ABSTRACT

The background of this project is about to change the inspection system from the conventional method to the Risk Base Inspection (RBI) system. The project oriented about to develop the piping inspection program at the naphtha hydro-finer piping circuit that running the process at high temperature (about 320 ^{0}C) and acidic service to identify their corrosion rate and the remaining life of the piping component involve in this line system. It also use to identify it probability to failure, consequences involve and the risk of the piping component,

The objective of this project is to develop an inspection planning by applying the thickness measurement method in order to get the remaining life of the piping component/system at the Naphtha hydro-finer line. This is related to the problem occur in order to replace the inspection conventional method to the Risk Base Inspection (RBI) method to analyze the pipe system more efficient.

The methodology/work flow of this project have been planning in order to make sure that the project can be finish with success within the time frame and the work flow have been assigning step by step. The finding from the past few week show that this project are feasible to be conduct since it will meet the objective in order to get the remaining life from the thickness data that been collect from the applicable NDT method.

As a result found that all of the piping component being assess are in moderate condition and safe for use base on the probability and consequence assigning to them from the calculation base on the thickness data. The fully develop inspection template have been construct for the future use to the reliability and maintenance engineer.

As a conclusion this project have meet their objective in order to determine the condition of the piping line to safely operate and to predict how long this pipe can be safely use base on the respected corrosion rate. This project have produce significant result that help reliability engineer to see the significant different between conventional way of inspection and by using Risk Base Inspection Method.

CHAPTER 1:

INTRODUCTION

1.1 BACKGROUND

This section briefly explains the development of Piping Inspection monitoring strategy (one of the piping inspection program) to be used in the petroleum industry especially in refinery. From the study on the available journal and appropriate research conducted on the inspection planning and inspection program regarding the method of Non-Destructive Testing (NDT), found that it was feasible and reliable to deeply understand about the inspection method and inspection program conducted on piping system since the piping system with their component play the important role regarding all the process as a product transportation medium.

The background of this project is about to change the inspection system from the conventional method to the Risk Base Inspection (RBI) system.The project oriented about to develop the piping inspection program at the naphtha hydro-finer piping circuit that running the process at high temperature (about 320^0C) and acidic service to identify their corrosion rate and the remaining life of the piping component involve in this line system. It is because, at this piping circuit have the higher probability for the corrosion to occur since it operate at elevated temperature and running the acidic product It also use to identify it probability to failure, consequences involve and the risk of the piping component. Naphtha hydro-finer piping circuit have been choose to asses for this project because this line are part of the piping system in the one of the refinery that been upgrading to asses the criticality by using RBI.

1.2 PROBLEM STATEMENT

1.2.1 Problem Identification

This project is the continuation of the project at one of the refinery that upgrades their inspection system from conventional method to Risk Base Inspection Method. Lately the Naphtha hydro-finer circuit at one of the refinery in this country, they being access by using the old method that been mention are not really accurate for the inspection data required. By this problem identification and the modernization of the piping engineering technology, The RBI assessment method have been widely use and this project are develop in term of change the old conventional method at that piping line to the accurate RBI assessment method.

How long that the piping system can be maintain in good operating condition, how to increase it life spend before going to replace it to new one and what is the probability, consequence and risk of the piping component due to failure to occurs. Since the inspection will give all the data required in order to identify the instant condition of the component and give sufficient information to predict the condition at the near future. Base on the data gathered, RBI can be use in order to solve the regarding problem and determine the condition of the piping component and to predict how critical it condition base on the thickness data. By that, the primary problem statement of this project is to predict the remaining life of the piping component by applying the thickness measurement method and to relate the data to the Risk Base Inspection (RBI) in order to predict the condition of the piping component to continuously running safe operation.

1.2.2 Significant of the Project

The significant of the project are the thickness measurement is one of the important inspection techniques that group as external inspection of the equipment. By conducting the thickness measurement, can be predict the corrosion condition at the internal surface and also can be calculate for it corrosion rate by applying appropriate formula. And by predicting the remaining life of the component, we can solve the questionnaire about the duration of the piping component can be safely operate. Furthermore, can also planning some mitigated step to conduct to reduce it corrosion rate and directly extent the life spend of the component after we know their criticality for the failure to occur from the RBI. [12], [13]

1.3 OBJECTIVE AND SCOPE OF STUDY

1.3.1 Objective:

- To replace the old conventional inspection method at naphtha hydro-finer pipeline to Risk Base Inspection (RBI) assessment method in order to get the accurate inspection date to asses the pipe component criticality.

- To assign the probability, consequence of failure to occurs and calculates the risk of the component expose by relate the thickness data, remaining life and the corrosion rate to the RBI.

- To assign the appropriate mitigated step in order to improve the criticality of the failure to occurs at that piping component

1.3.2 Scope of Study

This project is focusing on to replace the Naphtha hydro-finer pipe line conventional inspection method to Risk Base Inspection (RBI) method. This because the RBI are the latest proving inspection method widely use in the oil and gas industry. RBI will provide proper inspection program and planning schedule and more relevant process date regarding the criticality and risk of that location makes the life spend of the pipe component can be increase, the failure or any problem can be find at the early stage to conduct the appropriate mitigated step and the plant/refinery can be continue safely operation at maximum capacity in a long duration of time [6]. It also focus on the inspection method will be conducted (NDT method) in order to get the thickness data including:

- Ultra Sonic Thickness Measurement Testing (UTTM).

1.3.4 Feasibility of the Project within the Scope and Time Frame

This project is very feasible in term of time frame since it can be finish up by the end of month of October by following it module and following the progress planning because the model line to apply the project on have been chosen. All of the method conduct will give a positive feed back since have been prove before that then appropriate NDT method choosing have been given such an accurate and Precise result of thickness data required.

CHAPTER 2:

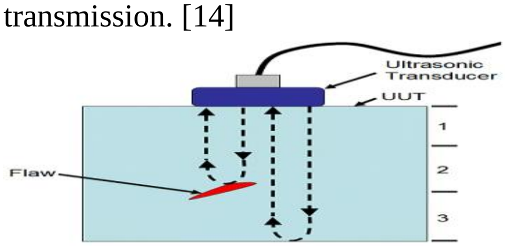
LITERATURE REVIEW

2.1 ULTRASONIC THICKNESS MEASUREMENT TESTING (UTTM)

2.1.1 Basic of Ultrasonic Test

Ultrasonic wavelengths are on the same order of magnitude as visible light, giving them many of the same properties of light. Ultrasonic wavelengths can be focused, reflected, and refracted. Ultrasonic waves are transmitted by high frequency particle vibrations, and can be transmitted through air, water, and solids such as steel. These waves are transmitted in homogenous solid objects much like pointing a flashlight around a room with various objects that reflect light. The directed energy in an ultrasonic wave is reflected by boundaries between materials regardless of whether the material is gas, liquid, or solid. Ultrasonic waves are also reflected by any cracks or voids in solid materials [14].

The Principe is the same in order to use it to measure the thickness of the piping component. The UTTM method can be applied in order to measure the piping component thickness. The ultrasonic wave will be reflecting back to the transducer when it reaches the boundary between piping component and the product service inside it (component internal surface). Than the irregular of the internal surface can be detect by the different reading collected on the UTTM gadget. The figure below shows how the UT scanning being conducted and for the UT wave transmission. [14]



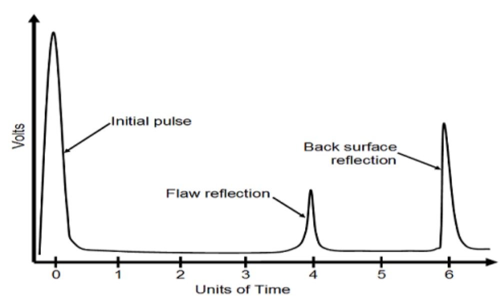


Figure 2.1: Ultrasonic Thickness Measurement transition wave.[1]

2.2 DATA COLLECTION DESCRIPTION

In the 1st stage of the work process, all of the data that been listed in Chapter 4 must be available in order to make sure that the project can be proceed to the next step. Below are the available description and information regarding the data collection.

2.2.1 Process and Instrument Diagram

Process and Instrument Diagram (P&ID) is a diagram which shows the interconnection of process equipment and the instrumentation used to control the process. In the process industry, a standard set of symbols is used to prepare drawings of processes [4]. *(Please refer to APPENDIX 1 for* Sample of Process and Instrument Diagram*.)*
As for processing facilities, it is a pictorial representation of

- Key piping and instrument details
- Control and shutdown schemes
- Safety and regulatory requirements and
- Basic start up and operational information

2.2.2 Original wall thickness

Original wall thickness can be checking it availability base on Nominal Pipe Size (NPS) that is one of the North America Standard that used for high or low pressures and temperatures. Pipe size is specified with two non-dimensional numbers, a nominal pipe size (NPS) based on inches, and a schedule. Based on the NPS and schedule of a pipe, the pipe outside diameter (OD) and wall thickness can be obtained from reference standard such as ASME standards B36.10M and B36.19M. [3].
(Further info about the original wall thickness base on standard please refer to APPENDIX 2)

2.2.3 Piping design pressure and temperature

The design shall be check for adequacy of mechanical strength under applicable knowledge. Basically the pressure and temperature design are base on each component type and base on it calculation applied.

Design Pressure:

The design pressure shall be not less than the pressure at the most severe condition of coincident internal or external pressure and temperature expected in normal operation. The Maximum Difference in pressure between inside and outside of any piping component or between any two chambers of a combination unit shall be considered, including the unintentional loss of external or internal pressure [4].

Design Temperature:

The design minimum temperature is the lowest component temperature expected in service. This temperature may establish special design requirements and material qualification requirements

For the un-insulated Components, the design temperatures have been stated in the available standard are:

(a) For fluid temperatures below 65°C (150°F), the component temperature shall be taken as the fluid temperature unless solar radiation or other effects result in a higher temperature.

(b) For fluid temperatures 65°C (150°F) and above, unless a lower average wall temperature is determined by test or heat transfer calculation, the temperature for un-insulated components shall be no less than the following values:

(1) Valves, pipe, lapped ends, welding fittings, and other components having wall thickness comparable to that of the pipe: 95% of the fluid temperature

(2) Flanges (except lap joint) including those on fittings and valves: 90% of the fluid temperature

(3) Lap joint flanges: 85% of the fluid temperature

(4) Bolting: 80% of the fluid temperature

2.3 Equipment Degradation Document (EDD)

2.3.1 Process Piping Deadlegs and Stagnant Zone

Stagnant Zones and Deadlegs are section of piping with little or no flow:

- Deadlegs, are the dead-ended of the piping that serves no real process function. Examples of the deadlegs are closure of a valve or installation of a blind.
- Stagnant Zones are unavoidable process required items [5].
  Examples of the stagnant zones include control valve bypasses and piping used only for startup and shutdown [5].

2.3.2 Corrosion under Insulation (CUI)

CUI refers to external corrosion of equipment underneath insulation/jacketing, which has allowed the ingress of moisture. CUI for carbon steel and low alloy steel may occur when equipment or piping operates at temperature between 25^0F (-4^0C) and 300^0F (50^0C). In general, the metal temperature will be approximately the same as the process temperature (for insulated equipment). However, if the insulation is damage and/or highly humid condition commonly exist, a process temperature significantly above 250^0F (125^0C) can result in metal temperature low enough to cause CUI. This is because that the CUI condition needs extra care in order to permit the corrosion to occur rapidly [6].

2.3.3 Injection/Mix Point Corrosion

Injection points are location where water or chemical (such as corrosion inhibitor and demulsifies) are added to a stream for process or corrosion control. Corrosion can occur as a result of this injection downstream on an injection point, right at the injection point, and usually within 2 changes direction downstream on injection points [7].

Mixing points are pipe locations where 2 streams of differing composition and/or temperature are brought together. In some cases, the corrosivity of the combined stream may be significantly higher than that of either of the individual stream [7].

2.4 RISK BASE INSPECTION (RBI)

Basically Risk Based Inspection or RBI is a systematic approach for evaluating the risk associated with fixed equipment included the probability of loss of containment and consequence of loss of containment. RBI also will provide a qualitative risk ranking of fixed equipment [8].

Use of RBI in the helping the inspection team is to decide the correct action to be conduct as a result to reduce the risk for the specific equipment. RBI basically uses to focus the inspection and monitoring efforts on the risk items includes, improve allocation of limited resources and to reduce inspection and maintenance cost. In other way, RBI also helps to reduces or prevents from the material-related incidents. Figure bellow shows the flow diagram related process flow of RBI and next figure shows the sample of the risk matrix in determining the probability and consequence [8].

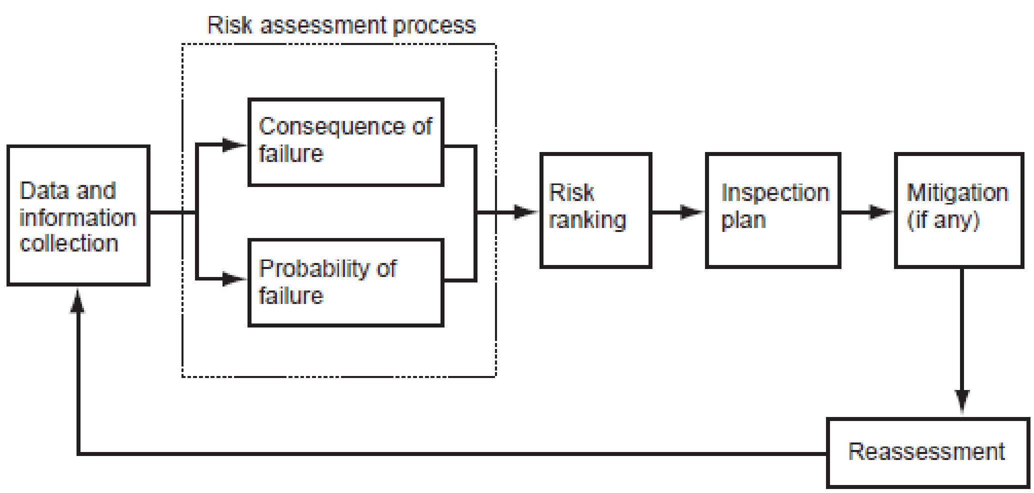


Figure2.2: Risk Base Inspection Planning Process Flow Diagram.[8]

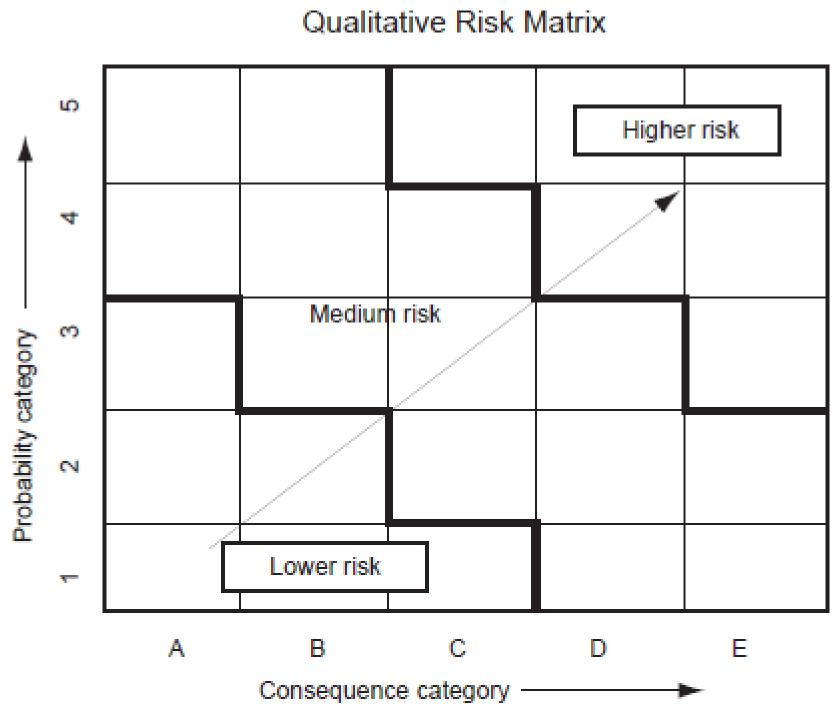


Figure 2.3: Sample of Risk Matrix using probability and consequence ranking.[8]

2.5 GENERAL THICKNESS MONITORING REQUIREMENT

2.5.1 Scope

This practice provides the requirement for a thickness monitoring program. It covers data acquisition, review, and storage. Requirement related to thickness monitoring coverage are handled in other equipment specification practice. This practice provides the requirement for a thickness monitoring program. It covers data acquisition, review, and storage. Requirement related to thickness monitoring coverage are handled in other equipment specification practice [9].

2.5.2 Introduction and Background

To establish the corrosion rates for inspection interval and retirement thickness measurement, thickness measurements must be obtained. Ultrasonic testing (UT) is the most common method for obtaining thickness measurements. Radiographic testing (RT) is also used, either to supplement UT inspection or in situation where UT is not practical or cost effectiveness (based on anticipated corrosion mechanisms), cost availability, and data utilization. Compared to RT, UT generally cost less, is less disruptive to other work, and can provide more accurate thickness measurement. RT is commonly use for thickness determination in non-uniform highly corrosive service. RT is typically more helpful than the spot UT for identifying the areas due to non-uniform corrosion, especially if statistical data treatment is not performed [11].

2.5.3 Data Gathering Technique:

- Necessary isometric or equipment drawings indicating the thickness measurement locations and test points shall be provided to the NDE personnel for taking the wall thickness readings. In addition, a blank Thickness Management System Data Entry Form.
- NDE personnel shall complete the inspection and shaded portions of the form.
- The minimum information recorded shall include name of person performing the test, date of the test, equipment identification, and identification of the test method and result of the test.

2.5.4 Retirement Thickness Determination for Piping

The retirement thickness shall be the greater of the value in Piping Maintenance Guide or when pressure containment controls the design, a value calculated by Save Pipe (or equivalent) using verified mechanical design condition. Table 1 shows the minimum thickness for piping retirement:

Table 2.1: Minimum Thickness for Piping Retirement [9]

Nominal Pipe Size (NPS)	Retirement Thickness, t(s) Inches(mm)
¾ through 2	0.083(2.14)
3 through 18	0.134(3.46)
20 through 22	0.148(3.82)
24	0.165(4.26)

For Nominal Pipe Size (NPS) greater than 24, t(s) = D/150

Note: The minimum thickness for retirement, t(s) from table above is intended to be evaluated in detail when the pipe subject to unusually large load or when economic incentive exist. For these situations, a more detailed engineering analysis such as "Save Pipe" should be performed, and the result of this analysis should be used for retirement thickness. [9]

2.5.5 Definition

2.5.3.1 Close Grid UT

A technique which consists of taking many UT reading on a grid pattern. Typically the readings are on a square pitch equal to 1 to 2 inches. It is used to find the thinnest area resulting from localize or non uniform corrosion **[9]**.

2.5.3.2 Test Points

Area(s) at a TML typically defined by circle having a diameter or not greater than 2 inch for a line diameter not exceeding 10 inches, or not greater than 3 inches for large inches. Thickness readings may be averaged within the area. A test point shall be within a thickness measurements location **[9]**.

2.5.3.3 Thickness Measurement Locations (TML)

Designated areas on designated areas where periodic thickness measurements are conducted at test points **[9]**.

Thickness Reading:
A specific measurement taken within a test point.
The inspection procedures contained in this standard are **[9]**:

1. Data gathering technique.
2. Thickness management system data entry form.
3. Temperature compensation
4. Obtaining measurement at a test point.
5. Data quality and evaluation.
6. Retirement thickness determination for piping.
7. Retirement thickness determination for pressure vessels and tanks.
8. Finding thin area due to localized corrosion.

2.6 Damage Mechanism (Naphthenic Acid Corrosion (NAC)

2.6.1 Description of Damage

- A form of high temperature corrosion that occurs primarily in crude and vacuum units, and downstream units that process certain fractions or cuts that contain naphthenic acids.**[12]**

2.6.2 Affected Materials

- Carbon steel, low alloy steels, 300 Series SS, 400 Series SS and nickel base alloys.**[12]**

2.6.3 Critical Factors [12]

- NAC is a function of the naphthenic acid content (neutralization number), temperature, sulfur content, velocity and alloy composition.
- Severity of corrosion increases with increasing acidity of the hydrocarbon phase.
- Neutralization number or Total Acid Number (TAN) is a measure of the acidity (organic acid content) as determined by various test methods such as ASTM D-664. However, NAC corrosion is associated with hot dry hydrocarbon streams that do not contain a free water phase.
- The Total Acid Number (TAN) of the crude may be misleading because this family of acids has a range of boiling points and tends to concentrate in various cuts. Therefore, NAC is determined by the acidity of the actual stream not the crude charge.
- The various acids which comprise the naphthenic acid family can have distinctly different corrosivity.
- Sulfur promotes iron sulfide formation and has an inhibiting effect on NAC, up to a point.
- Naphthenic acids remove protective iron sulfide scales on the surface of metals.
- NAC can be a particular problem with very low sulfur crudes with TAN’s as low as 0.10.

- NAC normally occurs in hot streams above 425 ^{0}F (218^{0}C) but has been reported as low as 350 ^{0}F (177 ^{0}C). Severity increases with temperature up to about 750 ^{0}F (400 ^{0}C), however, NAC has been observed in hot coker gas oil streams up to 800 ^{0}F (427^{0}C).
- Corrosion is most severe in two phase (liquid and vapor) flow, in areas of high velocity or turbulence, and in distillation towers where hot vapor condense to form liquid phase droplets.

2.6.4 Prevention / Mitigation [12]

- For units and/or components of systems which have not been designed for resistance to NAC, the options are to change or blend crude, upgrade metallurgy, utilize chemical inhibitors or some combination thereof.
- NAC can be reduced by blending crude to reduce the TAN and/or increase the sulfur content.
- Use alloys with higher molybdenum content for improved resistance
- High temperature NAC inhibitors have been used with moderate success, however potential detrimental effects on downstream catalyst activity must be considered. Inhibitors effectiveness needs to be monitored carefully.
- For severe conditions, Type 317L stainless steel or other alloys with higher molybedenum content may be required.

2.6.5 Inspection and Monitoring

- UT and RT are used for thickness monitoring but localized erosion may be difficult to locate so RT should be the primary detection method followed by UT thickness measurement.
- Monitor TAN and sulfur content of the crude charge and side streams to determine the distribution of acids in the various cuts.

2.7 Damage Mechanism Sulfidation

2.7.1 Description of damage

Corrosion of carbon steel and other alloys resulting from their reaction with sulfur compounds in high temperature environments. The presence of hydrogen accelerates corrosion. **[12]**

2.7.2 Affected Material [12]

1) All iron based materials including carbon steel and low alloy steels, 300 Series SS and 400 Series SS.
2) Copper base alloys form sulfide at lower temperatures than carbon steel.

2.7.3 Critical Factor [12]

1) Major factors affecting sulfidation are alloy composition, temperature and concentration of corrosive sulfur compounds.
2) Susceptibility of an alloy to sulfidation is determined by its ability to form protective sulfide scales.
3) Sulfidation of iron-based alloys usually begins at metal temperatures above 500^0F (260 ^{0}C). The typical effects of increasing temperature.
4) In general, the resistance of iron and nickel base alloys is determined by the chromium content of the material.
5) Sulfidation is primarily caused by H_2S and other reactive sulfur species as a result of the thermal decomposition of sulfur compounds at high temperatures. Some sulfur compounds react more readily to form H_2S. Therefore, it can be misleading to predict corrosion rates based on weight percent sulfur alone.
6) A sulfide scale on the surface of the component offers varying degrees of protection depending on the alloy and the severity of the process stream.

2.7.4 Effected Equipment [12]

1) Sulfidation occurs in piping and equipment in high temperature environments where sulfur-containing streams are processed.
2) Heaters fired with oil, gas, coke and most other sources of fuel may be affected depending on sulfur levels in the fuel.
3) High temperature equipment exposed to sulfur-containing gases can be affected.

2.7.5 Morphology of Damage [12]

1) Depending on service conditions, corrosion is most often in the form of uniform thinning but can also occur as localized corrosion or high velocity erosion-corrosion damage.
2) A sulfide scale will usually cover the surface of components. Deposits may be thick or thin depending on the alloy, corrosiveness of the stream, fluid velocities and presence of contaminants.

2.7.6 Mitigation [12]

1) Resistance to sulfidation is generally achieved by upgrading to a higher chromium alloy.
2) Piping and equipment constructed from solid or clad 300 Series SS or 400 Series SS can provide significant resistance to corrosion.
3) Aluminum diffusion treatment of low alloy steel components is sometimes used to reduce sulfidation rates and minimize scale formation; however, it may not offer complete protection.

2.7.7 Inspection and Monitoring [12]

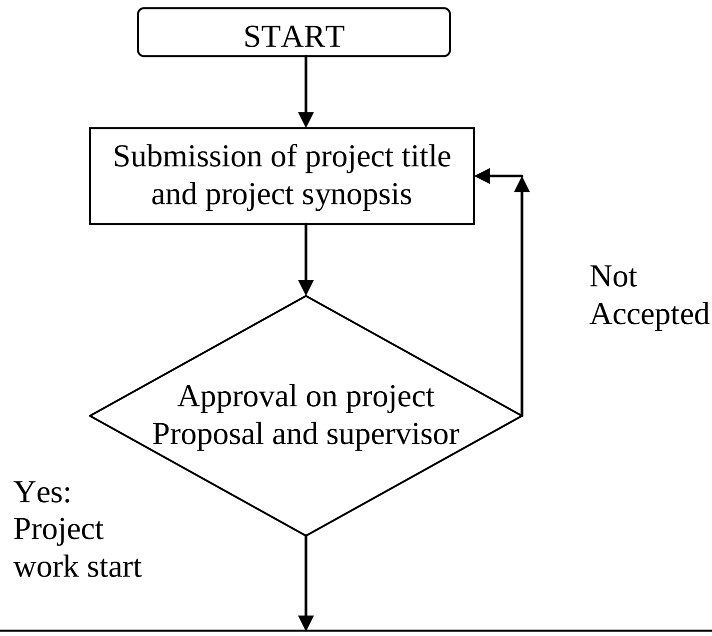
1) Process conditions should be monitored for increasing temperatures and/or changing sulfur levels.
2) Temperatures can be monitored through the use of tube-skin thermocouples and/or infrared thermo-graphy.
3) Evidence of thinning can be detected using external ultrasonic thickness measurements and profile radiography.
4) Proactive and retroactive PMI programs are used for alloy verification and to check for alloy mix-ups in services where sulfidation is anticipated.

CHAPTER 3:

METHODOLOGY / PROJECT WORK

Figure 4 bellow shows the process flow of this project from the starting of FYP1 until end of FYP2:

FYP 1:



Step 1: Conduct Research base on standard available and other journal to get the basic idea and important knowledge to start the project:
List of journal/standard are bellow:

- American Petroleum Institute (API) 570 – Piping Inspection code.
- American Petroleum Institute (API) 580 – Risk Base Inspection (RBI).
- American Petroleum Institute (API) 581 – RBI Base Resource Document
- American Petroleum Institute (API) 571 – Damage Mechanism.
- American Petroleum Institute (API) 579 – Failure Analysis.
- American Society of Mechanical Engineer (ASME) section B31.3 – Process Piping.

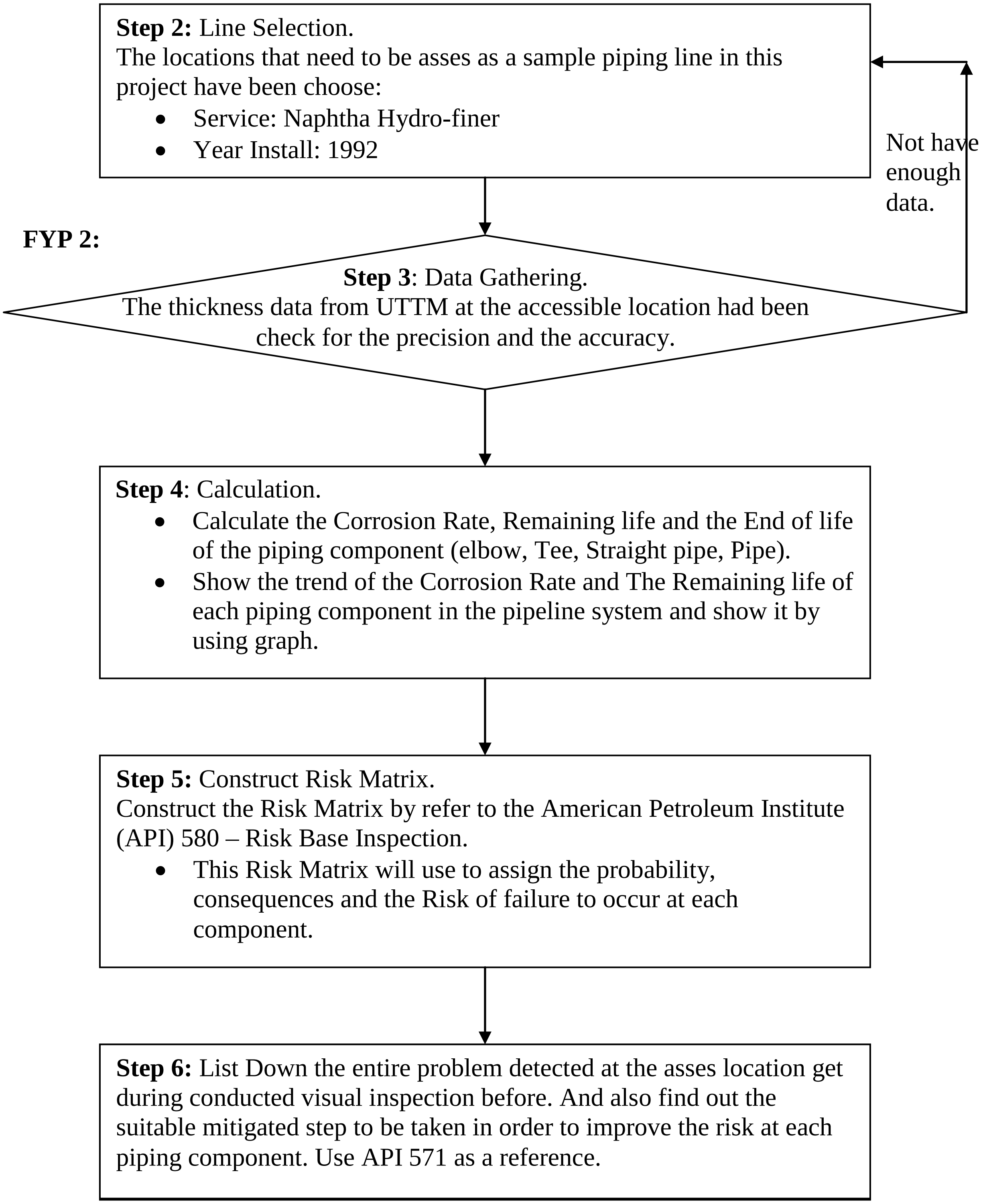


Figure 3.1: Process Flow Diagram of the project.

Basically the project flows have been divided in two stages. 1st stage is FYP 1 stages that more on the research and data collection. 2nd stage is FY2 stages that more on the project flow of calculation, related to Risk Base Inspection, Mitigation step taken and compile the result into database. The critical milestone for FYP1 and FYP2 is shown in APPENDIX 4.

This project will be started on the research study to get the better basic knowledge about inspection method, Risk Base Inspection, failure analysis, and the fitness for service of the pipeline. The second steps are to select the suitable line to be a sample of this project. One of the naphtha hydro-finer lines has been choosing to conduct this project on it. Since all of the data needed for this project by refer to this pipe line are available, this project can be process to the next step. After the line have been select, the flow of project will be continue to collect of the thickness data (by applying the thickness measurement method), process data, previous inspection data and result and other related data. Than the calculation will be apply base on the thickness data and other data available. The next step is to construct the Risk Matrix of (RBI) to assign probability, consequence and risk of failure to occur at the inspection location base on result of calculation. Lastly, list down the entire problem detected at the asses location get during conducted visual inspection before. And also find out the suitable mitigated step to be taken in order to improve the risk at each piping component. Use API 571 as a reference.

CHAPTER 4:

RESULT AND DISCUSSION

4.1 Thickness Data.

This table bellow shows the thickness data from past 3 last inspections conducted on each component being access and the respected date of the inspection method conduct on it. The table also have been including with the initial thickness data, the installation date of each piping component and their respected retirement thickness base on the piping schedule related to the standard use.

(*Please refer to the APPPENDIX 3 for the original thickness data for last UTTM conducted on each component in 2008*.)

Table 4.1: Thickness data

Component	Initial Thickness		Last 3 UTTM		Last 2 UTTM		Last UTTM		Installed	Retire Thk
	Thk(mm)	Date	Thk(mm)	Date	Thk(mm)	Date	Thk(mm)	Date		(Tmin) in mm
ELBOW 2	14.28	17-Nov-92	12.70	16-Dec-96	11.90	28-Oct-01	10.60	18-Sep-08	1992	7.57
ELBOW 3	14.28	17-Nov-92	12.50	16-Dec-96	11.60	28-Oct-01	10.10	18-Sep-08	1992	7.57
ELBOW 4	14.28	17-Nov-92	13.00	16-Dec-96	12.10	28-Oct-01	11.10	18-Sep-08	1992	7.57
ELBOW 5	14.28	17-Nov-92	12.60	16-Dec-96	11.80	28-Oct-01	10.60	18-Sep-08	1992	7.57
ELBOW 6	14.28	17-Nov-92	12.80	17-Dec-96	11.70	29-Oct-01	10.10	18-Sep-08	1992	7.57
ELBOW 7	14.28	17-Nov-92	12.90	17-Dec-96	12.00	29-Oct-01	10.80	18-Sep-08	1992	7.57
TEE 1	14.28	17-Nov-92	13.90	17-Dec-96	13.40	29-Oct-01	12.80	18-Sep-08	1992	7.57
STRAIGHT PIPE 1	14.28	17-Nov-92	12.90	17-Dec-96	12.10	29-Oct-01	10.80	18-Sep-08	1992	7.57
STRAIGHT PIPE 2	14.28	17-Nov-92	12.90	17-Dec-96	12.10	29-Oct-01	10.80	18-Sep-08	1992	7.57
PIPE 1	14.28	17-Nov-92	12.30	17-Dec-96	11.00	29-Oct-01	9.90	18-Sep-08	1992	7.57
PIPE 2	14.28	17-Nov-92	12.30	17-Dec-96	10.90	29-Oct-01	9.20	18-Sep-08	1992	7.57

4.2 Corrosion Rate, Remaining Life and End of Life

The table bellow shows the corrosion rate, remaining life and end of life of each of piping component that have been conducted Ultrasonic Thickness Measurement (UTTM) test on it. This data are base on the calculation have been done and this data shows how long the piping component can safely been use before it reach their retirement thickness.

Table 4.2: Corrosion rate, remaining life and End of life data

Last Thk - Retire Thk mm	Insp Date	Short CR (mm/yr)	Long CR (mm/yr)	SRL (yrs)	LRL (yrs)	EOL (SCR)	EOL (LCR)
3.03	18-Sep-08	0.189	0.232	16.1	13.1	October 10, 2024	October 8, 2021
2.53	18-Sep-08	0.218	0.264	11.6	9.6	May 3, 2020	April 19, 2018
3.53	18-Sep-08	0.145	0.201	24.3	17.6	January 15, 2033	April 17, 2026
3.03	18-Sep-08	0.174	0.232	17.4	13.0	February 11, 2026	October 2, 2021
2.53	18-Sep-08	0.232	0.264	10.9	9.6	August 10, 2019	April 19, 2018
3.23	18-Sep-08	0.174	0.220	18.5	14.7	April 4, 2027	May 31, 2023
5.23	18-Sep-08	0.087	0.093	60.0	56.0	October 4, 2068	September 3, 2064
3.23	18-Sep-08	0.189	0.220	17.1	14.7	October 30, 2025	May 31, 2023
3.23	18-Sep-08	0.189	0.220	17.1	14.7	October 30, 2025	May 31, 2023
2.33	18-Sep-08	0.160	0.277	14.6	8.4	April 22, 2023	February 19, 2017
1.63	18-Sep-08	0.247	0.321	6.6	5.1	April 27, 2015	October 17, 2013

4.3 Related Formula

Bellow are the formula use to calculate the corrosion rate, remaining life and end of life of the piping component. [9]

$$SCR = \frac{(2nd\ last\ UTTM\ thickness\ data - last\ UTTM\ thickness\ data)}{(last\ UTTM\ date - 2nd\ last\ date)}$$

$$LCR = \frac{(Initial\ thickness\ data - last\ UTTM\ thickness\ data)}{(last\ UTTM\ date - initial\ UTTM\ Date)}$$

$$SRL = \frac{(2nd\ last\ UTTM\ thickness\ data - last\ UTTM\ thickness\ data)}{SCR}$$

$$LRL = \frac{(initial\ thickness\ data - last\ UTTM\ thickness\ data)}{LCR}$$

$$EOL(SCR) = \frac{(2nd\ last\ UTTM\ thickness\ data - lastUTTMthickness\ data)/(SCR.x\ 365.25)}{Last\ UTTM\ date}$$

$$EOL(LCR) = \frac{(Initial\ thickness\ data - Last\ UTTM\ thickness\ Data)/(LCR\, x\, 365.25)}{Last\ UTTM\ date}$$

4.4 Sample Calculation.

4.4.1 Short Corrosion Rate (SCR)

Short corrosion rate have been compute and calculate by using the standard formula in order to determining the respected corrosion rate base on the short duration of inspection (between 2 last inspection date and 2nd last inspection date) and this result will be compare to long corrosion rate to find the high corrosion rate between those 2 corrosion rate. This is important in order to find the most critical one. This short and long corrosion rate been calculated because there are some variation of corrosion rate from time duration base on the environmental factor and other external factor. Bellow are the sample of calculation that been use and all of the data have been record in the table 3 above.

$$SCR = \frac{(2nd\ last\ UTTM\ thickness\ data - last\ UTTM\ thickness\ data)}{(last\ UTTM\ date - 2nd\ last\ date)} \quad \text{…………….Eq.1,[9]}$$

(2nd Last UTTM thickness data - Last UTTM thickness data)

= (11.90mm – 10.60mm)

= <u>1.30mm</u>

(Last UTTM Date - 2nd Last UTTM Date) = (18-Sept-2008 – 28-Oct-2001) days

= 2517.00 days

= <u>6.89 yr</u>

SCR = 1.30mm/6.89yr

= <u>0.189 mm/yr</u>

4.4.2 Long Corrosion Rate (LCR)

Long corrosion rate have been compute and calculate by using the standard formula in order to determining the respected corrosion rate base on the short duration of inspection (between the initial thickness data when the component being install and the thickness data from the last of the UTTM conducted) and this result will be compare to short corrosion rate to find the high corrosion rate between those 2 corrosion rate. This is important in order to find the most critical one. This short and long corrosion rate been calculated because there are some variation of corrosion rate from time duration base on the environmental factor and other external factor. Bellow are the sample of calculation that been use and all of the data have been record in the table 3 above.

$$LCR = \frac{(Initial\ thickness\ data - last\ UTTM\ thickness\ data)}{(last\ UTTM\ date - initial\ UTTM\ Date)} \quad \text{..........................Eq.2,[9]}$$

Initial thickness data - Last UTTM thickness data **=** (14.28 – 10.60) mm

= 3.68 mm

Last UTTM Date - Initial UTTM Date = (18-Sept-2008 – 17-Nov-1992) days

= 5784.00 days

= 15.84 yr

LCR = 3.68 mm/15.84 yr

= 0.232 mm/yr

Each of piping component have been calculate their respected short and long corrosion rate and this data have been record in the table 3 above. The data shows the different between both of the corrosion rate even the different are not significant but there are some different occurs from the external factor that have been mention before.

4.4.3 Short Remaining Life (SRL)

The remaining life has been calculate base on the corrosion rate to find how long that the component can safely being use in the production pipe line. The Short Remaining Life have been calculate base on the SCR above. Same as the corrosion rate, both of the data will be compare and the least will be selected base on it criticality. Bellow are the sample of calculation that been use and all of the data have been record in the table 3 above.

$$SRL = \frac{(2nd\ last\ UTTM\ thickness\ data - last\ UTTM\ thickness\ data)}{SCR} \quad \ldots\ldots\ldots\ldots\ldots\ldots \text{Eq.3,[9]}$$

2nd Last UTTM Thickness data - Last UTTM Thickness data

= (11.90mm – 10.60mm)

= <u>1.30mm</u>

SCR = <u>0.189 mm/yr</u>

SRL = 1.30mm/0.189 mm/yr

= <u>16.1 yr</u>

4.4.4 Long Remaining Life (LRL)

The remaining life has been calculate base on the corrosion rate to find how long that the component can safely being use in the production pipe line. The Long Remaining Life have been calculate base on the SCR above. Same as the corrosion rate, both of the data will be compare and the least will be selected base on it criticality. Bellow are the sample of calculation that been use and all of the data have been record in the table 3 above.

$$LRL = \frac{(initial\ thickness\ data - last\ UTTM\ thickness\ data)}{LCR}$$ …………………….Eq.4,[9]

Initial thickness data - Last UTTM Thickness data = (14.28 – 10.60) mm

= <u>3.68 mm</u>

LCR = <u>0.232 mm/yr</u>

LRL = 3.68 mm/0.232 mm/yr

= <u>13.1 yr</u>

4.4.5 End of Life (SCR)

The End of Life has been calculating base on the corrosion rate and the remaining life to find the respected date for the component to reach their retirement thickness and need to me retire from it service. The End of Life respected to (SCR) have been calculate base on the SCR above. Same as the corrosion rate, both of the data will be compare and the least will be selected base on it criticality. Bellow are the sample of calculation that been use and all of the data have been record in the table 3 above.

$$EOL(SCR) = \frac{(2nd\ last\,UTTM\ thickness\ data - lastUTTMthickness\ data)/(SCR.x\ 365.25)}{Last\,UTTM\ date}$$

…. .Eq.4,[9]

2nd Last UTTM Thickness data - Last UTTM Thickness data

= 1.30 mm (from above)

(2nd Last UTTM Thk - Last UTTM Thk) / (SCR) = SRL = 16.1 yr (from above)

((2nd Last UTTM Thk - Last UTTM Thk) / (SCR)) * 365.25) = 5880.53 days

EOL (SCR)

= 5880.53 days/18-sept-2008

= <u>10-Oct-2024</u>

4.4.6 End of Life (LCR)

The End of Life has been calculating base on the corrosion rate and the remaining life to find the respected date for the component to reach their retirement thickness and need to me retire from it service. The End of Life respected to (SCR) have been calculate base on the SCR above. Same as the corrosion rate, both of the data will be compare and the least will be selected base on it criticality. Bellow are the sample of calculation that been use and all of the data have been record in the table 3 above.

$$EOL(LCR) = \frac{(Initial\ thickness\ data - Last\,UTTM\ thickness\ Data)/(LCR\,x\,365.25)}{Last\,UTTM\ date}$$

……………...Eq.5,[9]

Initial UTTM Thk - Last UTTM Thk = 3.68 mm (from above)

(Initial UTTM Thk - Last UTTM Thk) / (LCR) = LRL = 13.1 yr (from above)

((Initial UTTM Thk - Last UTTM Thk) / (LCR))*365.25) = 4784.28 days

EOL (LCR)

= 4784.28 days/18-sept-2008

= 8-Oct-2021

4.5 Corrosion Rate and Remaining Life Relation

Figure 5 bellow shows the corrosion rate and the remaining life trend. From the trend that represent by graph shows that at the component with high corrosion rate, the remaining life of the component will slightly lower compare to the component with low corrosion rate will give the long life of the component can safely been use before it reach their retirement thickness. From this trend we can say that the remaining life are exponentially related to corrosion rate.

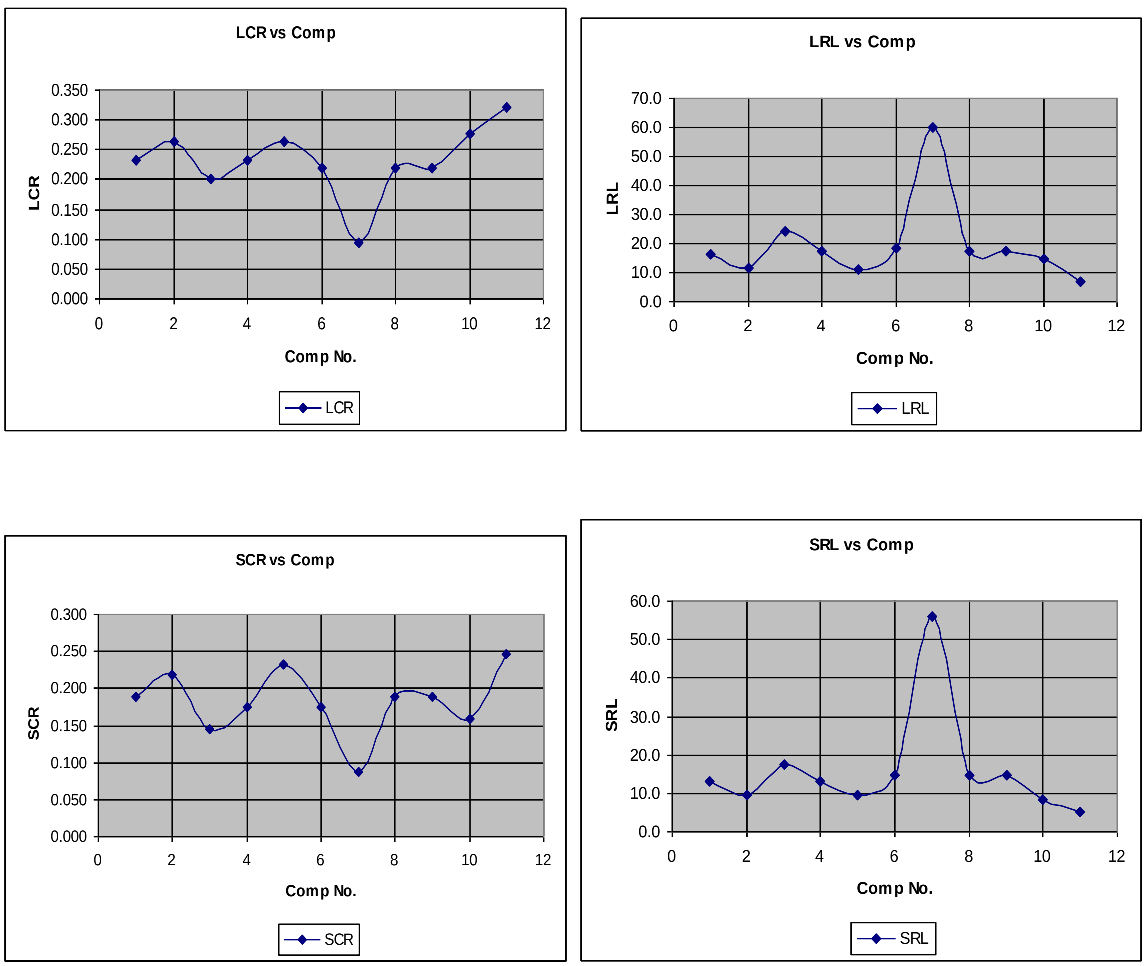
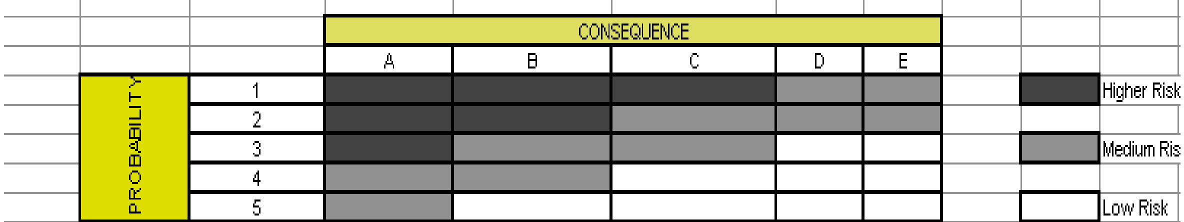


Figure 4.1: Corrosion Rate and Remaining Life Trend present by graph

4.6 Risk Matrix (RBI)

Figure 6 bellow show the respected risk matrix that use to find the probability and the consequence of each piping component that been access. This risk matrix has been developing by referring to API 580 (Risk Base Inspection) and the probabilities of failure have been assign base on the corrosion rate of each piping component. The consequence of failure have been assign base on industrial experience of failure and the pipe line historical data get from the respected refinery.

Risk Matrix



Associate Corrosion Rate (mm/yr)	Probability Category	Definition
0.505 - 0.630	1	Possibility of Repeated Incidents
0.379 - 0.504	2	Possibility of Isolated Incidents
0.253 - 0.378	3	Possibility of Occurring Sometime
0.127 - 0.252	4	Not Likely to Occur
< 0 - 0.126	5	Practically Impossible

Consequence Category	CONSIDERATIONS				
	Health/Safety	Public Disruption	Environmental Impact	Financial Impact	RM (Million)
A	Fatalities/Serious impact on public	Large Community	Major/extended duration/full scale response	Corporate	> 10
B	Serious injury to personnel/limited impact on public	Small Community	Serious/significant resource commitment	Regional	1 to 10
C	Medical treatment for personnel/no impact on public	Minor	Moderate/limited response of short duration	Site	0.1 to 1
D	Minor impact on personnel	Minimal	Minor response needed	Other	< 0.1
E	None	None	Little or no response needed	Other	0

Figure 4.2: Risk Matrix development [8]

4.7 Assigning Probability

Table bellow shows the assigning probability of failure on each of piping component. The results of this have been record in this table and the definition of failure to occur also has been given as in the table bellow.

Table 4.3: Assigning probability to the piping component

Equipment (piping component)	Highest Corrosion Rate (Between SCR and LCR) mm/yr	Assigning Probability Base Risk Matrix	Definition
ELBOW 2	0.232	4	**Not Likely to Occur**
ELBOW 3	0.264	3	**Possibility of Occurring Sometime**
ELBOW 4	0.201	4	**Not Likely to Occur**
ELBOW 5	0.232	4	**Not Likely to Occur**
ELBOW 6	0.264	3	**Possibility of Occurring Sometime**
ELBOW 7	0.22	4	**Not Likely to Occur**
TEE 1	0.093	5	**Practically Impossible**
STRAIGHT PIPE 1	0.22	4	**Not Likely to Occur**
STRAIGHT PIPE 2	0.22	4	**Not Likely to Occur**
PIPE 1	0.277	3	**Possibility of Occurring Sometime**
PIPE 2	0.321	3	**Possibility of Occurring Sometime**

From this table above, we can see hat the highest probability of failure to occur at the piping components are base on their respected remaining life. Thus by this record of probability, the proper mitigation step can be plan in order to reduce the corrosion and slightly reduce the material lost for the component and increase their remaining life for the safety operation.

The Risk Matrix being use for this project has been constructing by refer to American Petroleum Institute (API) 580: Risk Base Inspection, where the risk matrix used are 5 x 5 matrixes. The probability factor range from 1 to 5 assign by the respective corrosion rate from the highest (0.630) calculated base on the retirement thickness reaching on the last inspection date to the lowest possible set corrosion rate (0.000). The consequences of failure to occur have been construct base on the availability of the current risk matrix basically use by the other oil and gas company.

4.8 Assigning Consequences

Table bellow shows the assigning consequences of failure on each of piping component. The results of this have been record in this table and the definition of failure to occur also has been given as in the table bellow.

Table 4.4: Assigning consequence to piping component

Equipment (piping component)	Assigning Consequences	Environmental Effect	Health/Safety
ELBOW 2	C	Moderate/limited response of short duration	Medical treatment for personnel/no impact on public
ELBOW 3	C	Moderate/limited response of short duration	Medical treatment for personnel/no impact on public
ELBOW 4	C	Moderate/limited response of short duration	Medical treatment for personnel/no impact on public
ELBOW 5	C	Moderate/limited response of short duration	Medical treatment for personnel/no impact on public
ELBOW 6	C	Moderate/limited response of short duration	Medical treatment for personnel/no impact on public
ELBOW 7	C	Moderate/limited response of short duration	Medical treatment for personnel/no impact on public
TEE 1	D	Minor response needed	Minor impact on personnel
STRAIGHT PIPE 1	C	Moderate/limited response of short duration	Medical treatment for personnel/no impact on public
STRAIGHT PIPE 2	C	Moderate/limited response of short duration	Medical treatment for personnel/no impact on public
PIPE 1	C	Moderate/limited response of short duration	Medical treatment for personnel/no impact on public
PIPE 2	C	Moderate/limited response of short duration	Medical treatment for personnel/no impact on public

As we can see is it significant thing for someone to assign the consequences of failure to occur. The only way to assign the consequence in the pipe line component or system is base on the past experience of the failure and the historical data provide by the plant. The industrial knowledge about damage courses from this problem is highly important since it related to public problem.

4.8 Required Maintenance Identification [9]

Table bellow show the data require to be put in the piping monitoring strategy in order to monitor whether the piping component for the respected pipe life are fit to be use until the nest turn around in the 2 years period after the last thickness measurement testing conducted on it.

Table 4.5: Shown calculation result for Required Maintenance Identification.

a (yrs)	r (mm/yr)	t (mm)	Retirment t (mm)	T (mm)	ar/t
2	0.232	10.60	7.57	3.03	0.153
2	0.264	10.10	7.57	2.53	0.209
2	0.201	11.10	7.57	3.53	0.114
2	0.232	10.60	7.57	3.03	0.153
2	0.264	10.10	7.57	2.53	0.209
2	0.22	10.80	7.57	3.23	0.136
2	0.093	12.80	7.57	5.23	0.036
2	0.22	10.80	7.57	3.23	0.136
2	0.22	10.80	7.57	3.23	0.136
2	0.277	9.90	7.57	2.33	0.238
2	0.321	9.20	7.57	1.63	0.394

a = Time period of last inspection before next shutdown

r = Corrosion rate

T = Remaining corrosion rate allowance = (thickness - retirement thickness)

From the result above shows that, if the ar/t data get from the calculation give the result large than 1, the component are need for maintenance repair in order to prevent from any failure. Since result from table 6 above shows the respected ar/t are as low as possible to reach 1.00 thus this line did not need any maintenance repair for the nest turn around in the duration of 2 years after the last inspection.[9]

4.8.1 Sample calculation

Bellow are the sample calculation of ar/t. the result have been put inside table 6 for the entire component that been access in this project.

For Elbow 2:

a = 2 yrs.

r = corrosion rate = 0.232mm/yr

t = (thickness - retirement thickness) = (10.6 – 7.57) mm = 3.03mm

(a*r)/t = (2yr * 0.232mm/yr) / (3.03mm)

= <u>0.061</u>

4.9 Piping Inspection Monitoring Strategy

Table 4.6: Shows the part of the project include the operation data and service data of pipeline

PIPING INSPECTION MONITORING STRATEGY														
REFINING PIPING HIGH TEMPERATURE CARBON STEEL SYSTEM														
Line Name	Piping Component	Description	Material	Type of Coating	PWHT	Year of Installation	Year of Service	Pipe Schedule	Original Thickness (mm)	Surface Temperature (Degree C)	Operating Temperature (Degree C)	Operating Pressure (psig)	Design Temperature (Degree C)	Design Pressure (psig)
6"-PF-1539-1B1B	ELBOW 2	APS Bottoms from Tower XXX to Exchanger XXX and bypass line to mix pt, and over-flash	Carbon Steel	Bare	N/A	1992	16	SCH 120	14.275	300	350	236	380	525
	ELBOW 3		Carbon Steel	Bare	N/A	1992	16	SCH 120	14.275	300	350	236	380	525
	ELBOW 4		Carbon Steel	Bare	N/A	1992	16	SCH 120	14.275	315	350	236	380	525
	ELBOW 5		Carbon Steel	Bare	N/A	1992	16	SCH 120	14.275	310	350	236	380	525
	ELBOW 6		Carbon Steel	Bare	N/A	1992	16	SCH 120	14.275	310	350	236	380	525
	ELBOW 7		Carbon Steel	Bare	N/A	1992	16	SCH 120	14.275	310	350	236	380	525
	TEE 1		Carbon Steel	Bare	N/A	1992	16	SCH 120	14.275	300	350	236	380	525
	STRAIGHT PIPE 1		Carbon Steel	Bare	N/A	1992	16	SCH 120	14.275	315	350	236	380	525
	STRAIGHT PIPE 2		Carbon Steel	Bare	N/A	1992	16	SCH 120	14.275	300	350	236	380	525
	PIPE 1		Carbon Steel	Bare	N/A	1992	16	SCH 120	14.275	250	350	236	380	525
	PIPE 2		Carbon Steel	Bare	N/A	1992	16	SCH 120	14.275	314	350	236	380	525

This data shows the operation data of the pipe system that have been analyze in this project, Data includes: The description of service, material of the pipe component, type of coating use, required PWHT or not, year of pipe installation, year of service, pipe schedule, the component original thickness, component surface temperature, Operation temperature and pressure and design temperature and pressure.

Table 4.7: Shows the part of the project include the thickness data base on the inspection date and the suitable technique

PIPING INSPECTION MONITORING STRATEGY											
REFINING PIPING HIGH TEMPERATURE CARBON STEEL SYSTEM											
Line Name	Piping Component	Description	Installation		First Inspection		Second Inspection		Third Inspection		
			Year	Thickness data (mm)	Year	Thickness Data (mm)	Year	Thickness Data (mm)	Year	Thickness Data (mm)	Technique
6"-PF-1539-1B1B	ELBOW 2	APS Bottoms from Tower XXX to Exchanger XXX and bypass line to mix pt, and over-flash	17-Nov-92	14.28	16-Dec-96	12.70	28-Oct-01	11.90	18-Sep-08	10.60	UT C Scan and UT Grid
	ELBOW 3		17-Nov-92	14.28	16-Dec-96	12.50	28-Oct-01	11.60	18-Sep-08	10.10	
	ELBOW 4		17-Nov-92	14.28	16-Dec-96	13.00	28-Oct-01	12.10	18-Sep-08	11.10	
	ELBOW 5		17-Nov-92	14.28	16-Dec-96	12.60	28-Oct-01	11.80	18-Sep-08	10.60	
	ELBOW 6		17-Nov-92	14.28	17-Dec-96	12.80	29-Oct-01	11.70	18-Sep-08	10.10	
	ELBOW 7		17-Nov-92	14.28	17-Dec-96	12.90	29-Oct-01	12.00	18-Sep-08	10.80	
	TEE 1		17-Nov-92	14.28	17-Dec-96	13.90	29-Oct-01	13.40	18-Sep-08	12.80	
	STRAIGHT PIPE 1		17-Nov-92	14.28	17-Dec-96	12.90	29-Oct-01	12.10	18-Sep-08	10.80	
	STRAIGHT PIPE 2		17-Nov-92	14.28	17-Dec-96	12.90	29-Oct-01	12.10	18-Sep-08	10.80	
	PIPE 1		17-Nov-92	14.28	17-Dec-96	12.30	29-Oct-01	11.00	18-Sep-08	9.90	
	PIPE 2		17-Nov-92	14.28	17-Dec-96	12.30	29-Oct-01	10.90	18-Sep-08	9.20	

This 2nd page of data compiler shows the thickness data base on inspection method conducted, the year when the inspection done and type of inspection conducted in each component. This data also shows three pass inspection interval conducted on each pipe component on this line.

Table 4.8: Shows the part of the project include the corrosion rate, remaining life and end of life of the piping component.

PIPING INSPECTION MONITORING STRATEGY											
REFINING PIPING HIGH TEMPERATURE CARBON STEEL SYSTEM			Data								
					Corrosion Rate (mm/yr)			Remaining Life (yr)		End Of Life	
Line Name	Piping Component	Description	Corrosion Allowance (mm) t = New RCA	Retirement Thickness	Short CR	Long CR	Impose Corrosion Rate	Short RL	Long RL	EOL (SCR)	EOL (LCR)
6"-PF-1539-1B1B	ELBOW 2	APS Bottoms from Tower XXX to Exchanger XXX and bypass line to mix pt, and over-flash	3.03	7.57	0.189	0.232	1.00	16.1	13.1	October 10, 2024	October 8, 2021
	ELBOW 3		2.53	7.57	0.218	0.264	1.00	11.6	9.6	May 3, 2020	April 19, 2018
	ELBOW 4		3.53	7.57	0.145	0.201	1.00	24.3	17.6	January 15, 2033	April 17, 2026
	ELBOW 5		3.03	7.57	0.174	0.232	1.00	17.4	13.0	February 11, 2026	October 2, 2021
	ELBOW 6		2.53	7.57	0.232	0.264	1.00	10.9	9.6	August 10, 2019	April 19, 2018
	ELBOW 7		3.23	7.57	0.174	0.220	1.00	18.5	14.7	April 4, 2027	May 31, 2023
	TEE 1		5.23	7.57	0.087	0.093	1.00	60.0	56.0	October 4, 2068	September 3, 2064
	STRAIGHT PIPE 1		3.23	7.57	0.189	0.220	1.00	17.1	14.7	October 30, 2025	May 31, 2023
	STRAIGHT PIPE 2		3.23	7.57	0.189	0.220	1.00	17.1	14.7	October 30, 2025	May 31, 2023
	PIPE 1		2.33	7.57	0.160	0.277	1.00	14.6	8.4	April 22, 2023	February 19, 2017
	PIPE 2		1.63	7.57	0.247	0.321	1.00	6.6	5.1	April 27, 2015	October 17, 2013

Corrosion allowance = last inspection date – retirement thickness of the

EOL (LCR) = (((Initial UTTM Thk - Last UTTM Thk) / (LCR))*365.25) / (Last UTTM Date)

SCR = Highest Of (2nd Last UTTM - Last UTTM) / (Last UTTM Date - 2nd Last UTTM Date)

LCR = (Lowest Thk Initial UTTM - Lowest Thk Last UTTM) / (Last UTTM Date - Initial UTTM Date)

SRL = (2nd Last UTTM Thk - Last UTTM Thk) / (SCR)

LRL = (Initial UTTM Thk - Last UTTM Thk) / (LCR)

EOL (SCR) = (((2nd Last UTTM Thk - Last UTTM Thk) / (SCR)) * 365.25) / (Last UTTM Date)

Table 4.9: Shows the part of the project include the data of ar/t, probability, consequence of failure and risk of failure.

PIPING INSPECTION MONITORING STRATEGY									
REFINING PIPING HIGH TEMPERATURE CARBON STEEL SYSTEM									
Line Name	Piping Component	Description	ar/t Data				Probability	Consequence	Risk Level
			a	r	t	ar/t			
6".PF-1539-1B1B	ELBOW 2	APS Bottoms from Tower XXX to Exchanger XXX and bypass line to mix pt, and over-flash	2	0.232	3.03	0.153	4	C	Midium
	ELBOW 3		2	0.264	2.53	0.209	3	C	Medium
	ELBOW 4		2	0.201	3.53	0.114	4	C	Medium
	ELBOW 5		2	0.232	3.03	0.153	4	C	Medium
	ELBOW 6		2	0.264	2.53	0.209	3	C	Medium
	ELBOW 7		2	0.220	3.23	0.136	4	C	Medium
	TEE 1		2	0.093	5.23	0.036	5	D	Medium
	STRAIGHT PIPE 1		2	0.220	3.23	0.136	4	C	Medium
	STRAIGHT PIPE 2		2	0.220	3.23	0.136	4	C	Medium
	PIPE 1		2	0.277	2.33	0.238	3	C	Medium
	PIPE 2		2	0.321	1.63	0.394	3	C	Medium

Obtain from risk matrix

RCA in mm

Corrosion Rate in mm/yr (Minimum corrosion rate between SCR and LCR)

Time Period in year from last inspection to next shutdown

Table 4.10: Shows the part of the project corrodant and the critical factor of the process.

PIPING INSPECTION MONITORING STRATEGY					
REFINING PIPING HIGH TEMPERATURE CARBON STEEL SYSTEM					
			Corrodant		
Line Name	Piping Component	Description	Source	Critical Factor	Piping Process
6"-PF-1539-1B1B	ELBOW 2	APS Bottoms from Tower XXX to Exchanger XXX and bypass line to mix pt, and over-flash	Naphthenic Acid Corrosion (NAC) and Sulfidation	Click Here to See	Stagnant Zones Con
	ELBOW 3				
	ELBOW 4				
	ELBOW 5				
	ELBOW 6				
	ELBOW 7				
	TEE 1				
	STRAIGHT PIPE 1				
	STRAIGHT PIPE 2				
	PIPE 1				
	PIPE 2				

This part shows the corrodant effected the piping component base on the service of the pipe system. The critical factor can be determine in the next page

NAC - A form of high temperature corrosion that occurs primarily in crude and vacuum units, and downstream units that process certain fractions or cuts that contain naphthenic acids.

Sulfidation - Corrosion of carbon steel and other alloys resulting from their reaction with sulfur compounds in high temperature environments. The presence of hydrogen accelerates corrosion.

Table 4.11: Shows the part of corrodant between NAC and Sulfidation [12]

Unit: APS

Circuit/Description: APS Bottoms from T1023 to E9160/2149/2009/2008 and bypass line to mix pt, and overflash

Line size (inch): 6

Type of Damage: Naphthenic Acid Corrosion (NAC)

Temperature of Service: Between 200 - 400 degree C

Critical Factors:
NAC is a function of the naphthenic acid content (neutralization number), temperature, sulfur content, velocity and alloy composition.
Severity of corrosion increases with increasing acidity of the hydrocarbon phase.
NAC corrosion is associated with hot dry hydrocarbon streams that do not contain a free water phase.
The various acids which comprise the naphthenic acid family can have distinctly different corrosivity
Naphthenic acids remove protective iron sulfide scales on the surface of metals.
NAC normally occurs in hot streams above 425°F (218°C) but has been reported as low as 350°F (177°C). Severity increases with temperature up to about 750°F (400°C), however, NAC has been observed in hot coker gas oil streams up to 800°F (427°C).
Corrosion is most severe in two phase (liquid and vapor) flow, in areas of high velocity or turbulence, and in distillation towers where hot vapors condense to form liquid phase droplets.

Type of Damage: Sulfidation

Temperature of Service: Between 200 - 400 degree C

Critical Factors:
Major factors affecting sulfidation are alloy composition, temperature and concentration of corrosive sulfur compounds.
Susceptibility of an alloy to sulfidation is determined by its ability to form protective sulfide scales.
Sulfidation of iron-based alloys usually begins at metal temperatures above 500°F (260°C). The typical effects of increasing temperature.
In general, the resistance of iron and nickel base alloys is determined by the chromium content of the material.
Sulfidation is primarily caused by H_2S and other reactive sulfur species as a result of the thermal decomposition of sulfur compounds at high temperatures. Some sulfur compounds react more readily to form H_2S. Therefore, it can be misleading to predict corrosion rates based on weight percent sulfur alone.

As we can see, the results of all inspection data have been compiling in the Piping Monitoring Strategy. As shown in table 7 above, all of the operation and design data from the refinery for the pipe line that been access in this project regarding their specific process have been compile along with the inspection data. This because, in order to make situation easier for the future use of the reliability engineer to refer back to this monitoring strategy to get the information about the pipe line process data. The operation and service data provide in this Piping Monitoring Strategy include the material use to manufacture each of the piping components, type of coating, year of installation, pipe schedule, their operation and design temperature and pressure, and the NDT technique conduct onto it.

Table 8 shows that the thickness data get from the Ultra Sonic Thickness Measurement (UTTM) conducted in each component of piping. This data are important to see the trend of metal lost from time to time of the inspection conducted at the same piping component. And this thickness data will use in order to calculate the corrosion rate, predict remaining life and assign the probability of failure. Those it is very important to put on the thickness data history for the use of monitoring the metal lost because of corrosion.

Table 9 shows the respected corrosion rate after been calculated by using the thickness data available. Base in this corrosion rate, the prediction of remaining life and the end of life of the piping have been assigning in order to maintain safe operation. This data will show the rate of the metal lost as the specific piping component. To investigate what kind of chemical contamination infects the metal lost, table 11 will be use to tell about the corrodant affected the piping component base on it service.

CHAPTER 6:

CONCLUSION AND RECOMMENDATION

6.1 CONCLUSION

As a conclusion this project have meet their objective in order to replace the old conventional inspection method at Naphtha hydro-finer pipeline to Risk Base Inspection (RBI) assessment method in order to get the accurate inspection date to access the pipe component criticality. By the calculation done base on the thickness data so this project came with the appropriate corrosion rate, remaining life and the end of life in order to predict how long the component can be safely operate.

The project also has come out with the piping component probability and consequence of failure by using the risk matrix produce by the guideline from the API 580. This probability and consequence of failure will help the reliability engineer to prevent from the unexpected failure to occur.

And lastly, by the corrosion rate, probability, consequence of failure, and corrodant that affected the piping component, the suitable mitigation step can be assign to it in order to improve the criticality of the failure to occur at the component.

6.2 RECOMMENDATION

- To add more information about the piping process in the database develops.

- To apply this naphtha hydro-finer line RBI assessment to the other type of piping service.

- To give enough credit for the ICT member to develop the more sophisticated database to make it more user friendly and easy to asses by the reliability engineer.

CHAPTER 7:

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