Plant Aging and Life Extension Program

at Arun LNG Plant

Lhokseumawe , North Aceh , Indonesia

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1. Introduction

The Arun LNG Plant is located in Lhokseumawe, North Aceh, Sumatra-Indonesia. The plant is operated by PT Arun NGL Co as a non profit operating company and owned by Pertamina 55 % (The Indonesian Oil State Company), ExxonMobil 30 % and 15 % by Jilco representing Japanese buyers.

The Arun plant has five LNG Trains with annual production capacity of 10 Million M Tons of LNG. The plant has been continuously operated since August 1978. It has produced and delivered more than 3,700 cargoes of LNG to the buyers in Japan and South Korea safely and reliably.

The nominal design life of the most plant equipment is 20 years. However, the plant is expected to remain economically viable for another 7 years to come. In anticipating of this expected service life and to maintain plant reliability PT Arun initiated a Life Extension program in 1996.

The goal of the program is to determine what action(s) are required to maintain the plant reliability for the remainder of the plant life. First, by determining the existing condition of the plant equipment then developing an appropriate remedial program.

2. Analysis Method

2.1 Process parameters and Equipment specification

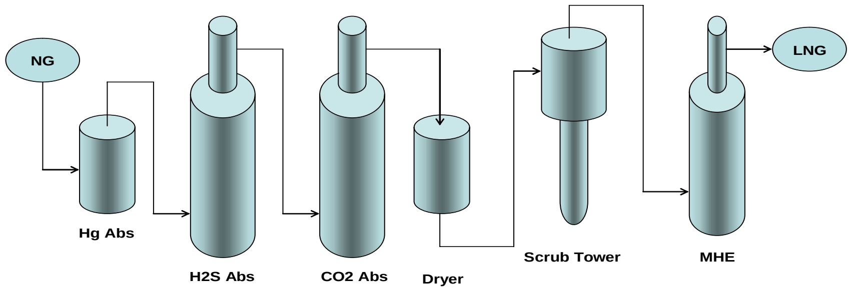
The main function of LNG Plant is to condition the natural gas by removing contaminants then liquefying the remaining gas stream to become LNG for efficient and economical transport to the end users.

Table-1; Arun Natural Gas properties (mole %)

Component	Natural Gas	Component	Natural Gas
C1 (Methane)	74.5	C6+ (Hexane Plus)	0.24
C2 (Ethane)	5.5	CO2 (Carbon Dioxide)	15.0
C3 (Propane)	2.5	H2S (Hydrogen Sulfide)	80 ppm
C4 (Butane)	1.0	H2O (Water)	700 ppm
C5 (Pentane)	0.37	Hg (Mercury)	Trace

Each “Arun LNG Train” consists of a gas treating unit and a liquefaction unit. The purpose of the gas treating unit is to remove impurities in natural gas. Natural gas from the field, after flashing in a series of flash drums to separate the gas from it's condensate enters the gas treating unit that removes the impurities such as Mercury (Hg), H_2S and CO_2 from the gas stream. Before the gas is cooled to cryogenic temperature, the water (H_2O) and some heavier hydrocarbon are removed.

DRAWING-1 ; SIMPLIFIED FLOW DIAGRAM OF LNG PROCESS



Appendix-a is a list of individual fixed equipment available at the gas treated unit and at the liquefaction unit.

At the liquefaction unit, the treated gas is then cooled and liquefied in the cryogenic main heat exchanger (MHE) to produce LNG with temperature at – 160 C. The LNG consists of Methane 86 %, Ethane 8.1 %, Propane 3.6 % and the rest could be Butane 1.7 % and N_2 0.7 %.

There are two refrigerant circuits in the unit, one charged with propane and the other with multi-component refrigerant (MCR). The MCR consists of Methane, Ethane, Propane and Nitrogen.

Major fixed equipment items in the LNG Train are drums, heat exchangers and columns to purify feed gas. The gas vapor dryers, Scrub Tower and main heat exchanger (MHE) as well as the banks of sea water exchanger that are used to remove heat from the two refrigeration systems.

In addition, to the fixed equipment there are three large gas turbines, four gas compressors and a number of smaller pumps.

2.2 Field Condition and History Record

In order to gain a complete picture of the critical equipment current condition, it was important to compile the historical damage and repair records. The accuracy and thoroughness of the maintenance records is a key factor in this process step and the importance of keeping thorough maintenance records can not be over stressed.

Table-2; Several equipment with specific field condition and history record

Equipment	**Field condition and History record**

DEA Exchangers	It has problem with the tube bundle. The problems are pitting corrosion at mostly near the inlet inside tube, mesa corrosion at top area of outside surfaces, crevice corrosion on tube contact point with baffle support, impingement corrosion on outside surface of tubes at inlet nozzle and porosity at seal welds of tube to tube sheet.
Carbonate Regenerator	It has repetitive problem with internal parts. The Chimney tray inside the manway #2 and Inlet deflector inside manway #8. At 36 Inch inlet pipe, due to miss alignment at the elbow joint, it creates high vibration then causes repetitive cracking to the welding joint.
Vapor Dryers	Due to cyclic operation, it has generic external corrosion or corrosion under insulation since the primer coating has become deteriorated and supported by contribution of moisture condensation.
Shell and tube reboiler	The shell, head and cover have experience of severe corrosion under insulation. The tube bundle has problem with the tube leaking due to acidic corrosion, crevice corrosion and porosity at seal weld joint between tube to tube sheet.
C2 MCR make up lines	It has serious corrosion under insulation most a long the line due to cold and intermittent operation. Most of the corroded pipes were replaced with new one and reinsulated by using polyurethane material.
Sea water coolers	These coolers have many of possible failure modes but mainly due to sea water that flowing in the tube side.
Main heat exchanger	It has three major failure modes ; Mercury attack, tube bundle subsidence and tube leaking due to vibration.

2.3 Assessment method

Damage Mechanism

Once the historical data was compiled, an overall study of the possible damage mechanism and failure modes was performed. In this study, each equipment was assessed with respect to likelihood of failure based on design, material used, operation parameter and actual experience. Due to some limitations, this paper will only discuss the fixed equipment and piping.

Initially 16 damage mechanisms were considered for the fixed equipment and piping in the plant. Appendix-b lists the damage mechanism that are considered in this study along with brief description of each item.

3. Analysis Process and Result

A damage analysis matrix was used to assess each individual fixed equipment items, the result is tabulated on Appendix (c and d). A comparison of the equipment original design, material used, process parameter, field condition and history record versus its possible damage mechanism. The comparison analysis led to the detailed consideration of the most dominant possible failure mode.

There are two types of failure mode. First is failure mode that is time dependent, for example; thermal fatigue, creep, hi cycle fatigue, erosion corrosion or by trending the equipment failure rate based on the repair history. The failure rate can be determined by using statistic calculation formula such as Linear distribution, Weibull and Monte Carlo simulation. Second is failure mode that is time independent, for example; brittle fracture, mercury embrittlement, corrosion under insulation and pitting.

Equipment aging or equipment service life can be determined by doing assessment based on the time dependent failure mode or by using the equipment failure record then performing calculation with suitable statistic formula.

3.1 Example of the time independent failure mode :

3.1.1 Brittle Fracture

The fracture toughness of carbon steels is lower at lower temperatures. Most steel at 30°C temperatures is ductile. Different grades of steel become brittle at different temperatures ranging from 30°C to as low as –50°C.

Administrative action by verifying the material document has been done to the equipment and piping that were most likely to have brittle fracturing based on service and specific operating condition. The verification result confirmed that all the equipment analyzed were built using proper material and suitable for the service.

3.1.2 Corrosion Under Insulation (CUI)

CUI will be discussed in detail in section-5 of this paper.

3.2 Example of the statistic analysis :

3.2.1 Scrubtower reboiler

By using the tube bundle failure record and analysis with Weibull Distribution, the statistic result can predict that there is a 91 % probability to have (3) years of bundle mean life, 77 % probability for (5) years of bundle mean life and 50 % probability for (8) years of bundle mean life. Therefore, the bundle is replaced in every 3 years to minimize downtime.

3.2.2 Main Heat Exchanger

By using tube failure record and analysis with Monte Carlo simulation model, the trending of tube failure can be predicted. The mean number of failure will be around 25 tubes for the service life to 20 years. The number of tube failures increases to 54 tubes after 40 years of service. There are 1839 tubes for the Feed Gas circuit, therefore (54/1839*100%) : 3 % or < 10 % (rule of thumb limit). This means that the MHE is still acceptable for continue service.

3.2.3 Feed gas duct heater

By using equipment properties, operation parameter and analysis with Creep Rupture Criteria of API-530, the simulation confirmed that the remaining life of heater is more than 40 years.

The following is a more detailed look at the steps taken in evaluating the sea water coolers

4. Reconditioning of Sea Water Coolers

There are 72 units of shell and tube heat exchangers in the plant that have sea water in the tube side. These sea water coolers have different type, function and dimension, but are similar in working principle. It is well known that sea water is powerful corrodent, therefore, those coolers are particularly susceptible to sea water corrosion attack. This is because of relatively thin tube wall, crevice area at the rolled joint of tube to tube sheet as well as the quality of sea water and sea water velocity.

To keep this type of exchanger reliable requires adherence to operation procedure along with extensive inspection and maintenance procedure.

This paper will focus on the MCR Intercooler study but steps used there can be applied to all similar exchangers.

DRAWING-2 ; SIMPLIFIED PFD FOR MCR INTERCOOLER

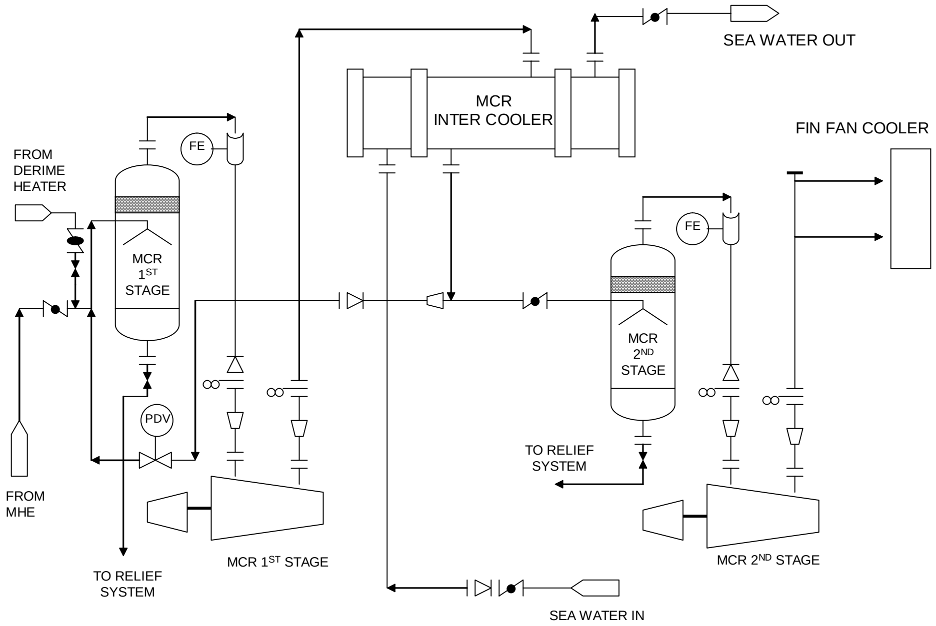


Table-3; General specification of MCR Intercooler

Description	Tube side	Shell side
Service and Pressure	Sea water, 4 Kg/cm2	MCR and 13 Kg/cm2
Temperature (In / Out)	(30 / 60) C	(60 / 35) C
Flow speed	3.5 mps	17 mps
Material and size	CuNi,90-10, ¾" BWG-14	A-515 Gr-70, 1.83 M
Quantity and type	1052 tubes and low fin	1 Shell and AEL

Comprehensive reconditioning to the sea water coolers is performed during the major shut down or in every 3 years.

4.1 Replacement of sacrificial anodes

The sacrificial anodes made of Fe or Al are installed in the inlet and outlet chambers of the tube side. As its function, these anodes are considered as the consumable material of Galvanic reaction. In fact, it is common to find that many of anodes are more than 50 % consumed. The consumed anodes have to be replaced with the new one for further service.

4.2 Relining of the ceilcote on bonnet, channels and covers

Based on experience the ceilcote lining applied on the bonnet, channel heads and covers have blistering, hair cracks and spot damage. By reapplying the ceilcote lining during each major inspection the galvanic protection is improved and the equipment service life is extended.

4.3 Steel scrapper cleaning to inside tubes

After 3 years in service, the inside tube surface has scaling from the contaminants sea. A steel scrapper cleaning system is used to remove the scaling so that the heat conductivity of the tubing is well maintained.

4.4 Eddy current inspection to every tube

The main purpose of this NDT is to identify the severity of inside tube surface pitting and under deposit corrosion. Based on this testing tubes nearing critical metal loss-thickness loss can be replaced before a failure occurs.

4.5 Replacement of the leaking tubes

The tube that meet the following criteria must be replaced with a new one for further service. They are; the tube that has two plugs at its both ends, the tube that is found leaking while pre-inspection using the remaining gas pressure on the shell side, the tube which is identified by eddy current inspection having metal lost more than 40 % of the original wall thickness.

4.6 Replacement of tube end protector (ferrules)

The fact finding showed that the inlet tube end is subject to severe erosion caused by the sea water velocity. It was determine that the tubes can be protected by inserting Teflon Ferrule. Generally the service life of ferrules is around 6 years. The missing and damage ferrules are replaced in every shutdown.

4.7 Pneumatic testing prior to operation

To ensure that the cooler has no leaking prior to putting back in service, a pneumatic test is performed using N2 gas on the shell side. The channel covers are left open, so that each tube can be tested by hand, using bubble test.

5. Discussion on Corrosion Under Insulation (CUI)

Insulation is commonly installed on process equipment and piping that operates above or below ambient. The primary purpose of the insulation is to prevent heat flow to or from the equipment and piping, which could adversely impact process conditions and efficiency.

Under certain conditions condensation can occur under insulation on piping or equipment and this can cause external general corrosion or Corrosion Under Insulation (CUI) for Carbon Steel Material and Stress Corrosion Cracking (SCC) for Stainless Steel Material. Both of these specific types of corrosion can also be classified as Corrosion Under Insulation (CUI).

CUI is a result of humidity and temperature that produces condensation underneath the insulation of CS Equipment and Pipes. Moisture will be more of a problem for insulated pipes and equipment that are cooler than ambient temperature since the metal surface temperature can often be cooler than the dew point temperature.

Arun LNG Plant is located at the Blang-Lancang Beach, Lhokseumawe, North Aceh. In general, the ambient temperature is ranging from (24-34) Centigrade and the humidity is always above 85 %.

In cases where there may have been condensation under insulation, inspection method such as thermographic surveys of the piping system can identify areas where there may be potential problem.

When coatings are applied to the metal, intermittent operation or thermal cycling of vessels and pipes can eventually break down the coating and increase the likelihood of corrosion. In such cases, a period of protection would be expected before corrosion might occur.

5.1 Factors that influence the CUI process

There are several factors that can support and accelerate the process of CUI on equipment and pipes and there are :

5.1.1 Operating temperature ; Hot, Medium or Cold

Medium temperature operation (0-80 C) is the more aggressive condition

5.1.2 Operation mode ; continuous, intermittent or cyclic

Intermittent operation is the worst condition for CUI attack. Cyclic operation is a little better and Continuous operation is the preferred mode to mitigate the CUI process.

5.1.3 Equipment design and shape

A simple shape or design of the pipe and equipment can significantly reduce the potential for having CUI attack.

5.1.4 Insulation design and material

A good design, proper application and use of good quality material will provide better resistance to CUI attack.

5.1.5 Moisture or humidity

An environment that has little moisture or low humidity will reduce the potential for CUI process.

5.1.6 Primer coating

A primer coating is the first line of protection against CUI. A good quality primer that is well applied will be more resistant to CUI attack.

5.2 Inspection Methods

There are several methods available to inspect for CUI. Each method has its advantages, disadvantages and specific application.

5.2.1 Visual Inspection

This is the simplest method and it has been used for a long time. Insulated equipment is visually surveyed for evidence of insulation damage. Where this is found, the insulation is removed and the metal surface is inspected to ensure the CUI progress. Usually, the survey is to identify the Gaps, Bulges, Rust Sustain and real condition of the inspected metal surface.

5.2.2 Thermography Inspection

This inspection method uses infra red to determine the integrity of the insulation material by comparing the temperature of each spot with a known reference. This method focuses on identifying the condition of insulation rather than CUI. As with a visual inspection once damaged insulation is identified, it must be removed to determine if any CUI may have occurred.

5.2.3 Real Time Radiography

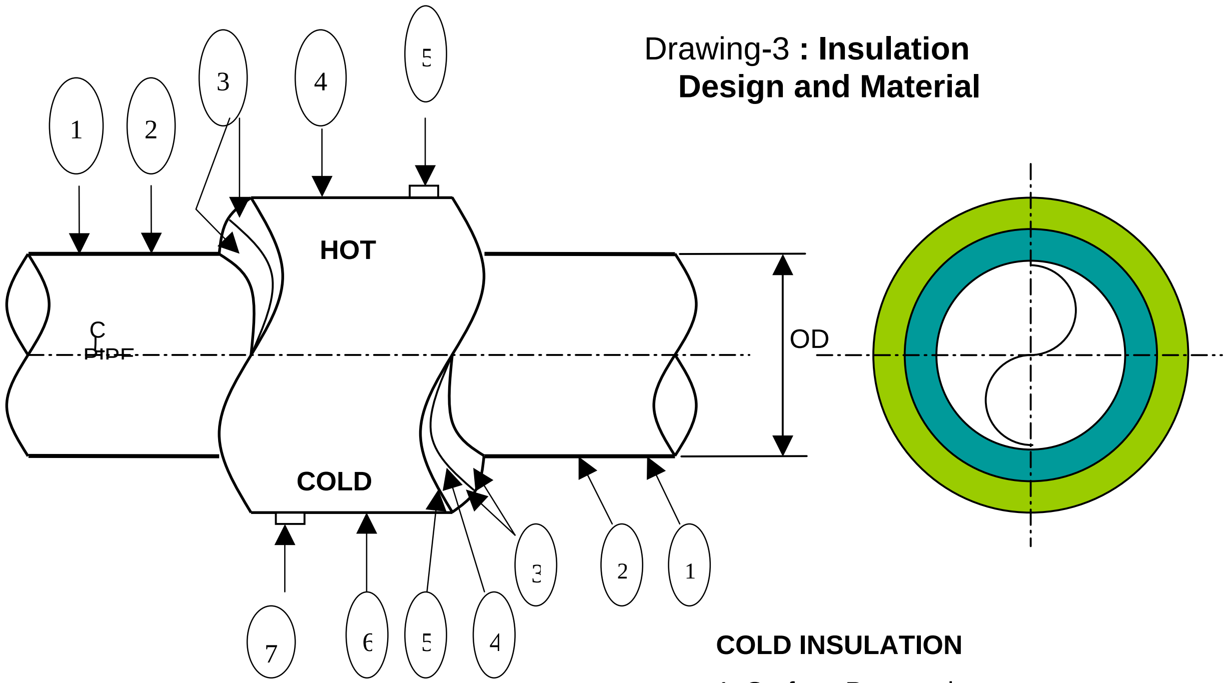
This method can help to identify CUI with-out damaging the insulation by showing surface roughness and any deposits of rust that have accumulated on the metal surface. A video image is used to view a real time radiograph.

5.2.4 LOFEC (Low Frequency Eddy Current)

In this method of inspection an electromagnetic field produced in the material by application of electrical current. Anomalies in the electromagnetic field identify areas of corroded metal. This method of inspection is more effective on piping system.

Typical Insulation design aspects

Drawing-3 : **Insulation Design and Material**



HOT INSULATION

1. Surface Preparation
2. Primer Coating
3. Hot Insulation
4. Jacketing (Aluminium)
5. SS Band

COLD INSULATION

1. Surface Preparation
2. Primer Coating
3. Cold Insulation (PUF + Sealer)
4. Mastic + Glass Cloth (Vapor Barrier)
5. Weather Proofing (Caulking) SS
6. SS Strap
7. Clip

5.3 Experience at Arun LNG Plant

The Arun LNG Plant has experience in using Thermography Inspection and Visual Inspection to identify CUI on the pipes and equipment.

The followings are samples of survey findings :

5.3.1 Scrubtower

The column is 20 M high, 3 M in diameter and made of CS A-5160-65 Normalized. It is blanketing with insulation of glass wool with 5 cm in thickness. The vessel operates at 45 Kg/cm2 and

4 Centigrade. After 17 years of service, severe CUI was found on almost all the outside surface. Comparing to its retirement thickness, the thickness of corroded area was still acceptable. The vessel was then reinsulated as original.

5.3.2 Deethanizer Reboiler

The reboiler is a shell and tube horizontal exchanger with hydrocarbon gas in the shell and saturated steam in the tube side. The shell is 1 M OD and 7 M long. It is blanketing with hot insulation of mineral wool with 5 cm in thickness. Recently, it was visually inspected by removing all the insulation. Hi pressure water jetting was used to remove all the severe CUI deposits that covered the whole outside surface. Referring to the shell retirement thickness, the severe corroded metal was still acceptable. Reinsulation was done as per the original condition.

5.3.3 C2 MCR make-up Lines

The lines consist of 2”, 3” and mostly 4 “ in diameter and cold insulated by using polyurethane of 5 cm in thickness along the pipe. The piping is made of CS A-333 and operated at 5 Centigrade. This is very susceptible to CUI since the line is operated intermittently. The Arun LNG Plant had experience replacing several spots of C2 MCR make-up line due to CUI attack and some of them were because of thru-wall leaking.

Based on the overall findings, it was concluded that the CUI on both piping and equipment is generally limited in extent. For those items that have cryogenic service (< -20 C), CUI is much less aggressive. CUI becomes more aggressive at the medium operating temperature (0-80 C) and become worst under cyclic and intermittent operating mode in cold or hot service.

5.4 Recommendations :

5.4.1 Initial inspections for CUI shall be done with in 5 years of initial operation and there after at intervals of (3-5) years.

5.4.2 For effectiveness and efficiency, area selection as well as selection of the inspection method must be done carefully.

5.4.3 Repairs to the damaged areas shall be done in accordance with the best practice application procedures including the application of primer coating to the metal surface.

CUI is best prevented by proper initial application of protective coatings to equipment and pipes that are located close to the sea shore or in location subject to heavy humidity. In Addition, care must be taken to ensure insulation is properly installed and that any damaged areas are quickly identified and repaired.

SUMMARY

The paper discussed the detail process of plant aging study and life extension remedial action plans. By doing the right thing right from the beginning (design, construction and commissioning), operation, maintenance and engineering support to the Plant Facilities and consistently applied will lead to the safe operation and reliable performance.

By applying the mentioned study, Arun LNG Plant facilities has been operated for 25 years and has delivered 3750 cargoes of LNG to buyers safely and reliably. Hopefully, the plant can also be operated safely and reliably throughout the remaining of the plant life.

Comprehensive reconditioning to the Sea water coolers that has been carried-out in a good manner shows that damaging effects of sea water can be minimized and controlled to reduce downtime and extend the equipment life.

CUI is a dangerous hidden destructive force that must be careful monitored. When CUI becomes acute, serious catastrophic failures can result. CUI is best prevented by proper initial application of protective coatings to equipment and pipe that are located close to the sea shore or in location subject to heavy humidity. In Addition, care must be taken to ensure insulation is properly installed and that any damaged areas are quickly identified and repaired.

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Appendix-b ; 16 Active Damage Failure Modes for Fix Equipment & Piping

1. **Corrosion Under Insulation.**
Corrosion under insulation is a function of temperature and moisture that can condense underneath the Insulation of carbon steel vessels or pipes. Moisture will be more of a problem for insulated pipes and vessels that are cooler than the ambient temperature since the metal can often be cooler than the dew point. In cases where the condensation has affected the insulation, thermographic survey of the piping system can identify areas of potential problems. When coatings are applied to the metal, intermittent operation or thermal cycling of vessels and pipes can eventually break down the coatings and increase the likelihood of corrosion.

2. **Internal Corrosion.**
Readings are often measured and tracked to identify internal corrosion. For all vessels, the corrosion allowance divided by the corrosion rate is the estimated life of the vessel. In piping system sulfur compounds often in combination with water maybe cause internal corrosion.

3. **Atmospheric Corrosion.**
Atmospheric Corrosion is defined as the degradation of material exposed to the air and its pollutants. In the absence of moisture, most metals corrode very slowly at ambient temperatures, but once moisture is present the aggressiveness of the environment increases. The marine or marine industrial type of environment is generally considered to be the most aggressive.

4. **Brittle Fracture.**
The fracture toughness of carbon steels is lower at lower temperatures. Most steel at 30°C temperatures is ductile. Different grades of steel become brittle at different temperatures ranging from 30°C to as low as –50°C.

5. **Insulation Deterioration.**
Condensation, build up of frost and biological attack are possible causes for the deterioration of thermal insulation on vessels and piping, long term deterioration of the insulation will change the thermal efficiency of the plant. Because most of the thermal insulation in the plant is on cold equipment, the some portion of the insulation is often below the due point temperature of the surrounding air. Water can then condense and in some cases freeze in the insulation layer. Repeated warm up and cool down cycles can also be damaging to the insulation.

6. **Thermal Fatigue.**

Cyclic stresses caused by cycling temperatures or thermal gradients is the driving force for thermal fatigue, plastic strains or near plastic strains are usually experienced during each cycle and as a result the number of cycles until significant of cracking is observed is in the order of (10^4 – 10^5). Because at elevated temperatures yield strengths and strains are often lower the rates of damage are often higher than for simple low cycle fatigue. The greater the temperature variation, the more likely thermal fatigue will occur and the more severe the damage. Thermal fatigue are possible when temperature variations are greater than 200°C and can be severe whenever temperature variations are greater than 300°C.

7. Tube side pitting corrosion in exchangers.
Heat exchangers using sea-water to remove heat from the feed gas and refrigerants are subject to corrosion problems caused be the exposure of metal to the corrosive action of sea-water.

8. High Cycle Fatigue (HCF).
Relatively low cyclic stresses caused by sources such as rotating equipment or flow-induced vibration in pipes are usually the driving forces for (HCF). Components such as machinery components are the most likely candidates for HCF problems.

9. Bio-fouling in exchangers.
Heat exchangers using sea-water to remove heat from the feed gas and refrigerants may be subject to bio-fouling of bacteria, algae, or other marine life being carried through the heat exchanger, impeding flows and worsening corrosion problems.

10. Mercury embrittlement of aluminium.
Minute concentrations of Hg in the feed gas stream can precipitate out of the gas and collect in crevices in these heat exchangers. Diffusion of Hg into aluminum can greatly embrittle the metal.

11. Chloride stress corrosion cracking.
Stainless steel vessels and piping can experience cracking due to exposure to chlorides. This type corrosion cracking is most often experienced at temperatures between (60°- 200°)C. Chlorides may leach out of the insulation.

12. Amine stress corrosion cracking.
Corrosion cracking has been observed to occur in gas treating units using alkanolamine solutions for scrubbing CO_2 and H_2S. Studies have concluded that the cracking can be caused by the alkaline amines (similar to caustic cracking), hydrogen embrittlement (similar to Wet H_2S cracking) or combination of mechanism. Cracking is more severe at elevated temperatures. Post Weld Heat Treatment is almost always effective at eliminating this type of cracking.

13. Erosion-corrosion (E/C).
Erosion-corrosion is the accelerated corrosion of metals in the presence of (high velocity, abrasive) fluids or at impingement.

14. Cavitation damage.

Cavitation damage is a form of (E/C) that occurs when vapor bubbles form and subsequently collapse in a liquid stream. The collapsing bubbles act to remove corrosion product films much in the same way that occurs with erosion-corrosion.

15. Baffle Wear.
This type of damage occurs on the tubes of shell and tube heat exchangers when the shell side velocities are sufficient to induce vibration in the tubes. The tube rubs against the baffles, resulting in loss of metal and eventual penetration of the tube.

16. Tube to Tubesheet Leaks.
In shell and tube heat exchangers, the tubes are normally mechanically rolled in the tubesheets. These joints are subject to leakage (usually very small) after some period of operation.

LIST OF MAJOR STATIONARY EQUIPMENT AT UNIT LNG TRAIN

Gas Treating Unit Appendix-a

No	Tag No	Equipment Name	Service	Temperature (C)		Pressure (Kg/cm2)		Material
				Opert'on	Design	Opert'on	Design	
1.	C-3X01	Carbonate Absorber	Lean Carbonate Solution	135	149	50	56	A-516, Grade-70
2.	C-3X02	DEA Absorber	Lean DEA Solution	70	149	50	56	A-516, Grade-70
3.	C-3X03	Carbonate Regenerator	Rich Carbonate Solution	128	177	1.5	1.7	A-285, Grade-C
4.	C-3X04	DEA Regenerator	Rich DEA Solution	126	177	1.5	1.7	A-285, Grade-C
5.	D-3X07 AB	Mercury Bed Absorber	Feed Gas	80	149	50	56	A-516, Grade-70
6.	E-3X01 AB	Feed Lean Carb. Exch.	Carbonate / Feed Gas	82/105	177/177	50/56	50/56	A-516, Gr-70/A-213
7.	E-3X02 AB	Carbonate Reg. Reboiler	Carbonate / Steam	130/150	177/193	2/7	5.5/13	A-595, Gr-C/SS-321
8	E-3X04 ABC	DEA Exchanger	DEA Solution Rich / Lean	121/66	177/177	1.5/50	5.3/62	A-285, Gr-C/A-179
Liquefaction Unit								
9	C-4X01	Scrubtower	Propane	-4	-29	45	56	A-516, 65, CVN -40C
10	D-4X13	Product Drum	LNG	-141	-162	1	7	SS-304L
11	D-4X24	Mercury Guard Bed	Feed Gas	20	-2	47	56	A-516, 70
12	E-4X02	Desuper Heater	Propane / Sea water	50/30	66/66	12/4	18/8	A-516, 70 / CuNi-9010
13	E-4X03	Propane Condencer	Propane / Sea water	50/30	66/66	12/4	18/8	A-516, 70 / CuNi-9010
14	E-4X12	MCR Intercooler	MCR / Sea water	50/30	66/66	12/4	18/8	A-516, 70 / CuNi-9010
15	E-4X13 AB	2nd MCR Intercooler	MCR / Sea water	50/30	66/66	12/4	18/8	A-516, 70 / CuNi-9010
16	E-4X14	MCR Hi Level C3 Exch.	MCR/Propane	10/17	-42/66	5/44	9/51	A-516, 70 A20/A-179
17	E-4X18	Main Heat Exchanger	Feed Gas / MCR	-45/-60	-170/-170	45/5	56/12	AL-5083/AL-3003
18	E-4X19	Feed Reject Gas Exch.	Feed Gas / LNG Vapor	-37/-147	-170/-170	47	50	AL-3003
19	E-4X22	Gas Duct Heater	Gas Hydrocarbon	300	538	5	7	A-333P-11
20	V-4X01 AB	Feed Vapor Dryer	Feed Gas	20/300	4/350	47	56	A-516, 70

Note : X can be (1, 3, 4, 5 and 6) Page 1 of 1

DAMAGE MATRIX CROSS CHECKING **Appendix-c**

Gas Treating Unit

No	Tag No	1	2	3	4	5	6	7	8	9	10*	11	12	13	14	15	16	Remark
1.	C-3X01	v	v	-	-	v	-	-	-	-	v	-	-	v	-	v	-	CUI is dominant failure mechanism
2.	C-3X02	-	v	v	-	-	-	-	-	-	v	-	-	v	-	v	-	No aggressive failure mechanism
3.	C-3X03	v	v	v	-	v	-	-	-	-	v	-	-	v	-	v	-	CUI & Int. Part Integrity are dominant
4.	C-3X04	v	v	v	-	-	-	-	-	-	v	-	-	v	-	v	-	CUI is dominant failure mechanism
5.	D-3X07 AB	v	v	v	-	v	-	-	-	-	v	-	-	v	-	-	-	CUI is dominant failure mechanism
6.	E-3X01 AB	v	v	-	-	v	-	v	-	-	v	-	-	v	v	v	v	CUI & Int. Part Integrity are dominant
7.	E-3X02 AB	v	v	-	-	v	-	-	-	-	v	-	-	v	-	-	v	CUI is dominant failure mechanism
8	E-3X04 ABC	v	v	-	-	v	-	v	-	-	v	-	v	v	v	v	v	CUI, Tube side corrosion & seal weld
Liquefaction Unit											**		*					**Appendix-d**
9	C-4X01	v	v	-	v	v	v	-	-	-	-	-	-	v	-	v	-	CUI + Brittle Fracture are dominant
10	D-4X13	-	-	-	-	v	-	-	-	-	-	v	-	-	-	v	-	No aggressive failure mechanism
11	D-4X24	v	-	-	-	v	-	-	-	-	-	-	-	v	v	-	v	CUI + Internal part integrity
12	E-4X02	-	v	-	-	-	-	v	-	v	-	-	-	v	v	-	v	Sea water corrosion & tube to t/s leak
13	E-4X03	-	v	-	-	-	-	v	-	v	-	-	-	v	v	-	v	Sea water corrosion & tube to t/s leak
14	E-4X12	-	v	-	-	-	-	v	-	v	-	-	-	v	v	-	v	Sea water corrosion & tube to t/s leak
15	E-4X13 AB	-	v	-	-	-	-	v	-	v	-	-	-	v	v	-	v	Sea water corrosion & tube to t/s leak
16	E-4X14	v	-	-	v	v	-	v	-	-	-	-	-	-	-	-	-	No aggressive failure mechanism
17	E-4X18	-	-	-	-	v	-	v	-	-	v	-	-	-	-	v	-	Hg embrittlement & Tube to t/s leak
18	E-4X19	-	-	-	-	v	-	-	-	-	v	-	-	-	-	-	-	Hg embrittlement
19	E-4X22	-	-	-	-	-	v	-	v	-	-	-	v	-	-	-	-	Creep
20	V-4X01 AB	v	v	-	-	-	v	-	v	-	-	-	-	v	-	v	-	CUI & Hi cycle fatigue

10 * ➔ Internal part integrity (V) ➔ means that the MDM possible to happen (-) ➔ means that the MDM is not possible to happen

10** ➔ Mercury Embrittlement (1, 2, 3, 4, ……, 15, 16) ➔ refer to appendix-b

12* ➔ Creep

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