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Heavy Oil

Controlled Document

Quest CCS Project

Material Selection Report

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Summary

The material selection report – updated has been prepared taking into consideration corrosion (pitting, crevice, etc.), sour service (none for Quest CCS), environmental cracking. Material selection has been carried out for the design as well as different operating temperature scenarios, including start-up, shutdown cases. All package material requirements have been reviewed, e.g. valves, vessels, columns, tanks, pipings, umbilicals, painting/coating, cladding.

Keywords

Materials, Corrosion

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1. OBJECTIVE

This document is a material selection report that summarizes the philosophy and materials of construction for the Shell Canada "Quest Carbon Capture and Sequestering (CCS) Project". There are 4 main process stages: amine absorber and stripper, CO_2 gas compression, TEG dehydration, and dense phase CO_2 compression. Each stage of the process requires material selection that must consider its own need plus consideration of downstream pipeline and injection operation to ensure process operability, longevity of the project, and minimal downtime. The design life has been defined as 30 years.

The main concern is corrosion products and amine degradation contaminants and their trace hydrates could precipitate in the pipeline and injection facilities and is addressed, in part, by material selection and process design.

Unlike traditional amine units, the absorber is removing CO_2 from the hydrogen CO_2 feed. The rich and lean amine is a Shell proprietary [redacted]% MDEA and [redacted]% DEDA specially formulated to enhance CO_2 recovery. In the amine loop, the material selection addresses potential corrosion products and elastomer swelling.

The dense phase CO_2 produced is essentially non-corrosive to carbon steel; however, the CO_2 can degrade elastomers and process excursions/upset conditions can lower the temperature below the brittle transition points of carbon steel and induce explosive decompression on elastomeric O-rings.

The material selections is supported by Shell laboratory and field data.

2. APPLICATION – PROCESS SUMMARY

The purpose of the Quest CCS Project is to capture, compress and store about 1.08 million tonnes of CO_2 per year from the Shell Canada Scotford Upgrader.

There are three (3) hydrogen manufacturing units (HMU1, HMU2 and HMU3) at the Scotford Upgrader. The production of hydrogen represents a significant source of CO_2 generated in the Upgrader, which is released from the reformer furnace stack. A significant portion of the CO_2 generated is a by-product of the steam reforming and shift conversion reactions. The CO_2 in the syngas stream from the HT-Shift Converter is cooled at high pressure, which presents an energy efficient source for CO_2 recovery, due to its high partial pressure.

An amine absorption and regeneration system is used to capture and recover about 80% of the total CO_2 from the three HMU PSA feed gas streams. The absorption process used is the ADIP-X process, which is an accelerated MDEA-based process licensed by Shell

Global Solutions International (SGSI). The CO_2 Rich Amine streams from each individual Absorber is combined and stripped in the Amine Stripper to recover CO_2 with about 95% purity.

The recovered CO_2 is compressed in an eight-stage, integrally-geared-centrifugal compressor with an electric motor drive. In the first 5 stages, free water is separated out through compression and cooling. The CO_2 from the 6th stage of compression is processed through a TEG dehydration unit to reduce the water content to a maximum of 6 lb per MMSCF. In the final two stages, the CO_2 stream is compressed to a discharge pressure in the range of 8, 000-11,000 kPag resulting in a dense phase supercritical fluid This dense, depending on the operating pressure, has a 10-50 times the moles CO_2 per unit volume versus high pressure CO_2 gas.. The CO_2 Compressor is able to provide a discharge pressure as high as 14,000 kPa at a reduced flow for start-up and other operating scenarios. This dense phase CO_2 is transported by pipeline from the Scotford Upgrader at to the injection locations which are located up to approximately 90 kilometers from the Upgrader a depth of 2000 -2500 meters to enable natural sequestering

3. CODES, STANDARDS, AND REGULATIONS

The following have been considered for this report:

- "Material Selection for CO_2 Capture Project – Gas Plant. Corrosion data provided by Shell dated June 7, 2010
- API 571 – Damage Mechanisms Affecting Fixed Equipment in the Refining Industry
- API 945 – Avoiding Environmental Cracking in Amine Units
- CSA Z662- Oil and Gas pipeline systems
- CSA Z245.1- Steel Pipe
- DNV RP-J202- Design and Operation of CO_2 Pipelines
- DNV Energy Report- Project Specifics Guidelines for Safe, Reliable and Cost Effective Transmission of CO2 in Pipelines
- Amine Service – Fluor Guideline, 2009
- Wet Carbon Dioxide and Carbonic Acid – Fluor Guideline, 2009
- Corrosion 95, Paper 571, Corrosion in refinery Amine Systems"
- Material Selection Diagrams (MSDs)

- Material Selection Tables (MSTs)

3.1. Following is a list of applicable MSDs for the Capture Scope:

- MSD 241. 0051. 000. 059. 005 Rev 0A
- MSD 242. 0051. 000. 059. 006 Rev 0A
- MSD 246. 0051. 000. 059. 001 Rev 0A
- MSD 246. 0051. 000. 059. 002 Rev 0A
- MSD 246. 0051. 000. 059. 003 Rev 0A
- MSD 246. 0051. 000. 059. 004 Rev 0A
- MSD 247. 0051. 000. 059. 001 Rev 0A
- MSD 247. 0051. 000. 059. 002 Rev 0A
- MSD 247. 0051. 000. 059. 003 Rev 0A
- MSD 248. 0051. 000. 059. 001 Rev 0A
- MSD 441. 0051. 000. 059. 005 Rev 0

3.2. Material Selection Tables (MSTs)

Following is a list of applicable MSTs for the Capture scope:

- MST -246-Piping Rev D
- MST -246-Exchangers Rev D
- MST -246-Vessels Rev D
- MST -246-Pumps Rev D
- MST -247-Piping Rev D
- MST -247-Exchangers Rev D
- MST -247-Vessels Rev D
- MST -247-Compressors Rev D
- MST -248-Piping Rev D
- MST -248-Exchangers Rev D

- MST -248-Vessels Rev D
- MST -248-Pumps Rev D

4. CO_2 PROCESS DESCRIPTION

The Shell Quest CCS Project is divided into 4 main metallurgical systems:

1. Amine
2. CO_2 Gas Compression
3. TEG Unit and Dehydration
4. Supercritical CO_2

4.1. Amine

The Amine system is divided into two main subsystems:

1. CO_2 Capture
2. Amine Regeneration

1. <u>CO_2 Capture</u>

Amine absorbers located within HMU 1 (Unit 241), HMU 2 (Unit 242) and HMU 3 (Unit 441) treat hydrogen raw gas at high pressure and low temperature to remove CO_2 through intimate contact with a lean amine (ADIP-X) solution consisting of [redacted]% MDEA, [redacted]% Piperazine and [redacted]% water.

The hydrogen raw gas enters the 25-tray absorbers below tray 1 of the column at a temperature of [redacted]°C and pressure of ~3000 kPag. Lean amine solution enters at the top of the column on flow control at a temperature of [redacted]°C.

The CO_2 absorption reaction is exothermic, resulting in the treated gas leaving the top of the absorber at [redacted]°C. The bulk of the heat generated within the absorber is removed through the bottom of the column by the rich amine, which has a temperature of [redacted]°C. Rich Amine from the three absorbers is collected into a common header and sent to the Amine Regeneration section.

Warm treated gas exits the top of the absorbers and enters the 9-tray water wash vessels below tray 1, where a circulating water system is used to cool the treated gas to a temperature of [redacted]°C. Pumps draw warm water from the bottom of the vessel and cool it to [redacted]°C in shell and tube exchangers using cooling water as the cooling medium. The cooled circulating water is returned to the water wash vessel above tray 6 to achieve the treated gas temperature specification. A continuous supply of wash water is supplied to the top of the water wash vessel in the polishing section. The purpose of the water wash is to remove entrained amine to less than 1 ppmw, and thus protect the downstream PSA unit adsorbent from contamination.

A continuous purge of circulating water, approximately equal to the wash water flow, is sent from HMU 1 and HMU 2 to the reflux drum in the Amine Regeneration section for use as makeup water to the amine system. The purge of circulating water from HMU 3 is sent to the existing Process Steam Condensate Separator, V-44111.

2. Amine Regeneration

Rich amine from the three absorbers is heated in the Lean/Rich Exchangers by cross-exchange with hot lean amine from the bottom of the Amine Stripper. The Lean/Rich Exchangers are Compabloc design to minimize plot requirements. The hot rich amine is maintained at high pressure through the lean/rich exchangers by a back pressure controller, which minimizes two-phase flow in the line. The pressure is let down across the 2 x 50% back pressure control valves and fed to the Amine Stripper.

The two-phase feed to the Amine Stripper enters the column through two Schoepentoeter inlet devices, which facilitate the initial separation of vapour from liquid. As the rich amine flows down the trays of the Stripper, it comes into contact with hot stripping steam, which causes desorption of the CO_2 from the amine.

The Amine Stripper is equipped with 2 x 50% kettle reboilers that supply the heat required for desorption of CO_2, as well as producing the stripping steam required to reduce the CO_2 partial pressure. The low pressure steam supplied to the reboilers is controlled by a feed-forward flow signal from the rich amine stream entering the stripper, and is trim-controlled by a temperature signal from the overhead vapour leaving the stripper.

The CO_2 stripped from the amine solution leaves the top of the Amine Stripper saturated with water vapour at a pressure of 54 kPag. This stream is then cooled by the Overhead Condenser to a temperature of [redacted]°C. The two-phase stream leaving the condenser enters the Reflux Drum, where separation of CO_2 vapour from liquid occurs.

In addition to the vapour/liquid stream from the Overhead Condenser, the Reflux Drum also receives purge water from the HMU 1 and HMU 2 Water Wash Vessels, as well as knockout water from the CO_2 Compression area. The Reflux Pumps draw water from the drum and provide reflux to the Stripper for cooling and wash of entrained amine from the vapour. Column reflux is on flow control, with drum level control managed by purging excess water to wastewater treatment.

CO_2 is stripped from the rich amine to produce lean amine to a specification of [redacted] mol CO_2/mol amine by kettle-type reboilers and collected in the bottom of the Amine Stripper. Hot lean amine from the bottom of the Stripper is pumped by the Lean Amine Pumps to the Lean/Rich Exchanger, where it is cooled by cross-exchange with the incoming rich amine feed from the HMU Absorbers. The lean amine is then further cooled to [redacted]°C by the Lean Amine Coolers, which use 25°C cooling water in shell and tube exchangers. The lean amine is then cooled to the final temperature of [redacted]°C by the Lean Amine Trim Coolers, which are Plate and Frame exchangers using cooling water supplied at 25°C.

A slipstream of 25% of the cooled lean amine flow is filtered to remove particulates from the amine. A second slipstream of 5% of the filtered amine is then further filtered through a carbon bed to remove degradation products. A final particulate filter is used for polishing of the amine and removal of any carbon fines from the carbon bed filter.

The filtered amine is then pumped by the Lean Amine Charge Pumps to the three Amine Absorbers in HMU 1, HMU 2 and HMU 3.

4.2. CO_2 Gas Compression

The CO_2 from Amine Regeneration is routed to the compressor suction, via the Compressor Suction KO Drum to remove any free water. The CO_2 Compressor is an eight stage integrally geared centrifugal machine. Further details of compressor performance will be developed through collaboration with the selected vendor and integrated with the control requirements of the pipeline system.

Cooling and separation facilities are provided on the discharge of the first five compressor stages. The condensed water streams from the interstage KO drums are routed back to the Stripper Reflux Drum to be degassed and recycled as make up water to the amine system. The condensed water from the Compressor 5th and 6th Stage KO Drums and the TEG Inlet Scrubber are routed to the Compressor 4th stage KO Drum. This routing reduces the potential of a high pressure vapour breakthrough on the Stripper Reflux Drum and minimizes the resulting pressure drops. The 7th Stage KO Drum liquids are routed to the TEG Flash Drum due to the likely presence of TEG in the stream.

The saturated water content of CO_2 at 36°C approaches a minimum at approximately 5000 kPag. Consequently, an interstage pressure in the 5000 kPag range is specified for the compressor. This pressure is expected to be obtained at the compressor 6th Stage

Discharge. At this pressure, the wet CO_2 is air cooled to 36 °C and dehydrated by triethylene glycol (TEG) in a packed bed contactor.

4.3. TEG Unit and Dehydration Process

A Triethylene Glycol (TEG) Unit consists of a lean TEG stream at a concentration greater than 99 wt% TEG contacts the wet CO_2 stream in an absorption column to absorb water from the CO_2 stream. The water rich TEG from the contactor is heated and letdown to a flash drum which operates at approximately 330 kPag. This pressure allows the flashed portion of dissolved CO_2 from the rich TEG to be recycled to the Compressor Suction KO Drum.

The flashed TEG is further preheated and the water is stripped in the TEG Stripper. The column employs a combination of reboiling, via a stab-in reboiler using low temperature HP Steam, and nitrogen stripping gas to purify the TEG stream. Nitrogen stripping gas is required to achieve the TEG purity required for the desired CO_2 dehydration, as the maximum TEG temperature is limited to 204°C to prevent TEG decomposition. Stripped water, nitrogen and degassed CO_2 are vented to atmosphere at a safe location above the TEG Stripper.

The lean TEG is cooled in a Lean/Rich TEG Exchanger. The lean TEG is then pumped and further cooled to 39°C in the Lean TEG Cooler with cooling water and returned to the TEG Absorber.

4.4. Super Critical CO_2 Compression

The dehydrated CO_2 is compressed to a discharge pressure in the range of 8,000-11,000 kPag resulting in a dense phase super-critical fluid. This dense phase has the density of a liquid and the viscosity of a gas. This dense phase, depending on the operating pressure, contains 10-50 times the moles of CO_2 per unit volume versus high pressure CO_2 gas.

The CO_2 Compressor is able to provide a discharge pressure as high as 14,000 kPa at a reduced flow for start-up and other operating scenarios. The supercritical CO_2 is cooled in the "Compressor Aftercooler" to 43°C, and routed to the CO_2 Pipeline. This dense phase CO_2 is transported by pipeline from the Scotford Upgrader to the injection locations that are located up to approximately 90 kilometers from the Upgrader.

4.5. Design Considerations for Materials

4.5.1. *Minimum Design Metal temperature (MDMT)*

Shell DEM1 specification 30.10.02.31-Gen, "Metallic Materials – Prevention of Brittle Fracture" and the Shell Canada Amendment "OSG-AS-10.06" state that the Lower Design Temperature (LDT), which is equivalent to the MDMT, is the lowest temperature at which equipment may be subjected to its design pressure. The LDT is determined by taking into account the normal lowest operating temperature, the lowest temperatures during start-up or shutdown, exceptional cool down events and the coldest ambient temperature of the climate at the plant location. In the case of Scotford, the coldest ambient temperature is -43°C. The DEP states that an LDT warmer than coldest ambient may be selected if there are significant savings and if the pressure in the system is physically limited at all temperatures colder than LDT. The LDT / MDMT for most systems in the Quest project is -29°C.

As outlined in the Minimum Design Metal Temperature Philosophy (A6GT-R-1041), most systems in the Quest project cannot start-up or operate below 0°C due to water in the system. Where allowed by metallurgy and for consistency, much of the piping and equipment will have an MDMT of -29°C to accommodate registration with ABSA and for consistency with existing Scotford practice. The primary exceptions are CO_2 systems that are subject to auto-refrigeration if depressured and the high pressure vent piping associated with these systems, which are designed with an MDMT of -80°C. The chosen MDMT values for Quest provide an As Low As Reasonably Possible (ALARP) solution.

The mitigation of using Electrical Heat Tracing (EHT) to maintain system temperature for non-flowing lines and during start-up and shutdown is consistent with current Scotford operating practice. The reliability of EHT is consistent with the Scotford electrical system, and if EHT fails due to a site-wide power failure during winter, Operations may hook up a portable backup generator to provide power. Without the backup generator in this case the process systems must be de-energized and drained.

5. GENERAL MATERIALS SELECTION PHILOSOPHY

Materials selection is based on a philosophy keeping in mind the economics of the project and the design class of facilities. However, a critical assumption in the prediction of the service life is that certain maintenance, repair and treatment activities are performed to an acceptable standard. These include operation of the plant, external coating maintenance and maintenance of insulation.

5.1. Equipment Design Life Guidelines

The following table describes equipment and piping design life guidelines.

Equipment	Design Life (Years) note 1
Pressure vessels, columns	30
Heat exchangers (high pressure alloy steel)	Shell – 30
Heat exchangers, bundles, channels	Shell – 30 Channels – 30 Bundle – 10 (CS), 15 (SS)
Air cooler headers	30
Stripper reboiler tubes,	304 – 8 316 – 12
Atmospheric tanks	Duplex – 30: CS – 30 (with nitrogen blanket)
Pumps	Stationary components – 30 Rotating – 10
Compressors	Main body – 30 Rotating elements – 15
Piping	**Design Life, Years**
Carbon steel piping	30
Stainless steel piping	30
Carbon steel lean amine	20
Carbon steel cooling water piping	20
Valves	30

NOTE: Life span is estimated life of the piping/equipment, but it does not include normal inspection and maintenance and repairs.

The selection of materials for equipment and piping are summarized in the Materials Selection Diagrams and Material Selection Tables.

5.2. Corrosion Allowance Guidelines

Materials selection is based on Materials Selection Tables, Process Flow Diagrams and Materials Selection Diagrams (referenced under Codes, Standards, and Regulations). Though corrosion testing at Shell Calgary Research shows very low corrosion rates on SS materials selected at Quest conditions, corrosion allowance of minimum 0.6 mm has been provided to meet ABSA requirements.

5.3. Elastomers

There are 2 materials issues with respect to elastomers: 1) Expansion of any elastomeric component in the amine loop 2) Elastomeric O-rings compatibility with the high-pressure CO_2 gas and the dense phase CO_2 streams (rapid decompression damage resistance and chemical aging).

1. The philosophy of the project is to minimize use of elastomers where practical. For example, in the compressor, all primary seals are carbon steel and secondary seals are vendor recommended elastomers that reflect the latest experience and track record.

6. CORROSION AND DEGRADATION MECHANISMS WITH PREVENTATIVE MEASURES

6.1. Amine Corrosion

1. Description - Amine corrosion refers to the general and/or localized corrosion that occurs on carbon steel in amine treating processes. Corrosion is not caused by the amine itself but results from dissolved acid gases (CO_2 and/or H_2S), amine degradation products, Heat Stable Amine Salts (HSAS) and other contaminants (API 571, para 5.1.1.1).

   In amine systems with CO_2, unlike H_2S systems, the protective film is iron carbonate versus iron sulphide. The iron carbonate film is fragile and less protective than an iron sulphide film. This film is particularly a concern for carbon steel, rich amine lines, but more of a concern for lean amine if the lean amine is allowed through process conditions to go to ultra lean to values of 0.002 loading. Shell testing is ongoing to validate the actual corrosion rate in lean amine.

The maximum velocity restrictions for rich amine and lean amine based on carbon steel or stainless steel are as follows:

- **Carbon Steel**:-
  Pump / Reboiler inlet - 1 m/s Maximum
  Piping and Pump outlet - 2 m/s
- **Stainless Steel**:
  5 m/s Maximum (excursion 9.2 m/s control valve modulating and shut off)

2. Affected Materials – Carbon steel
3. Prevention – Quality of amine will be maintained through filtration and amine make-up to minimize the corrosive effects of amine corrosion.

6.2. Amine Stress Corrosion Cracking (ASCC)

1. Description – Amine cracking is a common term applied to the cracking of steels under the combined action of tensile stress and corrosion in aqueous alkanolamine systems used to remove/absorb H_2S and/or CO_2 and their mixtures from various gas and liquid hydrocarbons streams. Amine cracking is a form of alkaline stress corrosion cracking. It is most often found at or adjacent to non-PWHT carbon steel weldments or in highly cold worked parts (API 571, para 5.1.2.2.1).
2. Affected Materials – Carbon steel
3. Prevention – Effective ways to prevent ASCC are to PWHT carbon steel in order to relive stresses, operate under accepted threshold temperatures of amine type and by alloying with 300 series stainless steel.

   Concerns have been raised about potential carbonate stress corrosion cracking (SCC) and all amine lines are either SS or PWHT CS, which mitigates the risk of this mechanism.

There was another concern about CO_2 to CO ratios, the CO is out of range of any potential carbonate formation.

NOTE: Shell Requirements: All carbon steel equipment and cold drawn bends and welds in piping and tankage shall be stress relieved to avoid stress corrosion cracking in amine solvents .

6.3. CO_2 Corrosion

6.3.1. *CO_2 Corrosion Process*

1. Description - Carbon dioxide (CO_2) corrosion results when CO_2 dissolves in water to form carbonic acid (H_2CO_3). The acid may lower the pH and promote general corrosion and/or pitting corrosion of carbon steel. Severe corrosion may occur where high levels of CO_2 are present in smaller quantities of acquiesce phase water (API 571, para 4.3.6.1).
2. Affected Materials – Carbon steel
3. Prevention – Effective ways of prevention are to keep streams dry, above water dew point and by alloying with 300 series stainless steel.

6.4. Brittle Fracture

1. Description – Brittle fracture is a sudden rapid fracture under stress (residual or applied) where the material exhibits little or no evidence of ductility or plastic deformation. Brittle fracture may occur if the CO_2 undergoes a loss of containment. (API 571, para 4.2.7.1) resulting in a Joule Thompson temperature reduction effect. Brittle fracture may occur if there is a drop in temperature below the brittle to ductile transition.
2. Affected Materials – Carbon steel

6.5. Chloride Stress Corrosion Cracking (External)

1. Description – Surface initiated cracks caused by environmental cracking of 300 series SS and some nickel base alloys under the combined action of tensile stress, temperature and an aqueous chloride environment. The presence of dissolved oxygen increases propensity for cracking. (API 571, para 4.5.1.1)
2. Affected Materials – 300 Series stainless steel
3. Prevention – Common ways to prevent Chloride Stress Corrosion Cracking (ClSCC) would be by using low chloride content insulation, wrapping pipe with

aluminum foil and epoxy coating. However, on Quest CCS process, humidity is low and based on Shell's previous experience, coatings are not required.

6.6. Chloride Stress Corrosion Cracking (Internal)

1. Description – Internal cracks caused by environmental cracking of 300 series SS and some nickel base alloys under the combined action of tensile stress, temperature and an aqueous chloride environment. The presence of dissolved oxygen increases propensity for cracking (API 571, para 4.5.1.1).
2. Affected Materials – 300 Series stainless steel
3. Prevention – Chlorides are expected to be very low (<20 ppm) in the amine solvent and thus are not considered a concern.

6.7. Hydrogen Induced Cracking (HIC)

1. Description – Hydrogen charging into the steel from corrosion in wet nascent hydrogen producing environments can result in HIC. Nascent hydrogen collects at sub-surface laminations, particularly at non-metallic inclusions, and reacts to form molecular hydrogen, which is trapped and, in turn, causes blistering and cracking.
2. Affected Materials – Carbon steels
3. Prevention – 1) Use clean carbon steels 2) Use SS cladding or overlay

6.8. Hydrogen Embrittlement

1. Description - Hydrogen embrittlement is a loss of ductility of high strength steels due to the penetration of nascent hydrogen which can result in brittle cracking. Hydrogen must be present at a critical concentration. The strength level and micro structure of the steel must be susceptible to embrittlement. A stress above a threshold must be present.
2. Affected Materials: Carbon steel, low alloy steel, and some hardenable SS.
3. Prevention – Use low strength carbon steels or, in corrosive aqueous services, apply SS cladding or weld overlay to prevent surface hydrogen reactions.

6.9. Carbonate Stress Corrosion Cracking

1. Description – Carbonate stress corrosion cracking is similar to caustic and amine cracking. Iron carbonates can embrittle steels.

2. Affected Materials – Carbon steel
3. Prevention – Carbon steel PWHT or SS cladding or weld overlay.

6.10. CO/CO_2 Stress Corrosion Cracking

1. Description - Stress corrosion cracking (SCC) of carbon low alloy steels can occur when there is presence of more than 0.4 bar partial pressure CO in a wet CO_2 environment. CO is covering the steel surface with a molecule layer as a protective layer. Disruption of this layer can introduce local CO_2 attack in stress corrosion appearance.

   Generic boundary conditions are:

   - PCO > 0.5 bar
   - PCO2 > 0.5 bar
   - H2S < 10 ppm
   - Operation below dew point
   - Temperature below 100°C (in combination with the above conditions)

   Upset conditions: even if corrosion resistant alloy are already in place if the construction is subject to high local stress, straining conditions, or cyclic service, the risk for cracking is very high in the above boundary condition levels.

2. Prevention - The CO level is negligible and substantially below any level of concern where a CO/CO_2 SCC in aqueous would be of a concern. The shift reactor produces a negligible CO concentration. Furthermore the CO_2 capture process is highly selective to CO_2 versus CO. The amine high pH reaction essentially equilibrates to forms a carbonate type bond between the CO_2 and the amine OH^- weak chelate type bond. For the described process, SCC effect resulting from CO is not present. Another consideration is that most of the material in the loop is stainless steel clad (per MSD review).

7. CORROSION CONTROLS SUMMARY BY PROCESS AREA: MATERIAL SELECTION CRITERIA

1. Absorption Section
2. Water Wash Section
3. Amine Flash Regeneration Section

4. Amine Stripper Section
5. Amine Regenerator Pump-Around Quench Section
6. Cooling and Filtering Section
7. Utility Section
    - Utilities will be provided by the Scotford Facility.
    - Steam condensate will be used as water make-up for the Water Wash vessels. Thus it is expected that chloride levels will be low (<20 ppm).
    - Demineralized water as well as cooling water will be used for air cooler and shell and tube exchangers.

7.1. Cooling Water

The corrosion allowance for the cooling water lines has been established at 1.5 mm since the cooling water at the Shell Athabasca plant appears to have unusual contaminants (e.g. selenium sulphide). The issue is being addressed by a Shell Task Force.

In addition, all heat exchanger tubes in cooling water service have been upgraded t o duplex SS to accommodate chloride excursions up to 500 ppm during pinching operations.

8. MATERIALS OF CONSTRUCTION

8.1. Amine Absorption Regeneration

a) Incoming hydrogen CO_2 streams have combinations of 304 SS and carbon steel material to accommodate wet CO_2 corrosion at low points in piping configuration. The process stream is at its dew point and corrosion control is achieved by heat tracing, insulation, and use of 304/L SS in potentially wet areas.

b) The amine consists of [redacted]% wt MDEA plus [redacted]% wt Piperazine. Typical rich amine acid loadings are [redacted] mole CO_2/mole amine, and typical lean amine acid loadings are [redacted] mole CO_2/mole amine.

304/L SS was selected for all piping and equipment in the rich amine loop and high-temperature piping in the lean amine loop. In the laboratory, testing conducted for the Shell proprietary rich amine resulted in corrosion products that were a concern for process contamination. Corrosive organic species formed from oxidation of amines resulting in heat stable salts. These salts can corrode carbon steel and the corrosion by-products can precipitate downstream. Other corrosion products can produce sludge and suspended solids such as, iron oxide, iron, magnesium, calcium oxides and carbonates that can foul downstream piping and equipment. For the 304/L, a minimum of 0.4 mm corrosion allowance has been specified to accommodate the laboratory test, reported corrosion values in SS.

c) The overhead wash-water system was also specified as 304/L SS due to a reported acidic pH from the wet CO_2.

d) The stripper-re-boiler tubes were specified as 316/L SS with a 0.6 mm corrosion allowance to accommodate the elevated temperature higher corrosion rate that has historically resulted in external pitting corrosion on the tube surface. Elevated temperatures of the stripper-re-boiler tubes will produce amine degradation products, which at elevated temperature and localized concentration can, in combination with the bulk amine, enhance tube pitting.

e) For the lean amine, SS was specified for the piping and equipment down to the lean-rich amine exchanger due to reported high corrosion rates and failures in this area. Downstream of the lean-rich amine exchanger, the material is carbon steel with a 0.3 mm corrosion allowance and PWHT to mitigate amine stress corrosion cracking. The consensus of the industry is to PWHT lean amine regardless of temperature due to reported failures.

f) The amine make-up tank has multiple purposes, and it is used for storage of rich-lean amine and upset and maintenance storage. This tank was specified as lean duplex SS with duplex flanges and fittings. Alternatively, carbon steel PWHT was considered technically acceptable but rejected on a cost basis. Refer to Project Decision Note PDN 059 for details of the decision.

8.2. Wet CO_2 Compression

a) The wet CO_2 piping is specified as 304/L SS to accommodate wet CO_2 corrosion. The CO_2 gas compressors, coolers, and knock-out drums were specified as 304/304L. However, the compressor vendor has recommended a martensitic12 chrome based on track record in wet CO_2 service.

8.3. TEG Dryer

a) Piping and equipment from the wet CO_2 compressor to the TEG dryer is304/L SS. Due to the concerns of contaminants that could interfere with normal operations of the downstream pipeline and equipment, the TEG dryer was specified as 304/L SS up to the TEG lean-rich exchanger. Piping and equipment from the exchanger to the TEG absorber is specified as carbon steel with 0.3 mm corrosion allowance.

8.4. CO_2 Dense-Phase Compression

a) The dry CO_2 piping and equipment are specified as 304/L SS to accommodate MDMT due to the concerns of dense-phase JT temperature upset. During a compressor upset trip, CO_2 from the TEG dryer can discharge to vent through the downstream compressor resulting in temperature drops to -25°C. However, the compressor vendor has recommended a martensitic 12 chrome based on track record. This process is different from classical dense-phase compression due to the addition of the TEG dryer. Acceptability of the material to comply with MDMT requirements is under evaluation.

b) Piping downstream of the dense-phase CO_2 compressor to the battery limit is 304/L SS as is the vent piping. This piping is used to depressurize the pipeline for upset, maintenance, and when temperatures can drop to -75°C for pure dense-phase CO_2 and to -85°C for dense-phase CO_2 with contaminants.

8.5. 8.5 Vent Stack

Preliminary design for vent at high point structure recommends 304L Stainless steel + 0.4 mm CA material to accommodate wet CO2 corrosion as well as 30 year design life. Metallurgy selection is consistent with piping and equipment upstream of the vent stack S-24603.

8.6 Pipeline Materials

The main concern with the CO_2 dense phase pipelines are ductile running fractures and CO_2 corrosion in upset operating conditions.

CO_2 pipelines may be more susceptible to long running ductile fractures than hydrocarbon gas pipelines. The need to prevent such propagating fractures imposes either a minimum required toughness (in terms of the Charpy V-notch impact energy) or a requirement for mechanical crack arrestors. Additional toughness specifications and tighter metallurgical requirements have been prescribed to eliminate the need for crack arrestors for the control of ductile running fracture. These requirements are listed in the document

Material selection diagrams for the pipeline section listed below have been prepared by Tri-Ocean Engineering (TOE) and reviewed by CRC.

- TOE Drg. No. 09223-0-DG-00020.01 Rev B
- TOE Drg. No. 09223-0-DG-00021.01 Rev B
- TOE Drg. No. 09223-0-DG-00022.01 Rev B
- TOE Drg. No. 09223-0-DG-00023.01 Rev B

8.7 Wells

Refer document 07-3-ZW-7180-0003 for details regarding material selection.

The following materials are recommended to be used for the tubular of the Quest injectors:

- Tubing: carbon steel
- Casing: L80 but the bottom part (potentially exposed to wet CO_2) will be designed with UNS 31803(25Cr duplex). Radway 8-19 bottom casing is 22Cr duplex snd a mitigation program is in place to monitor the potential for 22Cr material resistane to chlorides stress cracking. The well bottom has up to 140,000 ppm chlorides.
- Packer tail: potentially superduplex , 25 Cr as it could be exposed to wet CO_2 and high chlorides

The importance of using superdupex (25Cr) steel for casing material exposed to wet CO_2 has been sown by the chloride stress cracking evaluation done on the 22Cr duplex which showed some cracking initiation sites that characterizes this alloy as borderline resistant.

Elastomers used in a CO_2 well are subjected to two main risks:

(i.) The supercritical CO_2 tends to be absorbed by elastomers, making them swell which can potentially change their properties (e.g. the elastomer could become brittle)

(ii.) A sudden release of pressure could induce Explosive Decompression (ED), which would burst the elastomer

Both these phenomena would compromise the function of the elastomers. Since these elements are used as seals, sometimes for safety critical elements, the selection of elastomers should be supported by lab experiments at the expected conditions. Material selection Review performed by SGS for Barendrecht CCS project and other CCS technical guidelines suggest high hardness hydrogenated nitrile based elastomers as most suitable for CCS application where the partial pressure of CO_2 is above 10 MPa. Further lab tests have been performed at Calgary Research Centre, . and they resulted in recommendations of high hardness fluoropolimeric grades which combine resistance to both rapid decompression damage and chemical attack . An alternative consideration is to avoid elastomers and design the well with metal-to-metal seals.

9. SPECIAL GUIDELINES FOR STARTUP AND SHUTDOWN

Special considerations are considered necessary for start-up and shutdown of compressors and pipeline. The secondary seals on the compressor are elastomers rated to withstand moderate levels of explosive decompression. Special precautions regarding compressor start-up and shutdown are required.

Special considerations are required for the start-up and shut down of the pipeline to ensure that the dense phase is preserved. The use of nitrogen back pressure and controlled de-pressurization will ensure that CO_2 gas occurrence in the pipeline, in the presence of any drop out water (such as caused by an upset in the dehydration system) will not result in pipeline internal corrosion.

10. MATERIAL SELECTION (QUEST CONDITIONS VS. MARTINEZ EXPERIENCE)

Recently Martinez Refinery has experienced corrosion in some areas where 304 SS clad was used in ADIP X amine solutions. For the Quest project, 304SS clad was recommended in ADIP X amine units.