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The Challenges of LNG Materials Selection

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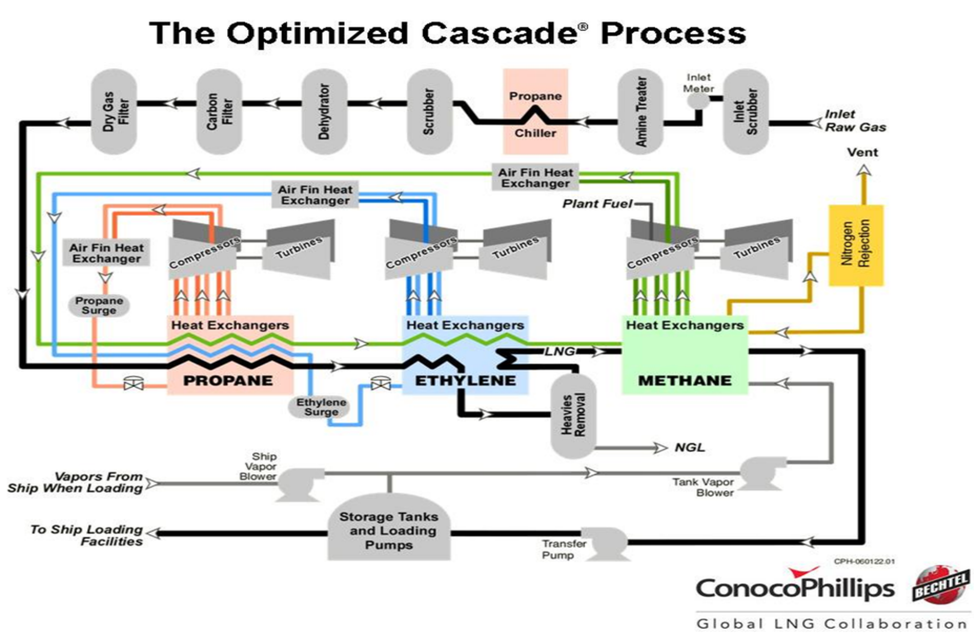
INTRODUCTION

This paper provides an overview for the selection of the materials of construction (MOC) for Liquefied Natural Gas (LNG) liquefaction plants. Some of the challenges are Inlet Gas processing to include acid gas removal, dehydration and mercury removal; refrigeration and liquefaction, and for utility units such as storage tanks, flare and vent stack, boil of gas compressors (BOG) and other equipment. Necessarily being located on the coastline also dictates consideration for marine/offshore structures and equipment (Jetty, Loading Arms, Flares, etc.). Consideration is also given to the overall corrosion control of the plant, along with special considerations to avoid brittle fracture in low temperature applications. The selection of optimum materials of construction plays an important role in major projects because it affects not only the initial capital investment, but also operational costs and profits.

In general, design lives are based on the followings:

- Equipment: 20 years
- Piping: 20 years
- Heat Exchanger Tubes: 10 years
- Heater Tubes: 100,000 hours

For the purpose of this paper, The Optimized Cascade® Process will form the basis for discussion even though the points discussed are applicable to several other liquefaction processes. See Figure below.



DEFINITIONS

For the purposes of this document, the following definitions apply:

Corrosion Resistant Alloy (CRA) highly alloyed metals, the majority being Type 304/304L SS and 316/316L SS.

Minimum Design Metal Temperature (MDMT) is defined as the minimum metal temperature that can be expected due to exposure to the lowest possible operating temperature of the process fluid or environment. It may also consider auto refrigeration temperatures during depressurization event.

Low Temperature Carbon Steel (LTCS) is defined as carbon steel that has been impact-tested at a temperature colder than -20°F (-29°C) according to the mandatory requirements of the ASME/ASTM material standard, such as A333, A334, A350, A352, A420. No special alloying is employed to improve low temperature impacts. The term of LTCS is not used for plate material, and in this document is used only for piping systems.

Environmental Assisted Cracking (EAC) is a brittle fracture mechanism. It occurs in normally ductile materials in which the corrosive effect of the environment is a causative factor, such as SCC, wet H_2S, caustic, amine, etc. The major EAC mechanism found in the plant will be chloride induced SCC of 300 series SS and amine cracking of CS.

Cryogenic Temperature/Service is defined as temperatures below -150°F (-101°C).

GENERAL GUIDELINES

The first step in the selection of material of construction (MOC) is to understand the plant processes and the environmental conditions to which the plant will be subjected. The process information can be obtained from Process Flow Diagrams (PFD) and Heat and Material Balance spread sheets provided by the Process Engineering Discipline. The environmental exposure conditions can be obtained from the basis of design document. Once this information is collected, a material selection philosophy is developed and discussed with the owner. When the philosophy is agreed to, the next step is to create Material Selection Diagrams (MSD). Once issued, these drawings are used by the other engineering disciplines to assure the selected materials are property utilized. Material Selection Diagrams (MSDs) provide a summary of the process loop conditions and the selected materials of construction. Material selection is based on:

- Feed gas composition.
- Economic and practical considerations (purchasing, constructability, etc.) - total installed cost.
- Maximum normal operations pressure, temperature, pH, velocity, dew point, phase, and process fluid composition including contaminants.
- Start-up, shutdown, and upset conditions
- Cyclic service and steam-out operations.

The following material degradation corrosion mechanisms are applicable for LNG Plants, depending on the gas source. Coal seam gas is generally clean with the possibility of some CO_2

- Carbonic Acid Corrosion by wet CO_2
- Sour service by wet H_2S
- Amine Corrosion and Cracking
- Caustic
- Environmental Assisted Cracking - Chloride Induced Stress Corrosion Cracking (CI-SCC)
- Chloride pitting corrosion of stainless steels.
- Microbiological Induced Corrosion (MIC)
- Liquid Metal Embrittlement (LME)
- Brittle Fracture in Low-Temperature Service

The corrosiveness of any process is a function of the fluid chemistry, contaminants, temperature, pressure, fluid velocity, and exposure. In order to select appropriate materials of construction, it is essential to understand the nature of the process exposures. The objective of this section is to identify some of the common environments encountered in LNG plants, and to describe material selection approaches for various operating conditions.

Wet CO_2 Corrosion

Wet CO_2 environments are typical in gas treatment systems. CO_2 forms carbonic acid when exposed to liquid water and is extremely corrosive to CS, especially at high pressure (high CO_2 partial pressure). Even with normally dry streams there is a possibility of periodic corrosion due to condensation of water. Where Heat & Material Balances Sheets indicate significant CO_2 concentration and liquid water, CS may not be acceptable without increasing the corrosion allowance, application of pH neutralizers, corrosion inhibitors, dehydrators (glycol, methanol), SS cladding, or a combination of these mitigating tactics.

Wet Hydrogen Sulfide Service (Sour)

Wet hydrogen sulfide (H2S) service as defined by NACE MR0175/ ISO 15156, occurs when a gas stream H_2S partial pressure exceeds 0.3 kPa. The presence of high or low pH can greatly increase the severity/corrosiveness of sour environments. In some cases, both CO_2 and H_2S may be present. Small amounts of H_2S may actually reduce the corrosion rate in services with high CO_2 levels. The NACE guidelines or owner experience should be consulted.

Amine Corrosion and Cracking

Both lean amine and rich amine pose corrosive issues. Environmentally assisted cracking (EAC) and general corrosion and are the potential degradation mechanisms. Proprietary amine solvents are used to remove acid gas (CO_2) from the incoming process feed stream. These amine solvents charged with the acid gases are corrosive. Factors that influence corrosiveness include the type of amine, solution strength, acid gas composition, acid gas loading, temperature, velocity, organic acids and the presence of heat-stable salts (HSAS). Oxygen contamination of the amine during storage and processing can lead to the formation of organic acids such as formic, acetic, etc. An enhanced corrosion allowance (3 millimetre as a minimum for CS) and velocity restrictions have been employed to mitigate general corrosion of CS due to amines. Normally the liquid velocity is limited to less than 2 meters per second for CS in lean amine service. 300 series SS with a 0.4 mm (1/64 in) Corrosion Allowance (CA) may be employed for piping in rich amine service. The fluid velocity limit for 300 series SS is 4 meters per second. Copper containing alloys should never be used in the amine treating or regeneration units.

Carbon or low-alloy steels are subject to environmentally assisted cracking (EAC) when in contact with hot amine solutions above approximately 4% by weight. This type of caustic cracking is also commonly referred to as caustic embrittlement. It manifests itself as a branched network of fine, predominantly intergranular cracks. For all CS equipment and piping in amine service, PWHT will be performed at 691°C ±14°C (1275°F ± 25°F) after welding or forming operations to mitigate caustic cracking.

Caustic

Caustic soda is sometimes used in water treatment systems. In many applications, CS is the material of choice for equipment and piping in caustic service. The corrosion rate of steel at ambient temperature is generally less than 0.05 millimeters per year when exposed to caustic concentrations below 50% weight. At higher temperature, corrosion rates can increase. At concentrations above 50% caustic is very corrosive to CS, even at ambient temperature. Nickel alloys may be used where higher temperatures and caustic concentrations promote corrosion greater than 0.1 millimeter.

Crevice corrosion is a concern when local high caustic concentrations are produced as a result of heating and/or solution evaporation. For this reason, care in design of heat transfer equipment (avoiding crevices) is advisable. Threaded connections are a common source of external leakage, and should not be used in caustic service.

Caustic cracking of highly stressed (e.g., as-welded or as-bent) CS is not anticipated when exposed to caustic solutions up to 50% weight, at temperatures below 46°C (115°F). In the 46 to 82°C (115 to 180°F) temperature range, cracking is a function of the caustic concentration. Above 82°C (180°F), cracking is highly likely for all concentrations above about 4% wt.

Various contaminants in caustic solutions, including oxygen and chlorides, have been shown to increase the cracking tendency.

300 series SS are not generally recommended for caustic service because they offer little advantage over CS. Their corrosion resistance is only marginally better, and they are also subject to caustic cracking above approximately 110°C (230°F). Nickel base alloys offer the best resistance to SCC in caustic solutions. NACE SP0403 offers guidance in determining the need for PWHT or Nickel Alloys in caustic environments.

Pitting and Environmental Assisted Cracking – Chloride Induced Stress Corrosion Cracking (CI-SCC)

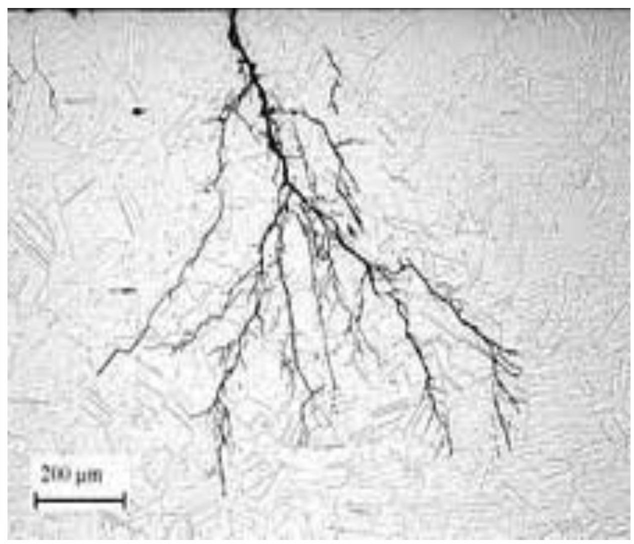
Chlorides in aqueous solutions can be aggressive under certain conditions. For example, in carbon steels a pH neutral solution at ambient temperature is not particularly aggressive; however, corrosion can be severe in an acidic solution with a pH ≤ 4.5. Introduction of chlorides into the process system is mitigated by use of demineralized water for absorber tower washing and solvent make-up. In chloride containing solutions, the 300 series SS are susceptible to pitting and under deposit corrosion. However, the most significant threat is from chloride induced-stress corrosion cracking (Cl-SCC) when the operating temperature is above the threshold temperature for SCC.

To reduce the potential for pitting and Cl-SCC, the following precautions are recommended for 300 series SS.

- 304L/316L series SS materials (e.g., plates, piping, forgings, fittings, etc.) are typically specified to be supplied in the solution annealed condition in order to minimize residual stresses that can contribute to Cl-SCC.

- Bulk 300 series SS piping components are generally externally coated and provided with end caps/plugs as an added precaution against pitting during transport and storage. During transport, piping will be shipped and stored inside in a closed dry environment wherever possible. Deck mounted equipment, pipe and components should be avoided for ocean shipment.

- Hydrostatic testing water quality should be controlled to reduce chloride concentration to an acceptable level. Chloride levels should be 50 mg/l for austenitic stainless steel and 100 mg/l for carbon steel.



Water Corrosion

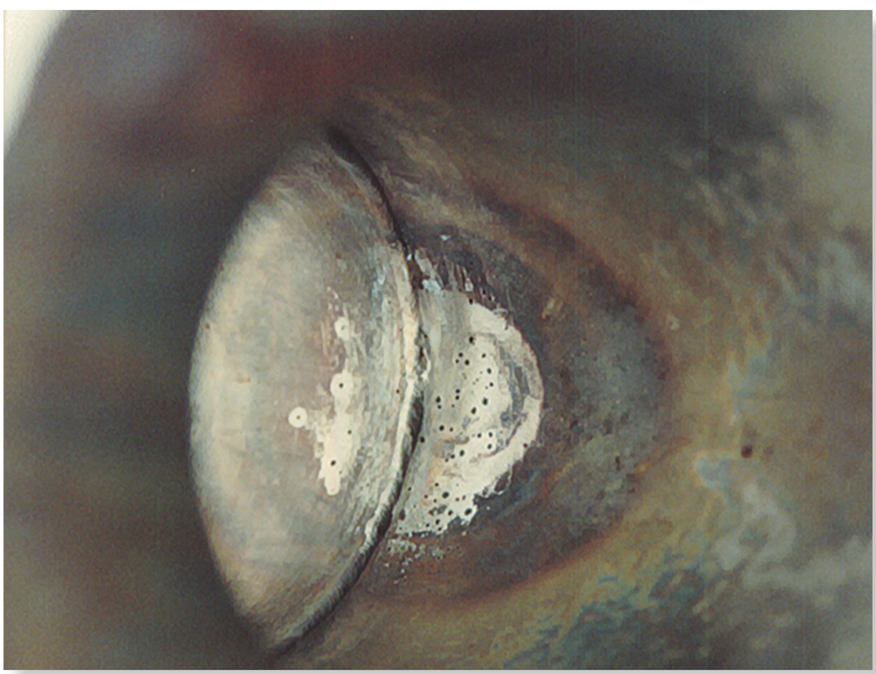
Corrosion rates of carbon steel piping are assessed using the Langelier Saturation Index (LSI) and other published corrosion production tools. In low corrosive waters where the flow is stagnant, a 1.5 mm corrosion allowance is adequate but 3 mm is called out for conservatism in CS piping and equipment. For higher corrosive waters, corrosion assessment will consider temperature, oxygen concentration, halide concentration, and other pertinent factors. Underground piping may be non-metallics. Corrosion of underground water piping will be mitigated by use of HDPE. Demineralized water is corrosive to CS. Above ground piping will be fabricated from 304L SS (or 316L SS), no corrosion allowance will be added.

Microbiological Induced Corrosion (MIC)

MIC is a form of corrosion caused by living bacterial. It is often associated with the presence of tubercles or slimy biofilms. MIC Corrosion is usually observed as localized pitting, sometimes under deposits or as tubercles that shield the organisms. In CS, damage is often characterized by cup-shaped pits within pits and in austenitic stainless steel as subsurface cavities. Critical Factors to be considered with MIC include:

- Velocity – stagnant or low-flow conditions
- Temperature
- Oxygen Concentration
- Nutrients including inorganic substances (e.g. sulphur, ammonia, H_2S) and organic substances (e.g. hydrocarbons, organic acids). In addition, all organisms require a source of carbon, nitrogen, and phosphorous for growth.

MIC has been found in heat exchangers, in the bottom of water storage tanks, piping with stagnant or low flow, and in piping in contact with some soils. Using well or ground water is especially susceptible to MIC contamination. Appropriate material selection, coating, chemical treatment (chlorine, bromine, ozone, ultraviolet light, or proprietary compounds) should be considered to minimize MIC. Bleach (NaOCl) is an effective biocide but must be used in the correct concentration (2 mg/l) to preclude damage to the MOC. A project hydrotest water quality specification should be issued for use during fabrication and construction, especially during hydrostatic tightness testing of equipment and piping. One of the most important steps is removal of water from equipment and equipment immediately after the hydrotest followed by proper drying, preservation and capping. Using dry, oil free compressed air with a dew point of -40°C (-40°F) has been proven to be effective. Systems that are not designated or intended for water containment should be kept clean and dry. MIC has been found in hydrotested equipment that has not been properly dried and in equipment but has been left outside and unprotected.



Liquid Metal Embrittlement

Liquid metal embrittlement (LME) results in the brittle failure of a normally ductile metal alloy in the presence of tensile stress (either applied or residual) and a specific liquid metal. Temperature, stress, and liquid metal wetting are the principal factors that influence LME in a specific alloy/liquid metal couple. Removal of any one of these factors eliminates the risk of LME. Secondary factors promoting LME are alloy composition and grain size.

The major concern for LME in an LNG Plant arises from exposure of aluminum alloys in the cold box to accumulated mercury from the feed gas. The amount of mercury and its location in the cryogenic exchangers is often unknown, and not easily estimated. As long as the cold temperature remains below the freezing point of Mercury, -38.8°C (-37.9°F), no LME problems exist. However, at some point the cold exchangers will be shut down, and reach ambient temperatures, where mercury melts, exists as a stable liquid, and LME of aluminum alloys can result.

Mercury Removal Beds are employed to eliminate mercury in gas streams entering the aluminum exchangers and the cold boxes.

Another source of liquid metal embrittlement occurs when zinc contaminated components are welded to stainless steel. Cracking has been known to occur when galvanized or zinc coated supports are welded to stainless steel pipe.

Low-Temperature Service and Potential for Brittle Fracture

The minimum design metal temperature (MDMT) is defined during design in order to allow material selection for resisting brittle fracture. This is purely a mechanical design requirement (no corrosion concern). The following criteria are used to establish the MDMT:

- MDMT may be based on consideration of the lowest expected operating temperature, the lowest ambient temperature, depressurizing condition, cooling/heating medium failure, preliminary equipment design condition, piping specification limits, or an operational upset, or any other source of low temperature. Transient conditions, such as auto-refrigeration may govern, particularly if the unit restart procedure does not permit warm-up prior to pressurization.
- MDMT may be established as the minimum exemption temperature allowed by the applicable engineering code.
- If the material of construction is impact tested, the MDMT can be taken to be the impact test temperature associated with satisfactory impact energy values.
- MOC's will be chosen to meet code requirements for brittle fracture mitigation.

The basic materials selection philosophy used is:

- For temperatures warmer than -29°C (-20°F), carbon steel (CS) is used
- Where temperature is colder than -29°C (-20°F) but warmer than -46°C (-51°F), low-temperature carbon steel (LTCS) or impact tested CS is specified
- For temperatures colder than -46°C (-51°F), Austenitic Stainless Steel is specified

CORROSION MITIGATION

Corrosion mitigation can be divided into areas - inside the pressure boundary exposed to process conditions and exterior exposed to weather. Exterior exposed to the environment corrosion issues are generally mitigated with protective coatings and cathodic protection. Cathodic protection is also commonly used to protect the interior of tanks.

Protective Coating and Insulation Selection

Structural steel can be protected by either a three coat paint system such as inorganic zinc primer, epoxy intermediate coat plus aliphatic polyurethane topcoat or hot tip galvanizing. Galvanizing offers several constructability advantages such as minimal damage during handling and being a more forgiving work process. Several alternate coating systems also warrant consideration such as inorganic zinc or zinc rich epoxy plus a topcoat of either polyaspartic or polysiloxane.

Inorganic zinc coatings are not typically used under insulation, as zinc coatings exposed to water, at temperatures above 66°C (151°F) become passivated, which can result in the coating become a cathode to the steel, resulting in the preferential corrosion of the steel substrate. Where insulation is required, the inorganic zinc coating should be covered with an additional epoxy coating.

For protection against atmospheric corrosion, the same three coat painting system specified for structural steel is sometimes specified for equipment/piping that operates at a temperature of 120°C (250°F) or less and is not insulated. Some projects select a two coat system which consist a coat of zinc rich epoxy plus a polyurethane topcoat. Heat resistant topcoats such as silicone acrylic or heat cure silicones are used for higher operating temperatures up to the melting point of zinc. Thermal Spay Aluminum (TSA) is an acceptable material for cyclic services with extreme temperature swings. 300 series SS may receive a single coat of epoxy for transportation purposes unless export packaging is specified.

Good practice is to procure bulk carbon steel piping with an inorganic zinc primer. The primer can then be topcoated in the field with most high performance coating systems where the operating temperature is below the melting point of zinc (400°C (750°F)).

Insulated equipment and piping, where the process temperature is between 0°C (32°F) and 150°C (302°F), should be coated to provide protection against corrosion under insulation (CUI). When temperature exceeds 150°C (302°F), no protection is required, as there is no corrosion due to absence of condensed water. Some owners have alternate temperature limits or require all surfaces to be coated regardless of temperature. TSA coatings are preferred by many clients; however, liquid applied coatings such as novolac and epoxy phenolic are also used at temperatures up to 200°C (400°F). When selecting a coating system for stainless steel, assurance that the coating will not promote stress corrosion cracking is a requirement.

For Cold Insulation, when cellular glass with vapor stops, sealants, and vapor barrier are specified, the insulation system is inherently impervious to water, and will eliminate corrosion concerns. Other sealed insulation systems such as preinsulated PIR systems with sealed vapor barriers offer the same degree of protection.

Cathodic Protection (CP)

The following facilities should be considered for the CP system:

- Existing CP Systems/Grid Integration
- Underground piping/pipelines
- Storage tank bottoms
- Storage tank internals
- Marine Jetty, Construction Dock, and Pipelines

CP requirements and monitoring systems are defined in project specifications. Metallic materials, including 300 series SS, which are underground, should be catholically protected; this includes large storage tanks (e.g., LNG tanks) which are not on ring wall foundations.

CP for marine Jetty and Construction Dock generally has a 25 year design life. For stationary marine structures, sacrificial systems are preferred. Water storage tanks that have internal lining will also have CP designs with a 25 year design life. Impressed current systems are generally specified for interior water tanks. Assurance that the tank coating system is compatible with the impressed cathodic protection system is a must. Improper selection can lead to accelerated lining failures.

Chemical Treatment

Where it is necessary to control internal corrosion of piping and equipment, the use of chemical treatments (e.g. including corrosion inhibitors, biocides, and oxygen scavengers) may be warranted. Chemicals are typically injected continuously at controlled concentrations to maintain corrosion within acceptable limits. The efficiency of a corrosion inhibitor increases with increases in its concentration. The 90% efficiency is typical for inhibitors when properly applied. The type of product and recommended dosing should follow the manufacturer's recommendation backed by laboratory tests. These material should also be field tested prior to making a final decision on usage. Where high flow rates are required, use of CRA's may prove to be more economical.

MATERIAL SELECTION FOR VARIOUS UNITS

Inlet Separation

Inlet facilities are designed to receive three phase flow (vapor + hydrocarbon liquid + aqueous liquid) from the feed pipeline via dedicated slug catcher. Hydrate inhibition of the subsea production system is achieved through the continuous injection of water scavenger originating offshore.

Feed gases temperature may vary with the feed gas but many are in the range of 15°C (59°F) to 25°C (77°F) with a pipeline MDMT of -29°C (-20°F) and an operating pressure of 50 to 75 bar gauge with formation water expected. As an example, if the beach valve temperature is 18°C and the pressure is 67 bar gauge, condensation can be expected because the dew point is 110 °C (230°F) in normal operating condition. As discussed earlier, small quantities of H_2S does not contribute to, and may reduce general corrosion.

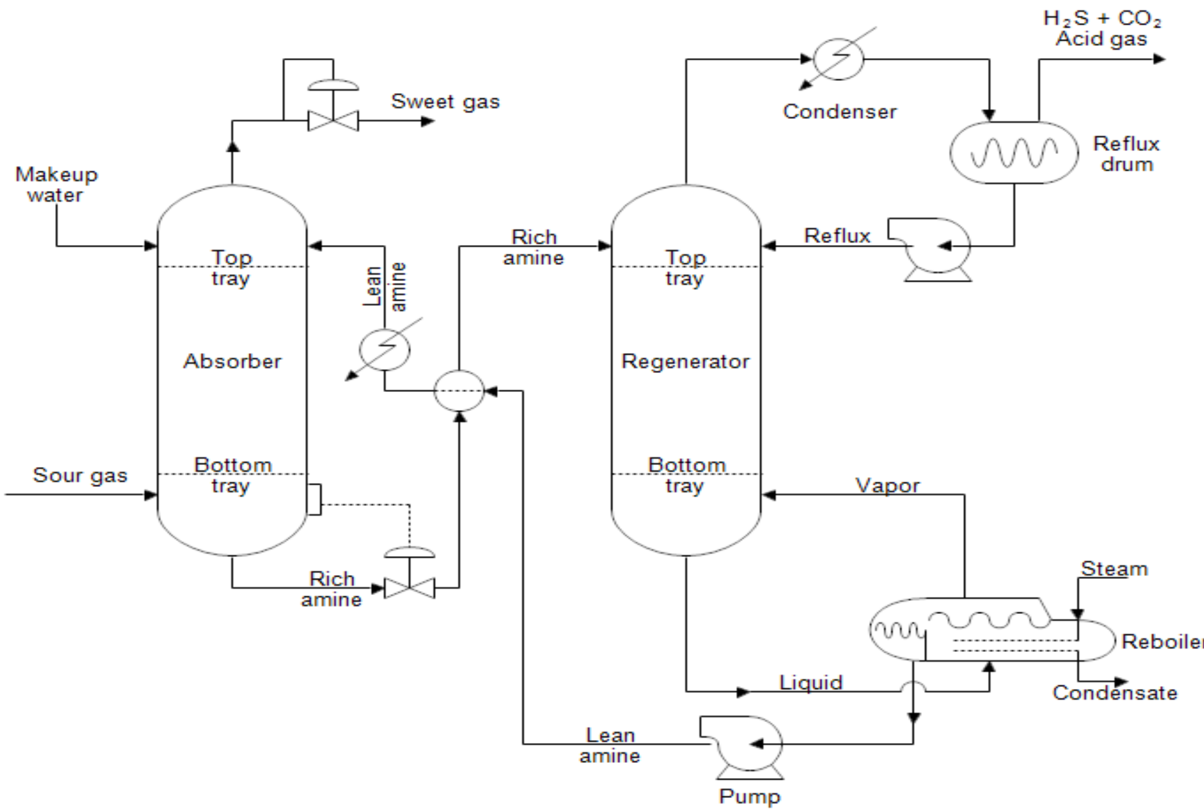
The inlet separation unit stands to be one of the three front-end units that could experience the highest corrosion rates in the LNG plant. Even though the steady state feed gas temperature may be above the water dew point, lower temperature excursions from external influences such as high winds can contribute to heat loss in the system that could promote periodic condensation of water from the feed gas stream. In this case it would be assumed that the equilibrium CO_2 concentration would follow the Henry's Law correlation. As CS is the primary material of construction, corrosion allowances may be increased from 1.5 mm to 3 mm and in some cases 6 mm for piping & 6 mm for equipment as a precaution.

CO_2 Removal Unit/Amine Regeneration

Depending on the feed gas composition, the Acid Gas Removal System and the Solvent Regenerator acid gas dissolved in the amine solvent may require alloy upgrades, increased corrosion allowances, and process controls to minimize corrosion. As discussed, feed gas to the acid gas removal unit (AGRU) generally contains CO_2 and may contain traces of H_2S. The CO_2 and H_2S must be removed to avoid freezing problems in the downstream liquefaction system. The removal of CO_2 and H_2S is accomplished by absorption of the gas by the re-circulating amine solvent system. The solvent selected is based on the ability to remove CO_2 to less than 100 parts per million/volume.

For lean amine (prior to exposure to acid gas) service, all CS welds in piping and vessels should be post weld heat treated (PWHT) to avoid EAC. PWHT relieves stresses caused during welding, minimizing the potential for EAC. The lean amine circuit is fabricated from CS with 3 mm corrosion allowance (CA), and in some cases a larger CA may be specified. In CS piping, the fluid velocity is limited 1.8 meters/second to reduce flow assisted corrosion.

Piping in rich amine streams are generally specified as 304/304L SS, which is a conservative measure recognized in the petro-chemical industry. While a 4 meters/second velocity limit is considered in the design, the use of 304L SS allows for upsets/perturbations. In this unit, CO_2 is reduced down to 50 parts per million/volume maximum. See the figure below which is a schematic of a typical AGRU unit.



Dehydration

Treated gas from the AGRU is chilled against high pressure Propane refrigerant in the Propane Feed Chiller to condense out excess hydrocarbons and water. Downstream filters and coalescers are designed to remove liquids or solids.

After this step, feed gas enters the Molecular Sieve Dehydrators which are on adsorption cycle. Water vapor is removed from the feed gas and is retained within the molecular sieve during the whole adsorption cycle.

Molecular Sieve Dehydrators are regenerated by back flowing clean, dry effluent gas from the Regeneration Gas Heater. The hot regeneration gas passes up through the molecular sieve bed currently off-line in the regeneration mode. The adsorbed water is stripped off of the bed together with some CO_2 and heavy hydrocarbons, restoring the adsorption capacity of sieves. Corrosion in the regeneration gas outlet system is not typical in these units.

The bone-dry gas from the dehydrators passes through the Dryer After-Filter prior to entering the Mercury Removal Beds, which contain a suitable mercury absorbent designed to reduce the mercury content of the gas. Mercury is removed down to a very low gas stream concentration in the 0.01 $\mu g/Nm^3$ before flowing to the refrigeration and liquefaction units.

Feed gas should be dry and free of impurities before being sent to the cryogenic section. Continuous monitoring is provided to indicate moisture and CO_2 content in the gas stream. Since no CO_2 or water is present, CS with minimal corrosion allowance is used for downstream equipment and piping.

Propane Refrigeration

Propane refrigeration chills the feed gas prior to liquefaction in the ethylene and methane refrigeration units.

No internal corrosion mechanisms are expected for the propane system. In this non-corrosive unit, the minimum corrosion allowance is 1.5 mm for CS. Both ASME Section VIII and B31.3 have guidelines for selection of material based on thickness and temperature. Materials for piping and pressure vessels follow guidelines of ASME codes. Generally use of CS piping is restricted to -29°C (-20 °F) whereas LTCS is selected for temperatures below -29°C (-20 °F). For field welding, standard practice should be to purchase all welding consumables for CS with Charpy V-notch impact testing at -46°C (-51°F), thereby mitigating fracture toughness concerns. There is also less likelihood of mixing impact tested with non-impact tested consumables.

Brittle fracture is the prevalent concern in this unit, especially in the propane circuits. Propane will boil at -45.6°C (-50°F) upon depressurization to atmospheric pressure. While CS piping (e.g. A106-B/API 5L) at thicknesses less than about 1 inch is satisfactory at -29°C (-20 °F), re-pressurizing is a concern when the metal is still at these lower temperatures. For most projects, all propane piping in liquid, liquid + vapor service within the process loops (not storage) is fabricated from Low-Temperature carbon steel (LTCS). For temperatures colder than -45.6°C (-50°F), 304L SS should be been chosen because of improved ductile-brittle transition at low temperatures.

Similarly, aluminum cores are not susceptible to low-temperature to brittle fracture.

Ethylene Refrigeration

Ethylene refrigeration cools and condenses the feed gas from the methane compressor discharge. No corrosion mechanisms are believed to be active in this unit. The most critical factor for MOC will be low temperatures during an upset condition. Brittle fracture has been mitigated by the use of aluminium, 304L SS, and impact tested CS where required.

Once the temperature drops below -46°C (-51°F) only 304L SS is used as this material has excellent cryogenic properties, and is exempt from impact testing down to -196°C (-320°F). Both ASME Section VIII and B31.3 require Charpy V-notch impact testing in weld deposit when minimum design temperature drops below -104°C (-155°F). Standard practice is to buy 304/304L SS dual certified with maximum carbon content of 0.03%, minimizing the potential for external Intergranular SCC. SS weld consumables are purchased with Charpy V-notch impact testing at -196°C (-320°F).

Aluminum is used for exchangers and piping. 9% nickel steel or 304L SS are used for ethylene storage drums.

Liquefaction & Methane Compression

No internal corrosion mechanisms are active in this unit. The most critical factor for MOC will be the MDMT. Brittle fracture has been mitigated by the use of aluminium and 304L SS.

Heavies Removal

The purpose of this Unit is to remove higher molecular weight hydrocarbons from the LNG product stream. Heavier end components (C^{6+}) are stripped out preventing hydrocarbon freezing in the downstream liquefaction equipment.

Normally there are no significant internal corrosion mechanisms unless there is a potential of boil over of rich amine. The most critical factor for MOC will be the MDMT by upset condition.

Flares

The flare and blow down system includes three flare systems (wet, dry, marine) and an Acid Gas Thermal Oxidizer.

<u>Wet gas flare stack</u> is designed to handle hydrocarbon streams that may be saturated with water vapor and/or contain free liquid hydrocarbons and water. The MOC are CS due to a MDMT of -29°C (-20°F) for stack.

<u>Dry gas flare stack</u> is designed to handle cryogenic hydrocarbons, both vapor and liquid. This flare stack is referred to as the Dry Gas Flare. The MOC is 304L SS due to a MDMT of -196°C (-320°F) for stack.

<u>Marine flare</u> is designed to handle LNG vapors from the LNG storage tank in the event of a failure of the Boil-Off Gas Compressors. The MOC is 304L SS due to a MDMT of -196°C (-320°F) for stack.

<u>Acid Gas Thermal Oxidizer</u> is designed to handle Acid Gas streams that are vented from all Gas Train processes. The 304L SS cladding is impervious to wet CO_2 corrosion.

Refrigerant Storage

The MOC for this circuit is typically 304L SS due to cryogenic temperature. No internal corrosion is anticipated.

Condensate Storage

The MOC for all circuits is CS. No internal corrosion is anticipated.

LNG Storage and Loading

LNG storage tanks are fabricated from concrete and 9% nickel steel plates. Ancillary equipment is fabricated from parts is 304L SS or 316L SS. No corrosion is anticipated.

Firewater System

Firewater is stored in Fire Water Tanks. Fire water is pumped from the fire water tank through a ring-main distribution system to hydrants, monitors, hoses and foam systems. A fire water line from the main loop to LNG and Condensate Loading Jetty will be provided for fire protection of the Jetty. The MOC for the firewater piping system will be as follows:

- Aboveground Pipe: CS
- Underground Pipe: Listed High Density Polyethylene Pipe (HDPE)

Severe corrosion is not expected. However, in order to mitigate plugging of fire water monitors, use of corrosion resistant alloys, or other corrosion mitigation strategies (e.g. lined pipe) may be considered. Firewater storage tanks are generally lined and catholically protected, depending on the fire code.

Water System

Treated potable/service water is supplied by the treatment plant. Many plants in remote locations rely on desalinated water which is low in protective calcium salts but high in chlorides. Plastic or stainless steel are acceptable MOC for potable water cleanliness. Stainless steel may be an issue in desalinated water with high chloride and high ambient temperatures. Insulation has been used to reduce the sun load in some instances. In the US galvanized pipe has been used but in some countries such as Australia, there is a general restriction against the use of galvanizing. Linings and materials used fin contact with potable water are required to be certified for use in potable water by the governing organization. CS with a CA is acceptable for service water piping MOC. 304L SS may be considered for demineralized water due to corrosiveness concerns.

Nitrogen Generation and Vaporization

Gaseous nitrogen is supplied to the plant by a Nitrogen Generator Package or a liquid nitrogen storage tank. Nitrogen is used as blanket gas for storage tanks; purge gas for the cold systems, loading arm swivel joint purges, compressor gas seals and buffer, and as purge gas required for repair and maintenance services and for other general purposes. Nitrogen used to blanket the amine storage tanks should not contain oxygen for the reasons noted earlier, i.e., the formation of organic acids. Internal corrosion is not anticipated.