scales sometimes as tenacious as those of calcite. The water temperature and chemistry (e.g. pH and ionic strength) have been shown to play a determining role for the nature of the precipitating calcium carbonate phases. It is also well known that the presence of magnesium ions, in solutions supersaturated with respect to CaCO_3 , favours the precipitation of aragonite and appears to hinder the formation of vaterite.

Calcite scaling occurs in the low temperature geothermal fields in Iceland (Gunnlaugsson et al). Two drillholes in the Sudueyrri geothermal field (active since 1978) both experienced calcite scales. The scaling has been overcome by injection of a poly-phosphate inhibitor

through a capillary tube to a position below the pump. Scaling was also found in certain wells at different times in the Laugarnes geothermal field Reykjavík. Most samples are close to equilibrium at given temperature but water samples with higher chloride concentration exist because of saline water entering the reservoir through wells due to shallow casings and these tend to have worse scaling potential. To avoid leakage of saline water into the reservoir, the contamination has been stopped by cement plugging some of the older drillholes in the field which showed inflow of saline water.

Silica Scale

Silica scale has been found in almost all high enthalpy geothermal fields that are water dominated, and is thus less relevant to the Netherlands geothermal production.

Magnesium silicates are formed upon heating of silica containing ground water or mixing of cold ground water and geothermal water. They have been shown to consist mainly of poorly developed antigorite (Gunnarsson et al., 2005). Their solubility decreases (deposition increases) with increased temperature and pH. The rate of deposition has been found to increase linearly with supersaturation but exponentially with temperature. Severe silicate scaling arose in 1990 in the Reykjavík District Heating as a consequence of mixing of the deaerated freshwater and geothermal water. Initially it was considered this could be tolerated if the mixing ratio was carefully controlled (Gunnlaugsson and Einarsson, 1989) but control of the mixing ratio was insufficient and heavy scaling occurred in the pipeline system. It soon became evident that scaling was more severe than expected which led to the abandonment of any mixing and the distribution system was modified to keep the waters in two separate distribution networks, each serving different regions of the city (Hauksson et al., 1995).

Siliceous scale is typically inert to most chemicals and, once formed, is very resistant to mechanical removal. Hence, most treatment methods focus on preventing silica deposition or on controlling the morphology of the silica particles. There are a number of ways to control silica scaling, including both engineering (e.g. maintain pressure and temperature) and chemical means (e.g. controlled precipitation and inhibition) (Hua, 2012).

Silica scale is extremely tenacious, highly insulating and very difficult to remove. Silica deposits are formed by polymerization, co-precipitation with other minerals, precipitation with other multivalent ions and biological activity in the water. Several of these processes may take place simultaneously, making it difficult to predict the equilibrium solubility. To prevent silica-based deposit, it is essential to control all these mechanisms simultaneously.

Sulphide Scale

In addition to the silica and calcium carbonate mechanisms described, less common are the sulphide scales. The geothermal wells in the Paris Basin, contain relatively large concentrations of chloride and dissolved sulphide, which results in iron sulphide scale deposits here, Andritsos et al (2016) and Criaud and Fouillac (1989). The early work by

Andritsos and Karabelas (1991) and also of Boisdet et al (1992) looked specifically at sulphide scales and they noted that iron sulphide on carbon steel does not provide complete protection as the scale was stated to be porous. This may be the case at low levels of H_2S , where the scale is a combined iron carbonate - iron sulphide scale but above a ratio of about 200:1 $CO_2:H_2S$ the iron sulphide is a very adherent corrosion product which is often very effective in stopping corrosion.

Injectivity Problems

The GPC Injectivity Report (2015) looked into severe injectivity decline noticed on several injector wells in the Netherlands (Californië (Grubbenvorst), Berkel, Bleiswijk, Pijnacker, Honselersdijk, Middenmeer, Koekoekspolder, Heemskerk). The report concluded that the main cause for accumulation of minerals as scaling was due to the degassing of CO_2 during the pressure drop of fluid in the production well and in subsequent parts of the geothermal system. CO_2 degassing results from the drop in the gas pressure at reservoir depth due to hydrostatic pressure to the relatively low pressure at which the geothermal system at the surface are operated. The loss of CO_2 and consequential rise in pH to more alkaline conditions results in precipitation of carbonate minerals and in this case resulted in the severe injectivity decline noticed on several injector wells.

Effect of Oxygen

According to Frick et al (2011), as long as geothermal fluids are not in contact with the atmosphere or mixed with O_2 containing surface water or shallow ground water then O_2 gas should not become dissolved in geothermal fluids. If O_2 , however, enters the fluid, it would quickly react to oxidise the reduced species of the fluid such as Fe(II) to form Fe(III) oxides or hydroxides which precipitate immediately.

Modelling of Scaling Potential in Dutch Geothermal Wells

Wasch (2014) used modelling software to investigate the effect of additional cooling of the produced water and the effect of degassing (removing CO_2 gas from solution) on the potential for scaling in geothermal wells in the Netherlands.

Wasch carried out geochemical simulations using the PHREEQC software to assess the scaling potential. Important assumptions in the simulations are equilibrium reactions (neglecting reaction rates) and chemical equilibrium in the reservoir and hence of the formation water. The simulations (for the most likely mineral scales) showed that the predicted precipitation increased with cooling. The simulations also indicated that the scaling potential of current operations is already significant and that further cooling than carried out at present is not advisable without a scaling prevention strategy. Wasch stresses that the model would require verification. The findings, that scaling is a thermodynamic likelihood for the water chemistries studied, is aligned with predictions that could be made with several



commercial scaling prediction software packages.

The conclusion from the study was that doublets that contain CO₂ have high scaling risks and that it is essential to keep the CO₂ in solution or re-introduce CO₂ (or another pH decreasing agent) during degassing.

C.5.1 Scale Inhibition Experiences

Effective scale prevention in geothermal operations is critical to the success of a project. Unfortunately, scale prevention methods must be designed to the very site-specific conditions in the field (Papic, 1991; Perez, 2000). These conditions dictate the type of scale prevention method that will be feasible.

Calcium carbonate scaling may be prevented by:

- Control of carbon dioxide partial pressure
- Control of the pH of the solution and
- Using chemical additives (scale inhibitors)

Pressure and temperature manipulations of the geothermal fluid can be achieved quite easily by pumping a geothermal well instead of relying on its natural flow. Utilising a down-hole pump decreases or eliminates the in-hole pressure and temperature drops caused by flashing.

The produced fluids can be maintained as a single phase system by means of a mechanical downhole pump. Thus, the formation of "pressure sensitive" scaling such as calcite can be eliminated. Another potential scale prevention method entails artificially maintaining a high carbon dioxide partial pressure by reinjecting some of the produced carbon dioxide back into the producing well, but it appears to work only for fluids with low carbon dioxide partial pressures.

Ungemach (2016) adds pH re-equilibration and partial CO₂ pressure control. pH handling, could consist of injecting HCl to match the desired pH figure. This technique may, however, not be feasible due to corrosion issues and the fact that strong buffering from bicarbonates would require large amounts of HCl to achieve a significant pH decrease.

CO₂ partial pressure control would either involve a reduction of well discharge, installing a submersible pump set in a self-flowing or flashing well or to inject CO₂ downhole.

Perez (2000) describes problems with scale inhibitors in that some of them can break down due to thermal decomposition. This has the combined effect of rendering them ineffective to prevent scaling but also creates decomposition products which can themselves form deposits or be corrosive to metal surfaces.

Guan (2012) and Andritsos et al (2016) give the techniques for controlling silica scaling which include both engineering (maintain pressure and temperature) and chemical means



(controlled precipitation and scale inhibition). Chemical techniques include:

- Diluting with fresh water
- Using chemical additives (e.g. reducing, complexing and sequestering agents)
- Removing silica from water by lime softening
- Precipitating the silica with metals or cationic surfactants
- Treating the water with geothermal silica scale inhibitors or dispersants

Guan (2012) also describes the cost of treating scaling, giving the example of one particular geothermal unit as costing \$7 million per year* - spent on acid and a scale inhibitor, specifically to deal with silica scaling tendencies. This should be viewed as a quit extreme case however. Given this level of expense considerable effort is now being made to investigate chemical additives that are suitable for controlling silica / silicate related deposits.

*Note that Table D.1 in the following appendix includes a simple determination of the cost of inhibitor per year for Dutch geothermal operations and the cost is estimated at approximately \$26k per year.



Appendix D Life-Cycle Costing for Well Casing



D.1 Life Cycle Cost (LCC) Calculation

Life Cycle Cost (LCC) analysis has been used to assess the total cost of a geothermal well over a 20 year design life. The candidate types of tubular material that are available on the Dutch market - Carbon Steel with Corrosion Inhibitor and 13Cr Martensitic Steels (Appendix B) are assessed. Note that GRE lined carbon steel is not currently available in the relatively small quantities for individual doublets.

The result of the LCC analysis is presented as the value of initial and future costs in today's (US) dollars as affected by the selected discount rate of 8%.

The factors considered in this LCC analysis are initial capital expenditure items (CAPEX) and then the ongoing operating expenditure (OPEX).



D.2 Inputs

The CAPEX for the geothermal well project includes rig mobilisation, well drilling and completion, well equipment (casing, wellhead, Xmas tree), tubing and associated completion equipment. This cost is considered as a single payment at the beginning of the project (at time zero). Other costs common to all well design options are not considered.

The yearly OPEX is the sum of chemical consumption for one well per annum.

if the tubing fails by corrosion it has to be replaced in a workover, or casing repaired e.g. with a casing patch. Thus there would be an intermittent higher operating expenditure for these workovers. This involves rig mobilisation, removal of the tubing, casing repair and then inspection and replacement of the tubing and other accessories in the well completion. This workover only occurs when the tubing or casing material fails; this failure is subject to the durability of tubulars under the operating environment.

The life cycle cost analysis has been made for a well design consisting of:

- 9.5/8" K55 production casing (1169m)
- 7" K55 liner (1418m)
- 4.5" K55 liner (412m)
- 6.5/8" K55 production tubing (428m)

The life cycle cost analysis is carried out by assessing the CAPEX, OPEX and workover (if any) costs throughout the well design life. The cost effectiveness of the different options are presented in the next Section. Table D.1 lists some assumptions made in the life cycle cost calculation.

Table D.1 LCC Calculation Assumptions

Parameter	Assumed Value
Well life (years)	20
Tubing depth (m)	3,427
No. of working day/y	365
Value of energy generated \$/MWh	200
Water production value \$/m3	10
No. of day/workover	10
Discount rate (%)	8
Chemical cost (\$/litre)	2



Parameter	Assumed Value
Water production rate (m ³ /h)	150
Inhibitor concentration (ppm)	20
Inhibitor injection rate (litre/hr)	3
Cost of inhibitor \$/year	52,560

CAPEX estimation of a geothermal well is categorised into the following:

- Rig mobilisation
- Well drilling and completion
- Casing
- Tubing materials
- Wellhead + Tree
- Completion assembly

D.2.1 Well Drilling and Completion

Well drilling and completion are the largest contributors to geothermal well CAPEX. The drilling processes cover drilling and running of the conductor section, surface casing section, intermediate (if applicable) and production casing / liner.

D.2.2 Rig Mobilisation

Rig mobilisation involves transporting the rig from where it was located to site and depends on where the rig has to be brought from. The rig mobilisation time and cost vary significantly on location of site. The daily rig mobilisation costs are estimated at US\$162,000 and number of days required is estimated at 2 days for a geothermal well.

D.2.3 Casing Materials

The cost of the two systems (CS + Inhibitor and 13Cr) have been evaluated for one well design in order to give a direct comparison between the two different options. Note that the following assumptions have been made in this analysis:

- Carbon steel is estimated to be \$2000 / ton (OCTG carbon steel pricing). This is an average for the different sizes.
- Price for 13Cr casing is estimated as 2.21 times the price of carbon steel based on evaluation of various suppliers historic prices.
- Total weight in metric tonnes for API 5CT carbon steel tubing is 146.18MT
- L80-13Cr tubing would potentially allow some wall thickness and weight reduction



compared with K55. However, this has not been adopted in the assessment and the same total quantity of material is used.

The costs of different materials are given in Table D.2.

Table D.2 Cost of Materials

Carbon Steel	13Cr Martensitic Steel
\$292,361	\$646,115

D.3 LCC Analysis Results

D.3.1 CAPEX

Table D.3 and Figure D.1 show the capital expenditure for geothermal wells using the different materials of construction. For Carbon Steel and 13Cr martensitic steel materials, the casing material cost is a relatively small proportion of the whole well capital cost (about 6-10%) as drilling costs are dominated by the drilling time element.

Table D.3 CAPEX (US\$) for Geothermal Well Using Carbon Steel and 13Cr

Item	Carbon Steel	13Cr Martensitic Steel
Well Drilling tasks	\$2,816,064	\$2,816,064
Tubular Material	\$292,361	\$646,115
Well Completion tasks	\$2,567,178	\$2,567,178
Inhibition / Monitoring equipment	\$25,000	\$25,000
Total	\$5,700,603	\$6,054,357



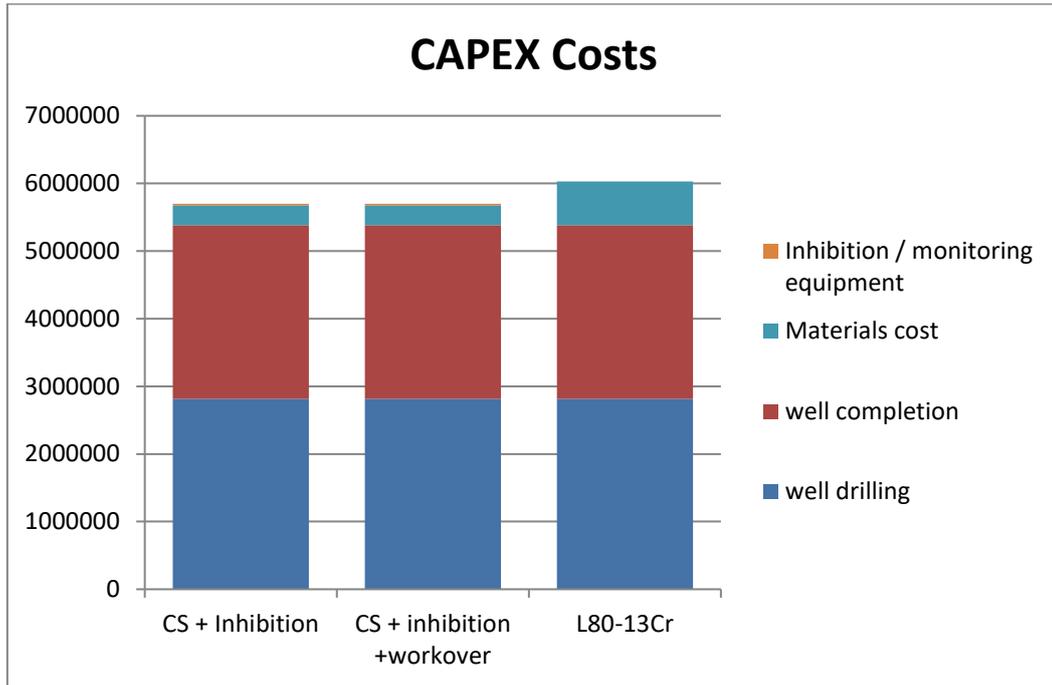


Figure D.1 CAPEX (US\$) for Geothermal Well Using Different Casing Materials

D.3.2 OPEX

The cost of corrosion inhibitor injection has been calculated based on an injection rate of 20ppm and 150m³/h water flow rate. Assuming a chemical cost of \$2/litre results in an annual chemical cost of \$52,560 per year. The NPV of this over a 20 year life at a discount rate of 8% would be \$516,042. This cost should be added to the CAPEX figures to give the full cost of the carbon steel option. At the end of the project life (year 20), the NPV reflects the total net present cost of CAPEX, and OPEX.

Table D.4 NPV of Different Materials (Assuming No Workover)

Carbon Steel plus Inhibitor	13Cr Martensitic Steel
\$6,216,645	\$6,029,357

If the assumption is made that a workover is needed (say in year 10) for the carbon steel + inhibitor option, that is assumed to add a value equal to to the original completion cost (\$2,567,178) discounted over 10 years (\$1,189,100). It is assumed that the other materials do not fail and do not require replacing or repair.



Table D.5 NPV of Different Materials (Assuming One Workover of Carbon Steel at Year 10)

Carbon Steel plus Inhibitor	Carbon Steel plus Inhibitor plus Workover	13Cr Martensitic Steel
\$6,216,645	\$7,138,870	\$6,029,357

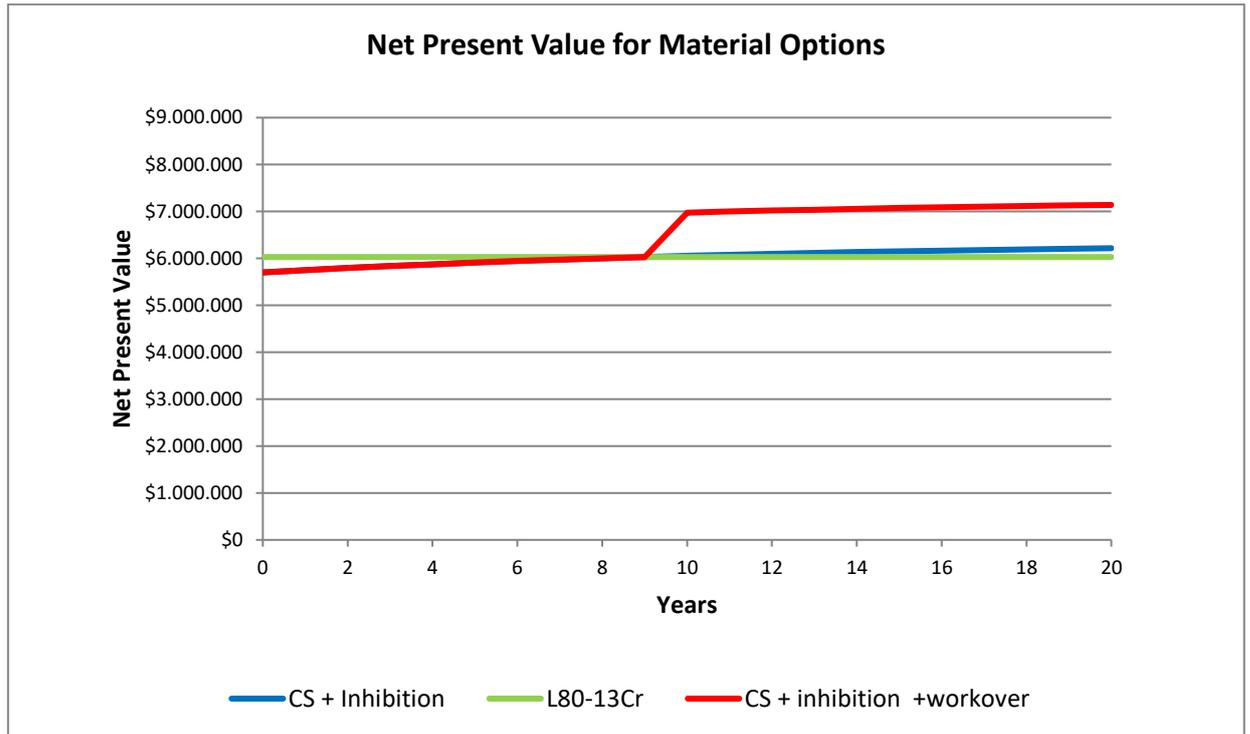


Figure D.2: Net Present Value for Material Options



D.3.3 Conclusions

Detailed life cycle cost analysis shows the relatively small impact of different materials on the cost of a geothermal well. The tubing material cost is actually a relatively small proportion of the whole well capital cost which is in fact dominated by the drilling and completing time element.

In terms of CAPEX, 13Cr martensitic steel is more than double the price relative to carbon steel. However, when the complete CAPEX cost for the well is considered the corrosion resistant material costs represents a premium of only about 6%. On an NPV basis and considering OPEX costs, the CRA option is indicated as more cost-effective for service life above 10 years in this example.

Carbon steel protected by inhibitor may possibly fail in the design life of the project and in that case this “cheapest” capital expenditure material then becomes the most costly on a total life cycle basis.

The conclusion of the study would suggest that material capital cost is probably not the most important factor in material selection for these wells. More critical concerns are the technical preference (from both corrosion and mechanical viewpoint) and the commercial availability. CRA material should be considered as a design option for geothermal wells on the basis of total life cycle costs.