EBN

KIRA Non-Alloy Based Tubulars Literature Review

September 2021

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EXECUTIVE SUMMARY

Non-metallic tubulars have been used successfully to combat corrosion in O&G, and low enthalpy, wells for well in excess of 30 years. Despite their use in a variety of Assets over this period, the application of non-metallic pipe is not as yet routine in candidate wells, despite the environmental advantages.

Report Background And Key Objectives

This report gives an overview of Non-Alloy Based Tubulars and their use in geothermal wells with a view to accelerating uptake. It is designed for a wide range of users, from the relative novice in this arena, who just requires a grounding in the topic, to the more experienced engineer who may require a guideline for a specific project. The report has been commissioned by EBN, as part of KIRA, the Kennis en Innovatie Roadmap Aardwarmte (Knowledge and Innovation Roadmap for Geothermal) – a Dutch organisation setup by EBN to develop geothermal energy solutions in the Netherlands.

Report Scope

The report is intended as a reference work for the selection of non-alloy downhole tubulars. It covers both basic information / background for the layman as well as relevant details/background, and references to other relevant technical reports, for the experienced engineer (e.g. material characteristics, temperature limitations of a particular concept and a summary of relevant technical issues and threats that need to be reviewed when planning the use of the technology). It is not intended as the definitive work on non-metallic tubulars, at this time however, rather as a guideline on the use of a key, environmentally sensitive solution that will evolve and develop as time and experience progress.

The report also includes a review of non-alloy materials and the key Vendors - full GRE, Electroless Nickel Coating and Lined Carbon Steel – and how they are manufactured.

The main narrative contains detailed synopses and conclusions from the most relevant reports, Appendix A summarises some key Vendors and their products. Appendix B depicts a Stage-Load matrix for typical low enthalpy geothermal wells and Appendix C is an example of a possible conceptual non-metallic solution.

Notional Concept Selection Criteria

The conditions under which a particular concept is suitable is outlined in Section 3. Appendix D. summarises, in more detail the respective properties of GRE lining and ENC coating. Below a particular depth, temperature will dictate its applicability as the properties of the base pipe will dictate its structural limits.

Material selection is ultimately determined by life cycle cost/value, which in turn will be determined by practical limitations – e.g. maximum temperature, pressure and tensile/axial strength for the service/load cases anticipated (e.g. Appendix D.). Furthermore, all steps should be taken to limit the potential threats to the long-term integrity/durability of candidate wells, by minimising exposure to activities that cause wear (wireline and coiled tubing activity) and abrasion due to ESP change-out (Section 8.2).

Additional Concept Selection Constraints

The maximum depth that a particular solution can effectively function is largely dictated by its temperature rating.

A typical configuration for a geothermal well is depicted in Section 6. and the primary barrier could look like – GRE lined carbon steel in injectors and Cr13 in producers. Cr13 can be susceptible to corrosion caused by air ingress at surface during upsets. A guide to the selection of the right CRA - Corrosion Resistant Alloys (CRAs) in the oil and gas industry – can be found in the selection guidelines update.

There is anecdotal evidence of glass fibres detaching from the GRE matrix. However, there appears to be limited experience of this phenomenon, either from literature or suppliers. Although it may be feasible under extreme circumstances, it is probably not significant, Various varieties of non-metallic tubulars have been used successfully to combat corrosion in O&G wells for well in excess of 30 years.

1. Given that chemical water treatment is imperfect and that composite tubulars are a robust and cost effective long term solution for use and should be continued if well-known threats are managed and within well-established constraints.
2. Generally, the options are corrosion resistant, but prolonged exposure to certain acids used for matrix simulation, particularly mud acid (Hydrofluoric acid), should be avoided.
3. Intervention frequency will be dictated by Electrical Submersible Pumps (ESP) change out frequency in producers, but a sealed annulus (isolated with a Polished Bore Receptacle (PBR)/packer of some description) should minimise the risk of external tubing and internal production casing corrosion.
   Although it could be argued that Electroless Nickel Coating (ENC) may not strictly fall within the category of Non-Alloy tubulars, it could potentially have some significant advantages in certain circumstances if it performs as claimed (refer Appendix D)

Resulting Principal Report Recommendations

A number of recommendations have been made, based on this literature review:

1. Adopt the practices summarised under Section 8.2 to minimise the costs of associated activities.
2. Apply a bottom up well design approach, where feasible.
3. Undertake future work, as summarised below.

In terms of future work, the following have been proposed:

1. Investigate the long term risk, and potential impact, of glass fibres being stripped from GRE and plugging screens, due, for example, to intervention activity and/or sand production
2. Investigate remedial options to rectify the above if it becomes problematic
3. Identify and test wireless production and integrity monitoring techniques, such as reflectometry, impedance or distributed acoustic system
4. Carry out rigorous surface testing to compare the abrasion/wear resistance of the primary tubular protection concepts, including the various coatings, to ensure that the most robust selection decision is made

TABLE OF CONTENTS

1 INTRODUCTION

1.1 OBJECTIVE

The purpose of the study is to create an inventory of existing literature published on the subject of non-alloy based materials, complemented with material from Vendors.

The report has been commissioned by EBN, as part of KIRA, the Kennis en Innovatie Roadmap Aardwarmte (Knowledge and Innovation Roadmap for Geothermal) – a Dutch organisation setup by EBN to develop geothermal energy solutions in the Netherlands.

The scope of work covers:

- An inventory of different materials in use to date
- An inventory of materials currently under R&D
- An inventory of tubular products currently available in the market
- Potential R&D needs
- A final document containing:
    - An overview of non-alloy materials in use today
    - An overview of non-alloy materials currently in R&D
    - An overview of currently available tubular products in the marketplace
    - Suggested fields of further R&D needed

Note: This is a very much a live document and can be updated and amended (both text and tables) as new information becomes available. Although it is targeted primarily at geothermal applications. much of this report is equally applicable for conventional oil and gas applications.

1.2 GIVENS - PROJECT BOUNDARIES

The following are the primary boundaries and starting assumptions for this project:

- Low Enthalpy - maximum temperature <110 Deg. C and hydrostatic
- These wells are relatively shallow (2-3 km), high porosity/poorly consolidated and, in wells where sand failure is anticipated, will probably require active sand control of some type.
- Only downhole tubulars exposed to corrosive fluid included (tubing and production casing, crossovers and other tubular accessories)
- Complex tubular accessories are not included, such as packers, sliding sleeves, side pocket mandrels, landing nipples, etc
- Barrier philosophy not challenged.
- Current chemical water treatment (particularly O2 removal and scaling control) is inefficient and brine subject to physical and chemical changes, and as a result corrosion and scale deposition will thus occur if unprotected carbon steel used for tubulars.
- More cost effective corrosion resistant solutions than the more exotic CRAs already exist for wetted areas exposed to well fluids – tubulars, accessories, etc., and these are the subject of this review.
- Full GRE linings and coatings included.
- Internal Plastic Coating included, despite the perceived potential high cost for a low temperature application

The following is a summary of basic well properties assumed for this project:

Property	Value	Comment
Reservoir(s)	4 various	3 sand, 1 limestone
Rock quality	Weak	High porosity sandstone
Depth	2 – 3 km	True Vertical Depth
Average temperature	<110 Deg C	Geothermal grad. +/- 31°C/km – locally to 35-38°C/km
Reservoir pressure	Hydrostatic	1 bar per 10m. Sub-hydrostatic should perform just as well
H2S (mol %) – gas phase	Zero	Initially, although some souring may occur
CO2 (mol %) – gas phase	0.24 – 56.7	
O2 (mol %) – gas phase	Zero	Although risk of being introduced at surface
Salinity/Chlorides (mg/l)	37-206,000	

Table 1-1 Basic reservoir properties of low enthalpy geothermal wells in the Netherlands

1.3 Potential Benefits of a Non-metallic Solution

In addition to the elimination of corrosion and the reduction in scale deposition due to the reduced roughness, potential benefits would include:

- Roughness/friction reduction will also result in increased flow., Typical absolute roughness coefficients for stainless steel, carbon steel and corroded carbon steel would be of the order of 0.002mm – 0.05 mm, 0.045mm – 0.09mm and 0.15mm – 4.0mm, respectively. The roughness of GRE, on the other hand, would be some 0.006mm. The roughness coefficient of corroding carbon steel will, of course, increase with time.
- The weight reduction (of a full composite string vis a vis steel), with the associated handling benefits.
- Transparency to a greater range of EM logging techniques.
- Another benefit is a lower Opex, because no corrosion inhibitor has to be used, saving up to € 100 K a year, although some scale inhibitor may still be required.
- Reduced carbon footprint of a full composite string and elimination of corrosion related workovers.

Figure 1-1 illustrates the complexity of selecting an appropriate Corrosion Resistant Alloy (CRA) for a geothermal application. Selection of a non-alloy option, on the other hand, is relatively straightforward, where the primary selection criterion is temperature.

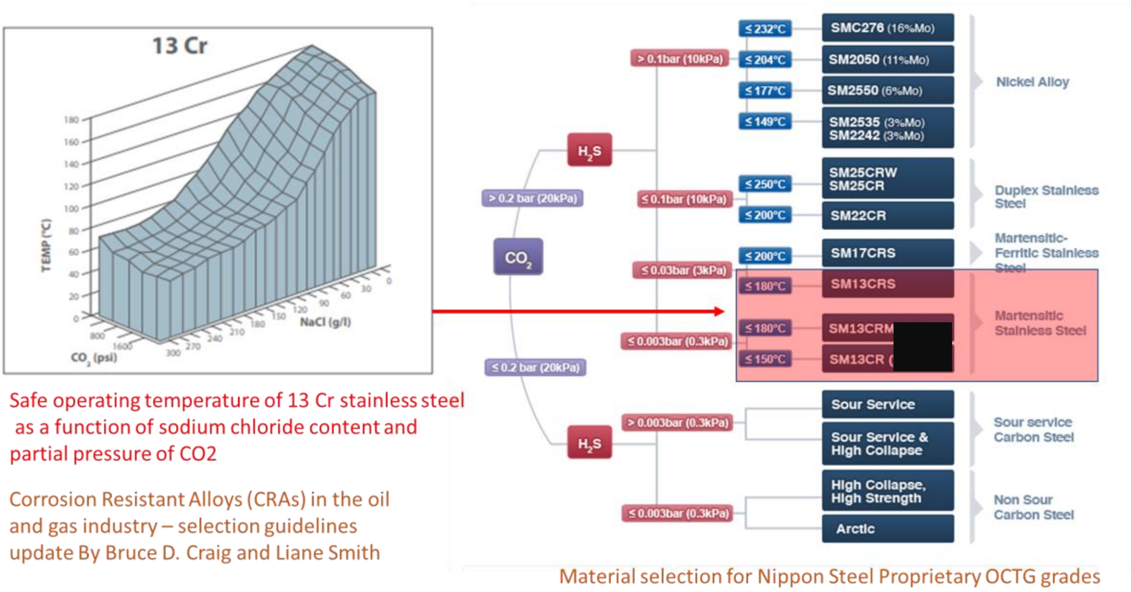

Figure 1-1 Conceptual Selection Process for Conventional Cr13 OCTG Alloy

2 STUDY APPROACH AND STRUCTURE

Many of the key elements of this note are contained in the Appendices. Appendix A is a summary of potential providers of non-metallic tubular downhole products and their relevant properties. Appendix B is a diagram depicting the long term loads that the wells are likely to be subjected to. Appendix C is an example of possible solutions and Appendix D is a comparison of the reported performance properties of ENC coating and GRE.

In addition to conventional sources, papers (e.g. SPE articles), input also solicited from industry experts - OCTG specialist (Geoff Thompson), composite specialist (Mike Hiton), completion engineer and engineers familiar with NL geothermal activity (Rob Peters).

The study is focused on what are perceived to be the most promising potential solutions – either complete GRE tubular solution, GRE or Thermoplastic lining on a carbon steel base pipe and abrasion resistant coating. Accessories, X-overs, PBRs, etc., are still assumed to be manufactured from more exotic alloys and Xmas trees and wellheads with internal cladding (e.g. Inconel.), with the exception that threaded X-overs are feasible with full GRE tubulars. This is due to the current manufacturing complexity and practicality with GRE tubulars. Sand screens are also assumed to be manufactured from higher alloy steel, or possibly ceramic screens with alloy or abrasion resistant coated, base pipes. A two barrier policy is also supported, and it assumed for practical and structural integrity reasons, this comprises a steel permanent outer production casing string/barrier and a replaceable inner string.

CRA lining is included, despite the fact that it is metallic as it has potential advantages vis a vis conventional alloy once developed.

In addition to the summaries in the Appendices, greater detail is also included in Section 4 for the most relevant SPE papers, and other key documents, on this topic - synopsis of paper and primary study conclusions.

3 OVERVIEW OF NON-ALLOY TUBULARS

This section looks at the overview of non-alloy tubulars. For each material, the following issues are addressed:

- What is it?
- Why do we use it?
- Manufacturing process
- Historical background – when and where has it been used – essentially everywhere for >40-50 years)
- Material specifications
  - Collapse
  - Burst
  - Tensile load
  - Axial load
  - Corrosion resistance – high in all cases equally.
  - Operating envelope (pressure, temperature)
- Costs
- Strengths and Weaknesses (Section 5/threats and section 1.3 pros)
- Other casing sizes (Appendix A)
- Rethreading possibilities
- Internally flush connections Appendix A
- ESP vibration threat

3.1 GLASS REINFORCED EPOXY (GRE)

Manufacturing Process for Full GRE Tubulars – e.g. STAR, Future Pipe and Huisman

The most common manufacturing process for GRE oil well tubulars is the filament winding process. By this method, a large number of resin impregnated glass roving are wound on a rotating steel mandrel, at a precisely adjusted helix angle under a uniform tension, thereby assuring that all fibres contribute to an equal extent to the strength of the pipe. Each glass roving consists of multiplicity of parallel glass fibre strands. The glass roving in the laminate will function as the load carrying reinforcement.

In combination with the curing time, the resin also determines the type of resistance (microbial corrosion, CO_2, etc.) that the pipe will ultimately be subjected to. Other than glass rovings, the primary factors that determine the mechanical strength and resulting performance of the pipe are the resin and manufacturing methodology. The design workflow for fiberglass pipe is case specific, rather than diameter/strength related as with carbon steel.

Future Pipe's "Wavistrong" tubulars are manufactured using this process. The maximum temperature of which is 100 Deg. C. A schematic of this process is as follows below (Figure 3-1):

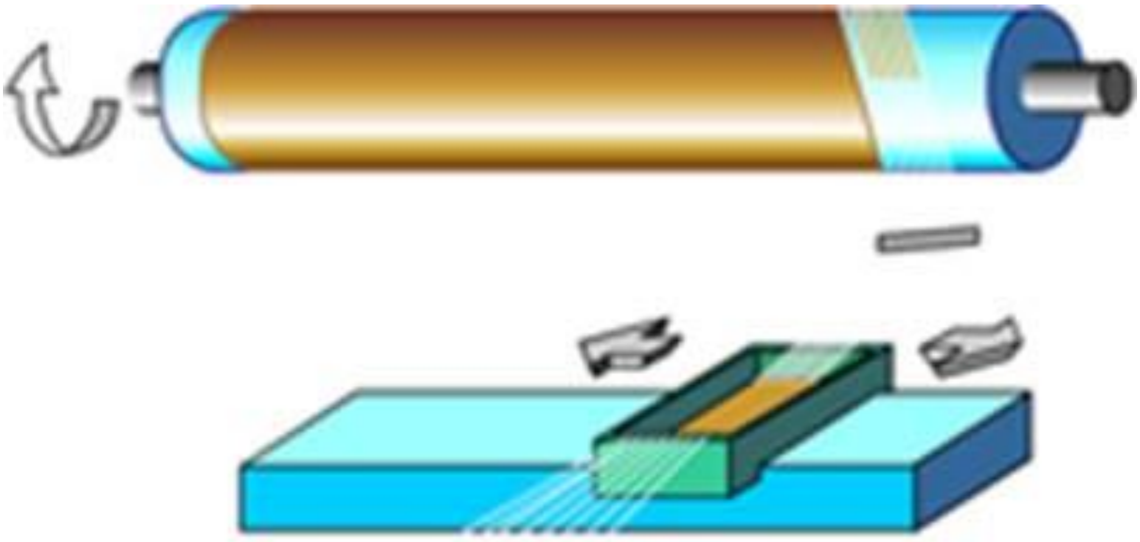

Figure 3-1 Simple Schematic of GRE Manufacturing Process

The wall structure consists of a resin-rich inner layer and is reinforced with a C-glass fleece. This inner layer gives the product a very good resistance to chemically aggressive media. The reinforced wall consists of E-glass reinforcement, impregnated with an amine cured epoxy resin. The thickness of the reinforced wall depends on the pressure rating. Finally, the wall has a topcoat of epoxy resin, with a minimum thickness of 0.3 mm (Figure 3-2).

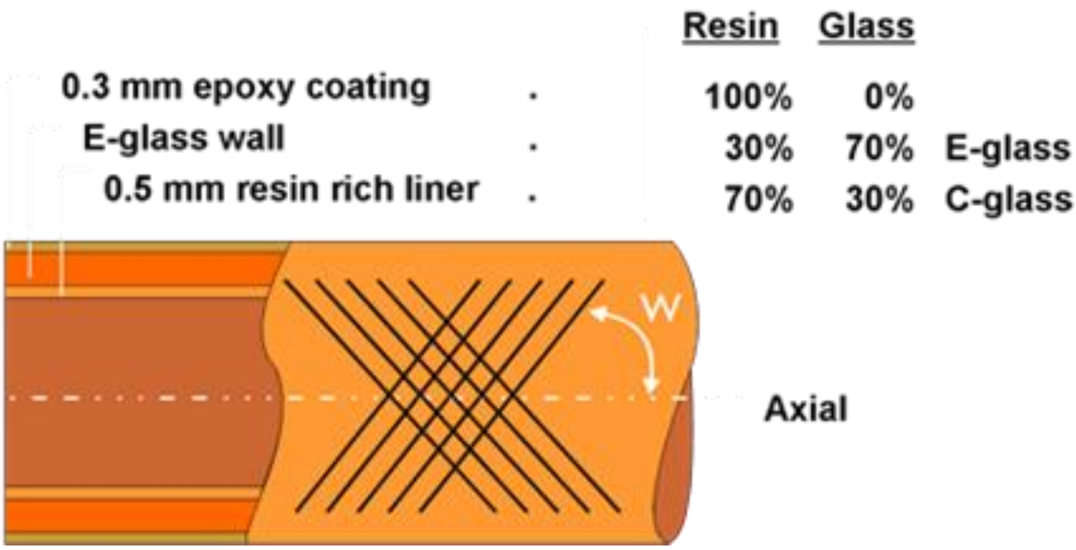

Figure 3-2 GRE Components

The performance characteristics of full GRE are essentially governed by wall thickness. To illustrate, the following is an example of a conventional (Future Pipe and NOV/STAR examples) 8” and 6 5/8” nominal pipe with a range of collapse strengths, with corresponding wall thicknesses:

Future Pipe	Collapse Pressure (psi)				
	500	1000	1500	2000	2500
Burst Pressure(psi)	1,350	1,750	2000	2000	2000
OD (in)	8.650	8.870	9.031	9.165	9.280
ID (in)	7.874	7.874	7.874	7.874	7.874
Coupling OD	12.559	13.189	13.639	13.639	13.639
Tensile rating (lbf)	45,911	60,111	70,740	79,626	87,442
Wall Thickness (in)	0.378	0.498	0.5785	0.6455	0.703

Table 3-1 Basic Dimensions Of Conventional 8” Nominal Pipe

NOV STAR	Collapse Pressure (psi)				
	400	500	1100	1900	2500
Series	1,000	1,250	1,500	1,750	2,000
OD (in)	6.52	6.07	6.22	6.37	6.51
ID (in)	5.94	5.50	5.5	5.5	5.5
Coupling OD (T&C)	7.54	7.80	7.8	8.25	8.25
Tensile rating (lbf)	46,000	44,000	56,000	68,000	70,000
Wall Thickness (in)	0.29	0.29	0.36	0.435	0.505

Table 3.2 Dimensions of STAR 6 5/8” Nominal Casing

The second method for manufacturing GRE pipe is the rotational/centrifugal casting method (CCM). This method essentially involves filling a mould with a polymer, to melt the material, rotating at high speed, cooling and removing the tubular. Huisman has refined this to have greater control of the manufacturing process, producing tubulars with a constant inner and outer diameter.

Overall, the filament winding method is more common, relatively low-cost, enabling reinforcement in specific areas. The main drawback is that the product may not be as strong and could potentially degrade with time, due to the angle of the fibres with respect to the pipe and due to the possible inclusion of air bubbles in the resin.

Typically, full GRE tubulars (e.g. Future Pipe) can be manufactured in sizes from 6” up to 24” (Nominal) and have the following characteristics

- Resin System – Aromatic Amine Cured Epoxy
- Joining System – FPI’s patented 4Rd, Threaded and Coupled Connection (T&C)
- Product Length – 12 meters (39.4 feet) Pin-Pin Pipe
- Shop / Mill Hydrostatic Test – 100% of pipes tested at 1.25 times the pressure rating
- Wall roughness k=0.01-0.02 mm– Hazen-Williams coefficient 150
- Depth >13,000 ft
- 100 Deg C Continuous
- Lead time 12-16 weeks

What	Use	Manuf. Process	Material	Collapse	Burst	Tensile	Axial	Temp'	Press	Cost vs CS	Threats
Tubular	P, WI & Geo Wells	Section 3.1	GRE	Up to 2,500 psi	Up to 2,000 psi	Table above	Table above	100 C	Depends on thickness	2-2.5	Wear?

Table 3-2 Data Sheet for typical full GRE – Future Pipe (more data included in Appendix A)

Cementing efficiency with GRE

It has been established that latex cement bonds to fibreglass casing as well as resin based cements.

The cement bonded well even after the pipe failed in compression – SPE 178729.

Cementing GRE thus shouldn't be an issue, as a variety of successful examples have been documented over the last >30 year. Precautions could, however, include cementing in two stages to minimise the risk of exceeding the collapse rating, keeping external/internal differentials below ratings and avoiding shock collapse pressures when seating wiper plugs.

3.2 Internal Plastic Coatings

Although Internal Plastic Coatings have historically had an anecdotal poor reputation, due to their perceived vulnerability to wear, and the associated risk of creating hotspots and accelerating corrosion at these points, their performance has improved during recent years (refer SPE 162182). They have therefore been included in this review. They are essentially applied by spraying either in liquid form or by powder coating. Good examples are NOV's TK range (Appendices A and E). Hillong (TC range) and Smith International/Schlumberger also market coatings.

What	Use	Manuf. Process	Material	Collapse	Burst	Tensile	Axial	Temp'	Press.	Cost vs CS	Threats
TK-2	Oil, fresh, salt water	Section (liquid)	Phenolic	Base Pipe	Base Pipe	Base Pipe	Base Pipe	204 C	Base Pipe	2-2.5	Wear?
TK-44LP	Line pipe	Section 3.2 (powder)	Epoxy	Base Pipe	Base Pipe	Base Pipe	Base Pipe	107 C	Base pipe	2-2.5	Wear?
TK-900	Oil, gas, water	Section 3.2 (powder)	Mod. Novolac	Base Pipe	Base Pipe	Base Pipe	Base Pipe	149 C	Base Pipe	2-2.5	Wear?

Table 3-3 Data Sheet for typical IPCs – NOV/Tuboscope (more data summaries in Appendices A and E)

3.3 THERMOPLASTIC

Manufacturing Process for Thermoplastic liners (TPL) - e.g. Western Falcon

Typically manufactured using an extrusion moulding process. Western Falcon is an example of a manufacturer of this technology and markets the following products.

Polycore is a High-Density Polyethylene (HDPE) abrasion resistant liner, chemically resistant to corrosive materials and tolerant to minor imperfections. Maximum temperature 82 Deg. C

What	Use	Manuf. Process	Collapse	Burst	Tensile	Axial	Temp'	Press.	Cost vs CS	Threats
HDPE	P, WI & Geo Wells	Section 3.3	Base Pipe	Base Pipe	Base Pipe	Base Pipe	82 C	Base Pipe	2-2.5	Wear?

Table 3-4 Data Sheet – Western Falcon Polycore (data summary in Appendix A)

Modified Polycore (HDPE) is highly abrasion resistant, mitigating tubing rod wear, wire line, mechanical, and handling damage. HDPE is chemically inert to corrosive materials. The mechanically bonded seamless thermoplastic tube is tolerant to minor imperfections. The maximum temperature is 71 Deg, C.

What	Use	Manuf. Process	Collapse	Burst	Tensile	Axial	Temp'	Press.	Cost vs CS	Threats
HDPE	P, WI & Geo Wells	Section 3.3	Base Pipe	Base Pipe	Base Pipe	Base Pipe	71 C	Base Pipe	2-2.5	Wear?

Table 3-5 Data Sheet – Western Falcon Modified Polycore (data summary in Appendix A)

Enertube is a liner manufactured from a blend of polyolefins. This liner is similar in mechanical properties to Polycore with a moderate increase in tensile strength and temperature resistance. This generation of Falcon liners is designed to operate in wells too hot for Polycore and is a seamless mechanically bonded liner providing a smooth tubing surface. Maximum temperature is 99 Deg. C.

What	Use	Manuf. Process	Collapse	Burst	Tensile	Axial	Temp'	Press.	Cost vs CS	Threats
HDPE	P, WI & Geo Wells	Section 3.3	Base Pipe	Base Pipe	Base Pipe	Base Pipe	99 C	Base Pipe	2-2.5	Wear?

Table 3-6 Data Sheet – Western Falcon Enertube (data summary in Appendix A)

Ultratube is a high-performance liner manufactured from polyphenylene sulphide thermoplastic resin for use in downhole oil and gas production environments. This liner has an increase in temperature stability, tensile strength, abrasion, and chemical resistance compared to the other liners. The polymers in this liner offer the broadest range of resistance to solvents, steam, strong bases, fuel, and acids. These polymers are designed to limit the permeability of acid gases - CO_2 and H_2S.T The maximum Temperature in 175° C in all services.

What	Use	Manuf. Process	Collapse	Burst	Tensile	Axial	Temp'	Press.	Cost vs CS	Threats
PST	P, WI & Geo Wells	Section 3.3	Base Pipe	Base Pipe	Base Pipe	Base Pipe	175 C	Base Pipe	2-2.5	Wear?

Table 3-7 Data Sheet – Western Falcon Ultratube (data summary in Appendix A)

Extremetube is a liner for extreme operating conditions. The liner is made from PEEK Polymer and is the highest tensile strength and highest temperature liner. It's a good alternative to CRA tubulars. Maximum Temperature 260° C.

What	Use	Manuf. Process	Collapse	Burst	Tensile	Axial	Temp'	Press.	Cost vs CS	Threats
PEEK	P, WI & Geo Wells	Section 3.3	Base Pipe	Base Pipe	Base Pipe	Base Pipe	260 C	Base Pipe	2-2.5	Wear?

Table 3-8 Data Sheet – Western Falcon Extremetube (data summary in Appendix A)

3.4 Nickel Coated Tubulars

Electroless Nickel Coating (ENC) Manufacturing Process – e.g. Integrated Protective Coatings (IPC)

IPC's ENC coatings have been used to minimize corrosion and erosion in the oil & gas industry for 50 years. ENC is a metallic glass, containing 11 to 12% phosphorus dissolved in the nickel. The coating is completely amorphous without segregation & grain boundary or separate phases. The structure produces the properties of this coating and makes it particularly suitable for corrosion/erosion protection.

With electroless deposits, the thickness is the same on all areas of the part: slots, holes, and the internal tubing walls have the same amount of coating as the outside of the component, especially important for equipment where close tolerances and smoothness are needed to avoid erosion and leakage. The high strength and good ductility of electroless nickel allow it to withstand considerable mechanical abuse without damage. Its high hardness and natural lubricity provide excellent resistance to abrasion and galling.

The wear resistance is comparable to that of hardened alloy steels. Additional heat treatments can produce hardness as high as 1100 VHN - abrasion resistance equivalent to commercial hard chrome coatings and comparable to that of some hard facing and ceramics.

The following process is used for the preparation and application of ENC.

- Thermal cleaning at 370° (700°F), to eliminate any organic contaminants

- Sandblasting with Garnet, (to remove any contaminants and to produce an adequate surface roughness.
- Rinsing in cold/hot water and chemical etching (this step helps remove any sub-microscopic contaminants, and allows the deposit to establish metallic as well as mechanical bonds with the substrate)
- Electroless plating (dipping into the plating bath at 85-90°C for several hours).

ENC is resistant to HCL (and HF) for the duration of a standard oil field stimulation treatment. It is also impervious to chloride stress corrosion cracking and hydrogen embrittlement from prolonged exposure to formation fluids.

A key benefit of both full GRE composite and ENC coatings is that both the inside and outside can be protected,

What	Use	Manuf. Process	Collapse	Burst	Tensile	Axial	Temp'	Press.	Cost vs CS	Threats
ENC	P, WI & Geo Wells	Section 3.4	Base Pipe	Base Pipe	Base Pipe	Base Pipe	205-399 C	Base Pipe	2-2.5	Wear?

Table 3-9 Data Sheet – Integrated Protective Coatings Electroless Nickel Coating (data summaries in Appendices A and D)

3.5 GRE Lining and Cladding

Internal GRE lining – e.g. MaxTube/Duoline 20 and NOV's TK

Essentially, a GRE insert is manufactured using the filament-winding process, in common with the full GRE solution. The GRE is installed, grouted, in OCTGs (new or old) for structural strength, with corrosion barrier rings at the connections to ensure completion integrity and prevent leakage.

GRE lining is a well-established technique for protecting the internals of OCTGs and generally accepted to be a more robust alternative to internal plastic coating for long term corrosion protection. Maximum temperature 121 Deg. C.

What	Use	Manuf. Process	Collapse	Burst	Tensile	Axial	Temp'	Press.	Cost vs CS	Threats
GRE	P, WI & Geo Wells	Section 3.5	Base Pipe	Base Pipe	Base Pipe	Base Pipe	140 C	Base Pipe	2-2.5	Wear?

Table 3-10 Data Sheet – Maxtube Duoline 20 (data summaries in Appendices A and D)

Duoline 10-PE uses a heavy wall, high density polyethylene liner. It is primarily used in low temperature/pressure wells. Maximum temperature 71 Deg. C.

What	Use	Manuf. Process	Collapse	Burst	Tensile	Axial	Temp'	Press.	Cost vs CS	Threats
GRE	P, WI & Geo Wells	Section 3.5	Base Pipe	Base Pipe	Base Pipe	Base Pipe	71 C	Base Pipe	2-2.5	Wear?

Table 3-11 Data Sheet – Maxtube Duoline 10 (data summaries in Appendices A and D)

RiceWrap and NOV's Tubo Wrap are external fibreglass-epoxy wraps for corrosion control in dual completions or other external corrosive environments. They have the same temperature limits as Duoline 20.

What	Use	Manuf. Process	Collapse	Burst	Tensile	Axial	Temp'	Press.	Cost vs CS	Threats
GRE	P, WI & Geo Wells	Section 3.5	Base Pipe	Base Pipe	Base Pipe	Base Pipe	140 C	Base Pipe	2-2.5	Wear?

Table 3-12 Data Sheet – Maxtube RiceWrap and NOV's Tubo Wrap (data summary in Appendix A)

An example of NOV- flush GRE lining connection is depicted below in Figure 3-3.

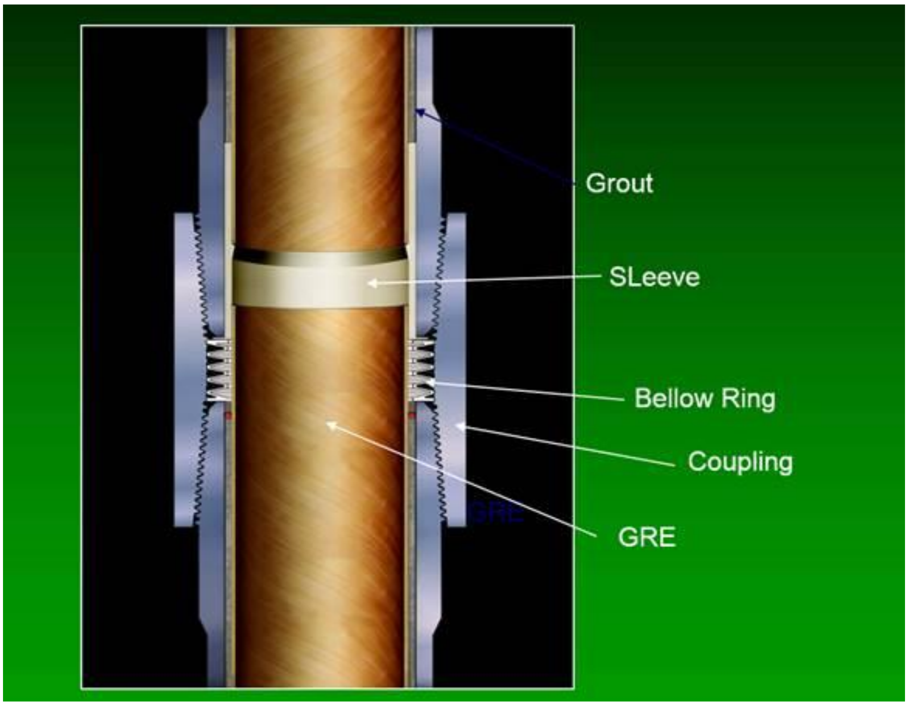

Figure 3-3 NOV - Tuboscope

A comparison of the reported performance properties of ENC coating and GRE lining is given in Appendix D.

3.6 CERAMIC COATING

Ceramic Coatings (e.g. Ceram-Kote, which is spray or powder applied) have been discounted due to short term practicality of internally coating tubulars at sufficient scale and sufficiently robust for tubular application and also at a reasonable cost. It may be possible for completion accessories. Ceramic coatings have been applied to the outside of tubulars, such as ceramic sand screen rings. However, this is not considered practical for the lengths of necessary for geothermal wells.

3.7 TITANIUM LINING

A CRA lined carbon fibre clad tubular concept (TCT) in the design phase. It has been included here, due to its potential once/if commercial.

The cost of smaller diameter pipe is anticipated to be roughly the same as Cr22. Larger diameter tubulars are expected to be slightly higher than Cr 22.

The first can be run as soon as a commitment has been made for a trial project.

Fourteen months lead time will be required in order to complete the API 5C5 CAL 4 test program and manufacture the tubing string.

Their manufacturing partner is Voith Composites in Munich Germany. Eventually, the aspiration is to construct a dedicated manufacturing plant.

3.8 METALLURGICALLY CLAD PIPE (BUTTING)

Butting also manufactures metallurgically clad pipes, but for surface applications. They offer the advantage of smaller wall thicknesses compared to austenitic solid-wall pipes and solid-wall pipes made from nickel-based alloys. Metallurgically clad pipes are used, for example, as SCR, riser or process pipes, pipelines or pipes for elbows and fittings. It is uncertain whether they ultimately intend to enter the downhole domain, but is perceived that they could eventually offer a comparable product to the titanium concept. It will, however, be a significant challenge to achieve if in a reasonable timeframe, at a competitive cost.

4 LITERATURE REVIEW

4.1 SOURCES

Sources were largely based on a review of relevant OnePetro published papers (SPE, etc.), discussions with key Vendors, Vendors published literature and experts, an Internet search and a summary of the most relevant documents identified.

Note. The specialists included Mike Hinton, a composites and materials specialist, Geoff Thomson, an OCTG specialist and Rob Peters, geothermal well expertise and knowledge of geothermal well activity in the Netherlands. In addition a number of service providers also provided valuable input, beyond their own product range – notably Future Pipe and IPC. The conclusions summarised for these reports (Section 4.2 and 4.3) are the published opinions/observations of the authors of the papers and not necessarily the views of the compilers of this document.

4.2 REPORTS

For the most relevant papers identified, a management synopsis and summary of primary conclusions was complied, below. Some additional relevant documents are also captured.

4.2.1 CORROSION REVIEW AND MATERIALS SELECTION FOR GEOTHERMAL WELLS – WOOD GROUP, JUNE 2017

Management Synopsis and Conclusions

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

4.2.2 OPTIMAL CHOICE OF WELL MATERIALS, PROJECTNUMMER: E16016, OCT 2016

Management Synopsis and Conclusions

This research focuses on the application of alternative casing in drilling for geothermal energy. Traditional drilling uses carbon steel. The use of carbon steel originates in the petrochemical industry. Casing used in geothermal projects is exposed to acidic and corrosive environments, just like in petrochemicals. The acid in this environment is released by a lower pressure and a higher temperature. In order to protect and (possibly) improve the investments and efficiency of the geothermal source, alternative casing is being investigated. This research describes the pros and cons of using the various options that can be used. The options are compared with the traditional carbon steel: - Carbon steel/Carbon steel (reference) - Chrome steel (13Cr80, DeepDrill) - Composite (NOV - Fiberglass Systems / Wavin - Future Pipe Industries / Akiet Downhole Composite Pipes) Based on the applicable laws and regulations, it has been analysed whether the alternatives comply. In addition, the properties of the alternatives have been compared with the reference material (Carbon steel). The elaboration of the product comparison and also the tooling developed can be found in chapters 7 to 10. Appendix C contains the web summary.

4.2.3 MICROBIOLOGY IN GEOTHERMAL OPERATIONS REPORT DEC. 2018

Management Synopsis

In a previous study it was shown that microbiology in geothermal systems is relevant for safe operations. This microbiology can originate from the underground. Previous studies were performed on one single geothermal system. The diversity of microbial species and corresponding risks for different geothermal systems was investigated in this study. Microbiological composition of production water of six geothermal system in the Netherlands was investigated using quantification (QPCR) and identification (NGS) molecular biological tools. With this information and help from operators four main microbiology related risks were defined 1. Obstruction, 2. H2S formation, 3. Microbiologically Influenced Corrosion (MIC) and 4. Degradation of corrosion inhibitor. The collected information is used to setup a risk assessment strategy which can be used for an optimal geothermal system from a microbiological point of view.

Conclusions

The results showed that bacteria are present in all geothermal systems analysed here. The composition of the microbial population showed variation between different systems but no direct relation was observed between the earth layer that was addressed for the geothermal system. In all systems Sulphur metabolizing bacteria were present. Sulphur metabolizing bacteria are related to MIC but also to precipitation of iron sulphide which can cause sudden release of hydrogen sulphide if acid is used for cleaning. Those species can only grow if Sulphur or sulphate is present. However, in geothermal water it is expected that a Sulphur source is available. The microbial results show that although the bacterial population differs from each other, all geothermal systems contains risks for the occurrence of microbial related obstruction, hydrogen sulphide formation, degradation of corrosion inhibitor and MIC.

4.2.4 INDUSTRY STANDARD SUSTAINABLE WELL DESIGN FOR GEOTHERMAL WELLS (JANUARY 2021)

Management Synopsis and Conclusions

Because it is important that geothermal energy is extracted safely and responsibly, the geothermal sector has developed an industry standard for the design of geothermal wells. The 'Industry standard sustainable well design for geothermal wells' was drawn up by Geothermie Nederland in collaboration with EBN. Well designs created from January 2021 must meet this standard.

The industry standard describes the process of achieving the safe and responsible well design over the entire life cycle, from design to decommissioning. This industry standard is a milestone for our sector. It gives confidence for the safe and responsible extraction of geothermal energy, which can promote the use of geothermal energy.

4.2.5 GEOTHERMICA - CASING SYSTEMS FOR GEOTHERMAL – NEW RESEARCH PROJECT GRE GEO

Management Synopsis and Conclusions

The EU-funded GEOTHERMICA program has launched new research project “Glass Fiber Reinforced Epoxy Casing System for Geothermal Application (GRE GEO) with 8 partners from Germany, the Netherlands, and Switzerland.

The consortium consists of eight partners:

- Gec-co Global Engineering & Consulting Company GmbH, Germany, main coordinator
- DrillTec GUT GmbH, Germany
- TU Clausthal (ITE), Germany
- Future Pipe Industries (FPI), The Netherlands, national leader
- Dynaflow Research Group DRG, The Netherlands
- Nuclear Research and Consultancy NRG, The Netherlands
- Eartha AG, Switzerland
- Service Industriels de Genève, Switzerland, cooperation partner

4.2.6 CARBON AND ENERGY FOOTPRINT OF NON-METALLIC COMPOSITE PIPES IN ONSHORE OIL AND GAS FLOWLINES

Management Synopsis and Conclusions

A Life Cycle Assessment (LCA) analysis was conducted to compare the carbon and energy footprint of several non-metallic composite pipes and carbon steel (CS) pipes used in onshore sour oil and gas (O&G) production flowlines, based on a specific deployment case (cradle-to-gate scenario). This work provides a systematic approach to assessing the carbon and energy footprint of fibre reinforced thermoplastic/thermoset pipes used in the O&G industry, while also accounting for the end-of-life recycling at the material phase, through the use of the recycled-content allocation method. The impact of corrosion allowance (CA), commonly used at design phase of CS pipes, is explicitly included and discussed. From the raw material extraction to the installation phase, all non-metallic pipe technologies assessed in this study were found to have a lower carbon and energy footprint than CS pipes. The reduction in CO_2 emissions can reach up to 60% while the energy footprint can be reduced by up to 50%. The material phase, particularly the composite layer for non-metallic pipes, was found to be the main contributor to the product footprint for all pipe technologies and any optimization in this phase could translate into a significant reduction in the overall CO_2 footprint of the pipe. The manufacturing phase is the second largest contributor to the emissions and was found to be (on average) five times bigger for CS pipes than any of the non-metallic pipe technologies assessed in this study. The use of stronger and lighter fibre reinforcements (e.g., carbon fibres) to substitute conventional glass fibres in RTP pipes enabled a noticeable reduction in the product weight. However, the potential in reduction of overall emissions was outweighed by the exceedingly high carbon intensity of carbon fibres. The results of this study are supporting an ongoing strategy for mass deployment of non-metallic pipes (a traditional driver in reducing operating costs) and provide a path for cleaner production and distribution of hydrocarbon resources. The conclusions of this work could be further developed by accounting for the operational phase of the pipes in question.

4.2.7 ADVANCED CARBON COMPOSITE MATERIAL FOR HEAVY OIL AND GEOTHERMAL ENERGY RECOVERY

Management Synopsis and Conclusions

Lack of high temperature elastic seals has been the bottleneck for the energy industry to economically and safely explore geothermal energy and heavy oils. The reserve of heavy oil is three times the total amount of conventional oil and gas combined, and resource of geothermal energy is almost unlimited. In these applications, hot fluids are required to be safely sealed in an enclosed system, the temperature of which could easily reach to 750°F (399°C) and above, and the seal material also has to survive the extremely corrosive downhole environment. Traditionally, elastomers are the materials chosen for downhole sealing applications. But this type of organic material is prone to decompose when temperatures approach 600°F (316°C) and even lower in wellbore fluids. Metal to metal sealing systems may have the temperature tolerance but lacks enough elasticity to provide reliable seal performance in downhole conditions. This presentation will introduce a newly developed elastic carbon composite (ECC), which is a highly engineered material with both mechanical and chemical properties readily tuned for specific applications. Tests show that the elastic carbon composite material has excellent thermal stability over 1000°F (538°C) and strong corrosion resistant to extremely corrosive environment including concentrated acid. In this presentation, we will also discuss the performance of the elastic carbon composite as a high temperature seal and provide some exemplary industrial applications in unconventional energy recovery, including packing elements, O rings, and chemical injection valves seals.

4.2.8 The Potential Application of Composite Pipes in Geothermal Drilling

Management Synopsis and Conclusions

One of the technologies that may undoubtedly revitalize the global geothermal market in the very near future is the use of composite materials for casing, liner and drill pipes in production as well as injection wells. Composites are created by combining two or more materials, one of which has a binding function and the others, introduced in granular, fibrous or layered form, serve to strengthen it. Composites are non-metallic anisotropic materials, that enable pipe constructions with different strength and physical properties depending on the direction of consideration. A typical composite pipe is made of a composition of resin reinforced with glass fibre. Pipes currently available on the market are able to operate at a downhole temperature not exceeding 105°C, however, research is underway to use composite materials under temperatures from 150 to 170°C in geothermal wells deeper than 3500 m. In the future, development of composite materials capable of operating in high enthalpy boreholes with temperatures of up to 300°C and depths of up to 5500 m is being investigated. Composite pipes with outside diameters between 5 ½ and 13 3/8 inches are currently available on the market. The maximum well pressure given by one of the manufacturers is 345 bar and their maximum strength is 450 tons. However, these parameters depend on the temperature in the well, geochemistry of the reservoir, the type of composites used and planned lifetime of the well. Composite pipes, on the basis of one of the manufacturers' data sheet, similarly to the conventional steel pipes, are 12 m long and have composite connections, which are installed when the pipes are being run into the hole. Such pipes are also compatible with conventional steel or composite-to-metal connections. Connecting two composite pipes on a drilling platform is the most technically demanding bricklaying process, which requires careful preparation, appropriate conditions and the right time to cure the adhesive material. The planned time for the installation of pipe joints is about 10 minutes.

4.2.9 Effect of Elevated Temperatures on Fiber Glass Composite Pipes used for Geothermal Well Completions

Management Synopsis

Geothermal well fluids may pose high corrosive loads on the casing and tubing used to complete the well. Recent developments in composite pipe manufacturing process, that allows the reduction of fabrication costs have pushed the composite pipes to enter on the market of well completion. Although high temperature may not be favourable to the implementation of composite pipes in high enthalpy geothermal wells applications, low enthalpy geothermal wells, especially those where the fluid temperature is lower than 150°C have considered the use of fibre glass reinforced composite pipes. This paper shows the experiments performed on several fibre glass composite pipes to understand its response to thermal cycles and the results found show that thermal cycling may reduce the pipe strength with up to 10%. The tests have been carried out for a time frame of 3 weeks, and some samples have been continuously heated, while others have been heated for 8 hours and left to cool for 16 hours. The samples' mechanical properties have been measured using a modified pipe crushing test, which allow the use of short samples. Altogether, the experiments will help better understand the use of composite pipes in geothermal well completions.

Conclusions

Designing the completion of low enthalpy geothermal wells by the help of fiberglass composite tubular is proving to be a very simplistic and optimistic approach in order to minimize well intervention, save costs related to corrosion prevention and complex devices to accommodate tubular length change. In this paper authors presented an experimental study in which fiberglass composite degradation with temperature has been evaluated and quantified, by taking into consideration various scenarios which could be found throughout the lifetime of a geothermal well, whether an injector or a producer. The scenarios follow thermal cycling and continuous exposure to temperature loading, which lead to the result that epoxy matrix degradation due to temperature decreases the strength of the material with about 10% for a 3 weeks exposure. Extrapolating our current data, shows that the tested composite samples will only survive for about 36 weeks at continuous exposure to 60°C temperature or 47 weeks at daily cycles. Hence this is not a valid option. However, due to limited amount of current data, the presented results should be carefully used, especially for other type or composite fiberglass systems. At this point, long term investigations on composite fibre glass pipe are necessary to fully understand the degradation mechanism at elevated temperatures.

4.2.10 New Technology: Installation Of Composite Tubular For Thisted Varmeforsyning

Management Synopsis and Conclusions

On behalf of Akiet and Huisman Well Technology, WEP was involved in the development of void-free composite tubular and installation equipment, testing, and installation in the geothermal injection well Thisted-5 of Thisted Varmeforsyning. In five days, during daytime operation, the tailor-made slender glued connections were bond together (without any reject) successfully until Top of Liner and spaced out on Polished Bore Receptacle. The benefit of the Akiet composite casing in this application is to prevent corrosion and scaling which results in low friction and pressure loss to minimize operational costs as much as possible.

4.2.11 How the Geothermal Sector Gets Off the Ground in the Netherlands (ThinkGeoEnergy 26/07/2019)

Management Synopsis and Conclusions

The complete article describes how, there are today around twenty geothermal installations at work in the Netherlands, almost all in greenhouse horticulture. But with the ambition of the government for the construction of heating networks for heating homes with geothermal energy, hundreds of those wells will have to be added in the coming decades. In 2050, roughly half of the homes in the country will be connected to district heating and perhaps half of the heat will come into those geothermal networks.

The article provides details on the approach on how the sector in the country is starting up.

4.2.12 Permeation Damage of Polymer Liner in Oil and Gas Pipelines: A Review

Management Synopsis

Non-metallic pipe (NMP) materials are used as an internal lining and standalone pipes in the oil and gas industry, constituting an emerging corrosion strategy. The NMP materials are inherently susceptible to gradual damage due to creep, fatigue, permeation, processing defects, and installation blunder. In the presence of acid gases (CO_2, H_2S), and hydrocarbons under high pressure and temperature, the main damage is due to permeation. The monitoring of possible damage due to permeation is not well defined, which leads to uncertainty in asset integrity management. Assessment of permeation damage is currently performed through mechanical, thermal, chemical, and structural properties, employing Tensile Test, Differential Scanning Calorimetry (DSC), Fourier-transform Infrared Spectroscopy (FTIR), and Scanning Electron Microscopy (SEM)/Transmission Electron Microscopy (TEM), to evaluate the change in tensile strength, elongation, weight loss or gain, crystallinity, chemical properties, and molecular structure. Coupons are commonly used to analyse the degradation of polymers. They are point sensors and did not give real-time information. Polymers are dielectric materials, and this dielectric property can be studied using Impedance Analyzer and Dielectric Spectroscopy. This review presents a brief status report on the failure of polymer liners in pipelines due to the exposure of acid gases, hydrocarbons, and other contaminants. Permeation, liner failures, the importance of monitoring, and new exclusive (dielectric) property are briefly discussed. An inclusive perspective is provided, showing the challenges associated with the monitoring of the polymer liner material in the pipeline as it relates to the life-time prediction requirement.

Conclusions

Carbon Steel pipelines are prone to corrosion attacks. NMP plays a promising role as a liner to prevent the pipelines from deteriorating due to their proficient features such as their light weight, low cost, ease of installation, chemically, and thermal inertness. Polymer pipes do not have a prolonged life due to permeation damage. They have an inherent nature to provide pathways to hydrocarbons and gases to permeate through them. Plasticization and swelling occurred as a result of hydrocarbon absorption. Certain important characteristics, such as tensile strength and elastic modulus decline.

Many other scholars explored the permeation of acid gases and hydrocarbons over the years. Its monitoring is crucial for the safety and integrity of the company's assets. One common approach is the use and assessment of coupons in the field research. The molecular weight and mechanical properties act as a predictive approach to polymer degradation. It did not explain the process of damage, neither when it began nor how it continued.

4.2.13 An Update on the Use of Fiberglass Casing and Tubing in Oil and Gas Wells

Management Synopsis

Thirty years after the last paper on the subject, an update is required. This paper initially outlines a basic review of fiberglass piping in the industry and the manufacturing process. Field issues identified through literature, interviews and operator experiences have been presented and analysed. Methods and avenues to address these issues have been researched, and a look to the future of fiberglass in the field is provided. Pipe failure, logging, joining methods, fire safety, and handling have been addressed. Generally, as fiberglass accumulates further field-experience, issues and obstacles have been overcome generating many successful case histories around the world.

Conclusions

The days of corrosion issues with steel tubulars down hole are slowly but surely coming to an end. Alternatives like fiberglass casing have made significant advances and accumulated sufficient field experience in order to become a viable replacement for conventional carbon steel. All field issues that currently exist with fiberglass tubulars have multiple avenues of resolution, provided users are proactive and progressive. Logging, fire safety, joints, and standards have all been addressed either through experience or innovation. What remains is a basic yet careful approach to the handling and use of this material, as with all crucial equipment in the oilfield.

4.2.14 Thirty years of fiberglass pipe in oilfield application: A historical perspective

Management Synopsis

A 30-year history of the use of fiberglass piping (FRP) systems for oil production piping is presented. Speculation about future uses of FRP in the oilfields is discussed. Problems encountered during the introduction of this type of pipe to the oilfields, and the evolution of early oilfield FRP systems is described. Improvements in FRP during the period of recent oilfield growth are reported. A representative list of significant uses of FRP in oilfield applications today is presented.

4.2.15 A review of the design and analysis of reinforced thermoplastic pipes for offshore applications

Management Synopsis

The development and recent applications of reinforced thermoplastic pipes for offshore oil and gas applications are reviewed. The design and materials of reinforced thermoplastic pipes are presented. Reinforced thermoplastic pipes have been increasingly accepted as an important alternative to traditional metallic offshore pipes due to their distinct advantages such as a higher stiffness to weight ratio, improved fatigue resistance and better corrosion resistance. Their potential applications can be extended to deep-water risers. Loading conditions which could be experienced by them for offshore applications are described. Existent studies and analyses of offshore pipes under these loading conditions are discussed. Based on this discussion, this article outlines the limitations of the current studies of reinforced thermoplastic pipes and future work to improve the analysis and design of reinforced thermoplastic pipes is recommended.

4.2.16 Successful Oil and Gas Production Well Applications of Thermoplastic Lined Downhole Tubing: A Compilation of Case Histories Dating Back to 1996 - (Western Falcon - published 2018)

Management Synopsis

Thermoplastic liners are commonly used to protect a wide range of oilfield tubulars offering the advantages of increased corrosion resistance, wear mitigation, and ease of tubular installation while diminishing pressure drop issues and maximizing fluid throughput capacity especially in high rate wells operating with high velocity fluids. Furthermore, they may offer a competitive advantage over corrosion resistant alloys (CRA's), plastic coatings and thermoset liner products in extending tubular life. This paper compliments a recent paper focusing on water injection and disposal applications of the same liner products The most commonly used thermoplastic liners in oil and gas production service are largely extruded from polyolefins for installation in environments up to 99°C; yet, for more demanding environments, engineering thermoplastics such as PPS are available to handle temperatures as high as 175°C. In the most extreme production environments up to 260°C, liners made of PEEK are utilized. All of these polymers are significantly more flexible and impact resistant compared to traditional thermoset materials historically used to protect injection tubing meaning that they can be practically applied in harsh field conditions and maintain a protective barrier against the tubing ID even after pulling/rerunning tubing combined with multiple wireline and coiled tubing surveys. The same liners can be used to protect costly downhole components and jewellery such as packers and tubing anchors. Examples of lined tubulars with both API and premium tubular connections will be covered. This paper will present case studies detailing the successful use of thermoplastic lined tubulars including liner products composed of HDPE, a proprietary polyolefin blend, PPS and PEEK. All of the lined tubulars in these wells are still in service today and some were installed back in 1996. A review of critical limitations of the liners such as temperature and diameter changes will also be discussed in an effort to avoid the misapplication of thermoplastic liners. Improved tubular service life, economic benefits, and enhanced flow characteristics due to the high quality surface finish of the liners will be detailed in at least sixteen specific case histories and production well environments. Furthermore, to exhibit the overall economic impact of thermoplastic lined tubulars, a review of field installation and handling procedures will be presented as well. The fundamental technical benefits of various thermoplastic lined tubulars will be covered with an emphasis on the proven extension of production tubing service life using thermoplastic liners.

Conclusions

With over fifteen years of successful documented operation under very extreme downhole production conditions, TPL have proven to outperform other polymers in protecting OCTG from corrosion and abrasion. The ductility, thickness, and impact resistance of thermoplastics are able to handle most of the daily abuse seen on well servicing and drilling units. It is important to note that while TPL have dramatically improved the damage resistance of OCTG polymer protection products, they are not indestructible and can be mechanically damaged when handled abusively or improperly. On the other hand, the success of TPL products in these mature producing fields around the world are an indication of how well they perform under the most extreme corrosive conditions when wear and abrasion are strong contributing factors to the root cause of tubing failures. With a wide range of proven benefits like lower capital expenditure requirements, reduced tubular maintenance, corrosion control, improving flow characteristics inside the pipe, reducing the pressure drop, and ease of installation, removal and reinstallation, TPL tubulars are still growing in their use both inside and outside of North America. The value proposition that TPL tubulars present include using existing equipment and installation methods with very few minor modifications to standard procedures resulting in the ability to install production tubulars with extreme reliability and service life expectations in severely corrosive wells measured in decades.

4.2.17 CORROSION RESISTANT ALLOYS (CRAS) IN THE OIL AND GAS INDUSTRY – SELECTION GUIDELINES UPDATE

Management Synopsis and Conclusions

Corrosion Resistant Alloys (CRAs) are essential for providing long term resistance to corrosion for many components exposed to oil and gas production environments. Components include downhole tubing and safety critical elements, wellhead and Xmas tree components and valves, pipelines, piping, valves, vessels, heat exchangers and many other pieces of equipment in facilities. There are many CRAs to select from, and they can be characterized by their resistance to specific environments. Key environmental parameters influencing the corrosion properties of CRAs are:

- Temperature
- Chloride ion concentration
- Partial pressure CO2
- Partial pressure H2 S
- Environment pH
- Presence or absence of Sulphur

Between them, these parameters influence

- the stability of the passive film (initiation of pitting or general corrosion)
- ease of repassivation of initiated pits
- rates of dissolution of metal from pits
- the risk of Stress Corrosion Cracking (SCC) initiating and propagating

4.3 TECHNICAL PAPERS

4.3.1 SPE-198572-MS: THE FUTURE OF NON-METALLIC COMPOSITE MATERIALS IN UPSTREAM APPLICATIONS

Management Synopsis

Corrosion in oil and gas operations is generally caused by water, carbon dioxide (CO2) and hydrogen sulphide (H2S) and can be aggravated in downhole applications where high temperatures in combination with H2S introduce other challenges related to corrosion and iron sulphide (FeS) scale formation. The repair costs from corrosion attacks are very high and associated failures have effects on plant production rates and process integrity. To overcome this existing problem in upstream, non-metallic composite materials were introduced for drilling, tubular and completions in high risk, corrosive environments. The goal being to increase the well life cycle and minimize the effect of corrosion, scale and friction in carbon steel tubulars. The new proposed materials have light weight, high strength, and superior fatigue resistance in addition to an outstanding corrosion resistance that is able to surpass many metallic materials.

Economic analysis shows that utilization of non-metallic tubulars and internal linings will yield substantial life cycle cost saving per well mainly due to the elimination of workover operations. However, with these advantages, composite materials pose several challenges such as single source provision, high initial cost of raw materials, the manufacturing process, and the limitation of standards. As results, the polymer and composite solutions for upstream oil and gas are still very limited even in targeting low risk applications such as low temperature and pressure scenarios. Therefore, research & development (R&D) efforts are ongoing to increase the operation envelope and introduce cost effective raw materials for high pressure, high temperature (HPHT) subsurface applications.

The present paper highlights practical examples of non-metallic materials selection and qualification for upstream water injection/producer and hydrocarbon wells. Several future NM applications in upstream will be summarized. Challenges and R&D forward strategies are presented in order to expand the operation envelope of current materials and increase NM deployment to more complex wells, i.e., extended reach drilling (ERD)

Conclusions

Non-metallic composite based materials have been introduced in oil and gas applications including onshore, offshore and downhole. As clearly stated in the present paper, the deployment of NM materials in downhole applications has allowed to overcome corrosion challenges, minimize frequent workover, and extend the life cycle of critical downhole products, including tubular, drilling and well completions. As a result, much efforts by the industry has placed a heavy emphasis on robust deployment and development methodologies in alignment with the field applications trends to qualify cost effective composite materials covering many downhole applications. The path forward, which already started in R&D, is focused towards improving the composite business to serve the oil and gas industry. This involves the development of specific roadmaps for different product to accelerate the mass deployment, support localization and investment in research studies. This effort requires joint work with different entities that sets the basis for increasing the deployment of cost-effective materials for more demanding HPHT applications.

4.3.2 SPE - 178729-STU Performance of Fiberglass Casing and Tubing in Highly Corrosive Environments

Management Synopsis

The UER formation in the Dukhan Field, Qatar has an aquifer associated with it. Since the 1950's the UER aquifer has been used for water-flood source water, produced water disposal, and is a loss circulation zone for drilling purposes. Over a period of years, the carryover-oil and bacterial contamination from drill cuttings have soured the formation which has led to many corrosion related problems such as surface casing failure, resulting in a well lifetime of 3-10 years. The conductor pipe in the Dukhan field suffers from tidal oxidation-corrosion and will not usually last longer than 5-8 years. These field results are confirmed by casing-inspection logs.

Research proposal was to replace these with fiberglass casing and tubing. Any casing that is replaced would need to withstand similar reservoir conditions as the original steel and fulfil the same collapse and burst pressure functions. Despite plenty of mechanical testing data available on fiberglass as a material, there is very little existing research on cementing fiberglass casing in sour environments. Therefore, a field-specific, quantitative and mechanical test on fiberglass casing and tubing was performed. Before conducting physical research, we compiled industrial advantages of fiberglass through fiberglass manufacturer guarantees and product ratings. In the laboratory, we re-established the high resistance to corrosion of fiberglass, and demonstrated comparable compressive and shear strengths of fiberglass piping to that of steel.

Research revealed that latex cement would bond to the fiberglass casing as good as the expensive resin-based cement. The cement bonded very well and held even after until the piping had failed under compression. Surface casing and conductors made of fiberglass would not only be cheaper to transport and install, but also more resistant to all forms of corrosion, lighter to handle and easier to push into deviated or horizontal wells. (Williams 1987). Overtime, there will be a lower cost of corrosion-control and casing remediation. Indeed, fiberglass casing and tubing can be employed in the place of steel not only in the UER formation, but in a large number of highly corrosive environments, both downhole and in surface facilities.

Conclusions

Research proved successful in not only proving previously known facts (such as resistance to corrosion and lower density) but also proved comparable resistance to pressures. This led us to conclude that indeed, fiberglass is more resistant to corrosion than steel and withstands corrosive environments that are similar to the UER aquifer. Most importantly, fiberglass casing and tubing can withstand similar levels of shallow-depth compression and collapse pressure ranges as carbon steel. Also to be noted is the fact that latex cement bonded extremely well to our fiberglass casing that withstood even the compression-failure pressure of the piping. Fiberglass tubing and casing could indeed replace currently used steel in highly corrosive environments, in shallow and surface oilfield applications. Further recommendations include a ceramic lined casing to prevent drilling damage, and fiberglass-wrapped casing for deep, corrosive applications.

4.3.3 SPE-9636-MS: The use of Glass Reinforced Epoxy Resin Tubing in Oman

Management Synopsis

A total of three strings of glass fibre-reinforced epoxy resin (GRE) threaded and coupled tubing has been installed on a trial basis in the Natih and Fahud fields in order to determine if the known corrosion resistance of GRE is matched by a long term mechanical reliability. After some eighteen months exposure to normal operating conditions, the tubing is two water-injectors continues to give satisfactory service. The tubing in a gas lifted oil producer however failed – discovered, from workover, that the GRE had failed in a number of places.

Conclusions

The use of glass-reinforced tubing in low pressure shallow water- injectors, where conditions are corrosive to steel tubing has been proven successful in the Natih and Fahud fields, after more than one year continuous service. Installation of three additional GRE strings in the Natih field will are scheduled.

The application of GRE material in wet oil producers has to remain the subject of further investigation, after a first unsuccessful field trial. Emphasis has to be put on the determination of the resistance of GRE to dynamic loading, on accurate monitoring of loads and torque applied during installation and on the effect of frequent wireline operations on the GRE texture.

4.3.4 SPE-186229-MS: Mechanism of Scaling Corrosion for Water Injection System and Its Solution through Non-metallic Composite Tubing.

Management Synopsis

Water injection has been widely applied in tapping oil and gas resources underground, however scaling corrosion in the water injection system was a universal problem, posing a huge threat to the longevity of downhole tubing.

In this paper, SEM and XRED were employed to study the mechanism of scaling and corrosion in the water injection system, non-metallic composite tubing was developed and evaluated in terms of its ability to resist scaling and corrosion, field operation was carried out to testify this approach.

The results indicated that inorganic scale was formed as a result of Cl – , Mg+ , Ca+ contained in the injection water, parameters including temperature and pressure played a role in this process, the scale could become highly corrosive in the weak acid environment; non-metallic composite tubing was developed based on self-propagating high temperature synthesis technique, it was composed of three layers, ceramics inside, ceramic-metal combination middle, metal outside respectively, its scale rate was 1/70 compared to the conventional tubing, meanwhile the mechanical properties were better than its metal counterpart, field operation was performed in several oilfields, demonstrating strong scale and corrosion resisting characteristics, the statistic over 3years indicated that non-metallic composite tubing guaranteed the smooth water flooding operation downhole, while conventional tubing was suffering from severe corrosion.

This paper contributed to better understanding the scale and corrosion in the water injection system and its prevention technique of non-metallic composite tubing, through the pioneering example and profound insights we were able to explore new horizons and yielded more benefits to development of water injection operation.

Conclusions

In this paper, corrosion mechanism of in the water injection system was studied, composite tubing was introduced and its scaling ability was tested, finally field sample tunings at different depth in the water injection system were collected and tested, several conclusions could be drawn in this paper as follows:

1. The formation of scale could be divided into organic and inorganic part; both were detrimental to the longevity of tubing.
2. Compared with traditional metal tubing, composite tubing could reduce the scaling significantly which has been proved in the field operation.
3. Field sample test demonstrated that coupling helped the formation of scale, while the well depth could reduce the intensity of scale due to temperature and pressure reason.

4.3.5 OTC-8620-MS: Spin-off Technologies from Development of Continuous Composite Tubing Manufacturing Process

Management Synopsis

A NISTIATP sponsored consortium was formed to develop a continuous process to manufacture high quality, long-length composite tubing, up to 3.1/2" diameter. The goal of the project was to produce a composite material from a continuous process that equalled the quality of composite material produced using more traditional batch type processes. The project has resulted in continuously produced composite tubing of a quality that meets and, in some cases, exceeds that of batch processed composite materials.

The research conducted in this effort to develop the manufacturing process and equipment, resulted in several significant advancements of composite manufacturing technologies. This paper discusses some technological advancements that came from this collaborative effort, including: a method of continuous resin impregnation that yields composite laminae with void contents consistently below 1%, a high speed process for wet pre-preg manufacturing, and a non-destructive inspection method for continuous in-line resin cure measurement. Brief mention is also made of a liner adhesion process. These technologies are key to the reliable production of cost-effective composite products being introduced for use in the oil industry.

Conclusions

In summary, process technology and associated hardware has been developed that enables the production of virtually void free wet resin impregnated fibre bundles. This material is useful in high-rate production of advanced composite structures in a variety of existing manufacturing approaches including fibre placement and filament winding. Fibre impregnation rates in excess of 60 feet per minute have been demonstrated. Finished filament wound composite laminates manufactured with this technology consistently exhibit void contents less than 1%.

A non-contact, non-destructive testing method has been developed to measure degree of cure of composite laminate in a continuous cure process. The method has application for quality control and verification in the manufacturing operations of continuously manufactured tubing. Work is currently underway to apply fuzzy logic to operational software to automate control of the upstream variables of oven zone temperature and dwell time. A liner adhesion process developed to bond Rilsan liner to composite laminate has been developed, and results in interfacial strengths in excess of the Rilsan yield strength.

These processes are being employed in the production of continuous, long length spoolable composite tubing. This tubing offers operational benefits in downhole coiled tubing operations, high pressure production and injection flowlines, and flexible production risers.

4.3.6 PETSOC-02-06-GE: Composite Lining of Tubulars as an Economically Sound Solution to Oilfield Corrosion

Management Summary

Tubular goods lined with Glass Reinforced Epoxy (GRE) composite liners have been used in corrosive service for 30 years and have gained worldwide acceptance as a solution to corrosion from salt water and exposure to acid-forming components of produced and injected fluids and gas. This acceptance is a direct function of the material's durability and long product life. This ultimately provides the end user a lower cost alternative to expensive steel alloys and opens up new opportunities in corrosive gas production and gas-lifted oil production, where previously chromium-nickel alloys have been exclusive choices. Advanced variations of GRE can now be utilized in deep gas production and corrosive high-temperature injection service, both on- and offshore.

Conclusions

Within the context of oilfield tubular goods, composite materials have been adapted to provide unsurpassed protection against corrosion. The marginal increase in cost over inferior products is justified by the extension in product life and freedom from the costs of maintenance, repair, and replacement of failed tubing and line pipe.

4.3.7 SPE-70027: GRE Composite-Lined Tubular Products in Corrosive Service: A Study in Workover Economics

Management Synopsis

This paper is a two-part discussion describing Glass Reinforced Epoxy composite linings manufactured and installed in oilfield tubular goods where the material functions as a barrier to corrosion. The paper first focuses on GRE composites in terms of effectiveness and product life compared with less-costly corrosion solutions (such as internal plastic coatings (IPC) and thermoplastic materials like HDPE and PVC). Next, actual case history economic data is presented to qualify the use of Glass Reinforced Epoxy-lined tubular goods over IPC for corrosive seawater injection service in the North Sea. These data are then extrapolated to construct a similar economic model based on workover costs in the Permian basin of West Texas. Additionally, net present value (NPV) analysis can be used to illustrate the saving s in long term operating costs over the life of the project.

Conclusions

Historically, the construction of a barrier between a corrosive fluid and a given material has been among the most effective means of protecting a valuable asset from unnecessary destruction. The evolution of the lining process for tubular goods has culminated in the prolific advance of composite materials as corrosion barriers, especially in the oilfield environment. Costly corrosion damage has been largely mitigated by protecting the tubular goods with Glass Reinforced Epoxy liners. This material has proven to be highly resistant to many forms of corrosive environments, durable to the extent of enabling wireline and coiled tubing operations, highly effective in gas service and well-suited to both downhole and surface environments in terms of material strength and performance. GRE is a premium lining product and the initial capital outlay for GRE lining unarguably exceeds that of internal plastic coating (IPC) and thermoplastic lining products such as PVC and HDPE. However, the performance of GRE and the longevity of projects using GRE lined tubular products in service are well-documented. The economic advantages of an incremental increase in expenditure at the outset of a project are made apparent upon examination of the costs of using less expensive products which will ultimately require high operating expense over the project life

4.3.8 OTC-8621-MS: Development Update and Application of an Advanced Composite Spoolable Tubing

Management Synopsis

Development of advanced composite spoolable tubing offers several new solutions to many challenging well servicing and well construction operations. These are available up to 3.1/2" diameter. Attributes such as excellent corrosion resistance, low material density and weight, coupled with high working pressure and extensive fatigue resistance, make this product attractive for a number of oilfield tubular applications. These include well servicing strings and corrosion resistant completion strings. The advantage of an advanced composite spoolable pipe over steel pipe is that it can be "engineered for particular applications to take advantage of the composite's enabling attributes while optimizing the cost. Development efforts led by a spoolable composite products company and an oilfield service company have produced a novel composite spoolable tubing design targeted to meet these well servicing and construction challenges. This paper will review the development efforts and operation issues the developers have addressed to qualify the advanced composite spoolable tubing for several enabling applications and explore how it will provide operators future solutions.

Conclusions

The first commercial strings of advanced composite coiled tubing for well servicing and well completions are in the final stages of qualification. Standard product designs have been established as well as standard qualification procedures. In some applications, the advanced composite spoolable pipe will cost more than conventional steel tubulars, however, in applications where excellent corrosion resistance is required, the benefits of a seamless, corrosion-resistant composite pipe may warrant the additional pipe cost. In well-completion applications, improved flow performance and reduced installation cost because of the speed and ease installing a continuous pipe string instead of jointed tubulars can make the economics favourable when compared to corrosive-resistant materials such as 13-chrome type tubulars. In well-servicing operations in harsh environments it is possible for the savings of using corrosion resistant composite CT to exceed the additional cost of the pipe. The first commercial applications for this material are expected to proceed during 1998.

4.3.9 SPE-82045-MS: Field Experience With Composite Coiled Tubing

Management Synopsis

Composite Coiled Tubing (CCT) has been field tested on a number of applications with generally good results. This paper will summarize these field experiences and how the tubing has been improved from early versions to the latest product.

Conclusions

Coiled tubing technology has many advantages, the primary one being the low cost of deployment in many downhole applications. While great advances continue to be made in performance of steel coiled tubing and new applications continually introduced, there are some inherent limitations such as, fatigue life, difficult handling of larger sizes and corrosion which present commercial or technical hurdles. It was envisioned that composite coiled tubing would overcome many of these disadvantages and allow the range of applications for coiled tubing to grow.

What has been learned is that while these advantages are real, composite coiled tubing has several limitations. These limitations include low axial strength and stiffness as well as several technical issues which have yet to be fully understood and characterized. These issues are application dependent parameters that may result in collapse, gas permeation, and chemical interaction all of which are affected by well bore temperature. These limitations require careful choice of application and attention to application design. The current strategy is to focus on areas where one or more of the attributes of light-weight, corrosion resistance, and fast deployment methods have commercial advantage; and to select applications well within the limitations of the materials – principally shallow, low temperature, low pressure applications – to allow commercial success as well as field exposure. Four applications in particular show promise:

1. Large diameter CT for drilling (3.1/2”).
2. Fast deployment of coiled tubing for PCP and ESP pump systems.
3. Velocity strings for shallow but highly corrosive wells.
4. Injection and shallow production. Large Diameter CT for Drilling. Building on the work already done, Fiberspar will continue to develop the technology for the drilling environment. Ultimately these strings will incorporate data and power networks through copper conductors or fibre-optic wave-guides. Larger sizes will be produced to expand the potential depth and breadth of applications in highly deviated wells.

Development will continue on external wear issues, with the ultimate target of a product in the range of 1.5 times the cost of an equivalent steel string, but a life of better than three times the equivalent steel CT.

A 4 inch-diameter composite CT string has been designed and a 5,000 ft length will be manufactured and deployed in Canada in Q2, 2003. A specification for this design is shown in Table 1, column V.

One of the advantages of such a design is its high stiffness to weight ratio, particularly in heavier drilling fluids. Modelling on this string showed that when drilling 65 /8" hole with 12 lbs/gallon mud, horizontal extensions of over 1,000 ft. are possible with at least 1,000 lbs weight on bit. With a mud density of 14 lbs/gallon, the string would be almost neutrally buoyant and the length of horizontal sections will probably be limited by cuttings removal or hydraulic considerations rather than string lock up.

4.3.10 SPE-60750-MS: Anaconda: Joint Development Project Leads to Digitally Controlled Composite Coiled Tubing Drilling System

Management Synopsis

In 1997, Statoil and Halliburton Energy Services, Inc. began jointly evaluating technologies that could be used for a revolutionary coiled-tubing and well intervention system. This system, which will be deployed in the Norwegian sector of the North Sea, sets a new standard for drilling with conventional drilling or coiled-tubing drilling units. The advanced well-construction system consists of a digitally controlled and automated coiled-tubing drilling system that uses a new advanced composite coiled-tubing (ACCT) with embedded wires and a tractor-driven bottom hole assembly (BHA). This system enables the geological steering of complex, extended reach well paths that were not previously achievable.

This paper discusses a joint development project in which the Operator and the Service Company worked together to design a fit-for-purpose system that met Norway's stringent Health, Safety and Environment (HSE) requirements. The system's three major sub-systems are discussed: the digitally controlled and automated surface equipment, the 2 7/8" ACCT with embedded wires, and the drilling and intervention BHA. Test results from qualification and pilot wells are also included.

Testing the System

The Anaconda advanced well-construction system is undergoing extensive testing at the Halliburton Research and Development in Duncan, Oklahoma prior to deployment to the Norwegian sector. At the R&D centre, multiple casing sizes of various ODs and lengths were constructed into horizonal test loops.

Several casing joints were filled with various grades of cement. Including gravel-filled concrete. The system's BHA was then used to drill these joints with WOB provided by pushing the tubing with the injector. Although the composite tubing has a low resistance to buckling, the WOB sensor allowed the injector force to be controlled with fine precision. Results varied, depending on the type of cement used. Cuttings removed with and without the electrically activated circulation sub were measured at varying flow rates. Effects of "wiper trips" were also evaluated.

When the tractor was added to the BHA, personnel tested the tractor's walking, pulling and pushing rates. They drilled four sections of cemented casing at various bit rates and penetration rates and milled an exit window out of the horizontal casing off a whipstock with the tractor and other BHA components.

Conclusions

At time of testing, the system had performed more than 300 circulating and tripping hours (cemented casing) and 30 milling and reaming hours in the surface test flow loop. The ACCT endured more than 50 times the number of stress cycles that are usually considered acceptable for steel CT. with an equivalent OD. Some design changes were made to BHA components, electronics, and software as a result of the horizontal surface test program, and control software and hardware were refined.

The system carried out its intended functions. A test well has been drilled and cased down to 1800ft at Halliburton's Duncan centre. The Anaconda system will drill three extended horizontal sidetracks with multiple turn and build sections to test 3D steering capabilities, exercise the formation evaluation and directional sensors in a realistic environment, and perform real-time geosteering. These drilling programs are intended to qualify the Anaconda system for offshore field trials in the Norwegian sector of the North Sea in the midsummer of 2000.

4.3.11 SPE-60734-MS: Composite Coiled Tubing Solution.

Management Synopsis

Depending on the application, composite coiled tubing (CCT) may serve as a cost-effective alternative to conventional coiled tubing.1 Gas wells in Alberta, Canada often lose production when hydrates form as a result of temperature drops in gas flow. To reduce gas-flow temperature drop and prevent hydrates from forming, operators commonly use a steel heater string to heat the annular area between the production tubing and casing. Some wells require more heat to reach the critical hydrate temperature depth than others, resulting in higher costs for heating and pumping equipment. To reduce these costs, operators looked for a solution to temperature drop, and found it in CCT. Because of its low thermal conductivity (heat loss), a CCT heater string can reduce the need for upgrading or replacing surface heating and pumping equipment.

Conclusions

Operators used the same injector to pull the steel tubing and run the CCT string. This operation took 8 hours, including the nipple-down and nipple-up of the wellhead and flowlines (Fig. 6, Page 6). Operators then heated the annular area to operational temperature by circulating water heated to 167°F at 16 gal/min down the string and back to the surface, and the well was put into production. The wells production (Fig. 7, Page 6) was increased in the following four increments over 6 days: • 1.7 MMscf/D (0.5 MMscf/D above the previous production rate) • 2.1 MMscf/D • 2.5 MMscf/D • 2.8 MMscf/D (maximum allowable production rate) A temperature log was run 1 day after the well reached a production level of 1.7 MMscf/D to confirm that the temperature drop through the composite heater string and flowing gas temperature remained comparable to that of the steel heater string. The composite heater string provided a temperature differential increase above the steel string of 59°F at 4,593 ft and increased the flowing gas temperature by 39°F at the surface (Fig. 8, Page 7). The final result was a continuous flow from the well without hydrate problems, and production that more than doubled from 1.25 MMscf/D to 2.85 MMscf/D. Because of the new production level, the overall cost of the operation was recovered in less than 3 months

4.3.12 SPE-40031-MS: Composite Coiled Tubing in Harsh Completion/Workover Environments

Management Synopsis

Recent advances in the development of large-diameter and high-strength steel coiled-tubing (CT) products have helped fuel growth in the coiled-tubing industry. Advanced spoolable composite CT may offer advantages in some applications to the industry over current steel products. Composite CT could expand the market for coiled-tubing service and well completion. The composite CT’s resistance to corrosion from CO2 and H2Scshould make it readily applicable in injection, disposal, and producing wells in which current tubular installations demonstrate limited lifespans or where costly corrosion-protection systems are used. The composite CT may be a cost-effective alternative to 13-chrome and glass-reinforced epoxy (GRE) jointed pipe. Because composite CT is resistant to chemical stimulation fluids such as HCI in sweet and sour wells, the tubing may be more reliable than conventional tubing, and may provide a cost savings in larger treatments such as those used in horizontal stimulations

Conclusions

Composite CT will not replace steel tubing. It will cost more than conventional steel tubulars. However, in applications where excellent corrosion resistance is required, the benefits of a seamless, corrosion-resistant composite pipe may warrant the additional pipe cost. In well-completion applications, the reduced installation cost because of the speed and ease installing a continuous pipe string instead of jointed tubulars can make the economics favourable when compared to corrosive-resistant materials such as 13-chrome type tubulars. In well-servicing operations in harsh environments it is possible for the savings of using corrosion resistant composite CT to exceed the additional cost of the pipe. The first commercial applications for this material are expected to proceed during 1998.

4.3.13 SPE-46053-MS: Applications Update - Advanced Composite Coiled Tubing

Management Synopsis

Composite Spoolable Pipe for use in the Oil and Gas Industry is a new emerging technology. Enabling benefits include increased corrosion resistance, major weight reduction over steel as well as increased fatigue resistance. One company is close to commercial introduction of composite spoolable pipe for both well servicing and well completion operations. This paper will detail the latest application developments achieved at the time of the conference. It will cover the advancements made since the last update, SPE paper No. 38414 "Update on Composite Spoolable Pip Developments" presented at the 2& North America Coiled Tubing roundtable in April 1997. The focus will be on the application of this technology in its first commercial operation.

Conclusions

The first commercial strings of advanced composite coiled tubing for well servicing and well completions are in the final stages of qualification. Standard product designs have been established as well as standard qualification procedures. In some applications, the advanced composite spoolable pipe W-II cost more than conventional steel tubulars, however, in applications where excellent corrosion resistance is require~ the benefits of a seamless, corrosion-resistant composite pipe may warrant the additional pipe cost. In well-completion applications, improved flow performance and reduced installation cost because of the speed and ease installing a continuous pipe string instead of jointed tubulars can make the economics favourable when compared to corrosive-resistant materials such as 13-chrome type tubulars. In well-servicing operations m harsh environments it is possible for the savings of using corrosion resistant composite CT to exceed the additional cost of the pipe. The first commercial applications for this material are expected to proceed during 1998.

4.3.14 SPE-46053-MS: Development of composite coiled tubing for oilfield services

Management Synopsis

As coiled tubing services expand to meet the challenges of the oil and gas industry, limitations of steel tubulars continue to temper the potential impact of this workover service. Presently, coiled tubing used in well servicing operations is milled from modified A-606 High Strength Low Alloy (HSLA) steel, with yield strengths ranging from 70 ksi to 100 ksi. Although current coiled tubing services can be performed safely and reliably with conventional steel coiled tubing, the behaviour of the isotropic metal limits the yield pressure and tensile load capability of the tube.

Conclusions

1. HSLA steel coiled tubing strings have a limited service life dependent upon the amount of internal pressure and bending cycles imposed upon the string.
2. The feasibility of constructing composite tubulars capable of being spooled onto and deployed through conventional coiled tubing equipment has been demonstrated.
3. Composite materials can be tailored to provide properties unavailable with metals such as high fatigue life, minimal diametral growth, and reduced weight.
4. Composite coiled tubing can be designed to meet spooling and high combined load imposed on high performance coiled tubing.
5. Composite coiled tubing provides the opportunity to expand the application opportunities to higher operating pressure and longer reach in horizontal and deviated wells.
6. Advanced low-cost manufacturing methods permit composite components to be produced at competitive prices

4.3.15 SPE-73928-MS: The Role of HSE in Field Testing - A Case History for the World's First Well Construction System Using Composite Pipe

Management Synopsis

Field-testing of new drilling tools introduces increased health, safety, and environmental (HSE) risks due to the unfamiliarity of the personnel with the new equipment and its operation. This paper presents a unique overview of the HSE challenges that were faced when an entirely new drilling system, not just the individual components, underwent its first field trial.

The Advanced Well Construction System (AWCS) introduced many new technologies, including Advanced Composite Coiled Tubing (ACCT), a downhole propulsion unit, and a hybrid rig design. By using a lightweight carbon-fibre pipe, the system was designed for geological steering of complex, slimhole well paths. The system incorporates three major subsystems: digitally controlled and automated surface equipment, a 3 1 /8-in. composite drillstring with embedded wires, and an electronically controlled bottomhole assembly (BHA). This system is designed to economically harvest hydrocarbon zones that were previously bypassed and to find and exploit new reserves from existing idle offshore wells.

Beginning with the initial feasibility study, both the oil company and the service company made a commitment to adhere to the highest HSE standards in all phases of the project. The resulting HSE program was derived from the knowledge, experience, and established procedures and processes of professionals throughout both organizations.

This case history presents details of the HSE program jointly developed and implemented by the service company and the oil company as part of a qualification program for this unprecedented drilling system. Evolution of the HSE program from project planning, through the HAZID/HAZOP processes, and on to full implementation during the drilling phase is examined. A detailed description of the cultural, engineering, and logistical challenges that were overcome during the implementation of the HSE program is provided. A discussion of the HSE program summary results and “lessons learned” during the project is also included.

Conclusions

Qualifying new systems and new technologies creates many unique HSE issues that must be anticipated and addressed to ensure a safe working environment.

- The operational and cultural differences between all involved parties must be recognized, defined, and mitigated as much as possible before the onset of the project.
- A single common HSE program, with clearly understood goals and terminology, must be defined, recognized, and understood by all parties involved in the project.
- A natural evolution of the HSE program occurs during the rig-up and operational phases of the projects as the different risks are identified and mitigated. The HSE program must be a “living and breathing” process capable of adapting to new situations as risks are discovered.
- The ability to have the program remain “dynamic” contributed greatly to the overall program success.
- Integration was the key to the HSE success on this project. Various cultures were brought together and performed at a high level under very challenging circumstances.
- HSE systems and programs must be customized for every scope change. Technologies that have worked independently present unique risk when operated simultaneously.
- Field support, line management, and “corporate” management must have aligned HSE objectives. Open communication is critical to maintaining an incident free working environment.
- Successful HSE performance can still be achieved even with some productive philosophical disagreements as long as the overriding objectives remain constant.
- The high level of commitment to creating an effective, fit-for-purpose HSE program, and emphasis on adhering to the highest HSE standards directly led to no lost-time accidents occurring during the project.

4.3.16 SPE-160236-MS: Experience with Fiberglass GRE Lined Carbon Steel Tubular for Corrosion Protection for Oil Production Applications

Management Synopsis

Saudi Aramco experienced serious corrosion problems in oil production tubing in one offshore field, attributed to presence of H_2S, CO_2 and varying levels of water cut.

In early 2002, the company installed on trial test basis Glass Reinforced Epoxy (GRE) or commonly known as fiberglass lined carbon steel tubing in three wells. The fiberglass lining was installed to provide a corrosion barrier to protect the steel tubing from internal corrosion. As far the technology, the fiberglass lining or sleeve is carried out joint by joint by inserting a solid fiberglass tube into the low cost carbon steel tubing and cement is pumped into the narrow annulus between the fiberglass liner and the carbon steel tubing. The connection area is protected by the combination of end flares and a corrosion barrier ring.

The company examined various methods to evaluate the performance of the fiberglass lined tubing, without having to pull out the tubing from the well as these wells are oil producers. After review of the evaluation options, it was decided to run a multi finger calliper to evaluate the condition of the fiberglass lining and check for any internal corrosion in the steel tubing. The log showed the fiberglass lining to be in good condition with no damage indicating that the steel tubing was protected from corrosion. The other two wells had no tubing leaks indicating the GRE lining is providing corrosion protection. Based on successful trial test results, the company adopted the technology to protect tubing strings deployed in corrosive environments in oil producers, water injectors and water supply wells.

Field experience has shown that the use of fiberglass lined tubing is a low "life cycle cost" solution compared to other options. There has been no workover in these wells since installation. Today fiberglass lined tubing is applied in Saudi Aramco in high water cut oil producers, water injectors and combined water source and injection wells.

The paper shares the history of corrosion, challenges and lessons learned during the implementation of the solution, various performance assessment methods evaluated and the results and interpretation of the calliper log.

Conclusions

Lessons learned:

- The GRE lined API 8 Rd EUE tubing exhibited a greater resistance to corrosion than the Premium IPC tubing over the 7 years of continuous service in production.
- Calliper results showed that majority of the tubing remained intact with no wall losses and scale build up as direct benefits of being inert to corrosive fluids and being smoother compared to carbon steel.
- Repetitive interventions over the 7 year period and the satisfactory status of the tubing showed that the GRE lined tubing is tolerant to wireline intervention without compromising its integrity.
- We could establish that 20% HCl pumped through the GRE tubing did not cause any appreciable damage to the ID and it is acceptable to bullhead 20% HCl acid through the GRE lined tubing.
- It is advisable to run non-motorized production roller centralizers whenever calliper runs are conducted on the GRE lining system.
- GRE lined API connection tubing can be a cost effective alternative to CRA tubing with Premium connections in low mechanical demand (lower depth and pressures, but with high corrosion potential) wells.

Benefits / Features of GRE Lined Tubular:

1. Extended well life and avoidance of frequent workover operations because of corrosion related problems.
2. Continuity of production / injection operations.
3. Positive business impact with less frequency of workover jobs and improved allocation of rigs and resources.

4. The connection area is better protected with GRE lined tubing compared to IPC tubing.

Drawbacks of GRE Lined Technology:

1. Reduction in inner diameter of the tubing and restrictions to run production logging tools. With GRE lined tubing the sizes of X-nipples need to be stepped-down.
2. Hydrofluoric acid (HF, commonly known as mud acid) cannot be pumped through GRE lined tubing. It is recommended using CT to spot the acid, if required.
3. For water injector wells, the maximum temperature limit is 130 °C (266 °F).
4. GRE lined tubing does not protect the tubing against scale formation from $BaSO_4$ and $SrSO_4$.
5. GRE Lining is not steel but it has better mechanical wear and resistance properties than Plastic or Epoxy coatings. The wireline operations require simple procedures and precautionary measures to get prolonged life.

Future Outlook

The product has been adopted for use in oil producers, power water injectors and water source wells. At the time of writing this paper, more than 22 wells have been installed with GRE lining between 2008 and 2012. This excludes the three wells where GRE lined tubing was installed in 2002; none of these wells have been reported of any failures.

4.3.17 OMC-2019-1030 Fibreglass Liner In Production And Water Injection Wells: Eni Experiences And Feedback

Management Synopsis

Glass Reinforced Epoxy (GRE) resin is a well-known and widely tested tubing lining system inside carbon steel tubing, that can be applied in production and water injection well as a cost effective alternative to high alloy materials.

This paper presents the characteristics of the technology applied, a summary of laboratory testing including CO_2 and H_2S resistance, high flow direct impact and erosion results, the implications and recommendations to be considered during the installation, case histories and the feedback from the fields where it has been applied.

The first of Eni's application of GRE lined tubing was done in 2005 in North Africa on production wells originally completed with Carbon Steel that were frequently prone to corrosion failures because of a high CO_2 concentration and high water cut and subjected to costly work-over.

Further field experience was achieved in another location in North Africa, with production tubing, which suffered frequent flow-induced corrosion, CO_2 corrosion and sand abrasion failures.

Another reported case is related to an installation in the Middle East, where the GRE lining has been run in two water injection wells, with cost saving in terms of Capex and Opex.

Eight water injection wells completed with 7" and 4"1/2 tubing in the Norwegian Sector of the Barents Sea is the last field case discussed in this paper. Due to high corrosiveness of the injection fluid, raw seawater with antifouling chlorination, the lining technology has been applied as a cost effective alternative to high alloy materials.

Feedback from the fields demonstrated that, when GRE resins are used within the operating limit, then this material represents a valid option for the well life extension and offers a life cycle cost saving.

Conclusions

The Glass Reinforced Epoxy Liner has been applied successfully in several Eni fields, onshore and offshore, as corrosion protection in oil production and water injection well tubings, and in surface gathering lines. The feedbacks from fields demonstrate that when used within the operating limits this material represents a valid option for life extension and allows to achieve a life cycle cost saving. The two tests verified the erosional resistance of GRE material with regards to its suitability for use in high velocity gas wells in very challenging conditions which simulated actual wells environments with regards to sand production and confirmed the GRE has the effective erosional properties needed. The economics of using GRE is well documented and further highlights the materials potential for cost savings over high grade corrosion resistant alloys in suitable Gas Production and Injection wells.

4.3.18 SPE 102963 Coulomb Na Kika: Deepest Water-Depth Completion With Internal Plastic Coating Tubing Application

Management Synopsis

The Coulomb field is the 6th field of the ultra-deepwater GOM Na Kika subsea development. The two subsea tie-back wells in the Coulomb development (the C-2 and the C-3) were completed in April and May of 2004, in 7,570' of water depth. When completed, the Coulomb wells held the industry record for the deepest water depth subsea completions in the world. The subsea trees and the surface-controlled subsurface safety valves also represented the deepest set to date. The development planning included selection of the optimum completion design to address a wild-cat in the northern block, which had not previously been penetrated. While the conceptual sand control design was based on data from the previously appraised southern block. The execution phase was performed on a Generation 5 Moored Mobile Offshore Drilling Unit (MODU) with no prior experience in deepwater completions. Value creation activities were employed to raise the awareness and competence of the rig team to transform improvement opportunities into high performance goals. The Heave-Compensated Landing System (HCLS)1 was used to install the subsea tree, tubing head spool and well jumpers from anchor handling vessels, hence expanding the scope of activities performed off the critical path of the rig and contributed significantly to the record breaking pace. Completion fluid, workstring and treatment fluid were carefully selected and tested for well-specific conditions. Specific challenges included the quick turnaround completion design and execution on a wild cat, optimizing the drill/complete sequence to complete in uncertain mineralogies, high day rate leading to a desire to be "quick but good", cooling effects due to huge riser volume and long riser trip times. Through extensive preparation and the use of several innovative concepts, record performance was achieved. This paper also gives an overview of the application of internal plastic coating of the production string in the Coulomb wells. Through nodal analysis with a match to the well performance data, it is demonstrated that the reduced tubing friction associated with the use of internal plastic coating in the tubing has been estimated to yield a 15% increase in daily production in these wells. Success in this application further proves the effectiveness of today's new and novel coating system.

Conclusions

The C-2 well achieved a maximum rate of 95mmscfpd, 25% above expectations. The C-3 well has performed as anticipated thus far at a rate of 45 MMscfd.

Use of internal plastic coating in production tubing improves hydraulic efficiency, up to 15% improvement is recorded on production rate.

4.3.19 SPE 162182 Advancements in the Abrasion Resistance of Internal Plastic Coatings

Management Synopsis

For more than 60 years, internal plastic coatings have been used for corrosion protection on tubing, casing, line pipe and drill pipe. One of the historic concerns with the use of internal plastic coating is the threat of mechanical damage and subsequent corrosion cell generation. Through the earlier years of usage of internal plastic coatings, applicators relied solely on enhanced surface preparation and adhesion to ensure minimal exposure of the steel substrate if damage were to occur. Even with this minimization, the potential for corrosion was still a concern for some. Due to this, a focus on developing internal coatings that offered higher degrees of abrasion resistance was initiated. At this time, several materials have been developed that offer abrasion resistances up to twenty times greater than what had previously been seen. These abrasion resistant materials allow internal coatings to be used in applications that were previously filled with alloys and GRE liners. These applications include production/injection wells that rely on frequent mechanical intervention, rod pumping wells, completion string systems and environments containing high amounts of entrained solids. This paper outlines the development of these products including the different chemistries used and their abrasion resistance, impact, laboratory evaluation of their abrasion resistance and initial case histories of applications where internal coatings have historically been excluded.

Conclusions

Historically, internal tubular coatings have been considered to be susceptible to mechanical damage that could expose the steel substrate to the corrosive nature of the production or injection fluids. Advancements have been made in both filler materials as well as resin chemistries that have shown in laboratory tests and field trials to increase the abrasion resistance of these coating systems by as much as fifty times. These abrasion resistant systems have proven themselves to perform well when subjected to mechanical intervention such as wireline and coiled tubing, to abrasive solids flow such as fraccing or the production of sand, and to abrasive wear in conjunction with impact forces typically seen in rod pumping applications. These new coating systems can reduce well construction costs, when compared to exotic alloys, as well as reduce production/injection downtime.

4.4 Review Topic Summary

The following is a list of reviewed papers categorized by key topic and chapter:

Category 1: General, well design, HSE, corrosion and erosion/abrasion

Carbon footprint – 4.2.6

Elastic carbon composite – Seals 4.2.7

General – 4.2.8

Temperature constraints of GRE - 4.2.9

Corrosion review and materials selection – geothermal wells - 4.2.1

Optimal materials choice for geothermal wells – 4.2.2

Microbiology in geothermal operations – 4.2.3

Industry standard well design for geothermal wells – 4.2.4

Geothermal in the Netherlands – 4.2.11

Permeation damage of polymer – 4.2.12

CRA selection guidelines in O&G – 4.2.17

NM materials use in O&G – 4.3.1

A comparison of scaling with metal and composites – 4.3.4

HSE in field testing – 4.3.15

Category 2: GRE lining

GRE lining – 4.3.6

GRE lined tubular economics – 4.7.7

GRE lined carbon steel - 4.3.16

GRE lined carbon steel – 4.3.17

Category 3: Full GRE

Use of fiberglass in O&G operations – 4.2.13

Use of fiberglass in O&G – A historical perspective 4.2.14

Full GRE – 4.2.5

Thisted development - 4.2.10

Performance of Fiberglass Casing and Tubing in Highly Corrosive Environments – 4.3.2

The use of GRE tubing in Oman – 4.3.3

Category 4: Plastic coating

Na Kika IPC experience – 4.3.18

Advances in abrasion resistance of IPC

Category 5: TPL

Review of thermoplastic pipes – 4.2.15

20 years of case studies of TPL – 4.2.16

Category 6: Composite CT

Field experience composite CT – 4.3.9

Anaconda – composite CT – 4.3.10

Composite CT solution – 4.3.11

Composite CT in harsh environments – 4.3.12

Applications update composite CT – 4,3.13

Products 7: in R&D phase (current and historical)

Development of composite CT 4.3.14

Development of continuous composite tubing manufacturing processes with GRE 4.3.5

Development update on advanced composite tubing – 4.2.8

Geothermica collaboration/R&D – 4.2.5

4.5 Vendor Information

The following is a summary of selected potential suppliers and developers of downhole composite tubulars, with a short description of the products they provide.

Tabular summaries of the key properties of these products are given in Appendices A., D and E.

4.5.1 Huisman- MaxFlow

Huisman develops and manufactures High Strength Composite Tubulars (formerly known as AKIET), using the Centrifugal Casting Method. High Strength Composite Tubulars are inert to downhole corrosion and provide an excellent everlasting smooth pathway for production fluids. 'MaxFlow' is a redesigned High Strength Composite Tubular from scratch, in which lengths of pipe are connected using a steel coupling (small OD). They are available in the desired diameters, yet the collapse rate has to be improved.

The current status of the Huisman full GRE development is summarised as follows: During the last 6 months, a complete re-design of the manufacturing process has been undertaken, as the old machinery was maintenance intensive and expensive to scale up for mass production.

The majority of the Akiet production equipment was scrapped and a new production process was set up from scratch.

The benefits of the new production process are perceived to be:

- Operationally, better control of production parameters.
- Tubulars:
    - Higher glass content and more homogenous distribution.
    - A larger range of possible wall thicknesses
    - Better for smaller sizes (<7").
    - Receptive to different polymers and fibres for further development (e.g. to increase temperature rating).

The new machinery is being manufactured and the expectation is that in roughly two months it will be possible to produce 9 5/8" tubulars at a rate of approximately 3 to 6 km/year.

In terms of other dimensions, 7", 7 5/8", 9 5/8", 10 ¾", 13 3/8", 16" are foreseen. Custom sizes (OD and wall thickness), crossovers from the MaxFlow™ and connection to other threads are options. The size after 9 5/8" is dependent on opportunities. Setting up to produce a new size is anticipated to take 2-4 months.

In parallel, manufacturing partners, with infrastructure for mass production and distribution of fibre reinforced polymers, are being sought. Until this time, manufacturing tubulars for upcoming projects will continue inhouse.

Dimensions of the steel collar specifically, will be approximately. 0.3" (8mm) to 0.4" (10mm). It can be manufactured in any reasonable size, however, but further investigation will be required for <5" or >16". The dimensions of the 9 5/8" tubulars currently in stock are

- OD Pipe: 9.72" (247mm)
- ID Pipe: 8.54" (=ID connection) (217mm)
- OD Connection: 10.32" (262mm)
- Pressure rating short term (<100hrs) – Burst - 3,000 psi (208 bar). Collapse, 2,120 psi (146 bar)
- Pressure rating long term (30 years) – Burst – 1,425 psi (95 bar). Collapse 1,100 psi (71 bar)

The connection is robust enough to ensure that it can be made up and broken out multiple times to full torque without damage.

It is envisaged that rethreading can be achieved similarly to drill pipe.

4.5.2 NOV - STAR, FIBERSPAR, TK LININGS AND INTERNAL PLASTIC COATINGS

STAR - GRE downhole tubing and casing products produced with three distinct curing agents that withstand temperatures up to 212°F (100°C). All products come in standard nominal joint lengths of 30 ft (9.1 m). The downhole products are used in a variety of highly corrosive applications such as saltwater and CO2 injection wells, for corrosion control, in observation wells for monitoring formations where steel can interfere with monitoring equipment and in producing wells where steel products corrode easily. Tubing is offered in 1½" through 9⅝" diameters (40 mm to 250 mm) with pressure ratings from 1,000 to 3,500 psi (6.9 to 24.1 MPa). Casing products range in size from 1½" through 9⅝" diameter (40 mm to 250 mm) with pressure ratings from 1,000 to 3,250 psi (6.9 to 22.4 MPa).

In terms of field repair, only moulding is feasible. Threads can't be cut as per steel.

Fiberspar - A spoolable lift system for downhole applications up to 3,500 ft (1,067 m) depth. This system is aimed at artificial lift operations, mainly the rapid and simple deployment of electrical submersible pumps. This system has the potential to eliminate the use of workover and drilling rigs, reduce the time required to deploy and replace pumps, and change the performance profile required from electrical submersible pumps while significantly lowering production and artificial lift installation and operating costs. The system utilizes SmartPipe which incorporates embedded power conductors into the body of the pipe, eliminating the need for externally banded cable, a major source of damage and failure.

Tuboscope™ TK™ - Liner products are glass-reinforced epoxy (GRE) liners designed to protect new and used downhole tubular goods and flowlines in corrosive environments.

The TK-Liner System is a high-performance corrosion-protective lining system that also provides thermal insulation for injection/disposal, production and geothermal applications. TK-Liner is available with a variety of connecting options up to 13 3/8" diameter. In most cases there are no modifications required to the threads. TK-liners are designed for VAM Top connections, for other connections a new TK-Ring has to be developed or the connection has to be modified to suit the VAM Top shaped TK-Ring.

Tube-Kote™ (TK™) is a line of internal plastic coatings (IPCs) for corrosion and wear prevention, improving hydraulic efficiency and controlling deposit mitigation.

TK™ Corrosion control products have been used in a variety of geothermal projects throughout the Netherlands, Germany and France since 2003. In addition to unmatched corrosion protection, Tube-Kote™ coatings prevent deposit mitigation and improve laminar flow efficiency.

Tubo-Wrap, an external tubular coating that provides corrosion protection and resistance to mechanical damage. Consisting of a proprietary epoxy matrix coating and a Ryton membrane, Tubo-Wrap reduces the effects of external corrosion and wear online pipe, tubing, and casing. Tubo-Wrap has shown the ability to reduce handling damage and reduce the necessity for field repairs during installation.

A full summary of the TK range of IPCs, together with their performance characteristics and intended applications is outlined in Appendix E.

4.5.3 Future Pipe Industries – Wavistrong (various)

The non-corrosive characteristics of fiberglass piping systems position them as the materials of choice for efficient transportation across a wide range of applications in all pressures, temperatures, and mediums.

An extensive portfolio of bespoke products and solutions, applied for over 40 years, which can meet extreme environmental requirements, is offered, including the ability to withstand pressures up to 240 bar (3500 psi) and temperatures up to 121°C (250°F).

The products are installed worldwide across a diverse range of applications such as Oil and Gas. Future Pipe has experience in downhole pipes used for water injection, CO_2 injection, waste injection and production lines in addition to well casings for oil, gas, water and chemical wells.

The large OD of the couplings have an impact on the entire well design, e.g.: a 13.3/8" casing has a coupling OD of about 18"

In terms of reuse/rethreading, the pin ends can be rethreaded if there's sufficient (external) upset remaining, and the coupler can be replaced, if required.

4.5.4 Western Falcon Energy -- Polycore + Various

Western Falcon was established in 1992 Odessa, Texas and offered Polycore HDPE liner primarily used for corrosion protection in water injections and disposal wells. In 1994, the first string was deployed in a beam pumped well to eliminate rod on tubing well failures. Since then, Western Falcon thermoplastic liners have proven successful in reducing tubing failure and workover costs.

In August 2000 ,Conestoga Supply Corp. , a leading supplier of new, used and surplus OCTG and line pipe, purchased Western Falcon and focused on expanding the applications of thermoplastic liners. Western Falcon has been heavily involved in research and development focusing on new thermoplastic materials and additional applications other than injection, disposal, flow lines, beam pumped and PC pumped wells. Western Falcon has developed several different proprietary thermoplastics resulting in four unique liners with temperature limits ranging from 160 Deg. F to 500 Deg. F (71Deg C. to 260 Deg. C). Liner applications have also expanded to most forms of artificial lift installations and velocity strings. Downhole tubing internal corrosion and rod on tubing failures are now controlled to the point of making it economical to produce many marginal fields that would otherwise be uneconomical to operate.

Western Falcon has run more than 70 million feet (21 million meters) of thermoplastic liners throughout the world.

4.5.5 MaxTube/Duoline – Duoline + RiceWrap

Maxtube's DUOLINE® has been developed to prevent corrosion in very demanding conditions. Protecting oilfield tubulars from corrosion since 1964, more than 100 million feet of DUOLINE® glass reinforced epoxy (GRE) lined tubing has been installed worldwide.

DUOLINE® 20 is a filament-wound Glass-Reinforced Epoxy (GRE) liner which is installed to OCTG in corrosive service. It is widely accepted that GRE lining is a more robust alternative to internal plastic coating. DUOLINE 20® is a very effective corrosion barrier with a long history of tubular protection in a variety of offshore and land based applications.

DUOLINE 10®-PE, is a lining system which utilizes a heavy wall high density polyethylene liner and is targeted for use in specific applications for reduction of tubing corrosion in low temperature and low pressure environments. DUOLINE® 10-PE is especially suited for shallow water injection well tubing where corrosive water is injected and performs within a temperature range of -20F+160F (71 Deg.C).

RICEWRAP® is a protective wrap of fibreglass epoxy externally applied and bonded to steel pipe.

4.5.6 Integrated Protective Coatings (IPC) – Electroless Nickel Coating (ENC) – ENC 3000 for Geothermal

IPC was founded in 1978 and has become the industry leader in the coatings application market in Western Canada.

Electroless Nickel Plating (ENP) is a process where nickel is evenly deposited to the surface of a metal, by dipping, without the use of an electrical current. The purpose of an ENC layer is to extend the life of the substrate metal by creating a barrier to protect against corrosion, erosion and abrasion.

4.5.7 CRA Tubulars – New Titanium Lined Concept

CRA-Tubulars | The Corrosion Resistant Alternative is a newly established engineering firm. The company operates in the energy sector and seeks to help operators solve the issue of well integrity, associated cost and subsequent loss of oil production.

The company is designing a titanium lined composite tubing (or 'TCT') that aims to disrupt the deployment of premium metallic tubulars in upstream oil and gas.

4.5.8 Butting (Metallurgically clad pipes)

Butting manufactures a similar concept to the titanium concept, above, metallurgically clad pipes, but it appears only for surface applications. It is uncertain at this time whether they ultimately intend to enter the downhole domain but it is perceived that they could eventually offer a comparable product to the titanium concept. As concluded, it will, however, be a significant challenge to achieve it in a reasonable timeframe, at a competitive cost.

4.5.9 Baker Hughes and Aramco JV (only surface pipe at present)

Aramco and Baker Hughes (NYSE:BKR) have announced, late 2020.the formation of Novel, a 50/50 Joint Venture (JV) to develop and commercialize a broad range of non-metallic products for multiple applications in the energy sector. It is understood that the initial focus will be on surface applications, but the longer term aspiration will be to move into downhole tubular,

4.5.10 Hilong (TC range)

Hilong produces the TC series of coating and anti-corrosion materials for use on drill pipe, tubing, casing, and line pipe.

4.5.11 Schlumberger/Smith International

Schlumberger (Smith International) commercializes Sub-One Technology's advanced InnerArmor coating technology for OCTG applications. The joint venture, Smith InnerArmor Technologies, has the exclusive license to supply a full range of OCTG coatings on a global basis. Sub-One Technology is a privately held company backed by Chevron, General Electric, Nomura, and Advanced Technology Ventures.

4.6 Summary of Findings

4.6.1 Overall Conclusions

1. Various varieties of non-metallic tubulars have been used successfully to combat corrosion in O&G, and low enthalpy, wells for well in excess of 30 years.
2. Although used successfully, and very extensively, for such an extended period, and in a variety of Assets, the application of non-metallic pipe is as yet not routine in candidate (relatively shallow) wells, despite its environmental advantages.
3. Given that conventional chemical water treatment has been imperfect and that composite tubulars are a robust and cost-effective long-term solution if well-known threats are managed and within well-established constraints and its use should be continued.
4. Generally, all of the options considered are corrosion resistant, but prolonged exposure to certain acids used for matrix simulation, particularly HF, should be avoided.,
5. Intervention frequency will largely be dictated by ESP change out frequency in producers, but a sealed annulus should minimise the risk of external tubing and internal production casing corrosion.

4.6.2 Conclusions From Reviewed Literature

1. Studies and Operator experience have identified corrosion and scaling as major potential challenges for the geothermal wells (ref 1).
2. Bacteria are present in many geothermal systems. The composition of the microbial population showed variation between different systems (ref 3).
3. Thermal cycling may reduce GRE pipe strength by up to 10% (ref 8.)
4. The days of corrosion issues with steel tubulars down hole are slowly but surely coming to an end. Alternatives like fiberglass casing have made significant advances and accumulated sufficient field experience in order to become a viable replacement for conventional carbon steel (ref 12.).

5. Reinforced thermoplastic pipes have been increasingly accepted as an important alternative to traditional metallic offshore pipes due to their distinct advantages (ref 14.)
6. In 2018 TPL is claimed to have outperformed other polymers in protecting OCTG from corrosion and abrasion. The ductility, thickness, and impact resistance of thermoplastics are able to handle most of the daily abuse seen on well servicing (ref 15.).
7. The path forward in R&D, is focused towards improving the composite business to serve the oil and gas industry. This involves the development of specific roadmaps for different product to accelerate the mass deployment. (ref 17.).
8. Fiberglass casing and tubing can withstand similar levels of shallow-depth compression and collapse pressure ranges as carbon steel (ref 18.).
9. Fiberglass tubing and casing could replace currently used steel in highly corrosive environments, in shallow and surface oilfield applications (ref 18).
10. The use of glass-reinforced tubing in low pressure shallow water- injectors, where conditions are corrosive to steel tubing has been proven successful in the Natih and Fahud fields, after more than one year continuous service, in 1981 (ref 19.).
11. Compared with traditional metal tubing, composite tubing could reduce the scaling significantly which has been proven in the field operation. Field sample test demonstrated that coupling helped the formation of scale, while the well depth could reduce the intensity of scale due to temperature and pressure reason (ref 20.).
12. A process technology has been developed that enables the production of virtually void free wet resin impregnated fibre bundles. These processes are being employed in the production of continuous, long length spoolable composite tubing (ref 21.).
13. Tubular goods lined with Glass Reinforced Epoxy (GRE) composite liners have been used in corrosive service for 30 years and they have been adapted to provide unsurpassed protection against corrosion. The marginal increase in cost over inferior products is justified by the extension in product life and freedom from the costs of maintenance, repair, and replacement of failed tubing (ref 22.).
14. The evolution of the lining process for tubular goods has culminated in the prolific advance of composite materials as corrosion barriers in the oilfield environment. Costly corrosion damage has been largely mitigated by protecting the tubular goods with Glass Reinforced Epoxy liner (ref. 23).
15. The first commercial strings of advanced composite coiled tubing for well servicing and well completions are in the final stages of qualification. Standard product designs have been established as well as standard qualification procedures, in some applications (ref 24).
16. Coiled tubing technology has many advantages, the primary one being the low cost of deployment in many downhole applications. Four applications in particular show promise:
    a. Large diameter CT for drilling, although probably too small for geothermal wells
    b. Fast deployment of coiled tubing for PCP and ESP pump systems.
    c. Velocity strings for shallow but highly corrosive wells.
    d. Injection and shallow production (ref 25).

    At time of testing, the system had performed more than 300 circulating and tripping hours (cemented casing) and 30 milling and reaming hours in the surface test flow loop. The system carried out its intended functions (ref 26.).
17. Canada often loses production when hydrates form as a result of temperature drops in gas flow. To reduce gas-flow temperature drop and prevent hydrates, Operators often use a steel heater string to heat the annular area between the production tubing and casing. Some wells require more heat to reach the critical hydrate temperature depth than others, resulting in higher costs for associated equipment. To reduce costs, operators tried using CCT, due to its low thermal conductivity, to reduce the need for upgrading surface equipment.

    Operators used the same injector to pull the steel tubing and run the CCT. Operators heated the annular area to operational temperature by circulating water heated to 167°F. at 16 gal/min down the string and back to the surface, and the well was put into production. The composite heater string provided a temperature differential increase above the steel string of 59°F at 4,593 ft. The result was a continuous flow from the well without hydrate problems, and production more than doubled.

    The overall cost of the operation was recovered in less than 3 months (ref 27.).

18. Composite CT will not replace steel tubing. It will cost more than conventional steel tubulars. However, in applications where excellent corrosion resistance is required, the benefits of a seamless, corrosion-resistant composite pipe may warrant the additional pipe cost. In well-completion applications, particularly in harsh environments, the reduced installation cost can make the economics favourable when compared to corrosive-resistant materials (ref 28.)
19. In applications where excellent corrosion resistance is required, the benefits of a seamless, corrosion-resistant composite pipe may warrant the additional pipe cost. In well-completion applications, improved flow performance and reduced installation cost because of the speed and ease installing a continuous pipe string instead of jointed tubulars, can make the economics favourable when compared to CRAs. In well-servicing operations in harsh environments it is possible for the savings of using corrosion resistant composite CT to exceed the additional cost of the pipe (ref 29).
20. Composite materials can be tailored to provide properties unavailable with metals such as high fatigue life, minimal diametral growth, and reduced weight. Composite coiled tubing can also be designed to meet spooling and high combined load imposed on high performance coiled tubing. In addition, composite CT provides the opportunity to expand the application opportunities to higher operating pressure and longer reach in horizontal and deviated wells.
21. Advanced low-cost manufacturing methods permit composite components to be produced at competitive prices – (ref.30.).
22. Qualifying new systems and new technologies creates many unique HSE issues that must be anticipated and addressed to ensure a safe working environment (ref 31.).
23. The advantages of GRE lined tubulars are: extended well life and avoidance of frequent workover operations, because of corrosion related problems and associated costs, and the connection area is better protected with, and general wear resistance is better with, GRE than with Internal Plastic Coating.

    The drawbacks of GRE lined tubulars are reduced ID, Hydrofluoric acid (mud acid) must be avoided, the maximum temperature limit for water injectors is 130 °C (266 °F) and GRE does not prevent BaSO4 and SrSO4 precipitation. Although the ID reduction is only a few millimetres, GRE is much smoother than steel, so the flow is almost the same.

    The product has been adopted for use in oil producers, power water injectors and water source wells. At the time of writing this paper, 2012, more than 22 wells had been installed with GRE lining between 2008 and 2012, excluding the three wells where GRE lined tubing was installed in 2002 - none of these wells have reported of any failures by 2012 (ref 32).
24. The use of IPC improves hydraulic efficiency, up to 15% improvement is recorded on production rate.
25. Abrasion resistant systems (IPCs) have proven themselves to perform well when subjected to mechanical intervention such as wireline and coiled tubing, to abrasive solids flow such as fraccing or the production of sand, and to abrasive wear in conjunction with impact forces typically seen in rod pumping applications.

5 POTENTIAL LONG TERM INTEGRITY THREATS TO RECOGNISE

Despite the fact that composite tubulars have exceptional, and proven, long term durability, it would be prudent to be aware of some potential issues that could threaten long term integrity. Examples would be:

- Temperature degradation
- Air inclusions/voids
- Creep
- Thermal cycling and resultant micro-cracking and delamination due to different thermal expansion coefficients with GRE/TPL linings.
- Wear due to intervention activity and sand production.
- Long term UV exposure (when stored)
- Collapse rating

Although the majority of threats can be adequately managed, which has been amply demonstrated by the numerous installations over the past >30 years, particularly for low temperature, relatively benign, applications, exposure to wear of some description during the well life cycle is almost inevitable. Obligatory periodic PLTs, ESP replacements, sand production and matrix acidisations to restore performance are all threats, for example. A two barrier well design (Industry Standard Sustainable Well Design) should provide a degree protection for the A annulus.

The abrasion resistance of a polymer composite is driven by the performance of the matrix. By their very nature the standard epoxy or polyester resins that are used to fabricate most GRE are not abrasive resistant - they have very low intrinsic hardness. Thus, the matrix is going to abrade at broadly the same rate whether the reinforcement is a glass or carbon fibre.

Although low level sand production may not cause a downhole erosional problem (Section 4.3.17), GRE could be susceptible to operability issues or erosional wear due to high volume sand production if screens are not installed. Although compressive/shear failure is unlikely to be a risk, as the reservoir pressures are likely to remain fairly constant, tensile failure is highly likely as many sands are un-, or weakly, consolidated. Any drawdown will precipitate sand production. Sand screens should be installed where recommended. Perforating, if used, will disaggregate the near wellbore rock, due to resulting shockwave interaction, which will, initially at least, cause further sand failure.

Once the matrix is stripped from the fibres the next determinant is the topology of the reinforcement. A filament wound tube is fabricated with continuous fibre rovings, which are laid onto a mandrel to form a basket weave pattern and depending on the number of rovings, will have relatively few cross over points. There is little to hold the fibre arrays in place and they rapidly fall apart under the flow of abrasive fluids. Alternatively, a woven fabric topology is more resistive to the flow of an abrasive liquid, acting like a filter paper, possessing sufficient integrity to hang together for a period.

A potential option would be to identify matrices that are highly abrasive resistant or, alternatively, to find woven forms of reinforcement that utilise abrasive resistant fibres.

Essentially, polyester resins are less resistive to acids than epoxies used widely in piping/pressure vessels. Phenolic resins are better but add cost and complexity (harder to process).Thermoplastics are more exotic are used in sub-sea and land based O&G production, with both glass and carbon fibre reinforcement. PEEK is used because of its chemical resistance. PEEK composites can be operated at 100 deg C but not in the > 140 deg C range. It is also feasible to manufacture a thermoset tubular with an inert thermoplastic liner (e.g. PEEK).

Glass fibres can be attacked by acids over time. HF, in particular, can be problematic and can dissolve glass. There are different types of glass fibre compositions and there is a variant designed to give greater chemical resistance (‘C’ glass). Carbon fibres are, on the other hand, relatively inert to acid attack.

In terms of combining the fibre and matrix, carbon/PEEK could give very good resistance to acids and is a contender. ‘C’ Glass/epoxy would provide acceptable performance for low enthalpy applications, particularly if the tubulars are purged with clean water after (HCl) acid stimulation activities are complete.

Ceramic matrix based composites and their associated reinforcements (e.g. silicon carbide fibres) would fit the bill, but only on the grounds of abrasive resistance. CMC's are exorbitantly expensive and hard to manufacture at the scale of a typical tubular, neither do they meet the structural requirements.

A simple concept could be to produce a woven structure using steel wires.

An option to minimize the wear on the production casing resulting from the tripping ESPs, could be to consider using Composite CT to Deploy ESPs in producers. It can potentially simplify and expedite change-out and reduce the risk of tubing abrasion.

In addition to the potential threats identified above, ESP vibration has also been highlighted as a potential issue. It has been experienced in numerous operations in the Netherlands and appropriate avoidance measures should thus be adopted.

For the deployment tubulars, If vibration is anticipated, anchor the ESP to the pipe wall with a packer/PBR, or use soft tipped centralisers of sufficient numbers to cater for the length of the ESP . If GRE, the area around the ESP can be reinforced and the adjacent casing can be coated with abrasion resistant coating. Particular attention should be paid to cable sizing if GRE tubulars are used.

In terms of the ESP operation specifically, attention should be given to the direction and amount of start-up torque, soft-start motors/VSDs should be used, diligent monitoring of the ESP is essential and adjusting the frequency/rate to minimise harmonics is recommended. Monitoring longer term for signs of increasing average vibration, which may indicate wear and/or scale deposition, is also essential.

6 CONCEPT SELECTION RATIONALE

A number of potential solutions could potentially work as the well conditions are relatively benign so the choice of concept can be well specific, In fact, a hybrid/bespoke design could be the best solution for a particular set of well conditions or anticipated exposure to wear. On a more general level, GRE seems to be preferred to Carbon Fibre for low enthalpy applications despite its better tensile strength and lower wall thickness advantages, possibly due to its perceived better impact resistance characteristics and lower cost. Carbon Fibre also has a lower tolerance to ill treatment due to its rigidity. It is, in principle, possible to adapt the GRE manufacturing process to produce carbon fibre pipe.

6.1 SIMPLE QUALITATIVE SOLUTION SELECTION PROCESS AND CRITERIA

The process for electing to choose a particular non alloy solution for this fairly benign application should be relatively straight forward, within proscribed guidelines, and ultimately may come down to just cost. An example of a very simple solution process could look something like the following:

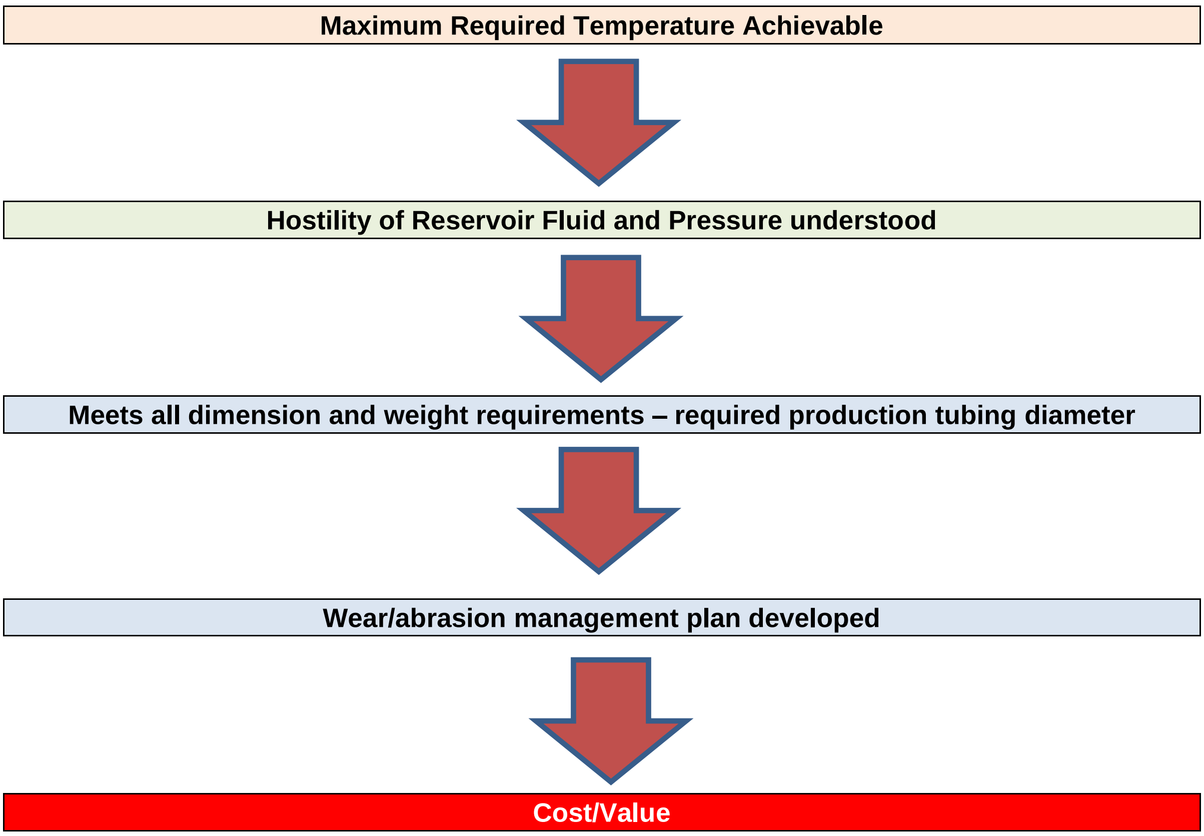

Figure 6-1 Simple Qualitative Solution Selection Process

Historical qualitative, illustrative comparative costs for a variety of existing potential tubular solutions, including well established non alloy examples, including full GRE, internally lined L80 and coated L80, are given below.

In principle, all corrosion related requirements could be met by the three potential solutions highlighted above. Ultimately, the choice will thus come down to cost/value (life cycle NPV-cost per unit of energy). The following is a very rough historical comparison of the relative costs of the three options compared to a variety of CRAs.

MATERIAL	FACTOR
L80	1
Full GRE string	2-2.5
L80 with GRE Lining	2-2.5
L80 with TPL	Assumed same as L80 with GRE 2-2.5
L80 with ENC and IPC Coating	2-2.5
13%Cr:	2-2.5
S13%Cr	3.5-6
Duplex-80ksi	15-18
Smaller diameter Titanium	15-18
Larger diameter Titanium	20
Duplex > 80ksi, (Cold Working required)	18-22
Super Duplex = 80ksi:	20-23
Super Duplex>80ksi (cold working required):	23-26

Table 6-1 Relative Costs Of Potential Tubular Materials For Low Enthalpy Geothermal Wells

These are indicative only as steel costs are governed by many factors – prevailing commodity prices, local/customer contractual conditions, location, connection type, etc.

It is assumed that internal protection only as external surfaces can be protected as and when necessary, by a packer or PBR at the bottom of the production casing, for example. However, both the full GRE and coating systems provide external protection for a small incremental cost. Whereas the lining systems require additional protection of some description if external threats are present.

A further advantage of both coatings and complete GRE options, is that connections are not an issue. With liners, Corrosion Barrier Rings are required.

It is evident, however, that a complete composite solution and the ENC coating are potentially several factors more economic than the more exotic CRA alternatives.

6.2 Qualitative Product Evaluation Matrix

The following is a decision checklist, with factors that may influence, or compromise, the selection of a potential solution. Some may be showstoppers (e.g. temperature too high), others may be just be "nice to have", help focus any testing needs or only affect cost. As the design will be case specific, and possible solutions have different capabilities/drawbacks, it is difficult to be definitive in terms of solution without a target application.

	Significance	**Comments**
	e.g., high, low, blocker	e.g. testing requirements
Temperature		
Max. Injection/Production Pressures		
Carbon Footprint Impact		
Insulating Efficiency		
Weight		
Handling Complexity		
Coupling Simplicity		
Logging flexibility		
Impact of Holidays (corrosion)		
Exterior + interior pipe protection		
Wall thickness		
Available sizes		
Re-threading issues		
Burst/collapse issues		
Internally flush connections		
ESP vibration issues		
Cost		

Table 6-2 Qualitative Product Evaluation Matrix

<u>Recommendation</u>

Investigate viability of using environmentally sensitive stimulation techniques, if required, as an alternative to potentially damaging acids – e.g. surge/water hammer devices, pulsed stimulation technique, and non-acidic stimulation fluids.

<u>Given.</u>

Wells will not be hydraulically fracture stimulated as it would add another, and overriding, level of complexity in terms of wear/erosion and required treatment parameters.

<u>Potential long-term threat to recognise</u>

Possibility of glass fibres stripping from tubulars and posing an, effectively, immovable impairment risk in injectors, although having difficulty finding examples in current NL wells.

<u>Overall Conclusions</u>

The applications are comparatively benign, apart from possible sand production, which can cause erosion of GRE as well as potential problems with the ESPs in producers, and wear/abrasion due to

ESP tripping and wireline/CT intervention. In injectors, assuming that they are largely inert with respect to environmental conditions, corrosion shouldn't be an issue.

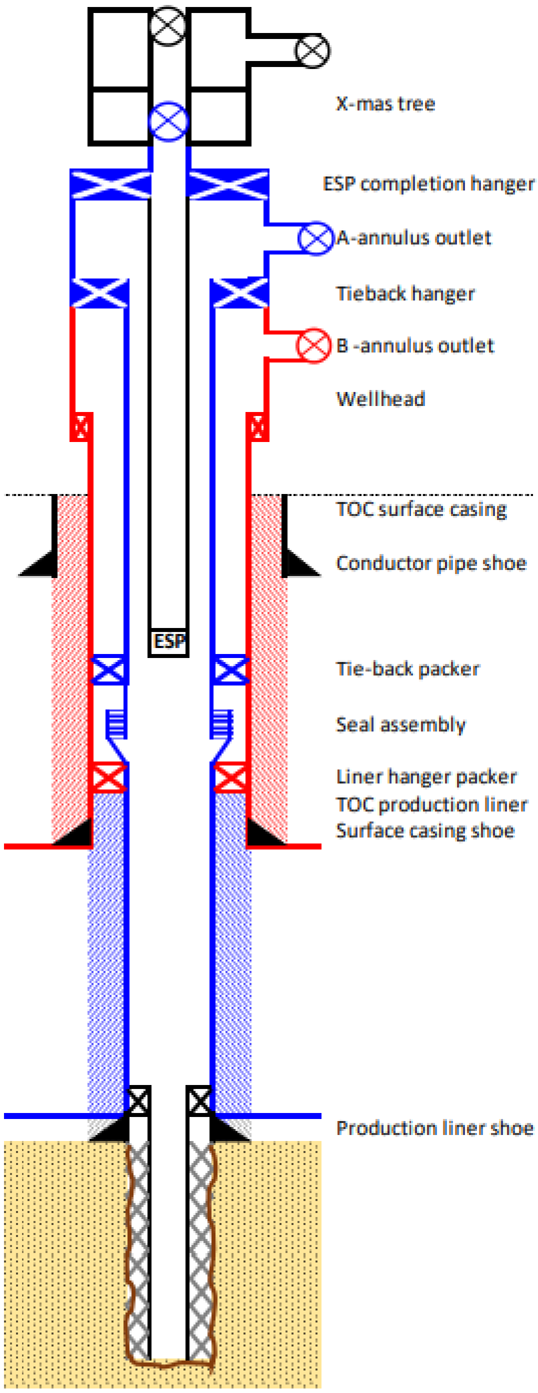

Figure 6-2 Example of Conceptual Well Completion Diagram in the Netherlands

Note. This is depicted only for illustration purposes, not to dictate a particular configuration.

7 OBSERVATIONS

Several suppliers can provide composite casing, which has been used successfully in O&G and low enthalpy geothermal applications for >30 years, although a number of potential life cycle integrity challenges need to be managed.

Under a two well integrity barrier scenario. wellbore fluid can't be considered an adequate primary barrier in operational wells being the origin of integrity issues in the first place.

If the upper production casing, the conventional secondary barrier, does require monitoring, in accordance with guidelines (B annulus), a production packer of some description will have to be installed towards the lower end of the tubing string (to provide a closed system for monitoring). Alternatively, a logging device of some sort, e.g. DTS/DAS, an ultrasonic cement/casing integrity evaluation device, or a "Visuray VR360" type concept – an integrity monitoring device (R&D) that can, potentially, log though multiple strings. Field trialling of his particular device should start in 2021 and may then be deployed, assuming trials are successful.

More work is required on the examination of possible negative case studies to underpin the assumption that a 30-40 year design life is routinely achievable; published case studies being invariably overly positive

A full composite solution (i.e. resulting in a significant reduction in steel use) would minimise the carbon footprint of wells, depending on the OD of the couplings.

8 RESEARCH AND DEVELOPMENT

8.1 Current Situation

The low enthalpy Geothermal environment is relatively benign, apart from potentially aggressive reservoir and stimulation fluid and long term abrasion and wear (e.g., there's an extensive history of satisfactory performance of non-metallic tubulars as long as well-known threats can be adequately managed).

8.2 Future Outlook

R&D scope for low temperature enthalpy applications of tubulars, particularly when taking manufacturing challenges into account, is probably comparatively limited. higher temperature applications do have scope, however, with cladding, novel coatings and linings (e.g. ceramic and Titanium) likely contenders.

When looking exclusively at tubulars, the principal challenge could well be identifying, or indeed constructing, a manufacturing facility.

In terms of associated opportunities, however, the following could be adopted:

- Eliminate well entries in injectors - undertake them only on opportunistic basis or combine activities to minimise the exposure to wear (SodM requires logging at a minimum of every 5 years)
- Minimise potential abrasion due to ESP replacement by using soft (e.g. Teflon coated) cable clamps/protectors or plastic centralisers.
- Continued use of VSDs to maximise run-lives of ESPs.
- Continued use of sand screens to avoid wear, and later well operability problems (HUD issues and the need to run CT).
- Investigate GRE Coiled Tubing deployment to speed up ESP change-outs minimise frictional pressure losses due to the ESP riser and enable the running of round cables to minimise cable distortion..
- Closed annuli (two barrier philosophy) supported - should protect the majority of the production casing, which is the internal casing from surface to TD.
- Re-use pipe during ESP replacement unavoidable – although rejection rate is comparable to carbon steel.

8.3 Requirements and Opportunities for Research (Wish List)

Although progress appears to have been somewhat slower than ideal in key areas, particularly in relation to full GRE connection dimensions, impact of ESP/drilling loads and strength/collapse resistance relative to OCTGs, there are a number of associated opportunities that could be implemented in the short term to minimise the risk of tubular/coating damage, including novel and non-invasive surveillance and improved water treatment.

Variations on the acoustic reflectometry theme, for example, could be investigated, not just for monitoring fluid levels, but also for establishing injection profiles in injectors, as its single phase flow. In terms of well integrity of existing wells, possibly the use of the "Visuray" VR 360 type tool could be explored to monitor the condition of the exterior of the wells, assuming that it functions as claimed.

9 CONCLUSIONS AND RECOMMENDATIONS

The conditions under which a particular concept is suitable is outlined in Section 3. Appendix D. summarises, in more detail the respective properties of GRE lining and ENC coating. Below a particular depth, temperature will dictate its applicability as the properties of the base pipe will dictate its structural limits.

9.1 Conclusions

Material selection for well design is ultimately determined by life cycle cost/value, which in turn will be determined by practical limitations – e.g. maximum temperature, pressure and tensile/axial strength for the service/load cases anticipated (e.g. Appendix B.). Furthermore, all steps should be taken to limit the potential threats to the long-term integrity/durability of candidate wells, by minimising exposure to activities that cause wear (wireline and coiled tubing activity) and abrasion due to ESP change-out (Section 8.2).

In terms of lift technique, ESPs are perceived to be the only viable option for this very high water production application in the Netherlands. A degree of exposure to any associated abrasion is thus considered unavoidable.

The maximum depth that a particular solution can effectively function is largely dictated by its temperature rating.

A typical configuration for a current corrosion avoidance geothermal well project is depicted in Section 6. Typically, the current practice is for GRE lined carbon steel in injectors and Cr13 in producers. A guide to the selection of the right CRA - Corrosion Resistant Alloys (CRAs) in the oil and gas industry – can be found in the selection guidelines update.

There is anecdotal evidence of glass fibres detaching from the GRE matrix. However, there appears to be limited experience of this phenomenon, ,either from literature or suppliers. Although it may be feasible under extreme circumstances, it is probably not significant, Various varieties of non-metallic tubulars have been used successfully to combat corrosion in O&G wells for well in excess of 30 years.

1. Given that chemical water treatment is imperfect and that composite tubulars are a robust land cost effective long term solution if well-known threats are managed and within well-established constraints its use should be continued.
2. Generally, the options are corrosion resistant, but prolonged exposure to certain acids used for matrix simulation, particularly HF, should be avoided.
3. Intervention frequency will be dictated by ESP change out frequency in producers, but a sealed annuus should minimise the risk of external tubing and internal production casing corrosion.
4. Although it could be argued that ENC coating may not strictly fall within the category of Non-alloy tubulars, it could potentially have some significant advantages in certain circumstances (refer Appendix D) if it performs as claimed.

9.2 Recommendations

1. Adopt the practices summarised under Section 8.2 to minimise the costs of associated activities.
2. Apply a bottom up well design approach, where feasible.
3. Undertake future work, as summarised below.

9.3 Future work

1. Investigate the risk, and potential impact, of glass fibres being stripped from GRE and plugging screens, due, for example, to intervention activity and/or sand production.

2. Investigate remedial options to rectify the above if it becomes problematic.
3. Identify and test wireless/non-invasive production and integrity monitoring techniques, for example acoustic and RF reflectometry concepts and low frequency noise monitoring techniques.
4. Carry out further rigorous surface testing to compare the abrasion/wear resistance of the primary tubular protection concepts, including the various coatings, to ensure that the most robust selection decision is made.

10 UNITS & GLOSSARY

B(s)cf	Billion (1e9) (standard) cubic feet
bbl	barrel
cP	centi-Poise (unit of dynamic viscosity)
ft	feet
ftSS	feet (below mean sea level)
m	meter (unit of length)
M(s)cf	Thousand (standard) cubic feet
mD	milli-Darcy (unit of permeability)
MMstb	Million stocktank barrel
psi	pounds per square inch
psia	pounds per square inch (absolute)
rb	reservoir barrel
scf	standard cubic feet (i.e. @ 15 degC and 1 atm)
stb	stocktank barrel

AAPG	American Association of Petroleum Geologists
AOI	Area of interest (can be vertical, areal, or 3D)
BU	build-up (no-flow period in DST, or pressure rise in injecting well)
CGR	Condensate-Gas Ratio
CMC	Ceramic Matrix Composite
CRA	Corrosion Resistant Alloy
DAS	Distributed Acoustic Sensing
DD	Drawdown (flow period in DST, or pressure drop in producing well)
DST	Drill Stem Test
DTS	Distributed Temperature Sensing
EIA	United States Energy Information Administration
ENC	Electroless Nickel Coating
EoS	Equation-of-State
EPC	Equivalent Pore Column
EUR	Expected ultimate recovery
FBHP	Flowing bottom hole pressure
FC	Forecast
FDP	Field Development Plan
FWL	Free Water Level
GIIP	Gas (volume) initially in place (also as solution gas)
GOR	Gas-Oil Ratio

GR	Gamma-Ray
GRE	Glassfibre Reinforced Epoxy
GRV	Gross Rock Volume
HC	Hydrocarbon(s)
HCIIP	Hydrocarbon(s) Initially In Place
HDPE	High Density Polyethylene
HDT	High Resolution Dipmeter Tool
HCPV	Hydrocarbon Pore Volume
HM	History Match
IPC	Integrated Protective Coatings or Internal Plastic Coating
KB	Kelly Bushing (datum for MD and TVD)
KIRA	Kennis en Innovatie Roadmap Aardwarmte (Knowledge and Innovation Roadmap for Geothermal) – a Dutch organisation setup by EBN to develop geothermal energy solutions in the Netherlands
LKO	Lowest Known Oil (the deepest of a group of ODT's)
MD	Measured Depth
MDT	Modular formation Dynamics Tester (formation pressure measurement tool)
NM	Non-Metallic
µ	Oil Viscosity
NTG	Net-to-Gross ratio
OBM	Oil-Based Mud
OBMI	Oil-based Mud Formation Imager
OCTG	Oil Country Tubular Goods
ODT	Oil-Down-To
OWC	Oil-Water Contact
PEEK	Polyether Ether Ketone
PI	well Productivity Index
PLT	Production Logging Tool
PSDM	Pre-Stack Depth Migration
PSTM	Post-Stack Time Migration
PTA	Pressure Transient Analysis
RDT	Reservoir Description Tool (obtains formation pressures and fluid samples)
Realisation	Combination of (uncertain) subsurface parameters (structure, contacts, etc.)
RF	Recovery factor
RFT	Repeat Formation Tester (often used as a generic name for formation pressure measurements)
RT	Rotary Table (datum for MD and TVD)
SCAL	Special Core Analysis (refers to both relative permeabilities and capillary pressures)

Scenario	Combination of development parameters (well count & locations, constraints, etc.)
SGS	Sequential Gaussian Simulation (geologic modelling method)
SGS	Societe Generale de Surveillance
SGS	SGS Netherlands
SLB	Schlumberger
SPE	Society of Petroleum Engineers
STOIIP	Stocktank oil (volume) initially in place (also as condensate)
TPL	Thermoplastic Lining
TVD	True Vertical Depth (datum unspecified)
TVDRKB	True Vertical Depth below KB
TVDSS	True Vertical Depth Subsea (i.e. below mean sea level)
USGS	United States Geological Survey
WBM	Water-Based Mud
WCT	Water Cut
WFT	Wireline Formation Testing
WOR	Water-Oil Ratio
WUT	Water-Up-To
Z2D	Z-to-D (the process of tying a PSDM seismic cube to the wells)

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12 APPENDIX A: VENDOR INVENTORY

Vendor Contacted	Product	Description	Sizes	Max. Temp	Internal Upset	Status / lead time	Operating Years	Cost/m	Link	Other comments
Huisman	Max Flow	GRE Tubular	Aim - 7"-16"	85 Deg C	No	R&D - 3-6km/y		ca €280/m *	https://www.huismanequipment.com/	* 9 5/8" nominal
NOV	Fibrespar	GRE Tubular	1 1/2" - 6 1/2"	82 Deg C	-	12-16 weeks	-		NOV	Pressure 2,500 psi
	STAR	GRE tubular	1 1/2" - 9 5/8"	100 Deg C	No	12-16 weeks				Pressure 3,500 psi
	STAR Shallow	GRE tubular	1 1/2" - 2 7/8"	65,5 Deg C	No	12-16 weeks				Pressure 1,500 psi
	TK Liner System	GRE lining	2 3/8" - 13 3/8"	120 Deg C	No	12-16 weeks				ID 1.995" - 8.681"
NOV Tuboscope assorted - examples	Tube-Coat IPC -TK	IPC Phenolic liquid	Appendix E	204 Deg C	-	12-16 weeks	IPC >80 years			Pressure - pipe yield
Summarised in Appendix E	TK44LP	IPC Epoxy Powder	Appendix E	107 Deg C	-	12-16 weeks				
	TK900	Modified Novalac Powder	Appendix E	149 Deg C	-	12-16 weeks				
Hilong & Smith / Schlumberger also	numerous								HilongGroupofCompani...	

Vendor Contacted	Product	Description	Sizes	Max. Temp	Internal Upset	Status / lead time	Operating Years	Cost/m	Link	Other comments
Future Pipe Industries	Wellstrong / many	GRE Tubulars	Assorted to 24"	100 - 121 Deg C	No	12-16 weeks	>40 years	Between CS & stainless	https://futurepipe.com	Pressures up to 3,500 psi
				100 Deg C Cont.						>13,000 ft
Western Falcon Energy	Polycore	High Density Polyethylene (HDPE)	2 3/8" - 3 1/2" *	71 Deg C		Available	29 years		HTTPS:westernfalcon.com	Can provide smaller, larger & Casing
	Modified Polycore	High Density Polyethylene (HDPE)	2 3/8" - 3 1/2" *	71 Deg C		Available			-	Can provide smaller, larger & Casing
	Enertube	Polyolefin	2 3/8" - 3 1/2" *	99 Deg C		Available			-	Can provide smaller, larger & Casing
	Ultratube	Polyphenylene Sulphide (PPS) resin	2 3/8" - 3 1/2" *	175 Deg C		Available			-	Can provide smaller, larger & Casing
	Extremetube	PolyEther Ether Ketone-(PEEK)	2 3/8" - 3 1/2" *	260 Deg C		Available			-	Can provide smaller, larger & Casing
Geothermica		GRE Tubular			No	R&D			www.geothermica.eu	Development consortium

Vendor Contacted	Product	Description	Sizes	Max. Temp	Internal Upset	Status / lead time	Operating Years	Cost/m	Link	Other comments
MaxTube	Duoline 20	GRE Lining	7" (13 3/8"?)	140 Deg C	No	Available	>55 years		https://maxtube.com	Numerous fishing trips
	Duoline 10	GRE Lining		71 Deg C	No	Available				>100 million ft run
	RiceWrap	GRE External Wrap	2 3/8" - 7"	121 Deg C	-	Available				0.1" thick external wrap
Integrated Protective Coatings	Various	ENC coating (dipped)	Any	205-399 Deg C	-	10,000m/m	>43 years	€130-250/m Coating only	https://www.ipccoatings.com	Series 3000 ENC best for geothermal. Can coat 10,000m/month

13 APPENDIX B: GEOTHERMAL WELLS - TYPICAL LIFE-CYCLE STAGE-PRODUCTION CASING & TUBING THREATS

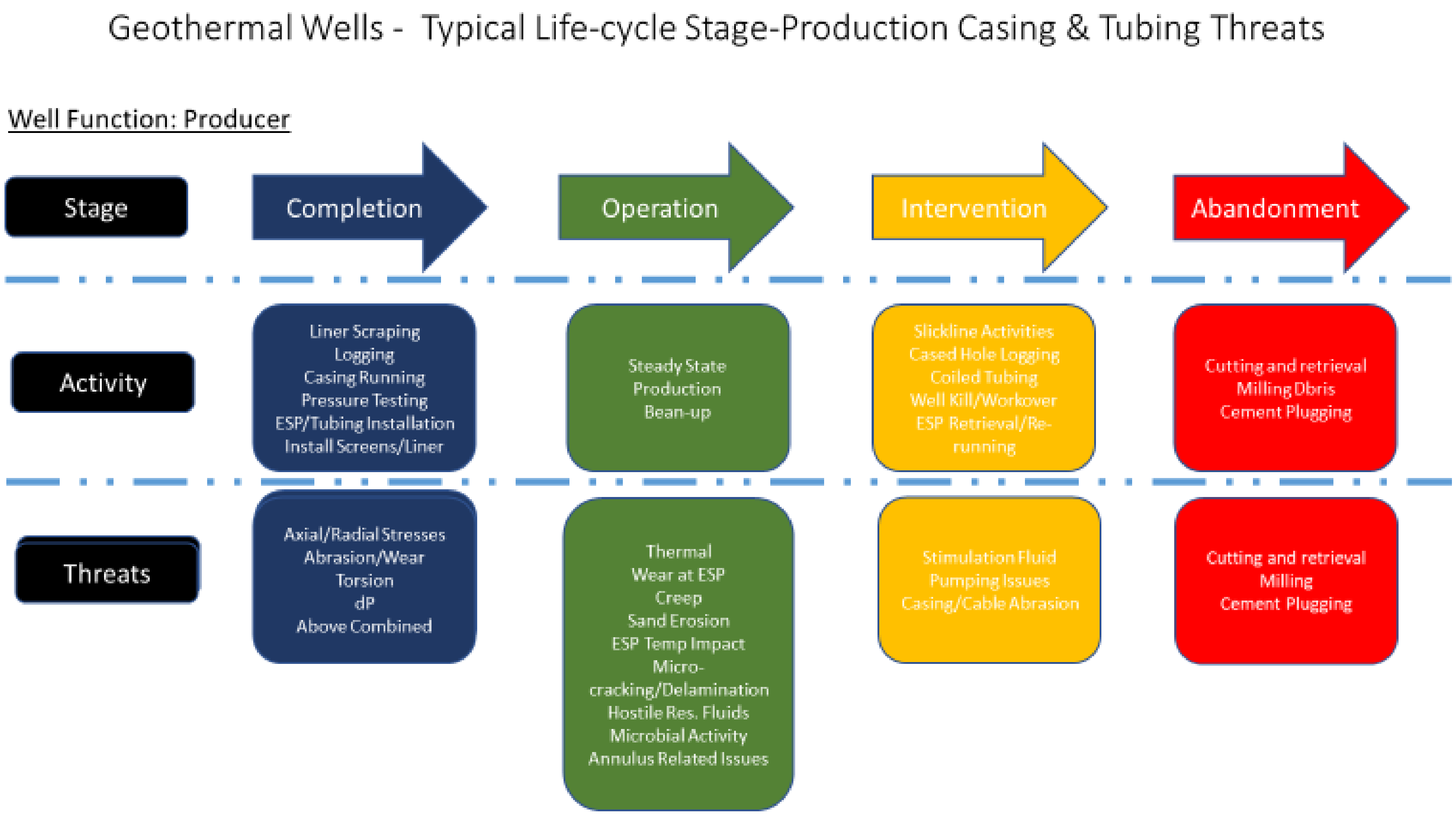

Figure 13-1 Geothermal Producer: Typical Life-Cycle Stage-Production Casing & Tubing Threats

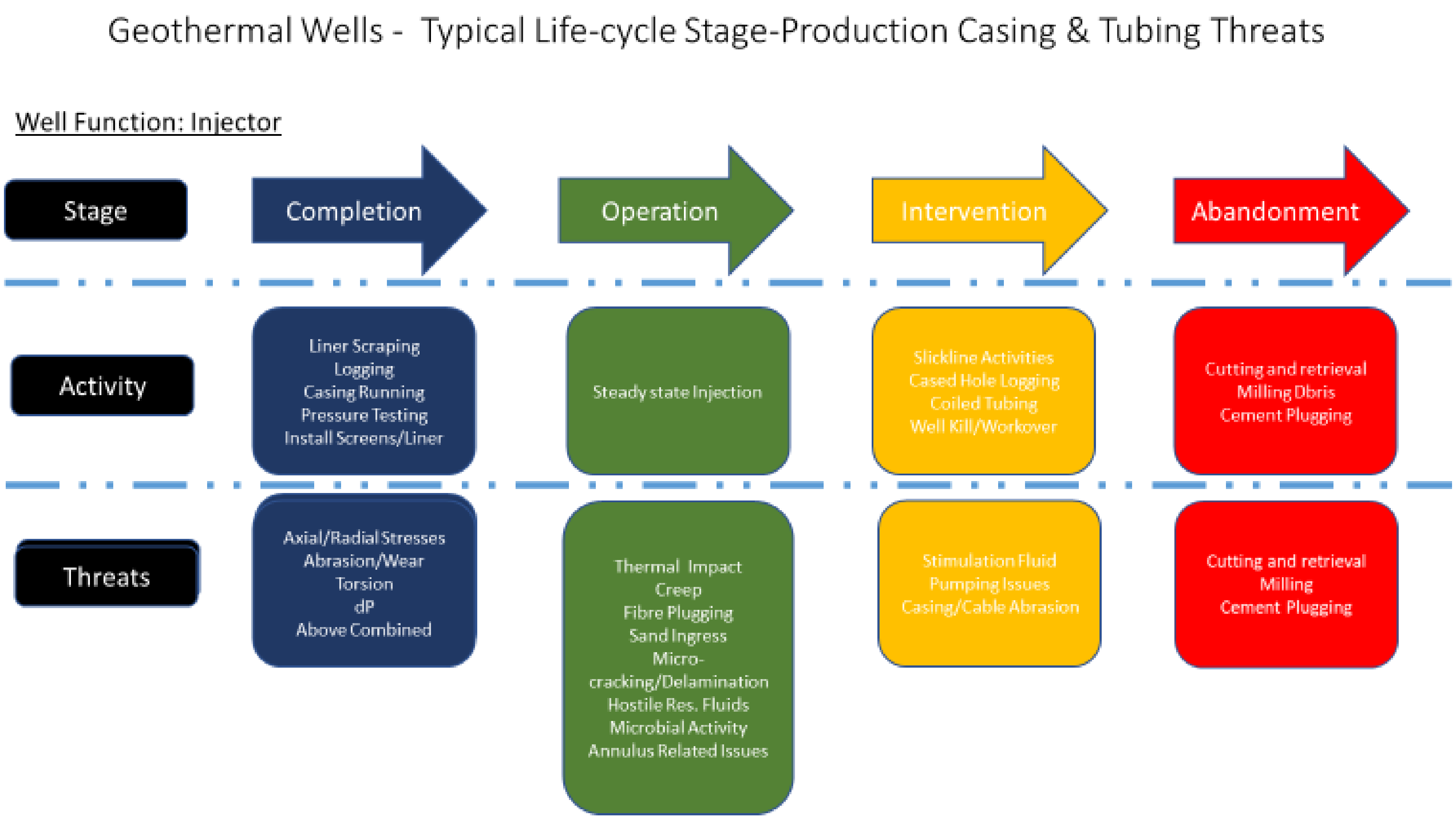

Figure 13-2 Geothermal Injector: Typical Life-cycle Stage-Production Casing & Tubing Threats

14 APPENDIX C: EXAMPLES OF PRACTICAL NON-METALLIC AND COATED SOLUTIONS FOR TYPICAL GEOTHERMAL WELL CONFIGURATIONS

Barrier	Primary Barrier (Production Tubing)	Secondary Barrier (Production Casing)	Production Liner/Screens
Configuration 1. **Packer Completion - Low Enthalpy**	GRE/TPL Tubing/Lining or Abrasion Resistant Coating Internally Inhibited Annular Fluid to Eliminate Corrosion	GRE Casing. Possibly Carbon Steel above Packer Abrasion Resistant Coating Below Packer	Ceramic Screens with Coated Base Pipe (only short lengths of ceramic rings)
Configuration 2. **Packerless Completion - Low Enthalpy**	GRE/TPL Tubing/Lining or Abrasion Resistant Coating Internally GRE Wrap on Outside of Tubing	Abrasion Resistant Coating Internally.	Ceramic Screens with Coated Base Pipe (only short lengths of ceramic rings)
Alternative for Configuration 2.	Potentially Composite CT to Deploy ESP Simplify Change-out and reduce risk of casing wear		
Configuration 3. **Packer/Packerless Completion - High Enthalpy**	Coating Internally Coating externally for Packerless	Abrasion Resistant Coating Internally.	Ceramic Screens with Coated Base Pipe (only short lengths of ceramic rings)

Notes.

- High Enthalpy solution would also be applicable in Low Enthalpy wells.
- Options aren't mutually exclusive so one could envisage a hybrid concept. For example, a packer and inhibited annular fluid to protect the production casing of injectors, a high alloy with erosion resistant coating in the packer region, GRE/TPL tubing or lined tubing, an erosion resistant coating on the production casing below the packer where there should be less wear in both producers and injector and coated screens with coating on the base pipe. Alternatively, adopt a "belt and braces" approach in Low Enthalpy wells with, say, GRE/TPL tubing/lining to guard against corrosion and abrasion resistant coating to protect the GRE/TPL against wear.
- Benefits of composites vis a vis steel, are corrosion resistance, transparency to EM logging, minimal scale deposition, light, lower friction, carbon footprint and insulating.
- Accessories can be manufactured from conventional materials, or coated with abrasion resistant coating, with same performance characteristics.

15 APPENDIX D: A COMPARISON OF THE REPORTED PERFORMANCE PROPERTIES OF ENC COATING AND GRE LINING

From Integrated Protective Coatings Inc.by Andrew Migdal, P.Eng., June 21, 2021

	Tests / Product characteristics	**Glass Reinforced Epoxy**	**IPC Series 3000 (ENC)**
1	Material	Glass Reinforced Epoxy Resin System	Metallic -amorphous (Electroless Nickel-High Phosphorous Alloy)
2	Coating thickness	7-15 mils (178 -381 µm)	2 - 2.2 mils (51- 56 µm)
3	Corrosion resistance	Excellent	Excellent Lab Tests & Field Tests in Oi & Gas Ind.: 5% H_2S, 100%CO_2, 90,000mg/l of Chlorides, T= 204°C (400°F), 1000 psi
4	Anti-scaling/Anti-fouling properties	Excellent	Excellent • AFM Force Test in aqueous NaCl at different concentrations, pH's and additions of Ca^{2+}) • LAB Bulk Scaling Test at 25° and 60° C • SAGD Lab Test (in NaCl, N-dodecane, Sodium Bicarbonate, 5% H_2S, 2%N, 20% CH_4, 73% CO_2 at 250° C, 3.8MPa for 30 days • SAGD Field Test in Western Canada (in 11 SAGD Producer Wells, 2.5 months' circulation and 2 weeks' production)

5	Working Temperature/Pressure	121°C Common temperature range (between 80 and 100°C) Cannot be used under high temperature for a long time, as beyond a certain limit, the epoxy resin in the tubular fails to support the glass rowing's and the pipe fails. Poor corrosion resistance after high temperature long-term exposure which translates into an overall reduction of the mechanical strength and reduction of adhesion (risk of disbandment and cracking). Compared to failure methods of steel pipe such as collapse and burst, fiberglass piping fails with seepage. Because of the resins' thermal limitations, steel is still favoured in high temperature environments. <u>Pressure limit</u> (3,000 psi) At higher pressures the tubing is prone to creep, which results in tubing failure before its design life is reached. This is especially true in high temperature applications as the creep is proportional to temperature. Creep is also the reason why this type of material proves to operate very poorly under cyclic conditions. Saudi Aramco has tried GRE for some shallow casings/liners but had corrosion problems between the resin and H2S. The use of fiberglass tubulars in aggressive environments seems to be somewhat limited and this option is not recommended because: the most common application is in low corrosion, low	230°C

		temperature and low pressure wells there are problem areas such as connections (area protected by the combination of end flares and a corrosion barrier ring), certification, compatibility with other components, and creep resistance. The joints or connections between steel piping and the fiberglass tubular have been reported to have had the most failures.	
6	Melting point	230 °C (thermal stability)	880°C
7	Adhesion bond strength between coating and substrate	approx. 20 MPa (2900 psi) DIN EN ISO 4624:2003 the most common complaints concerning fiberglass piping is leakage at joints (peeling and flaking)	450 MPa (65,000 psi) Chemical and mechanical bonds between coating and substrate
8	Coating Hardness	80-85 Shore D	52-53 HRC
9	Density	1.8 g/cm3	7.8 g/cm3
10	Thermal expansion coefficient	40 µm / m x °C (Breaks/cracks may be caused by thermal expansion and contraction?	12 µm/ m x °C (Low carbon alloy casing/tubing and EN coat have the same thermal expansion coefficient)
11	Mechanical properties	Tensile Strength 300 MPa (43,500 psi)	Tensile Strength 800 MPa (116,000 psi)
12	Abrasion	32-35 mg loss/ 1000 cycles ASTM D4060 - 19 Standard Test Method for Abrasion Resistance of Organic Coatings by the Taber Abrader	15-17mg loss/1000 cycles ASTM B607 - 15 Standard Specification for Autocatalytic Nickel Boron Coatings for Engineering Use.
13	Hydrogen embrittlement	Test results – not available	ENC coat is an excellent hydrogen permeation barrier. No hydrogen permeation, no hydrogen embrittlement

16 APPENDIX E: TUBOSCOPE – DRILL PIPE, PRODUCTION, INJECTION AND LINE PIPE COATINGS

	Coating Description	Type	Color	Temperature	Applied Thickness	Primary Service	Primary Application
TK™-2	High temperature, corrosion resistant thin film coating	Phenolic *(Liquid)*	Maroon	to 400°F *(204°C)*	5–8 mils *(127–203 μm)*	Oil, fresh and salt water, sweet corrosion *(CO_2)* and organic acids to 400°F *(204°C)*; gas production to 200°F	Production tubing, chemical vessels, flow lines, wellheads *(Christmas trees, chokes)*, acidic and CO_2 lines, pumps and tools; hydraulic improvement
TK™-7	High temperature, high pressure, enhanced corrosive gas resistant thin film coating	Modified Phenolic *(Liquid)*	Tan	to 400°F *(204°C)*	5–8 mils *(127–203 μm)*	Oil and gas, CO_2 up to 400°F *(204°C)* and sour gas to 300°F *(149°C)* and above depending on CO_2 and H_2S concentration	Production tubing and downhole equipment; hydraulic improvement
TK™-15XT	Chemically resistant thick film coating with enhanced flexibility for use in high wear applications	Modified Novolac *(Powder)*	Dark Green	to 300°F *(149°C)*	10–18 mils *(254–457 μm)*	Oil, natural gas, fresh and salt water, sweet corrosion *(CO_2)*, mild H_2S and alkaline service to pH 12. Paraffin mitigation	Formulated for increased wear resistance. Production tubing, water and CO_2 injection, disposal wells and flow lines; hydraulic improvement.
TK™-34	Drill Pipe	Epoxy Phenolic *(Liquid)*	Green	Will withstand all temperatures commonly encountered during drilling provided circulation is maintained.	5–9 mils *(127–229 μm)*	Natural and synthetic drilling muds and completion fluids	Drill pipe coating for corrosion protection, scale mitigation and hydraulic efficiency.
TK™-34XT	Drill Pipe	Modified Epoxy Phenolic *(Liquid)*	Blue Green		5–9 mils *(127–229 μm)*	Natural and synthetic drilling muds and completion fluids	Drill pipe coating for corrosion protection, scale mitigation and hydraulic efficiency. Formulated for increased wear resistance
TK™-34P	Drill Pipe	Epoxy Novolac *(Powder)*	Green		6–12 mils *(152–305 μm)*	Natural and synthetic drilling muds and completion fluids	Drill pipe coating for corrosion protection, scale mitigation and hydraulic efficiency.
TK™-44LP	Flexible, thick film coating that provides good temperature performance for line pipe applications	Epoxy *(Powder)*	Red	to 225°F *(107°C)*	10–20 mils *(254–508 μm)*	Line pipe applications including water handling, salt solutions and crude oil	New line pipe and low concentrations of H_2S
TK™-70	Highly flexible, thick film corrosion resistant coating	Epoxy *(Powder)*	Dark Red	to 225°F *(107°C)*	10–20 mils *(254–508 μm)*	Subsurface CO_2 and water handling systems, salt solutions, crude oil and mild mineral acids	New and used tubular goods and line pipe; hydraulic improvement
TK™-70XT	Highly flexible, thick film corrosion resistant coating for use in high wear applications	Epoxy *(Powder)*	Maroon	to 225°F *(107°C)*	10–20 mils *(254–508 μm)*	Subsurface CO_2 and water handling systems, salt solutions, crude oil, mild mineral acids and artificial lift applications	Formulated for increased wear resistance. New and used tubular goods and line pipe; hydraulic improvement.
TK™-99	Highly flexible, thick film corrosion resistant coating	Epoxy *(Powder)*	Black	to 225°F *(107°C)*	12–25 mils *(305–635 μm)*	CO_2 fresh and salt water, oil and gas service to 225°F *(107°C)*, and rod pump applications	Tubing and flow lines; hydraulic improvement
TK™-236	High performance corrosion resistant coating, with enhanced corrosive gas resistance	Epoxy Novolac *(Powder)*	Green	to 400°F *(204°C)*	7–15 mils *(178–381 μm)*	High temperature, high pressure sweet and sour oil/gas wells, and CO_2 tertiary oil recovery systems	Production tubing, downhole equipment, surface equipment and line pipe
TK™-805	High temperature, high pressure corrosion resistant coating with enhanced wear properties	Phenolic Novolac *(Powder)*	Black	to 350°F *(177°C)*	6–13 mils *(152–330 μm)*	Oil, natural gas, fresh and salt water, sweet corrosion *(CO_2)*, mild H_2S, and alkaline service to pH 12. Paraffin mitigation	Formulated for increased wear resistance. Production tubing and downhole equipment; hydraulic improvement.
TK™-900	High performance corrosion resistant coating with maximum wear resistance	Modified Novolac *(Powder)*	Dark Green	to 300°F *(149°C)*	7–15 mils *(178–381 μm)*	Oil and gas, fresh and salt water, sweet corrosion *(CO_2)*, mild H_2S,and alkaline service to pH 12. Paraffin mitigation formulated for abrasion resistance	Formulated for maximum wear resistance. New and used tubular goods and line pipe; hydraulic improvement.

Hydraulic Improvement All coatings provide a smooth and consistent surface finish allowing for improved flow dynamics that can maximize productivity.

Stimulation Fluids When stimulation fluids are charged through the coating, they generally cause little effect if the fluids are flushed completely. A Tuboscope representative should be consulted when a stimulation is planned.

Coating Recommendation Maximum operating temperature and H_2S level will be dependent on total operating environment. Contact a Tuboscope representative for a proper coating recommendation.

Pressure Up to yield strength of pipe.