REFINERIA DI KORSOU
TECHNICAL AUDIT REPORT

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Executive Summary

Management of the Multidisciplinary Project Team (MDPT) and Refineria di Korsu (RdK) have approached E&D Technologies LLC (E&D) with a request to carry out a technical audit of the a portion of the refinery to assist them with future business decision about the refinery. The objective of the audit has been to provide Refineria di Korsou N.V. (RdK), the owner of the Curacao's Isla Refinery, with a general overview of the plant stationary equipment condition by conducting technical audit of the refinery.

E&D Technologies LLC (E&D) have approached the task by reviewing the originals and copies of the files available in inspection archives as well as through interviews of Isla Refinery personnel to the degree they have been made available. Extracted data and information have been summarized in excel style spreadsheets, which have been individually prepared for each analyzed units. We have also identified equipment in the spreadsheets by colour. Red colour have been used for equipment, which based on the data available, may require significant repair or replacement within five (5) years from the date of the audit. Equipment has been identified by yellow colour if the available information hasn't been sufficient to make such judgement. Green colour has been used on equipment for which enough information has been available to assume useful life extends beyond the five-year period. Refer to table 1.1 below for the list of units reviewed during the audit. General trends in opportunities and suggestions for improvement applicable to most process units have been extracted from the database and summarized below. Equipment issues for individual units were listed in individual tables per unit. These tables a part of this report. Special fitness for service assessment of stripper V-5 of FCCU has been prepared and it is appended at the end of the report.

ISLA Refinery appears to have an acceptable control and management system and operational such as DCS, SAP and probably uses other systems (not in audit scope) to control their daily business. In inspection and reliability/ availability area however, there are number of opportunities where improvements could be made by introduction of management systems. ISLA has a good, well led inspection team but their efforts and progress have been significantly stymied by lack of suitable, modern and dedicated inspection database, which would allow them to collect, analyze and plan their activities more effectively. There is a number of such system packages on the market. Use of such systems is essential to meet contemporary demands on reliability and safety in refineries.

One example of a significant benefit could be significant improvement in forecasting capability of equipment residual life. While reliable loss of containment statistics have not been made available it has been apparent from statements made by inspection personnel and from inspection reports that loss of primary containment (LOPC) incidents have been comparatively frequent. In some cases, "run to failure" mode has been said to be a matter of policy. In other cases, LOPC incidents may have been unforeseen. While "run to failure" mode is practiced in selected situations in other refineries as well, we feel that well thought-out risk based decision process is required to select equipment, which can be allowed to be run to failure. We haven't been able to secure a written policy on the subject. While no major catastrophic incidents have occurred recently in the Isla Refinery, its performance and reliability /availability has been probably adversely affected by combination of variable crude supply and some inspection and maintenance practices, which do not always correspond to practices of similar refineries E&D specialists are familiar with and/or with RAGAGEP (recognized and generally accepted good engineering practices). Details supporting this view are included in the audit assessment documents. It has been a consensus within the E&D specialist group that integrity of Isla Refinery can be improved and that the refinery has been relatively fortunate in avoiding a major incident.

E&D Technologies also report on items which appear not to comply with RAGAGEP (recognized and generally accepted good engineering practices) for the units listed in the Agreement. This could increase risk of plant safety, reliability, environmental incidents and premature shutdown or long-term cessation of operations. Not all of such potential situations could however been detected during the audit.

Limitations

In preparing for the audit, E&D Technologies LLC (E&D) has relied on data and reports provided by Refineria di Korsou N.V. (RdK) and ISLA refinery staff and on representations made by the RdK team and ISLA personnel interviewed in the course of the reviews. We note that while we relied on representations made, the persons consulted are solely responsible for the integrity and accuracy of their verbal and documented responses to our enquiries, and for the integrity and accuracy of project and related (printed and electronic) documents provided. We further note, that our report is a high level review by subject matter experts for management information and it is not intended for day to day inspection or maintenance decisions such as “inspect or not to inspect or repair” equipment or other operational decisions without further verification. Such verifications and decisions have to be done by refinery staff based on their own knowledge and understanding of the equipment condition. The selection and execution or any other use of recommendations listed in this report is the responsibility of RdK’s Management.

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1. General Introduction

1.1 BACKGROUND

Opening discussions about the audit of the refinery between MDPT/RdK and E&D Technologies have been initiated in May 2015. Preliminary exploratory visit and audit preparation work started in September 2015. Definition of requirements and scope have been prepared and modified throughout year 2016 as per MDPT requirements to reflect changes in business environment. Based on MDPT/RdK requirements the final stages of the audit and technical integrity assessment of the Curacao Isla refinery stationary process equipment has been conducted from January 4, 2017 to April 11, 2017. This report summarizes, audit findings and recommendations for critical equipment in units selected and agreed to by MDPT/RdK during the project kick-off meetings.

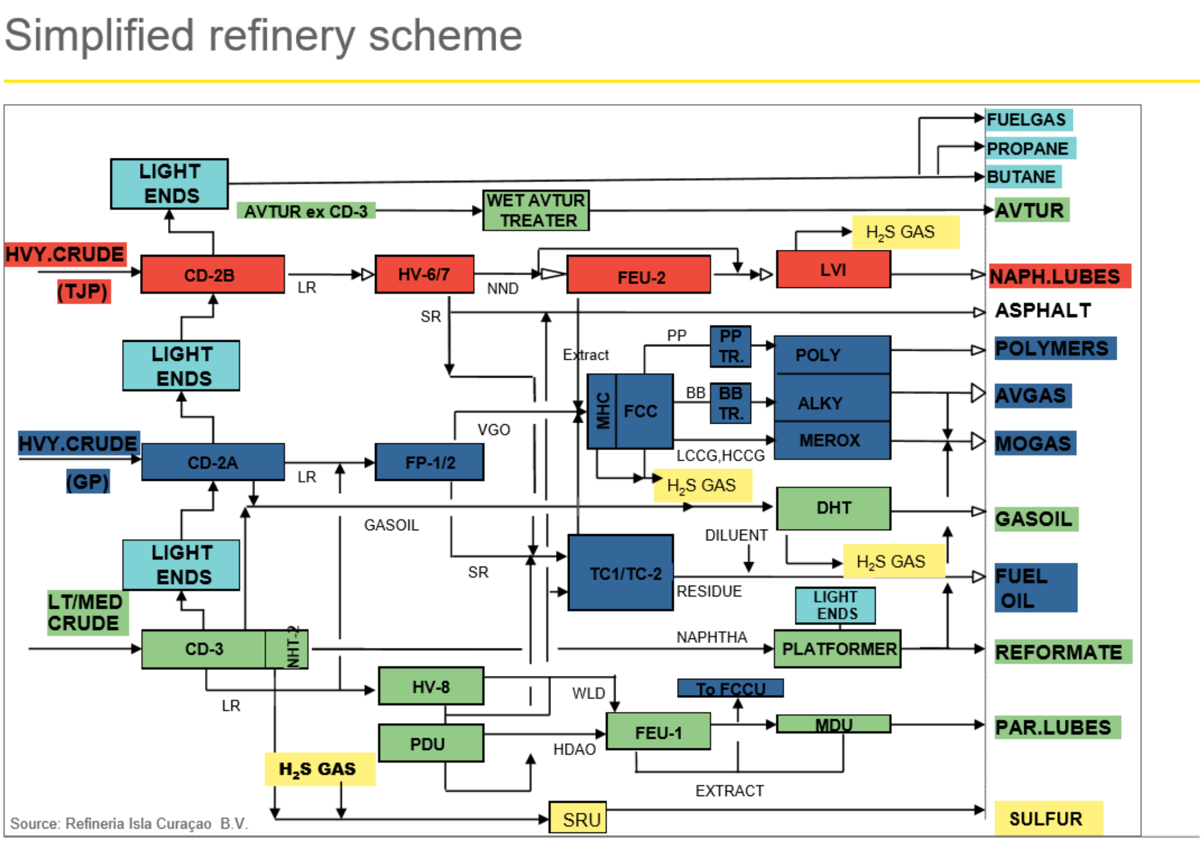

Figure 1.1

1.2 OBJECTIVE

The objective of the audit is to provide RdK with a general overview of the plant stationary equipment condition by conducting technical audit of the refinery and remaining life assessment when needed, as it may impact equipment integrity and plant reliability and help them with future business decisions. This report identifies the status of executed work to the date of its completion, lists main categories of issues, and presents emerging general trends and points out some specifics issues detected thus far. Furthermore, it outlines work to be undertaken including information and documentation collection should RdK/MDPT choose to proceed with additional unit analysis and integrity and reliability improvements.

1.3 SCOPE

The scope of the technical audit at the refinery has been prepared in accordance with the RDK TOR / RFP Technical Audit at Refinery and Oil Terminal in Curacao dated December 2014 and as modified by the subsequent addendums and requests for new proposal to conduct a technical audit at the oil refinery in Curacao dated May 1 2015. Critical equipment of selected units has been agreed and approved by RDK prior to the project kick-off. Selected units are CD-3, DHT (Distillate Hydrotreater), HF Alky, FP-2, NHT, VGO-MHC, FCCU Fractionator, FCCU R&R, LVI, and Platformer. Reviewed has been stationary pressure equipment and piping listed on Process Flow Diagrams of these units.

Table 1.1 Units selected to be reviewed

Units
DHT Unit
HF Alky Unit
FP-2 Unit
NHT Unit
VGO-MHC Unit
FCCU Fractionator Unit
CD-3 Unit
FCC Reaction and Regeneration Unit
LVI HF
Platformer
HV 6
FFS of Stripper V-5, FCCU

1.4 METHODOLOGY

The E&D audit team was comprised of five subject matter specialists. The opening meeting with the audit team and stakeholders was held on Jan 9 2017 and followed by another kick-off meeting on Jan. 16-17 2016.
The team relied on the data, reports and representations provided by RdK and ISLA refinery staff and other personnel interviewed during the course of the reviews. For approximately 6 months, E&D examined reports obtained from the refinery on inspections, maintenance and other applicable and available materials. These were combined with the information obtained from meetings and interviews with select personnel from RdK and the Isla Refinery.

Subject matter specialists of E&D Technologies carried out the audit based on information provided by various sources. It was expected that 1) Inspection and related data are comprehensive and readily available. 2) Equipment is designed and manufactured per the recognized codes such as ASME, DEP.
It is assumed that the refinery inspection program does follow the concepts of API 510 PV Inspection Code and API 570 Piping Inspection Code and related mandatory references of these documents. Refinery inspection practices and results will be compared to these Codes.

Condition of the equipment has been assessed in accordance with the practices outlined in the above Inspection Codes and compliance verified against equipment design Code, where ASME Section VIII and B31.3 Codes have been applicable. In situation where equipment has been designed to different Codes and application of the ASME Code would not be meaningful such equipment would have been assessed in accordance with the RAGAGEP concepts (recognized and generally accepted good engineering practices).

Meaningful basic assessment shall be made as a part of the audit. Few situations, which fell outside of the design or inspection Codes were assessed for fitness for service in accordance with API 579. It was also assumed that refinery was using some method of “RBI” (risk based inspection). This turned out not to be actively pursued by the refinery at this time.

Inspection and maintenance data have been provided by the client and used by the team at their face value. Where data were not interpretable, team specialists questioned them but it is the client responsibility to provide relevant data for the analysis. Also, assessments were generally made based on RAGAGEP (recognized and generally accepted good engineering practices) and on concepts expressed in the “top 11 primary reasons for continuing FEMI (Fixed Equipment Mechanical Integrity) failures in the hydrocarbon process industry” listed below.

1. *Inadequate or lack of identifying and managing the highest priority FEMI risks in each process unit*
2. *Inadequate or lack of comprehensive Corrosion Control Documents (CCD’s) for each process unit*
3. *Inadequate or lack of a thorough, comprehensive piping inspection program*
4. *Inadequate or lack of a comprehensive program for Integrity Operating Windows (IOW’s) for FEMI*
5. *Inadequate or lack of a comprehensive Management of Change (MOC) process for FEMI issues*
6. *Inadequate implementation of all the guidance contained in the latest editions of industry codes and standards for FEMI*

7. *Inadequate or lack of comprehensive programs to learn from the bigger FEMI failures in the industry before similar failures at your site*
8. *Insufficient inspection planning and not using the best available technology for non-destructive examination (NDE)*
9. *Inadequate or lack of comprehensive FEMI record-keeping and data analysis*
10. *Insufficient FEMI training and knowledge transfer for all those with a role in maintaining FEMI…"*
11. *Insufficient or lack of reliable basic documentation such as PFDs, MSDs, P&IDS and key equipment design information.*

1.5 SUMMARY OF KEY FINDINGS – GENERAL TRENDS

Significant number of equipment appears to be operated to failure.

More than a typical number of equipment appears to be operated to failure, which includes LOPC (loss of primary containment). This is supported by fairly frequent unscheduled outages reported in inspection files and during personnel interviews. This is considered acceptable by the refinery personnel due to low throughput and a capability "to catch-up" on production after unscheduled SD. We have not identified a written procedure clearly stating criteria for RTF (run to failure) situations neither have we identified a comprehensive written risk assessment procedures justifying and supporting these decisions. In the absence of an effective risk assessment program this approach may represent a significant safety risk. In particular, all aspects of the risks represented by LPG leaks or risks of leaks in streams containing HF do not appear to have been fully considered in the extent considered acceptable in many US or Canadian refineries.

So far it can be concluded that in recent years the refinery has been relatively fortunate in avoiding major incident.

Recommendation: Develop comprehensive management policy and evaluate individual situations based on quality risk assessment, which will include a thorough safety risk evaluation. Review and decide on implementation of relevant safety related recommendations of this audit report.

Risk Assessments and Risk Based Inspection (RBI)

Risk assessment matrices have been developed but are not used in the inspection program applications. Cursory review indicated that the assessment methodology used has been atypical leading to results, which are not usable for direct inspection planning. In number of cases (e.g. HF carrying streams or LPG) they appear to be significantly under-estimated. This system is recognized as not usable in its current development stage. The plan is to implement RBI by the year of 2020.

Recommendation:

Develop proper risk assessment processes and procedures and Implement RBI in as soon as practical.

Quantitative estimates of residual life / Trending of wall thickness measurements

- **Equipment**
  In case of equipment, such as vessels, exchanger shells, exchanger tubes and many furnace tubes, thickness measurements are not trended. It is unclear what premises are used to estimate residual life of the equipment or to calculate the next inspection dates. Inspection intervals tend to be determined more by turnaround intervals than actual corrosion rates to specific pieces of equipment.

- **Piping**
  The refinery uses piping isometric drawings, which show CMLs (Condition Monitoring Locations). Measurements are recorded and trended using calculated CML average short and long-term corrosion rates and actual reading point short and long corrosion rates. Probabilistic methods of residual life determination are not used.
  CMLs are assigned with little knowledge of actual corrosion mechanisms. This tends to lead to significant over inspection in areas where internal corrosion doesn't take place and under inspection in areas of active corrosion.

  Recommendations: Develop and implement system of corrosion analysis (CCM: Corrosion Control Manuals or CCD: Corrosion Control Documents) and system of IOWs, which can guide inspector in planning their inspections. This is key for being able to handle corrosion in a pro-active way. Develop trending system for equipment thickness measurements as that used for piping. Develop an overall, integrated inspection program forecasting reliably residual life based on assessment and control of active damage mechanisms and risk. Implement integrated inspection management system based on one of the commercially available platforms.

Record Keeping and Documentation Quality

Thickness monitoring locations are not given specific locations on fixed equipment, such as vessels and exchangers, or for heater tubes. Drawings or ad hoc hand sketches are used to identify the approximate area where measurements are taken during specific inspection, but these locations are not necessarily the same locations where prior thickness measurements have been taken.

Record keeping is done in the form of basic inspection observations, which are then collected and summarized in TA reports. Observations discuss mostly results of visual inspections. Component thickness measurements are typically addressed in only a summarization of the lowest thickness measurements and do not provide calculated corrosion rates or remaining projected life.

In case of piping, the PIRS system uses a system of inspection sketches to communicate measurement locations and areas requiring repairs or replacements more accurately. The inspection iso's /sketches allow to locate the right fitting but they do not necessarily allow to identify the same point. A slight deviation from the exact previous UT location could show an incorrect corrosion rate.

Recommendations: Develop a system of inspection sketches for equipment where inspection locations can be shown accurately as well as uniform, written methodology of inspection measurements. The inspection sketches should show clear description of material of construction of components and design and typical operating conditions.

Lack of standard Inspection procedures

Standard format for TA report summaries appears to be available and in use. We found however no standard procedures, guidelines or prescriptions on how to carry out inspections of different types of equipment and what inspection reports should contain. Some TA reports appear to be copies of the previous TA report. Records of observations and NDE inspections are not always consistent and sometimes they lack necessary information and detail. These are best provided in form of tables/simple questionnaires, which the inspector fills in.

Recommendation: Implement standard inspection programs and procedures to improve inspection and reporting consistency and quality.

CUI detection program

Significant effort is being made in recent years on external corrosion of piping. Based on the amount of actual damage such costly programs would warrant a special focus or standalone risk based program with its own budget and long-term plan. Such is the common practice with many other operators. During our discussions, a full agreement has not been reached between the audit team and the refinery group on the selection criteria for initiating under insulation inspection.

Recommendations: Consider separating the CUI detection and repair program into an activity with its own focus, procedures and budget. Agree on criteria for initiating inspection, methods of inspection used and rejection criteria. Numerous methods are available for CUI detection. Their use will vary based on technical feasibility, costs and risks. TA worklists need to be prepared jointly to optimize the repair program.

Turnaround Planning and Planned Outages

Turnaround planning appears to be almost exclusively time based, i.e., units typically have static turnaround intervals. Typical intervals between major turnarounds have been approximately four to six years. Some equipment is not open each TA and will not have internal inspections for longer periods. Inspection dates are shown in unit analysis sheets. There has been no evidence pointing towards use of formalized risk-based and not entirely consistently applied condition-based planning. Refer to comments about condition evaluation based on inspection programs and procedures discussed above.

Recommendations: Most refineries have converted to condition-based, a hybrid of condition-based combined with time-based or a risk-based turnaround planning system. We recommend that RdK implements a risk-based turnaround planning process.

On-stream Inspection (OSI) Programs

Apparently most of external and wall thickness inspection is carried out when units are shutdown. Less or little systemic inspection is done during the run. In regards to thickness monitoring, other refinery operators perform as much inspection as possible while units are in operation, particularly for equipment operating below 230°C. This could be optimized to increase the timeliness and effectiveness of inspection forecasts. Refer also to the CUI inspection recommendation.

Recommendation: Develop an optimized OSI program

Use of contemporary NDE techniques to assess condition of equipment

NDE techniques such guided wave, phased array (PAUT), tube inspection such as Eddy Current (ET), remote field eddy current (|RFT), Flux leakage (FL), internal rotating Ultrasonic Inspection (IRIS), Borescope, laser or white light. Real time radiography, neutron back scatter, profile radiography, infrared inspection, etc. are becoming increasingly available and cost competitive.

Inspection reports show little evidence of equipment condition monitoring using more advanced NDE methods, other than spot ultrasonic thickness measurements, penetrant testing and magnetic particle testing. Use of more advanced methods can provide more accurate picture of equipment condition and residual life.

Recommendations: While the access to the advanced NDE may be more difficult on the island, greater use of advanced techniques would reflect itself in better life predictions and reduced TA scope while improving reliability.

For heat exchanger tube monitoring, consider using techniques such as IRIS, ECT and RFECT to better quantify corrosion and remaining tube wall thicknesses. For piping thickness monitoring, consider using more profile radiography. This technique can be particularly advantageous for inspecting small bore piping (≤ 4" NPS) and for detecting localized corrosion, such as can often be found in piping dead legs, and with localized corrosion mechanisms associated with welds.

Inadequate monitoring of high temperature hydrogen attack (HTHA) and detection program.

Refinery hasn't been applying the latest API RP941, which doesn't give credit to C-0.5Mo material and which lowered limits for non-PWHT CS weldments. HTHA may be occurring in several pieces of refinery equipment. This equipment is identified in the individual unit report and unit analysis spreadsheet. This may represent significant risks to the refinery as there is numerous C-0.5Mo equipment and some CS equipment appears to operate above the limits (C-0.5Mo doesn't get any credit over CS) based on data available to us. Chemical Safety Board recommendations have been made mandatory in the US after the Tesoro exchanger incident. http://www.csb.gov/tesoro-refinery-fatal-explosion-and-fire/

Recommendations: Review carefully long-term exposure (since installation) to hot hydrogen of all equipment, which operates above the contemporary API RP941 limits. This audit report identifies most of them but not necessarily all equipment, which may be so affected. Details are discussed with individual cases. It needs to be mentioned that even contemporary HTHA NDE methods are not fully reliable and sampling may not identify all problems as HTHA resistance depends on thermal and forming history each component has been exposed to during its fabrication.

Low effectiveness of the special emphasis programs

Refinery uses Special Emphasis Programs for Sulphidation corrosion, wet H2S and High Temperature Hydrogen attack. Some of these programs however appear out of date and not always focused on the right equipment (e.g. HTHA addressed mostly higher alloy equipment while most risks is likely with the C-0.5Mo or CS equipment. This is also discussed in the above paragraph.

Wet H2S program / HIC detection program has been significantly curtailed and reliance is placed on coatings to prevent sulfide cracking or HIC. The E&T team feels that coatings may not be effective in situation where serious SCC threat would exist. With an exception of a few locations serious HIC threat in this refinery is however low. Also sulfide cracking tendency, if severe, would have occurred by now. Effectiveness and even need for such coatings is hence questionable.

There appears to be lack of clarity in application of PWHT and application of NACE sulfide cracking prevention rules: NACE SP MR0103 (Materials Resistant to Sulfide Stress Cracking in Corrosive Petroleum Refining Environments). This standard should be fully complied with whenever such sour condition exists. Much of the refinery process equipment and piping can at one time or another be exposed to sulfide cracking conditions. PWHT is not required for compliance with the NACE MR0103 but may be required or recommendable in other situations. (refer to NACE SP0472, Methods and Controls to Prevent In-Service Environmental Cracking of Carbon Steel Weldments in Corrosive Petroleum Refining Environments).

Recommendations: Revise your special emphasis program to bring them up-to-date, better still replace these with targeted Corrosion control manuals (CCMs). Clarify application of NACE MR0103 for purchasing and fabrication of equipment: all equipment in sour service should meet the MACE MR0103 requirements and clarify rules for PWHT. It is probably better philosophy to consider all process piping in basic refinery units as potentially exposed to sulfide cracking and make exception for equipment, which positively will not be exposed than the other way around.

No special focus on monitoring of injection and mixing points

Major industrial accidents have been caused by corrosion or erosion at injection or mixing points. Almost all refineries have implemented special programs of identification of injection and mixing points, which may lead to damage either by corrosion, thermal stress or vibration and implemented mitigation programs aimed at redesign or monitoring of such locations.

Recommendations: Develop and implement such focused inspection programs.

No programs have been identified for monitoring of critical valves (other than relief valves**)**

Certain valves have critical safety related functions. Such critical check valves are usually installed on transfer lines between heaters and reactors in medium and high pressure hydroprocessing or hydrocracking units. Other critical valves may be check valves a MOVs with a safety function, or emergency SD valves. These valves should receive special monitoring and maintenance.

Relief/safety valve maintenance program is in place and is functional. This home-built ACCESS based monitoring program has limited analytical and reporting capabilities. Newer systems not only monitor the maintenance aspects of relief valves but allow to check their continued suitability for different relieving scenarios, handle MOC, material management and other important aspects of overall relief valve management program.

Recommendations: Develop and implement focused inspection and maintenance program for critical valves and implement comprehensive relief valve management program.

Use of partial patches or lap patches (external or internal liners) to reinforce thinned areas.

Lap patches have been applied at number of locations. Lap patches should be considered only to be temporary repairs. Insert/flush as well as lap/fillet weld patches should be designed and installed in accordance with engineering procedures complying with ASME PCC-2 and API 510 Code rules.

Recommendation: Improve patch installation, monitoring and replacement management.

Inspection Performance Metrics and KPIs

There has been no evidence of quantified inspection performance measurement.

Recommendations: Develop the basic inspection performance measurements in 2017

Proactive management of integrity via monitoring of quality of workmanship of Inspection and maintenance contractors to ensure they work in accordance with procedures as well as operators to ensure they are operating within set and agreed IOWs (integrity operating windows).

Recommendations: QA and QC programs for maintenance and NDE work monitoring should be fully implemented and followed.

Heaters

Refinery heaters suffer mainly from the pitch fuel firing. Probably some are of somewhat obsolete design and possibly suffer from less than optimum operation. Massive cost are incurred almost every TA for refractory repairs, casing repairs and replacements as well as tube replacements due to corrosion, overheating or environmental cracking.

Recommendation: Much can indeed be attributed to the fuel fired but some improvements could possibly be achieved if the heaters are reviewed by heater design and material specialists and in cases where warranted firing models applied to optimize the firing and reduce equipment damage.

While primary objective of the audit report is to identify specific issues, we list additional important suggestions, which could improve equipment integrity, process safety and costs in future in table 1.2.

Table 1.2 Additional Systemic Issues for Consideration

SYSTEMIC ISSUES	Impact on		Cost of Issue mitigation
	Safety / Integrity	TA Efficiency	
Equipment Register and Work Planning System Reliable Computerized Equipment Register listing all key documents and assets appears not to be available in the Inspection. Significant effort is being made by MDPT /RDK to scan and digitize available equipment documentation however. Such registers are usually part of business operating systems such as SAP, Oracle -Enterprise One, Business World - ERP (enterprise resource planning) type software. Number of Computerized Inspection and Maintenance software packages can be associated with these business systems. Currently we are not aware of the details of the business operating system ISLA is using other than it is based on SAP. Listing of most popular inspection and maintenance planning packages is included in an attachment to this report. These inspection software systems are equipped with connection to the business systems and process computers (DCS and similar) and provide standardized monitoring, reporting, trending and residual life forecasts, inspection and maintenance planning. Some members of E&D Technologies have developed such inspection systems in the past and have first-hand experience with their application and operations. Expert advice from experienced specialists is however essential during implementation of these systems to assure success.	High	Very high	High

Table 1.2 Additional Systemic Issues for Consideration (continued)

SYSTEMIC ISSUES	Impact on		Cost of Issue mitigation
	Safety / Integrity	**TA Efficiency**	
Adequate Basic Documentation There is no comprehensive MSD (Material Selection Diagrams) or similar system of documents, which would allow quick orientation in operating data, parameters influencing corrosion, materials etc. Other key documentation such as PFD & P&IDs have not been produced to a common quality standard and they are not always up-to-date. It is important that these documents are produced to a good quality standard and contain relevant information needed for corrosion or material integrity assurance. Shell DEP system contains standards for production and upgrade of the key PFDs and PEFDs (P&IDs) documents.	High	Very High	Will depend on system selected
Need for Up-To-Date And In-Depth Corrosion Analysis Of All Process Units. Knowledge of damage mechanisms is developed through a thorough unit analysis done by experts in given field with presence of the relevant personnel. This is then converted into the CCM documents and fit for purpose optimized inspection programs. CCMs are also an excellent learning tool for the inspectors and corrosion engineers. It has to be prepared however with consideration of the most recent advances in understanding of relationship between plant operation and resulting damage mechanisms. Lack of such understanding leads to over inspection and corresponding drain on resource in areas, which do not need high intensity inspection and under inspection in critical areas where focused inspection is needed and resulting safety risk and reduction in reliability. As mentioned above the damage mechanism are closely related to and tied with operating parameters of the Units. Only the most experienced specialists can produce useful and functional corrosion analysis and design CCMs and fir for purpose inspection programs.	Very High	High	Medium

Table 1.2 Additional Systemic Issues for Consideration (cont'd)

SYSTEMIC ISSUES	Impact on		Cost of Issue mitigation
	Safety / Integrity	TA Efficiency	
Inspections Need to be Done With Good Understanding Of Active Damage Mechanisms Lack of good understanding of damage mechanisms active leads to over inspections on location where deterioration is negligible and at the same time to potentially dangerous under inspection in areas where corrosion is active. Understanding of essential damage mechanisms and how they apply to the particular process unit and how corrosion control is accomplished by expert process and corrosion analysis of individual process units is essential for development of an effective inspection program. This is achieved through preparation of a corrosion/ damage control documents, which connects damage mechanisms occurrence and severity with key process parameters and variables. It develops a program of their monitoring via integrity operating windows (IOW), which allows prevention of corrosion damage. Some E&D Technologies specialists have been developing these CCDs (or CCMs) for decades and are very experienced (world class) in this work.	Very High	High	Low-Medium
Adequate Expertise/Training Of Inspection personnel Training for damage mechanisms, corrosion analysis of the units and setting of integrity operating windows (IOWs) is best carried out by the specialist who prepared the CCMs during the CCM application & indoctrination sessions.	Very High	High	Low

Table 1.3 DHT UNIT – Specific Equipment Related Issues and Big Ticket Items

Unit	Item	Issue	Impact	Note
DHT-1100	C-1101 Frac. Col.	**Integrity risk :** Top section of the Fractionator has been found in deteriorated condition both externally and internally. Top 2m of shell appear to have been replaced and miscellaneous external patches have been applied. In 2008 the Column has been recommended for replacement (per TSPH plant change). No evidence of replacement having been done in 2011 or 2013. Further deterioration is likely, both external and internal. Column top section may be beyond usability /reparability and it may present a LOPC (loss of primary containment) risk. Re-asses conditions based on known data, consider replacement at an early opportunity.	Major repair or replacement is indicated. LOPC (loss of primary containment) risk	*Big ticket item, possibly also integrity issue*
	R-1101 Rx	**Main Integrity risk** : the reactor is made from C-1/2Mo material and may be susceptible to HTHA based on the design condition on the PFD. This material is not recommended by API 941 for similar hydrogen service. Proper inspection was not carried out because the record showed that only one nozzle has been inspected for HTHA in y 2000 (17 years ago). Therefore, integrity of the vessel is difficult to ascertain and is questionable. Detailed FFS assessment is needed for further operation	HTHA program is not adequately exercised. Reactor may be threatened by HTHA and failure by fracture	*Possibly integrity Issue as well as big ticket item*
	E-1101 E & D	The hottest shells for the F/E train: C-1/2Mo material is not recommended for hydrogen service at the design conditions. Issues and risks are similar to the R-1101 above. Detailed FFS assessment is needed for further operation	Components of the Exchanger might fail by fracture	*Possibly Integrity Issue*
	E-1102 A-D	These REACs appear to suffer from ammonium salt fouling and corrosion. Tubes are not regularly internally inspected along their full length; corrosion mitigation measures not fully effective. Condition of the tubes cannot be guaranteed and their condition may be deteriorated beyond usefulness. Detailed FFS assessment is needed for further operation	Tube may fail unexpectedly	*Possibly integrity Issue as well as big ticket item*

Table 1.4 VGO-MHC - Specific Equipment Related Issues and Big Ticket Items

Unit	Item	Issue	Impact	Note
VGO - MHC	E1502	REACs: the **main integrity risk** in this unit appear to be condition of the cold end of the REACS E1502. Existing inspection program cannot assess tubing condition adequately. Tubing is not inspected internally hence LOPC (loss of primary containment) incident risk of this high pressure air-cooler is elevated. Detailed FFS assessment is needed for further operation. Process conditions leading to fouling and corrosion are not well controlled (wash water) and probably not fully understood. Tools for predicting and eliminating this corrosion are nowadays available and can be applied. Internal inspection of tubes in this unit is recommended.	Leak in hi pressure air cooler can result in fire or explosion resulting in damage or destruction of surrounding equipment.	*Potoentially an integrity Issue as well as big ticket item*
	V-1501	**Second Integrity risk** can be represented by V-1501 HP Separator, which operates in high hydrogen charging and corrosive environment. Vessel is corroding and is being repeatedly internally coated. Such coatings ared deemed to be of questionable effectiveness by other refinery operators. Coating is regularly deteriorated (in a few months) and may not be effective in preventing hydrogen embrittlement or HIC/SOHIC. Hydrogen /HIC cracking has been detected. ISLA personnel is persuaded of the effectiveness of these coatings. Coating damage is ascribed to steam out operation only. Last recorded visual inspection 2008. No documented evidence of proper WFMT inspection (with high quality surface prep per NACE specs). Plate spec: A212 B FBQ; it is an older material (not made any more), more susceptible to HIC damage or SOHIC in the vessel compared to newer materials. HP separators usually operate in more aggressive environment and frequently suffer from HIC problems. Thorough FFP assessment of the vessel is recommended.	If damage to the vessel continues it may render the vessel un reliable or unusable.	*Potentially an integrity Issue*
		Other risks can be the generally poor performance of both furnace coils and possible ammonium salt deposit and corrosion in the cold end of the E-1568.	Frequent replacements Nuisance leaks	*High costs, medium integrity risk*

Table 1.5 NHT UNIT - Specific Equipment Related Issues and Big Ticket Items

Unit	Item	Issue	Impact	Note
NHT	V-1301	H2 blistering and HIC detected. No PWHT done on some weld repairs. Also failures of internal coating are common. No systematic WFMT program with high quality surface preparation is in place. Carry out FFS evaluation to support further operation or replace vessel with suitable design and manufacture.	Damage may spread to threaten integrity of the vessel	*Integrity issue*
	E1306	Shell of the exchanger approaching end of life (corrosion); reassess condition or replace shell.	Components of the Exchanger might fail by fracture	*Integrity issue*
	Piping systems 73004 & 73006	Effluent piping upstream and downstream of the E1307 is badly corroded and will require comprehensive replacement	Sections of the high pressure piping might fail – significant fire risk	*Integrity Issue*

Table 1.6 PLATFORMER - Selected Issues and Big Ticket Items

Unit	Item	Issue	Impact	Note
Platformer	Reactor Effluent Cooler (E-1702 C1/C2)	Tubes suffer from internal pitting, damage mechanism not documented, probably chloride corrosion. Cooling performance and corrosion is not uniform due to piping manifold configuration. Retubes done every 2-4 years, last one was in 2013.	Leak can result in fire or explosion resulting in damage or destruction of surrounding equipment.	*Possibly an integrity Issue as well as big ticket item*
	Stabilizer O/H Condensers (E-1706 A-B)	Shell bottom heavily corroded 6mm, close to (11.1mm) min WT (10.9mm). The exchanger has been modified but it is still under designed. Replace shell or consider re-design if there is or may be in future a capacity issue.	Leak can result in fire or explosion	*Possibly an integrity Issue, possibly capacity issue if unit operated at full thru-put*
	1st and 2nd Reactor (R-1702 and R-1702)	In 2010 R-1703 was changed to hot-wall (2.25Cr-1Mo) design. R-1701 and 1702 remain as cold wall design. Reasons for conversion may exist for these two vessels as well. Cold wall design is less reliable (possibility of back channeling and shell damage) compared to hot wall. Review condition of the cold wall vessels.	Reliability of cold wall design / possibility of shell damage	

Table 1.7 HV6 UNIT – Selected Specific Issues and Big Ticket Items

Unit	Item	Issue	Impact	Note
HV6	Vacuum Column C-1 (DA-1)	Over years the column suffered from significant corrosion, sulfur, NA, Caustic cracking, Oh'd dew point corrosion. It is difficult to assess accurately the level of damage and whether it is economically repairable for long-term service. Carry out detailed FFS analysis.	Significant repairs/ upgrades will be required	*Possibly an integrity Issue as well as big ticket item*
	Exchangers # 4, 5, 6, 7, 8	These units suffer from S and NA corrosion. Due to large number of units this may be a significant cost item.	Future cost issue	*Potentially big ticket item*

Table 1.8 LVI -HF UNIT - Selected Specific Issues and Big Ticket Items

Unit	Item	Issue	Impact	Note
LVI-HF	E1304 HP Gas Air Cooler	Ammonium salt corrosion is not well controlled, leakage occurs. High pressure unit.	Leaks can lead to LOPC & fire.	*integrity Issue*

Table 1.9 HF-Alky UNIT - Selected Specific Issues and Big Ticket Items

Unit	Item	Issue	Impact	Note
HF ALKY	Air Coolers A-605 A-E	Corrosion occurs, units nearing end of life. Leak means releasing of large are with isobutane containing HF.	Possibility of fire or contamination of area with HF acid.	*integrity Issue*
	C-604, HF stripper	Corrosion in top section of the column, based on inspection projections w.t. probably below retirement thickness. Top section should be replaced with Monel clad material	Potential for leakage and contamination	*Integrity issue and potentially big ticket item.*
	Piping	HF containing piping is representing elevated risk because the temperatures are not well controlled, the record of high water incidents is not entirely reliable (not monitored by inspection) special materials required for HF (low resid elements) are not consistently used.	Potential for leakage, fire and HF contamination	*Integrity issue.*

Table 1.10 FP-2 UNIT – Selected Specific Issues and Big Ticket Items

Unit	Item	Issue	Impact	Note
FP-2	Vacuum Column, C-1	Corrosion in the top section, corrosion under the strip lining. Upper section including the cone was recommended for replacement during next TA in 2015. In the long-term top 25' may need replacement with clad section. Corrosion issues should also be understood and addressed.	Possible collapse of the shell, internal fire, outage.	*integrity Issue and possibly big ticket item*
	Piping: C-1, Vac Column, Overhead Circuit 22120	Sections of this piping system were being replaced over time. Some sections are still original and likely near the end of its life.	Possible pipe collapse, air intake into piping.	*integrity Issue and possibly big ticket item*

Table 1.11 FCCU – RR Section - Selected Specific Issues and Big Ticket Items

Unit	Item	Issue	Impact	Note
FCC-Reactor & Regenerator	V-5 Stripper	Overheating of the vessel led to the deformation of the shell and metallurgical changes affecting properties of the material. Circumference of the vessel increased 132mm from 1990 to 2012 (6mm/year). Creep is suspected to be one of the damage mechanisms. Mechanical integrity of the vessel is questionable and decision to continue to use or replacement has to be made. Remaining life can be asses more accurately if material properties and operating condition are given. For long term use, we recommend to replace the vessel with new design/material.	Loss of function and significant outage for the whole FCCU	*Big Ticket item*
	Rx OH'd line MK56-58	Measurements show line thinning at a high rate. 13 section will likely need early replacement	Possibility of LOPC incident and fire	*Integrity and big ticket item*
	Rx standpipe MK – 5-7	Graphitization was identified in 2011 turnaround. Graphitization occurs in carbon steels and Carbon 1/2 Mo at temperatures ranging from 450C to 620C. More accurate definition of the damage is recommended or plan for replacement next T/A. Consider material upgrade to at least 1% Chrome, 1/2 moly.	If graphi-tization concentrates around weld zones, sudden failure of equipment may occur	*Integrity and big ticket item*

Table 1.12 FCCU FRACTIONATOR- Selected Specific Issues and Big Ticket Items

Unit	Item	Issue	Impact	Note
FCCU - Fractionator	Fractionator 24" Oh'd line	High corrosion rates may have already resulted in section of the pipe being below retirement limit. This stream contains high concentration of LPG and in case of leak there is a potential for detonation. Similar risks may exist in the GRU (downstream section) De-ethanizer or De-butanizer oh'd systems. (not part of this audit scope)	LOPC, fire , detonation	*Major integrity Issue*
	Slurry Piping	Cs material in the service may suffer from irregular and high corrosion rates, which are difficult to monitor. Cr-Mo materials are significantly more reliable in this service.		

TABLE 1.13 CD-3 COMPLEX - Issues and Big Ticket Items

Unit	Item	Issue	Impact	Note
CD-3	Lap patches	Lap patches have been applied at number of locations in CD 3. Lap patches should be considered only to be temporary repairs. Insert/flush and lap patches should be designed in accordance with engineering procedures complying with ASME PCC-2 and API 510 Code rules. This is applicable to other process units as well not only CD-3 complex	Potential for shell damage and LOPC.	*integrity Issue*
	Wet H2S cracking program	Wet H2S cracking detection program has been applied in the refinery. Over time vessels, vessels in which inspection did not detect cracking have been dropped from the program. Very special surface preparation is needed for this inspection to be successful. In some cases the program recommendation weren't followed and coatings have been applied. Coating applications for this purpose in many of these services are unique to the RDK.	Program should be re-assessed and updated	*Potential integrity issue*

1.6 REPORT ON MISSING EQUIPMENT

Inspectors compared the presence of the equipment with the drawings of specific units and we identified several equipment are not in the place. Summary of findings are listed below in table 1.14.

Table 1.14 Missing Pumps and Motors

Unit	Equip-ment #	Motor	Pump	Comment
Cat Cracker	4A	No	Yes	
	P-608A	No	Yes	
	P-603A	No	Yes	
	P-603B	No	Yes	
	P607B	No	No	
	P-613	No	Yes	
FP-2	9	No	Yes	
Poly Plant	P-10	No	No	
	P-12	No	No	
	p-18	No	No	
	p-20	Yes	No	
	p-25	No	No	
	P37	Yes	No	
GT-7	p-001	No	No	
	p-7A	No	No	
	p-10	No	No	
	p-10A			Not in service
VGO	811A			Not in service
	811B			Not in service
	1507A	No	No	
	1507B	No	No	
	1509			Not in service
	1553			Not in service
	1564B	No	No	
	1601		No	
	1602A			Not in service
	7	Yes	No	
	8	Yes	No	
	15	Yes	No	
	16	Yes	No	
	22	Yes	No	

Table 1.14 Missing Pumps and Motors (cont'd)

Unit	Equip-ment #	Motor	Pump	Comment
DHT	1106B			Not in service
	1108A	No	No	
	1108B	No	No	
	1109A	No	No	
	1109B	No	No	
	1112A	No	No	Not in service
	1113			Not in service
	1116A			Not in service
	1116B			Not in service
LVI	K1101B			Not in service
	K1301A			Not in service
	K1301B			Not in service
	1302B	Yes	No	
	1324A	No	No	

Table 1.15 Missing Pressure Equipment

UNIT	EQUIPMENT
CAT CRACKER	E 17AB
PLATFORM	E1702A
	1702B-1
	1702C-1
	1702C2
	J1708
	E-1702A1
	E1706A
	E-1706B1
	E-1704
	V 1704
	E-1723
	E 1723A
	E 1702
HV-6	J-2A
	J-2BSTACK 2
HFR	E-625
	E-603
	V 611
CD2	2AB
	2A BE10
	2A -BE11
	E 10
	2ABE-103
	2AB-V101

Note: E-17AB location is in process of verification

2. DHT Unit

2.1 INTRODUCTION

This report summarizes audit findings for RDK DHT Unit (Distillate Hydrotreater, 1100 series equipment) as shown in Figures 2.1 and 2.2. This unit treats straight run Gas Oil Distillates from CD-3 and CD-2 Units. It reduces organic Sulphur and Nitrogen content and to some degree, heavy metals in the feed stock to meet the refinery Gas Oil fraction specifications. Original process description mentions also TCU Gas Oil as feed stocks. The new bloc diagram doesn't support that options however and shows that the TCU's GO is normally routed to MHC VGO for treatment. This second version makes the feed mix somewhat less complex and less aggressive.

Hydrogen needed in the process is supplied form a SMR type hydrogen plant and supplemented by Cat Reformer hydrogen. Product of the unit is Gas Oil stream with H2S gas and sour water as by-products. These are concentrated and converted into elemental sulphur in SWS/Amine and Sulfur Recovery Units.

Generally, long term corrosion rates in the unit are not excessive, at least not in recent years. Exceptions are vacuum condensers (E1511, -12), which have been replaced number of times (more than 10 times during the last 20 years!). This, however, may change if the ISLA's plans to process higher Sulfur and Nitrogen feeds are realized. Limitation to the feed quality downgrading may be the limited conversion capability to meet product specifications. The feed stock quality changes should be monitored, understood and included in the integrity monitoring plans.

First section of this report covers systemic findings, which are more general nature and quite similar for majority of the unit, which have analysed. Since the inspection process is developed and administered by the same inspection group only relatively small differences in the systemic issues can be found amongst the analyzed process Units.

The Table 2.1 summarizes areas of concern based on the type of issue, such as short residual life, susceptibility to certain type of damage etc. Equipment and recommendations listed in this table should be prioritized addressed based on the refinery business priorities.

DHT – Process Flow Diagram

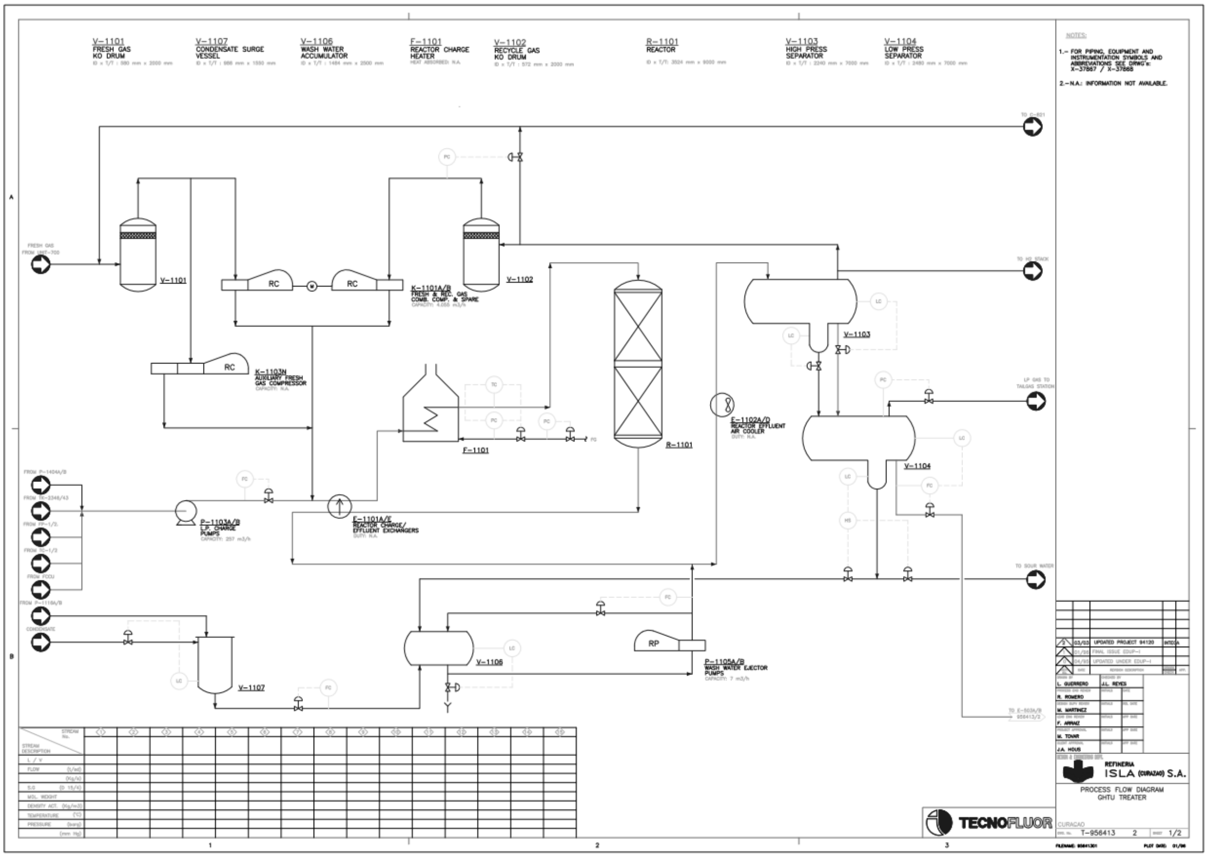

Figure 2.1 PDF of DHT -1

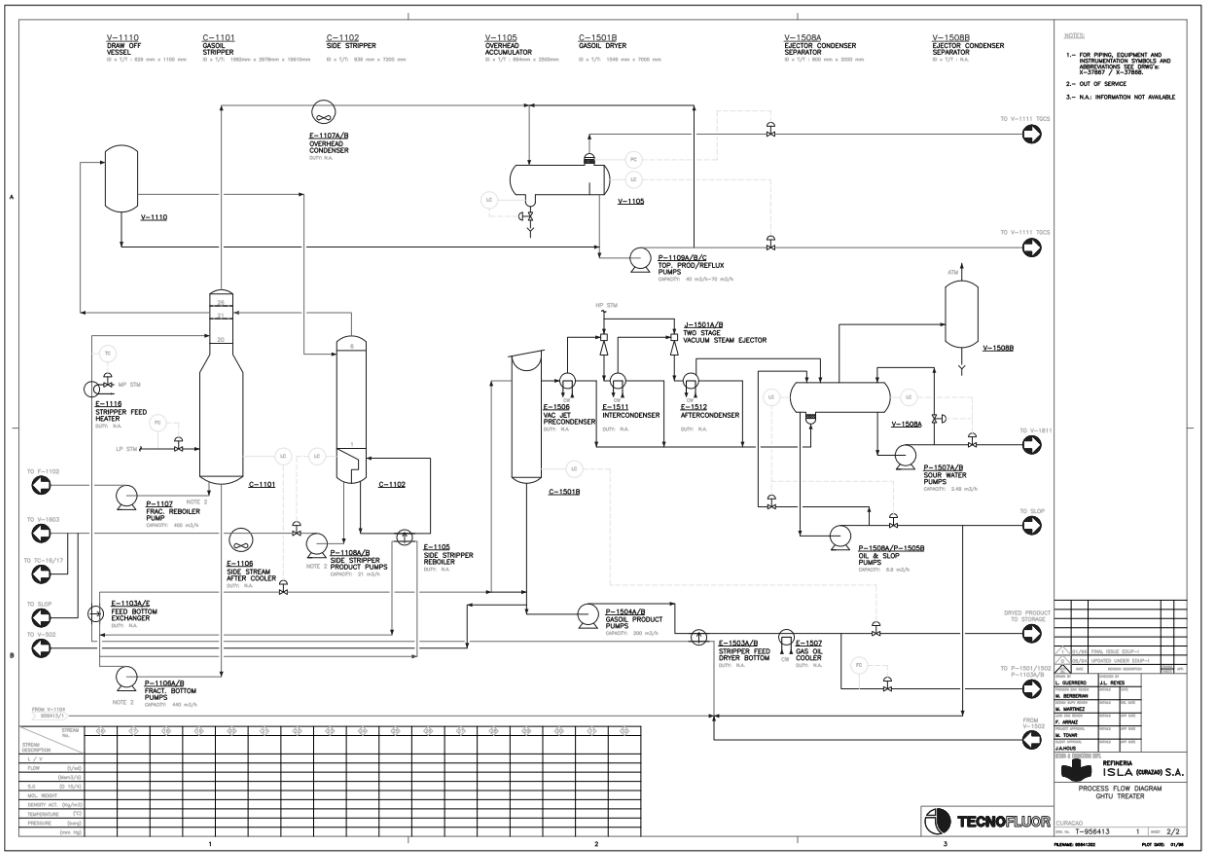

Figure 2.2 PFD of DHT -2

2.2 THE MAIN INTEGRITY RISKS

Based on available data, probably **the main integrity risks** in this unit appear to be unknown condition of the Reactor R1101 components. Material of construction of the reactor is identified as C-0.5Mo and there is a risk of HTHA given the hydrogen partial pressure under design/operating temperature shown on drawings. Actual long-term/lifetime operating history (e.g. DCSD printouts) hasn't been made available however.

Recent failure of F/E exchangers of a Hydrotreater by HTHA in Tesoro refinery in Anacortes have been investigated by CSB. Number of recommendations have been reached. The most important one being that the CS curve of non-PWHT weldment, CS curve is also used for C-0.5 Mo materials**, has been further lowered**. It is possible that some of refinery equipment does not meet the requirements of API RP 941 exposing the refinery to integrity/safety risk and increased liability risk.

Original operating conditions of R1101 is shown below in Fig. 2.3. C-1/2Mo curve has been eliminated in 1977, replaced by CS curve and in 2015 the CS curve has been further lowered by approximately 40C. Relevant CSB link http://www.csb.gov/tesoro-refinery-fatal-explosion-and-fire/ is well describing the issues.
Based on information made available there could be a hydrogen damage to some sections of the Reactor shell or forged components, which the test methods reported in available inspection files would likely not detect. Special inspection techniques need to be applied and their reliability has been deemed by their users to be low. Also since the sensitivity of the C-0.5Mo to HTHA depends on thermal history of (method of manufacture and heat treatment) examination of one component will not necessarily prove soundness of other components. For these reasons number of operators have decided to replace C-0.5Mo equipment in hydrogen service by higher Cr-Mo alloys.

While the vessel is equipped with internal cladding from austenitic SS316, which has lower Hydrogen permeability compared to ferritic steels and may be considered to reduce the Hydrogen concentration at the cladding/base metal interface, most Operators do not consider this as being an adequate mitigating measure and do not take a credit for the SS cladding in thick wall vessels operating in hot hydrogen service.

The second major threat may be also the risk of HTHA at the hot end of the Feed/Effluent exchanger E1101 bank, shells D and E, which are also made of C-0.5Mo. These units have been identified as operating above the CS line, which also represents the C-0.5Mo material, Fig. 2.3 originates from RDK/ISLA files. Lowering of the Nelson curve may bring the E-1101-C into the non-recommended zone if some non-PWHT welds (new or repairs) have been installed. The same argument concerning material testing as the one indicated for the R-1101 case applies for the hot components of these exchangers. Due to the lower thickness of the components and gradually lowering temperature gradient the probability and of damage may be somewhat less compared to the Reactor. This, however, would not eliminate the need to address this potential issue.

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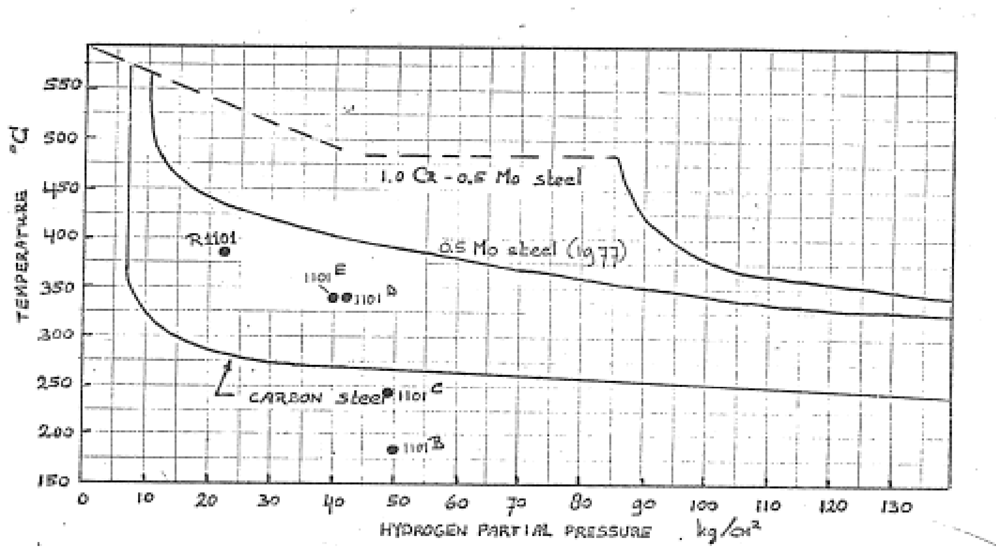

Figure 2.3 1977 - Nelson Curves (Operating Limits for Steels in Hydrogen Service)

For comparison the latest curves from API RP 941 are shown below in Fig. 2.4. The drop of the curve for non-PWHT CS may result in inclusion of equipment, which has been considered in the past to be operated in a "safe zone".

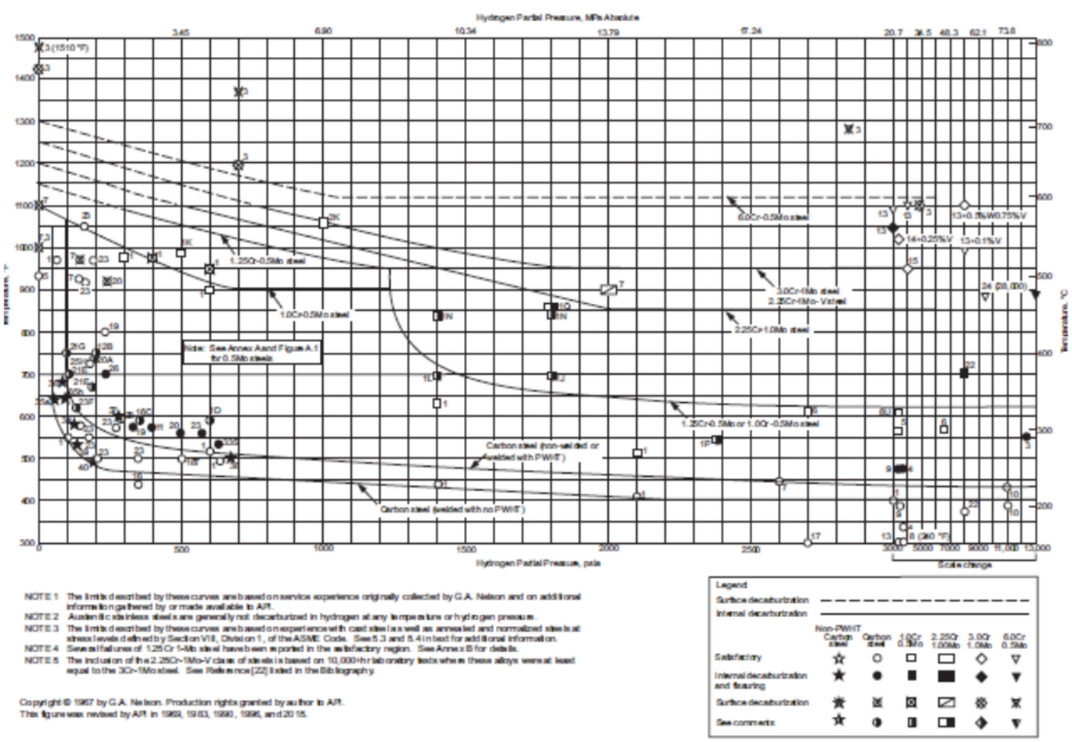

Figure 2.4 Operating Limits for Steels in Hydrogen Service to Avoid High Temperature Hydrogen Attack

Cold end of this E-1101 exchanger bank (units A and B) appear also to suffer from ammonia chloride salt fouling and corrosion. Refer to the de-sublimation curves shown below in Fig.2.5 to estimate the corrosion potential. More discussion is provided in section 6 – VGO-MHC Unit.

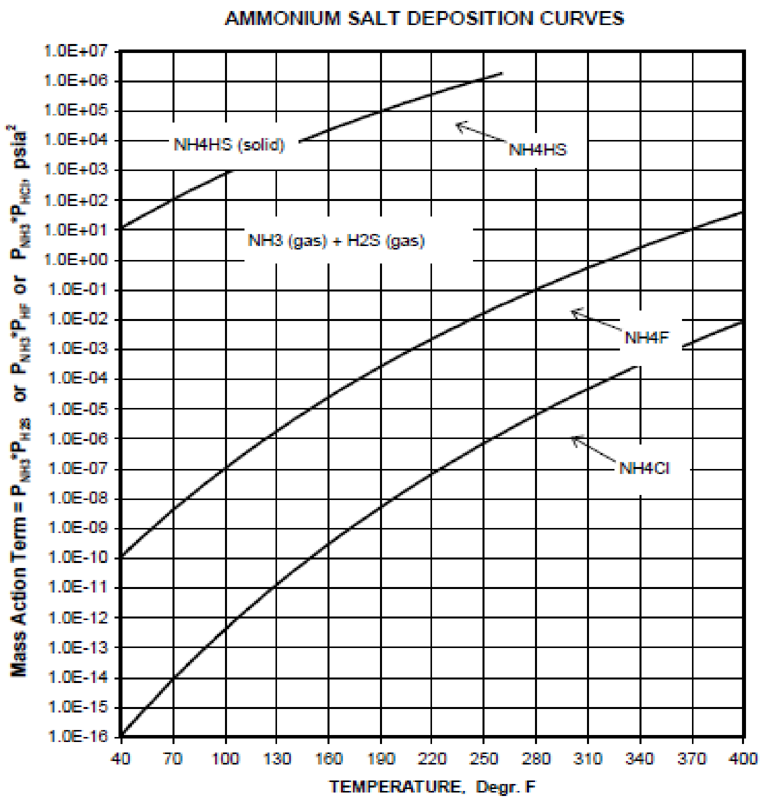

Figure 2.5 Ammonium Salts De-sublimation Curves

The third significant threat is salt fouling in the REACs E-1102 A-D. Ammonia salt fouling goes hand in hand with corrosion, whether it is chloride or bisulfide type. Due to lack of actual long term process data it is difficult to analyze in detail.

Special mention warrant units E1506, 1511 and 1512. Some of these units have been replaced more than 10 times during the last 20 years. These unit foul, fail but operate under vacuum, so while this is an integrity and cost problem the level of risk of the LOC (cooling water leaks into sour water systems) is lower. In our opinion the contemplated redesign using different more corrosion resistant material (Titanium) should be implemented.

Additional info on the above is listed in table 2.1.

2.3 GENERAL COMMENTS

2.3.1. Pressure Equipment (Vessels, exchangers, air coolers and heaters)

A) Inspection Sketches
Record keeping by ISLA inspectors is currently in form basic inspection observation notes, which are written into a SAP module and then inserted into an equipment file in paper form. Observations are summarized in TA reports. Observations available in the inspection files discuss mostly results of visual inspections. Wall thickness (W.T.) measurements if available are usually referred to as “satisfactory”, but sometimes without actual measurement record.

System of centralized UT and other NDE program results appears not to be available for equipment such as pressure vessels, columns, heaters and heat exchangers. Since trending of wall thickness measurements is not done, quantitative estimates of residual life cannot be effectively done. It is unclear how estimates of residual life are done with any degree of accuracy. In many (most?) cases inspection is not based on well understood corrosion or degradation mechanisms and how they relate to operating conditions. *Refer also to assessment of the Special Emphasis* Programs.

Measurements are not collected consistently and they are almost never trended. Measurements are sometime indicated on hand made sketches. Older files do show use of dedicated inspection sketches. These however do not show open shell envelop to locate the CML accurately.

Without having standardized comprehensive system of inspection drawings / sketches dedicated to the NDE record it is in our opinion nearly impossible to assess progress of changes in equipment condition in a quantitative way and to predict residual life with a measure of accuracy or do the effective NDE planning. Most operators use sketches with level of detail corresponding to simplified General Assembly (GA) drawing of equipment to identify areas of measurement or observed damage and repairs. In the ISLA system, we didn’t find standardized equipment inspection sketches of newer vintage, which would show the general configuration on “open envelop” format, materials, operating conditions and key appurtenances.

B) Bundle Inspection
Only visual inspection of bundles and tube ends is usually reported. In the VGO-MHC unit essentially no internal tube inspections using either borescopes, eddy -current, IRIS or similar quantitative techniques has been reported although reports from 2012 CD-3 TA show some use of EC inspection. Tube removal and splitting to assess condition are apparently also not practiced. No measurement trending has been done reported so far during bundle inspections. It is our opinion that accuracy of the bundle life prediction without doing quality internal tube inspections is expected to be low. This may lead to either unplanned leakage or premature replacements.

C) Fabrication and Material Records
Fabrication records such a drawings and design information (data sheets, calculations, welding and heat treatment procedures etc.) are available for some files only. It is also difficult to identify reliably actual materials of construction. Copies of the drawings are, if available, sometimes not legible. Good records should allow to retrieve basic information in matter of seconds.

D) Standardized Inspection Procedures
Records of inspections appear not to follow standardized procedures. Such procedures would be useful tool to ensure that the inspections are carried out consistently and thoroughly and records and conclusions more relevant for future planning.

Recommendation for Pressure Equipment:
Update or develop a system of standardized inspection sketches, and inspection procedures, which can be utilized for the purpose of planning NDE inspections, UT thickness measurements (TMLs and CMls) and repair definition. In case of piping this has been mostly done. Piping sketches have been prepared and are used for the above purpose.

Wall thickness measurements should be kept in a computerized central record register/ data bank. Develop standardized data sheets which would summarize whatever relevant information can still be located in refinery archives and other sources, like personal files etc.

Current standards for TA planning contain a major component of condition based decisions, i.e. equipment is included in the maintenance program bases assessment of its actual condition and the risk it represents for Operations. This is much more effective approach to plant efficiency compared to the simple time based inspection.

E&D Technologies specialize in development of such plant inspection programs based on detailed corrosion analysis of process units. Proposals for or development of such inspection systems can be prepared for RDK management upon request.

2.3.2 Piping

In case of piping the PIRS (Piping Inspection Records System) this system uses inspection sketches discussed above, which show CML / TML locations. This is available for piping only however. The system is developed in adequate detail and is suitable to communicate measurement locations and areas requiring repairs o replacements. Results of piping wall thickness measurements are recorded in spreadsheets of the PIRS system (MS AXES based).

Corrosion rates are calculated and residual life estimated bases of simple arithmetic extrapolation of data. No other more complex data manipulations such as risk assessment or statistical evaluations are performed by PIRS.

CMLs are assigned based on historical experience without a benefit of more sophisticated corrosion analysis. This may lead to significant over inspection in areas where little or no internal corrosion takes place and an under-inspection in areas of active corrosion. Also, the system of queries and reports allowing analysis of data in different ways, such as “what if…” type of queries, is limited. No statistical evaluations or measurement quality assessments are available in the PIRS system.

Notwithstanding some of the shortcomings, implementation of PIRS has led to a very substantial improvement in piping reliability since the time it has been implemented.

While piping inspection programs are significantly more structured compared to the pressure equipment it still lags behind contemporary standards of risk based concepts and more complex evaluations of data.

Key component of piping inspection, exchanger bundles and pressure equipment, is understanding of the knowledge of relevant corrosion mechanisms and parameters, which influence them. Such comprehensive analysis would allow us to focus on areas of active corrosion and distribute the inspection effort more effectively, i.e. help to prevent missing those areas, which require more intensive coverage and reduce inspection intensity in areas, where corrosion in not taking place.

The PIRS system has been claimed to cover all key process piping systems. While its usefulness is undisputable the system still contains some errors and inaccuracies and would benefit from a QC review.

Recommendations for Piping:
Develop an inspection program based on assessment of active corrosion mechanisms (CCMs) and assessment of risk each such situation represents.

First step in development of knowledgeable based corrosion & Inspection system is assessment of individual process loops. Subsequent steps consist in implementation of the following programs:

1. Appropriate grouping lines and equipment into loops (development of corrosion loops and Material Selection Diagrams with all relevant information needed for corrosion analysis).
2. Corrosion assessment of the loops.
   Development of parameters influencing corrosion and setting of integrity operating windows (IOWs).
3. Development of inspection/NDE programs for uniform and localized corrosion.
4. Development of inspection/NDE for dead-leg corrosion.
5. Inspection programs for injection/mix point corrosion.
6. Inspection/NDE of vents and drains (small connections)
7. Inspection of critical valves and check valves (similar to the RV inspection program)
   Relief valves are covered by a separate basic inspection and maintenance program, which is in place and appears functional but it has not been evaluated in detail.

2.3.3 CUI Programs

We have noted that since approx. 2015 the maintenance and inspection group are engaging in an more extensive piping external corrosion programs. It is likely that units, which have been shut down for turnarounds in 2016 and 2017 have their piping inspected and repaired. Since a comprehensive CUI program is not specifically defined in writing it is not clear what criteria are used to decide on equipment repair and how effective such program is even though the plan for repairs of piping external corrosion for example in CD-3 area for the Spring 2017 TA appeared to be quite significant.

Development of specific inspection programs for corrosion under insulation (CUI) is in most plants known to E&D are usually carried out as parallel to the internal corrosion monitoring but separately administered programs. Most of the external corrosion detection can be done during operations and it is independent of operations. In case of RDK, where CUI is a major component of piping system repairs it would probably be useful to be able to separate the costs of maintenance due to external deterioration from that of internal deterioration so the improvements in design, protection or material changes and be analyzed based on their own merit. Details of such programs need to be developed. There is no CUF (corrosion under fire proofing) inspection program at RDK.

2.3.4 TA Planning

TA planning appear to be almost exclusively time based, i.e. it is based on predetermined period. Commonly it appears to be a 4year interval between major TA. Sometimes it is extended to 6 years. Not all equipment is opened and internally inspected every SD. There has been no evidence pointing towards using condition based planning. This may lead to under inspection in some cases if the equipment is not effectively assessed, e.g. refer to the above mentioned relatively rare use of NDE methods. Comprehensive information/statistics on LOPC and unplanned outages have not been made available.

It is our opinion that the quality of the inspection programs does not consistently support extended internal inspection intervals if low LOPC frequencies and high availability factors for units are required. Also there is a safety aspect associated with extension of inspections.

Recommendations
Most refineries have converted to condition based or hybrid planning condition based combined with time based planning and risk assessment to determine optimum TA interval. Such programs offer the best reliability and lower program cost. It would be advantageous for RDK to develop such capabilities on ASAP bases. E&D Technologies specializes in implementation of such programs.

2.3.5 Onstream Inspection Programs (OSI Application)

From the available inspection reports, it would appear that almost all inspection is carried out during TA. Little systemic inspection is done during the run. While some hot components are more difficult to inspect onstream this could be optimized to increase the OSI component of the inspection programs to spread the work load more uniformly and provide fresher, more accurate data for maintenance decisions.

Recommendation:
Develop and implement an optimized OSI program.

2.3.6 Use of contemporary NDE techniques to assess condition of equipment

It has been mentioned above that advanced NDE methods have been used sparingly. Methods such as guided wave, phase array (PAUT), tube inspection such as Eddy Current (ET), remote field eddy current (|RFT), Flux leakage (FL), internal rotating Ultrasonic Inspection (IRIS), Borescope, laser or white light., real time radiography, neutron back scatter, profile radiography, infrared scanning, etc. all these and other are available to assess condition of equipment more accurately.

2.3.7 Risk Assessments and Risk Based Inspection (RBI)

Risk assessment matrices have been developed but not used in the inspection program applications. Cursory review indicated that the assessment methodology used has been atypical leading to different result reached when other techniques are applied. This system is not usable in its current development. The plan is to implement RBI by the year of 2020.

Recommendation: Accelerate the RBI development and application with targeted completion by 2018.

2.3.8 Inspection Performance Metrics and KPIs

There has been no evidence of formal, quantified inspection performance measurement.

Recommendations: Develop the basic inspection performance measurements in 2017

2.3.9 Pressure relieving and other safety devices

There is and "homemade program developed and used for RV status monitoring. Its capabilities are relatively limited however it reports on condition of the valve and overdue repairs and appears to be up-to-date. This program hasn't been studied in detail.

Recommendation: Implement one of the most commonly used programs for RV inspection. Most of the commercially available inspection programs will provide greater flexibility and their application considered when refinery documentation system is upgraded.

Table 2.1 DHT UNIT - Summary of Equipment Issues

Category	Equipment		Comment
Equipment with residual life of < 5 y	Fractionator Column	C-1101	Replacement recommended by a Plant change. Sections have been replaced. Exact condition is difficult to assess from existing record. Review situation based on new inspection and good NDE data.
	Gasoil Drier Column	C-1501B	Evaluate if the older recommendation for column replacement is still valid.
	REACs / Aircoolers	E-1102 A,B,C,D	Exchangers shows signs of fouling and corrosion. Possibility of ammonia salt (most likely chloride or chloride bisulfide mix. Corrosion rates are not quantified. Water wash is probably not adequately effective.
	Feed/effluent exch. Cold end	E-1101A	Deposits and corrosion in the cold end of the bundle are possibility.
	SS 316 Lines	63003/04 05	Inspect externally next TA for Cl SCC damage.
	Fractionator Oh' cooler	E-1107 A,B	Overdue replacement of an old bundle.
	Compressor K-1103	E-1113	Shell reported severely corroded. No evidence of replacements found in available inspection files , and appears not replaced
	Vacuum Intercondenser	E-15011	Brass bundle severely fouls and corrodes due to CW corrosion. Frequent replacements (up to 10 replacements in last 20+ years). Carry out RCE on of the corrosion. Install upgraded metallurgy
	Vacuum Intercondenser	E-15011	Shell requires frequent replacements and brass bundle severely fouls and corrodes due to CW corrosion. Frequent replacements (up to 10 replacements in last 20+ years). Carry out RCA; Install upgraded metallurgy
Equipment requiring inspection for environmental cracking		V-1101, V-1102, V- 1103 V-1104	These four vessels have been scheduled for WFMT in 2016. This inspection has been postponed.

Table 2.1 DHT UNIT - Summary of Equipment Issues (cont'd)

Category	Equipment		Comment
Equipment at Risk of HTHA	Feed/effluent exch	E-1101C	Verify for HTHA potential based on actual operating data (temperature and hydrogen pressure trends)
		E-1101 D,E	Risk of HTHA on CS or 0.5Mo components. Verify PMI and actual operating conditions to determine the risk. Use actual historical operating data when making the assessment as well as relevant data of material condition and performance of the material when in such condition (C-0.5Mo material HTHA resistance depends on its fabrication method and thermal history. Coarser grain structures with unstable carbides do not have adequate HTHA resistance). Liner should not be considered as a barrier to Hydrogen penetration.
	REACTOR	R-1101	Data sheet shows A204A – C-0.5Mo materials for shell (some marking on records show CS) Shell with clad with SS liner. Even use of 0.5Mo material may not meet the requirements. Refer to discussion above. Liner should not be considered as an adequate barrier to Hydrogen penetration. Verify shell components by PMI. Based on design data (long term ops data not made available) vessel operates above its relevant Nelson curve. Some extent of HTHA is probable in either case. Due to the age of the vessel this could indicate high risk situation. Diligent attention to the issue is required. Use actual historical operating data when making the assessment as well as relevant data of material condition and performance of the material when in such condition (C-0.5Mo material HTHA resistance depends on its fabrication method and thermal history. In C-0.5Mo structures with unstable carbides do not have adequate HTHA resistance).

Table 2.1 DHT UNIT - Summary of Equipment Issues (cont'd)

http://products.asminternational.org/fach/index.do?search=Molybdenum Cracking in Carbon-Molybdenum Desulfurizer Welds.
Case History involving Material: ASTM A204 grade A, Molybdenum or molybdenum-sulfide alloy steel
Failure Category: Corrosion,
Fracture Failure Type: Hydrogen damage and embrittlement, Intergranular fracture
Welds in two carbon-molybdenum (0.5% Mo) steel catalytic gas-oil desulfurizer reactors cracked under hydrogen pressure-temperature conditions for which hydrogen damage would not have been predicted by the June 1977 revision of the Nelson Curve for that material. As a result of this experience, a major refiner instituted regular ultrasonic inspections of all welds in its Fe-C-0.5Mo steel desulfurizers. Investigation. During a routine examination of a naphtha desulfurizer by ultrasonic shear wave techniques, evidence of severe cracking was found
Hydrogen-Embrittlement Cracking in a Large Alloy Steel Vessel.
Case History involving Material: ASTM A204 grade C, Molybdenum or molybdenum-sulfide alloy steel
Failure Category: Corrosion
Failure Type: Hydrogen damage and embrittlement on the outside surface just above the area of the failure. The vessel was made of ASTM A204, grade C, molybdenum alloy steel. The head was 33 mm (1 in.) thick, and the shell was 59 mm (2 in.) thick. Metallurgical Investigation .

Category	Equipment		Comment
Equipment at risk of elevated temperature corrosion (Sulfidic or naphthenic acid	Feed Effluent exchangers	E-1101 D,E	Any low alloy materials on TS (e.g. TS or channel), which if not clad or lined with high alloy (can't confirm) would be subject to sulfidation corrosion, E the hottest unit in particular.
	Heater	F-1101	Apparently the SS316Cb/(and Ti?) tubes are suffering form internal corrosion as well as embrittlement by stigmatization and cracking (weldment). Same material is apparently being used for repeated replacement. SS316Cb is specialized material, which require narrow chemistry limits to prevent embrittlement. The damage also points towards a poorly designed heater, easily coking and fouling resulting in high tube temperatures
Equipment requiring Inspection for CUI	Gasoil Drier	C-1501B	Severe corrosion has been reported

Table 2.1 DHT UNIT - Summary of Equipment Issues (cont'd)

Category	Equipment		Comment
Injection and Mixing point program			No injection and mixing points assessment and inspection focussed program has been implemented. Injection and mixing points are sources of frequent failures. The most prominent example is the wash water injection point but there may be others.
Critical valve & check valve programs			Check valve(s) on heater outlet lines need to be regularly inspected; no evidence of that happening. No critical valves identified for performance checks.

3. HF Alkylation Unit

3.1 INTRODUCTION

This report summarizes the assessment findings for the RDK Hydrofluoric (HF) Alkylation Unit.
While the refining industry has long shown that HF alkylation units can be operated in a safe and reliable manner, these units are considered to have some of the highest consequence risks. This unit uses liquefied petroleum gases (LPG) and HF acid, which if released in quantity may cause significant fires, explosions and highly toxic hazards. In addition, the unit contains various process streams that if not operated within well-defined safe limits or sufficiently alloyed may result in relatively high rates of corrosion and cracking.

Some examples of corrosion on various pieces of equipment and piping systems noted in this assessment represent characteristics of various operational issues, such as operating at excessive temperatures, e.g., greater than 50°C in carbon steel systems containing free or concentrated HF, acid carry-overs and having water content greater than about 1.5 wt %.

Table 3.1 summarizes areas of concern. Equipment and recommendations listed in this table should be addressed on a priority basis.

3.2 THE MAIN INTEGRITY RISKS

Based on available data:
The highest integrity risks in most HF Alkylation units involves piping systems. This is generally due to the facts that piping systems typically have less initial corrosion allowance than pressure vessels, are more difficult to effectively inspect than pressure vessels, e.g., cannot do internal inspections, and that even small leaks can create highly hazardous conditions. Also, corrosion susceptibility of carbon steel components in HF service is high when the sum of the residual elements, copper, nickel, and chromium is higher than 0.20 wt %. These materials do not seem to be exclusively used for construction/repairs of the piping.

Another potentially high risk in the HF Alkylation unit involves the Recycle Condenser Air Coolers**, E-605A, B, D and E.** These air cooler bundles have required re-tubing after 4 to 12 years of service. Since the last re-tubes were in March 2006 (E bundle has not been re-tubed since 2002) they may be approaching end of life. It should be noted that since the last inspection, conducted in 2012, was only a visual inspection, rather than an IRIS or RFECT examination, little significance should be given to the results of that inspection of the tubes. While most refinery air coolers are not typically considered high risk equipment, these are somewhat unique in that they contain either trace or main HF acid and isobutane, where even a relatively small leak, given the right environmental conditions, could result in a hazardous condition. Most refiners have either chosen not to use air coolers in this service in the initial design of their HF Alkylation units or have modified their units to have shell-and-tube exchangers. While air coolers can be safely operated in this service, frequent, effective inspections are required.

Also**, C-604, the HF stripper** column, may represent a significant risk, particularly an economic risk. Inspection write-ups state that the only corrosion noted since the 1984 replacement of the top head and top shell-can due to internal corrosion has been localized to welds, requiring weld build-up. However, UT measurements taken in April 2012 of the second shell-can from the top shows to have UT measurements down to 11.1 mm. This shell-can was originally 14 mm thick (nominal) with a 3 mm design corrosion allowance. If the 2012 measurements are correct, then this section of the column is currently below the specified minimum required thickness. Because of the corrosive nature of this service, i.e., it operates above 60°C with significant levels of HF, many refiners have chosen to upgrade the upper sections with Alloy 400 (Monel) materials.

3.3 GENERAL COMMENTS

This section of this report covers systemic findings, which are of a general nature and similar for majority of the units which have been analysed. It is covered in the general section of the report.

TABLE 3.1 HF Alky - Summary of Equipment Issues

Category	Equipment	Comment
Equipment with residual life of < 5 y	HF Stripper Column, C- 604	Inspection write-ups state that the only corrosion noted since the 1984 replacement of the top head and top shell can due to internal corrosion has been localized to welds, requiring weld build-up. However, the UT's taken in April 2012 of the second shell can from the top shows to have UT measurements down to 11.1 mm. This can was originally 14 mm nominal with a 3 mm corrosion allowance. UT measurements taken in 1996 show this can to be 13.8 mm. If the 2012 measurements are correct then this section of the column is possibly currently below the specified minimum required thickness. **Recommendation**: Consider evaluating the second shell can from the top for renewal.
	Depropanizer Column, C-605	Although inspection writeups state that there is no significant corrosion other than those areas lace welded in 2002 and 2012, UT measurements taken do not confirm this. In 2002 the measurements showed minimum remaining wall of 9.3 mm below tray-21 and a minimum of 10.2 mm below tray 9. While measurements taken in 2012 do not appear to have been taken in the same areas as those taken in 2002, a remaining wall of 10.4 mm was measured in the upper shell can. Using the design corrosion allowance of 3 mm and the original nominal thickness in these areas it is determined that 10 mm is the minimum required design thickness. **Recommendation**: Perform a thorough ultrasonic of all shell cans above the transition cone and evaluate for corrosion.

TABLE 3.1 HF Alky - Summary of Equipment Issues (cont'd)

Category	Equipment	Comment
Equipment with residual life of < 5 y (cont'd)	HF Acid Cooler, E-604A	This shell has seen significant internal corrosion in its history. It was replaced in 1986 after 14 years. Then in 2001 UT measurements showed that it was at, or below, its renewal thickness. A replacement for the shell was recommended for 2003. No write up of such a replacement was made available to the assessor. Even if it was replaced (which seems likely since the 2012 inspection did not note excessive corrosion) it is now likely approaching end of life based on prior history. Also, in the 2012 write up the inspector noted that the shell had cluster pitting and "cracks forming" which were not repaired. No UT data was made available to the assessor for the 2012 inspection. The 30-70 Cu-Ni tube bundle was last replaced in 2011 after 9 years of service. Based on this information the bundle may require retubing within the next 5 years. Although a short stop was taken in January 2016 and the channel cover was dropped, revealing no issues with the tube ends, the assessor is not showing this as having sufficient coverage to take credit for the inspection. This did not affect the assessor's evaluation of this equipment. **Recommendations**: A thorough inspection and evaluation of the shell should be made to determine if it should be replaced. IRIS or ECT inspect the tube bundle to determine remaining life of the tubes.
	HF Acid Cooler, E-604B	This shell has seen significant internal corrosion in its history. It was replaced in 1986 after 14 years. Then in 2001, UT measurements showed that it was at, or below, its renewal thickness. A replacement for the shell was recommended for 2003. No write up of such a replacement was made available to the assessor. Even if it was replaced (which seems likely since the 2012 inspection did not note excessive corrosion) it is likely approaching end of life based on prior history. Also, in the 2012 write up the inspector noted that the shell had cluster pitting and "cracks forming" which were not repaired. No UT data was made available to the assessor. The 30-70 Cu-Ni tube bundle was last replaced in 2011 after 12 years of service. Based on this information the bundle may require re-tubing within the next 5 years. **Recommendations**: A thorough inspection and evaluation of the shell should be made to determine if it should be replaced. IRIS inspect the tube bundle to determine remaining life of the tubes.

TABLE 3.1 HF Alky - Summary of Equipment Issues (cont'd)

Category	Equipment	Comment
Equipment with residual life of < 5 y (cont'd)	Recycle Condenser Air Coolers, E-605A, B, D and E	These air cooler bundles have required re-tubing after 4 years to 12 years of service. Since the last re-tubes were in March 2006 (E bundle has not been retubed since 2002) they may be approaching end of life. It should be noted that since the last inspection, conducted in 2012, was only a visual inspection, rather than an IRIS or RFECT examination, little significance can be given to the results of that inspection of the tubes. **Recommendation**: Plan to IRIS inspect these bundles and possibly re-tube based on findings. Note that IRIS should be used in lieu of RFECT because pitting corrosion is likely and IRIS is better at detecting and quantifying this type of corrosion than RFECT. Note: since the C bundle was re-tubed in 2011 (later than the other four) it may only need inspecting at this time.
	Recycle Cooler, E-606	This is the original shell, but has seen significant internal corrosion. The remaining wall, basis UT measurements, was 6.89 mm (11 mm nominal with a design corrosion allowance of 3 mm). A calculated renewal thickness of 5.4 mm as determined; however it should be noted that the calculation in the file only took into account hoop stresses and did not look at nozzle reinforcement or saddle stresses (Zick analysis). **Recommendation**: Plan to replace this exchanger shell in the near future.
	Feed Recycle Cooler, E-607	This shell has seen significant internal corrosion - similar to E-606, however this shell appears to have more corrosion allowance than E-606. The minimum thickness found in April 2012 was 9.8 mm (13 mm nominal with a design corrosion allowance of 3 mm). A calculated renewal thickness of 5.4 mm was determined; however, it should be noted that the calculation in the file only took into account hoop stresses and did not look at nozzle reinforcement or saddle stresses (Zick analysis). It should be noted that only 16 UT measurements were documented for entire shell, so it is unlikely that the thinnest area was actually measured. The 70-30 Cu-Ni bundle has had a service life ranging from 9 to 12 years. Since the bundle was last retubed in April 2002, it is likely that the bundle is nearing end of life. **Recommendations**: A thorough inspection and evaluation of the shell should be made to determine if it should be replaced. This should include UT scanning (not just spot UTs) and a complete set of calculations for minimum required thickness.

TABLE 3.1 HF Alky - Summary of Equipment Issues (cont'd)

Category	Equipment	Comment
Equipment with residual life of < 5 y (cont'd)	Feed Recycle Cooler, E-607 (cont'd)	IRIS inspect the tube bundle to determine remaining life of the tubes. This bundle will likely require retubing in the near future.
	Fractionator/Stripper Condenser, E-614	The shell has a historic corrosion rate of 0.22 mm/yr. It was last renewed in 1986. The UT measurements in 2012 showed a remaining wall of 14.78 mm (19 mm nominal). Using the long term corrosion rate, this exchanger will reach end of life in 2021. It is already overdue for its 1/2 -life inspection. The bundle has been retubed three times in its history, with an average life of approximately 10 years. Even using its longest life span, i.e., 13 years, it is already near or at end of life. It should be noted that the last inspection in 2012 was only a visual inspection. **Recommendation**: Both the shell and bundle should be considered for replacement.
	Propane Treater Feed/Effluent Exchanger, E-617	The channel head was documented in 2012 as requiring replacement at the next turnaround, but did not give a specific remaining life. The bundle has had an erratic history of re-tubes (anywhere from 4 years to 12 years), but may possibly be reaching end of life. **Recommendations**: The channel head and bundle should be inspected in the near future. While this is a small exchanger (20 tubes) a leak of the bundle cold result in a reliability issue and a leak of the channel head could result in a leak of LPG.
	Fractionator Stripper Accumulator, V-606	This vessel shell was originally 25 mm nominal with a design corrosion allowance of 3 mm. The 2012 UT measurements show that the vessel has already generally (not localized) lost its design corrosion allowance, with the greatest loss being 5 mm. **Recommendation**: A thorough assessment should be made of this vessel, possibly requiring a complete replacement of the vessel.

TABLE 3.1 HF Alky - Summary of Equipment Issues (cont'd)

Category	Equipment	Comment
Equipment with residual life of < 5 y (cont'd)	Propane KOH Treater, V-610	After having been partially replaced (the bottom section) in 1996, the vessel was completely replaced in 2012 due to significant corrosion in the bottom head. UT measurements taken in December 2013, showed that the new bottom head had already corroded to 13 mm (original thickness was 20 mm, as measured in 2012). This calculates to a corrosion rate of approximately 4 mm per year. Premised on a calculated required thickness of 11.35 mm and the corrosion rate experienced in 2012/2013, this head is already corroded beyond end of life. **Recommendation**: The bottom head of this vessel has potentially already corroded to beyond end of life and should be assessed for possible replacement.
	Piping – Outlet of Fractionator Reboiler Furnace, Circuit 56046	The thickness data from the last inspection in 2011 shows that this circuit is experiencing corrosion. For example, CML 29, a 6" elbow had a thickness of 5.0 mm. Since this component shows to have been renewed in 2002, this calculates to a corrosion rate of 0.22 mm/yr. At this rate this component would reach its designated renewal thickness of 3.50 mm sometime in 2018. **Recommendation**: Consider either inspecting or replacing the 6" NPS components in this circuit.
	Piping – Fractionator Bottoms, Circuits 56029, 56030 and 56050	Most of circuit 56029 has not been inspected since 2011. Based on corrosion rates calculated using measurements taken in 2011 much of this 12", 8" and 4" could already have corroded to near or below their designated renewal thicknesses. While the 6" components of circuit 56030 had thickness measurements taken in 2016, the 8" NPS components have not be measured since 2011. The 2011 thickness data on these 8" NPS components show significant corrosion. In fact, CML 8 may already have corroded to its designated renewal thickness by now. Circuit 56050, the Fractionator Reboil Furnace cross-over piping is showing corrosion. All of the 4" components in this circuit were renewed in 2012. The 6" components have not been renewed since 2001 and showed significant corrosion at their last inspection in 2011. Premised on the UT measurements taken in 2011 these 6" components are currently at, or near, their designated renewal thickness of 4.1 mm.

TABLE 3.1 HF Alky - Summary of Equipment Issues (cont'd)

Category	Equipment	Comment
Equipment with residual life of < 5 y (cont'd)	Piping – Fractionator Bottoms, Circuits 56029, 56030 and 56050 (cont'd)	**Recommendations**: Consider either inspecting or replacing all of circuit 56029 (12", 8" and 4" carbon steel piping), as well as the 8" NPS components of circuit 56030. Consider replacing the 6" NPS components in circuit 56050.
	Piping – Fractionator Overhead, Circuit 56004	Thickness measurements from 2016 show that some of this 8", 3" and 2" carbon steel piping will be below renewal thickness in the next few years. For example, CML 11, an 8" NPS schedule 40 elbow that was last renewed in October 2009 was already down to 5.90 mm in 2016 (a loss of 2.1 in 7 years -- a corrosion rate of 0.7 mm/yr). The designated renewal thickness for this 8" piping is 4.0 mm. **Recommendation**: Consider at least partially replacing this 8", 3" and 2" carbon steel piping system.
	Piping – Top of Acid Settler to Fractionator, Circuit 56003	'he last UT measurements on this circuit were taken in 2016. They showed that this 10" NPS has lost as much as 4.20 mm in the last 10 years (CML 7). With a designated renewal thickness of 4.50 mm this piping circuit was already approaching end of life at that time. **Recommendation**: Consider replacing this 10" carbon steel piping system.
Equipment requiring inspection for environmental cracking		API-751, Safe Operation of Hydrofluoric Acid Units, states that "Pressure vessel walls should be inspected for environmental cracking and blistering using an appropriate technique such as WFMT or shear wave ultrasonic testing (UT)." This is because products of the HF corrosion reaction with carbon steel are iron fluoride and atomic hydrogen. The atomic hydrogen can enter the steel and cause hydrogen blistering, hydrogen embrittlement, and various forms of environmental cracking such as hydrogen stress cracking (HSC), hydrogen-induced cracking (HIC), and stress-oriented hydrogen-induced cracking (SOHIC). The assessor saw no indication where the refinery has done any inspections in the HF Alkylation Unit that would detect such cracking.
Equipment at Risk of HTHA		HTHA is not an issue in the HF Alkylation Unit.
Equipment at risk of elevated temperature corrosion (Sulfidic or naphthenic acid		Elevated temperature corrosion, such as sulfidic and naphthenic acid corrosion, is not an issue in the HF Alkylation Unit.

TABLE 3.1 HF Alky - Summary of Equipment Issues (cont'd)

Category	Equipment	Comment
Equipment requiring Inspection for CUI	Fractionator Column, C-602	Significant external corrosion was found on the 2" nozzle between T3 and T4 (just above the reboil section of the column. A recommendation was made to strip the vessel to inspect more thoroughly for CUI. There is no available documentation showing that this has been done to-date. **Recommendation**: This vessel needs to be inspected for CUI.
	HF Stripper Column, C-604	Some local areas of insulation were removed for inspection2006 with no CUI noted. However, the 2012 inspection noted "severe" corrosion on the skirt and recommended installing reinforcing plates and totally stripping the entire column of insulation to inspect for CUI. This has not been done to date. **Recommendation**: Repair the skirt as required and thoroughly inspect the entire vessel for CUI.
Injection and Mixing point program		In general, the refinery does not have an effective, well-structured inspection program for injection and mixing points
Critical check valve program		The refinery does not have a program for the identification and inspection of critical check valves.

4. FP-2 Unit

4.1 INTRODUCTION

This report summarizes the assessment findings for the RDK FP-2 (Feed Preparation 2) Unit. The FP-2 unit is what many refiners call a Vacuum Flasher. This unit takes its feed of long residue from CD-2 and CD-3. It operates at relatively low pressures, ranging from full vacuum to about 11 or 12 BARG for the side streams. However, the temperatures can be as high as 400°C, as seen at the feed inlet to the fractionation column, C-1.

The primary corrosion mechanisms typically seen in vacuum flashers are high temperature sulfidic corrosion, naphthenic acid corrosion and acid corrosion (commonly found in the upper sections and overhead of the fractionation system). CUI has also been known to be particularly aggressive in insulated equipment and piping located in cooler areas of the unit, typically from the area on the fractionator where the number 2 reflux returns (tray 14 and upward until the equipment is no longer insulated).

Table 4.1 summarizes areas of concern. Equipment and recommendations listed in this table should be addressed on a priority basis.

4.2 THE MAIN INTEGRITY RISKS

Based on available data:
The **highest integrity risk** in this unit appears to be the fractionation column itself, C-1. This vessel has a long history of corrosion in the top section (above tray 11). During the last turnaround (October 2015) the strip liner in the top head was found to be severely corroded and approximately 70% of the liner was replaced. The inspection write up recommended replacing the "top section" during the next turnaround. It appears that the "top section" referred to the 6.5' and 18' diameter sections of the vessel (about 25 feet of the vessel). The 18' to 6.5' reducing head showed UT measurements down to 14.2 mm (nominal - 19 mm with a 3 mm design corrosion allowance). The thinnest measurement in the 18' diameter shell cylinder was 13.4 mm. It must be noted however that one thickness measurement in the transition cone above tray 11 was 15.9 mm (nominal – 25 mm with a 3 mm design corrosion allowance).

Another significant area of concern is with the vapor piping system in the overhead of the fractionation column, C-1. Although some (possibly all) of the 54" NPS portion of this piping circuit was replaced in 2015, the 36" NPS portions have not been renewed since they were replaced in sections during the 1990's. Based on corrosion rate calculations, significant portions of this 36" NPS could reach end of life within the next 5 years.

Also, the bundle for the Pre-condenser Exchanger, 2L-1B, could pose a significant reliability and financial risk. The bundle in this exchanger was last re-tubed in 2012. The typical life of the bundle ranges from 3 years to 10 year with admiralty tubes (B-111-687). Due to the lack of reliability of the tubes, the exchanger parallel to this one was re-tubed in 2015 with titanium tubes. This exchanger has 2054 tubes, thus re-tubing in the future with titanium will be a significant expense.

4.3 GENERAL COMMENTS

This section of this report covers systemic findings, which are of a general nature and similar for majority of the units which have been analyzed. It is covered in the general section of the report.

Table 4.1 FP-2 Summary of Equipment Issues

Category	Equipment	Comment
Equipment with residual life of < 5 y	Pre-condenser, 2L-1B	The bundle in this exchanger was re-tubed in 2012. The typical life of the bundle ranges from 3 years to 10 year with admiralty tubes (B-111-687). Due to the lack of reliability of the tubes, the exchanger parallel to this one was re-tubed in 2015 with titanium tubes. This exchanger has 2054 tubes thus re-tubing in the future with titanium will be a significant expense. **Recommendation**: Consider re-tubing this exchanger bundle with Titanium tubes.
	Vacuum Column, C-1	This vessel has a long history of corrosion in the top section (above tray 11). The last inspection (October 2015) found the strip liner in the top head severely corroded and replaced approximately 70% of the liner. The inspection write up recommended replacing the "top section" during the next turnaround. It appears that the "top section" referred to the 6.5' and 18' diameter sections of the vessel. The 18' to 6.5' reducing head showed UT measurements down to 14.2 mm (nominal - 19 mm with a 3 mm corrosion allowance). The thinnest measurement in the 18' diameter shell cylinder was 13.4 mm. It must be noted however that one thickness measurement in the transition cone above tray 11 was 15.9 mm. The wall thickness behind the stripped lined portions were not provided. Also, Draw Deck A (below the bottom tray) was found in 2015 to be completely collapsed. It was temporarily repaired, but was recommended for replacement at the next turnaround. This deck is 12% Cr and is approximately 25' in diameter. The assessor is unable to determine the as-repaired condition of tray due to the lack of information in the inspection write up. A more complete assessment should be made prior to replacing. **Recommendations**: Consider replacing the upper approximately 25' of this vessel with alloy clad material. This section of the vessel is comprised of a 6.5' diameter section and an 18' diameter section. Also, evaluate the upper transition cone for replacement. If so, consider using alloy clad material for this as well.

Table 4.1 FP-2 Summary of Equipment Issues (cont’d)

Category	Equipment	Comment
Equipment with residual life of < 5 y (cont’d)	Vacuum Column, C-1 (cont’d)	Assess the 2015 as-repaired condition of Draw Deck A (approximately 25' in diameter) and determine if it needs to be replaced. If so, use 12% Cr material.
	Piping: C-1, Vacuum Column, Overhead Piping, Circuit 22120	Although some (possibly all) of the 54" NPS portion of this circuit was replaced in 2015, the 36" NPS portions have not been renewed since they were replaced in sections during the 1990's. Based on corrosion rate calculations significant portions of this 36" NPS could reach end of life within the next 5 years. **Recommendation**: Evaluate the 36" NPS portions of this circuit for possible replacement.
	Piping: Transfer line from Charge Heater to C-1, Circuits 2221A and 2221B	All six of the 8" NPS CMLs for these two piping circuits are shown to have been below the required thickness documented in the PIRS database at the time of the last inspection in 2015. The minimum UT measurements on these elbows range from 2.40 to 2.80 mm while the documented required thickness in PIRS is 4.00 mm. The nominal thickness for these schedule 10S components is 3.75 mm, indicating that they have lost wall thickness. This could be attributed to faulty measurement techniques or actual corrosion. Although the strength and toughness of stainless steel material is superior to that of standard carbon steel materials sufficient thickness must still be available to provide structural integrity. **Recommendation**: Perform a thorough design assessment of these two piping circuits to determine the appropriate minimum allowable thickness. Also, perform a thorough inspection of the systems to verify the remaining wall thickness.
	Piping: Outlet of Reflux Drum-3, Circuit 2272B	Thickness measurements taken of CMLs 3 and 8 of this circuit in 2015 show that significant loss of wall thickness has occurred. CML 8, a 6" NPS elbow shows to have a remaining wall of 2.50 mm while the minimum required thickness shown for this component in PIRS is 3.50 mm. **Recommendation**: Analyze this piping system and develop an appropriate required minimum thickness for these components to maintain structural integrity. Thoroughly inspect this circuit to determine the actual condition. If the thinning illustrated by the UT measurements taken in 2015 are accurate, then it is further recommended that circuits 2272 and 2272A be re-inspected since they are in the same service as 2272B.

Table 4.1 FP-2 Summary of Equipment Issues (cont'd)

Category	Equipment	Comment
Equipment requiring inspection for environmental cracking		In general, the review of this unit did not disclose any significant deficiencies in the refinery's inspection program for detecting environmental cracking in this unit.
Equipment at Risk of HTHA		HTHA is not an issue in the FP-2 Unit.
Equipment at risk of elevated temperature corrosion (Sulfidic or naphthenic acid		In general, the review of this unit did not disclose any significant deficiencies in the refinery's inspection program for detecting elevated temperature corrosion other than those noted elsewhere in this report.
Equipment requiring Inspection for CUI	Crude to Reflux-3 Exchangers, 2T1-J and K	The 2015 inspection reports for these two exchangers noted external scattered pitting (CUI) and recommended completely stripping the shell and heads at the next turnaround for inspection and coating. **Recommendation**: Since exchangers J and K are the coolest operating in this series of 10 exchangers, consider stripping them to inspect for CUI. If any significant CUI is found, consider also inspecting G and H.
Injection and Mixing point program		In general, the refinery does not have an effective, well-structured inspection program for injection and mixing points.
Critical check valve program		The refinery does not have a program for the identification and inspection of critical check valves.

5. NHT Unit

5.1 INTRODUCTION

This report summarizes the assessment findings for the RDK Naphtha Hydrotreating Unit.

This unit takes its feed from the CD-3 unit. Figure 5.1 shows PDF of the unit. The feed is unstabilized gasoline (naphtha), which contains sulfur and nitrogen. The sulfur in the feed can lead to corrosion, both from salts (H_2SOx) and high temperature sulfidic corrosion (at temperatures above approximately 270°C). In the reaction part of this process the nitrogen in the feed is partially converted into ammonia (NH_3) which can form corrosive salts at the point of condensation, resulting in ammonium chloride and ammonium bisulfide corrosion. The reaction section of this unit operates at moderately high pressures and temperatures, e.g., 25 BARG at 380°C.

Table 5.1 summarizes areas of concern identified in this assessment. Equipment and recommendations listed in this table should be addressed on a priority basis. Section 5.2 describes three major items to address. An excel spread sheet which provides assessment criteria and evaluation scheme is also provided in the appendix.

5.2 THE MAIN INTEGRITY RISKS

Based on available data:
Hydrotreating units are commonly known for their potential to have significant corrosion in the outlet piping of the reactor effluent air coolers (E-1307). Per the data provided, 8 of the CMLs being monitored in this system have less than 5 years of remaining life. CML 1, 8" NPS, now has a remaining calculated life of less than one year. In fact, it is likely that other points are in similar condition but this fact is being hidden because all the thickness measurements have been taken using spot UT techniques. The likely damage mechanism for this piping circuit is NH4HS (ammonium bisulfide) which can be very localized and difficult to detect using spot UT.

Another integrity risk in the NHT involves V-1301, the High Pressure Separator. In April 1977, the sump on this vessel was replaced due to H2 blistering (no PWHT was done to the repairs). Then in April 1989, the vessel welds were 100% examined with WFMPT, with numerous cracks being found. Most of these cracks were superficial and ground out in shallow depths less than the corrosion allowance and were not weld repaired. However, cracks found in the sump welds were determined to be 11 - 12 mm in depth and after being ground out were weld repaired and (again as in 1977) no PWHT was done. Since that time the vessel has been internally coated with coal tar epoxy. However, failures of the coating have been noted, as in June 2004 when approximately 10 M2 of the coating was found to be "blistered" and required replacement. Failures of this coating expose the metal surface to a potential crack inducing environment, particularly since this vessel is fabricated from non-HIC (hydrogen induced cracking) resistant materials and is not post weld heated.

Also, the channel head for E-1306, the hottest Feed to Effluent Exchanger, may be susceptible to HTHA (High Temperature Hydrogen Attack). The conditions on the PFD show a reactor outlet temperature of 380°C at 22 BARG. Assuming a H2 partial pressure of 75% (18 BARG), this means that the head operates approximately 65°C above the current carbon steel Nelson curve for PWHT carbon steel (the curve currently recommended for C-1/2Mo materials). According to the documentation provided, no examination for this mechanism has ever been conducted.

5.3 GENERAL SYSTEM FINDINGS

This section of this report covers systemic findings, which are of a general nature and similar for majority of the units which have been analyzed.

Table 5.1 NHT Summary of Equipment Issues

Category	Equipment	Comment
Equipment with residual life of < 5 y	Feed to Effluent Exchanger, E-1306	Shell: This shell was replaced in 1/96, after approximately 24 years of service, due to corrosion of the shell near the 18" outlet nozzle. Due to the operating conditions of this exchanger this corrosion is apparently high temperature H_2/H_2S corrosion, for which the 1 Cr material provides little more resistance than carbon steel. While thickness measurements taken during the 6/04 inspection showed no significant corrosion, there were no measurements shown to have been taken in the area most susceptible to this corrosion mechanism, i.e., near the outlet nozzle (the hottest area of the shell). Based on the earlier life of this shell, unless the corrosion rate has decreased, this shell, which is now 21 years old, may be approaching end of life and should be thoroughly inspected. Bundle: This bundle has had a history of vibration fatigue tube failures. An additional baffle was installed near the floating tube sheet in 12/83, however this apparently did not completely arrest the issue since subsequent tube failures have occurred. Since the current bundle has been in service since 2004 (12+ years) it is possible that a vibration fatigue failure of the tubes may occur in the near future. The Eddy Current examination scheduled for the 2017 turnaround should only be expected to identify a problem if the cracking has already been initiated, which will only occur in the very final stages of tube life. **Recommendation**: Perform a thorough UT examination of the shell and nozzle in the area of the 18" outlet nozzle.
	Effluent Air Coolers, E-1307 D, E and F	Each of these six air coolers, E-1307 A –F, have been re-tubed several times in the past, for an average life ranging from 6 to 9 years. The last re-tubes were in 2004 for exchangers A, C, D and F and in 2007for B and E. Then during the March 2017 turnaround all six bundles were inspected using RFECT. Bundles A, B and C were said to have severe corrosion and were retubed, while bundles D, E and F were reported to be in good condition. The results for D, E and F seem questionable. Also, the use of RFECT for these inspections was not optimum in that this technique is not considered reliable for quantifying the pitting type corrosion to which these bundles are susceptible.

Table 5.1 NHT Summary of Equipment Issues (cont'd)

Category	Equipment	Comment
Equipment with residual life of < 5 y (cont'd)	Effluent Air Coolers, E-1307 D, E, F (cont'd)	**Recommendation**: Either inspect bundles D, E and F using IRIS or re-tube these air cooler bundles.
	High Pressure Separator, V-1301	In April 1977, the sump on this vessel was replaced due to H2 blistering (no PWHT). The lower portion of the shell and heads of this horizontal vessel have "crater" pitting approximately 1-1/2 mm deep. In April 1989, the vessel welds were 100% examined with WFMPT. Numerous cracks were found. Most of these cracks were superficial and ground out in shallow depths less than the corrosion allowance and were not weld repaired. However, cracks found in the sump welds were determined to be 11 - 12 mm in depth and after being ground out were weld repaired (again as in 1977) no PWHT was done. Since that time, the vessel has been internally coated with coal tar epoxy. However, failures of the coating have been noted, as in June 2004 when approximately 10 M^2 of the coating was found to be "blistered" and required replacement. Also, in June 2004 and subsequently in April 2010 four 2" nozzles were found to be thinning (apparently from not being able to be coated with the coal tar epoxy well). These were recommended to be renewed at the next turnaround. **Recommendation**: Consider replacing this vessel with one that is fabricated from HIC resistant steel and post weld heat treated, rather than rely on a coating solely for protection.
	Low Pressure Separator, V-1302	This vessel was internally coated in 1977, but by 4/89 the coating had failed. In 4/89 corrosion was noted in the bottom of the shell (horizontal) and sump, .5 - 1.3 mm deep; and 4-2" nozzles required "repair" due to corrosion. Also in 1989, WFMPT was performed and detected "many" cracks. These cracks were ground out apparently within the corrosion allowance and were not weld repaired except for the sump weld which was ground out and rewelded, but not PWHT'd). The vessel was recoated with coal tar epoxy. But by June 2004 the coating had once again failed (approximately 90%). The vessel was then recoated in April 2010. **Recommendation**: Carry out FFS assessment or consider replacing this vessel with one that is fabricated from HIC resistant steel and post weld heat treated, rather than rely on a coating solely for protection.
	Piping: Feed to Charge Heater, Circuit 73002	Per the data provided, some of this piping was replaced in 2000 and other portions were replaced in 2004. CML 17 was measured in May 2015 and has a remaining corrosion allowance of only 0.8 mm. Since this section of the piping system was replaced in 2004, this would suggest an on-going corrosion rate of 0.25 mm per year. With a specified renewal thickness of 3.5 mm, this would result in a remaining life of less than four years from the 2015 inspection date,

Table 5.1 NHT Summary of Equipment Issues (cont'd)

Category	Equipment	Comment
Equipment with residual life of < 5 y (cont'd)	Piping: Feed to Charge Heater, Circuit 73002 (cont'd)	i.e., a renewal date of 2019. This corrosion rate is not surprising given that the piping is fabricated from 5% Cr material. The Couper-Gorman curves used for predicting corrosion rates due to H_2/H_2S gives no credit for resistance of 5% Cr materials to corrosion than carbon steel. It should be noted that the 18" NPS components were fabricated from schedule 60 material (nominal thickness 19 mm) and thus has significantly more corrosion allowance than the 6" components, thus should still have significant remaining life. **Recommendation**: Consider replacing the 6" NPS components in this piping system with 9% Cr material which is significantly more resistant to H_2/H_2S corrosion than 5% Cr.
	Piping: Reactor Effluent to Air Coolers, Circuit 73004	Per the data provided, there is at least one CML (6) which is currently below its designated renewal thickness, one CML (9) with only 0.3 mm corrosion allowance (in May 2015) and two others (12 and 13) with less than 1 mm of corrosion allowance remaining. This piping system has had numerous partial replacements in the past (1995, 1996, 1998, 2000, 2001 and 2004). The damage mechanism is likely NH4CL (ammonium chloride) corrosion. Numerous dead leg components are not set up as CMLs and therefore, while susceptible to this damage mechanism, are not being regularly inspected. **Recommendation**: Consider replacing this entire piping system.
	Piping: Effluent Air Cooler Outlet Piping, Circuit 73006	Per the data provided, 8 of the CMLs being monitored have less than 5 years of remaining life. CML 1, 8" NPS, now has a remaining calculated life of less than one year. In fact, it is likely that other points are in similar condition but this fact is being hidden because all the thickness measurements have been taken using spot UT. The likely damage mechanism for this piping circuit is NH4HS (ammonium bisulfide) which can be very localized and difficult to detect using spot UT. **Recommendation**: Consider replacing this entire piping system. Also, when inspecting this system, spot UT should not be utilized, rather use more general scanning techniques such as profile radiography or automated UT.
	Piping: Liquid off the Low Pressure Separator, Circuit 73019	Premised on the thickness data taken in 2015 this circuit is experiencing significant corrosion (approximately 0.31 mm/yr). Given this corrosion rate, much of this 8" piping system is at, or near, its designated renewal thickness. **Recommendation**: Consider replacing the piping in this circuit.

Table 5.1 NHT Summary of Equipment Issues (cont'd)

Category	Equipment	Comment
Equipment requiring inspection for environmental cracking	Recycle Gas Knock Out Drum, V-1303	Although this vessel may be susceptible to Wet H_2S Cracking no documentation of WFMPT is available. **Recommendation**: Perform WFMPT of all internal weld surfaces in the lower 1/3 of this vessel. If no cracking is found, consider recoating. If cracking is found, consider replacing this vessel with one fabricated from HIC resistant material and post weld heat treat.
Equipment at Risk of HTHA	Feed to Effluent Exchanger, E-1306	Channel Head: According to the HTHA (High Temperature Hydrogen Attack) spreadsheet provided, this head operates at 309°C / 363 psi partial pressure of H2. This information does not correlate with those operating conditions shown on the process flow diagram (PFD) or original specification document provided. The conditions on the PFD show an Rx outlet temperature of 380°C at 22 BARG. Assuming a H2 partial pressure of 75% (18 BARG), this means that the head operates approximately 65°C above the current carbon steel Nelson curve for PWHT carbon steel (the curve currently recommended for C-1/2Mo materials). Under these operating conditions this head may be susceptible to HTHA. According to the documentation provided, no examination for this mechanism has ever been conducted. It should be noted that current thinking does not distinguish carbon steel from the C-1/2Mo material that this head is constructed from. Also, although this head is clad with stainless steel, while API-571 recognizes that such cladding can reduce the H2 partial pressure which is exposed to the base material, it also states that most refiners give little credit to such cladding for preventing HTHA.
Equipment at risk of elevated temperature corrosion (Sulfidic or naphthenic acid		While the refinery appears to have an effective program for monitoring for elevated temperature corrosion in the NHT it should be noted that the 5% Cr piping materials associated with the charge heater a likely much less resistant to corrosion than the designers understood. The Couper-Gorman curves used for predicting corrosion rates due to H_2/H_2S gives no more credit for resistance of 5% Cr materials to corrosion than carbon steel. In such cases, it is recommended that at least 9 Cr materials be used.
Equipment requiring Inspection for CUI	Feed to Effluent Exchangers, E-1301 and 1302.	Given the temperature range of the shells and channel heads, these exchangers are likely susceptible to CUI. There is no documented evidence that any CUI inspections have been conducted. Recommendation: Perform a thorough CUI inspection of these shells and channel heads.
Injection and Mixing point program		In general, the refinery does not have an effective, well-structured inspection program for injection and mixing points.
Critical check valve program		The refinery does not have a program for the identification and inspection of critical check valves.

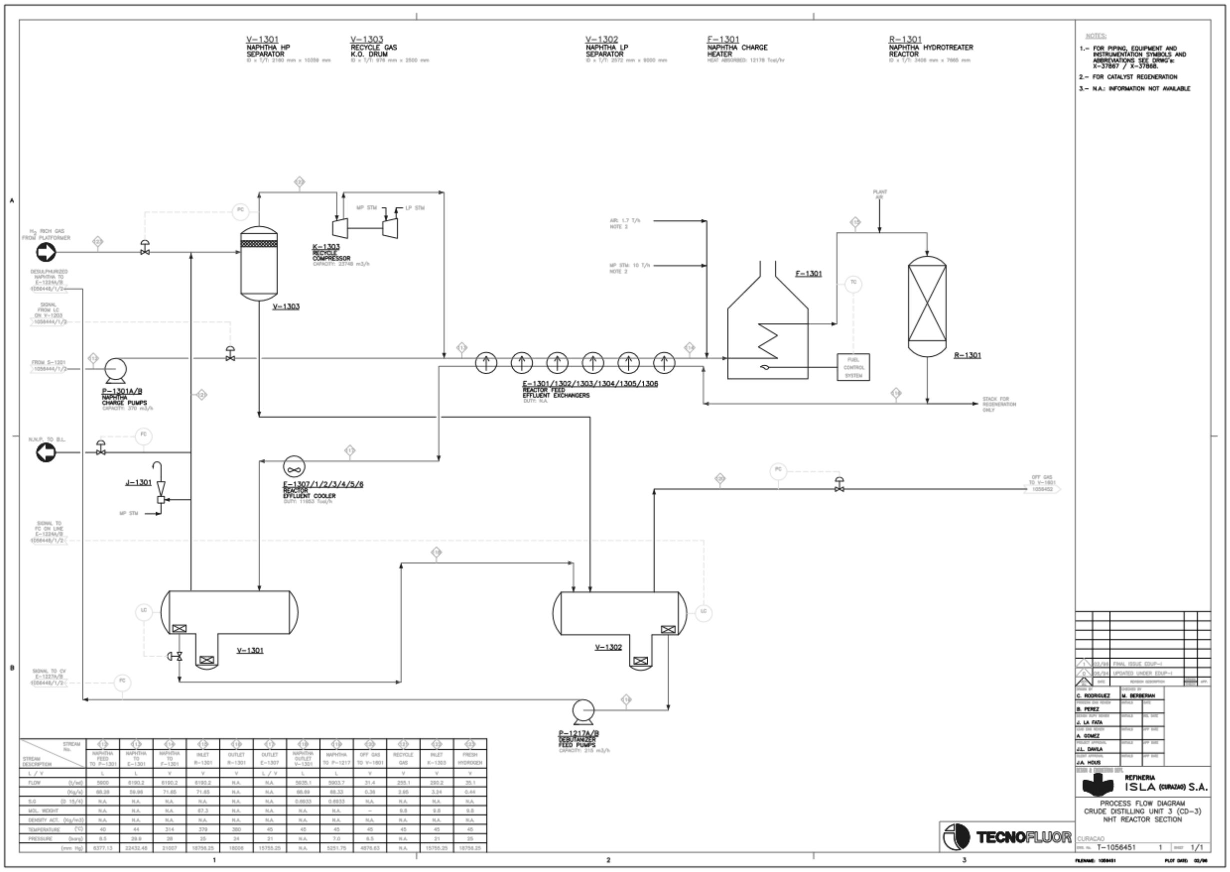

Figure 5.1 PDF of NHT Unit

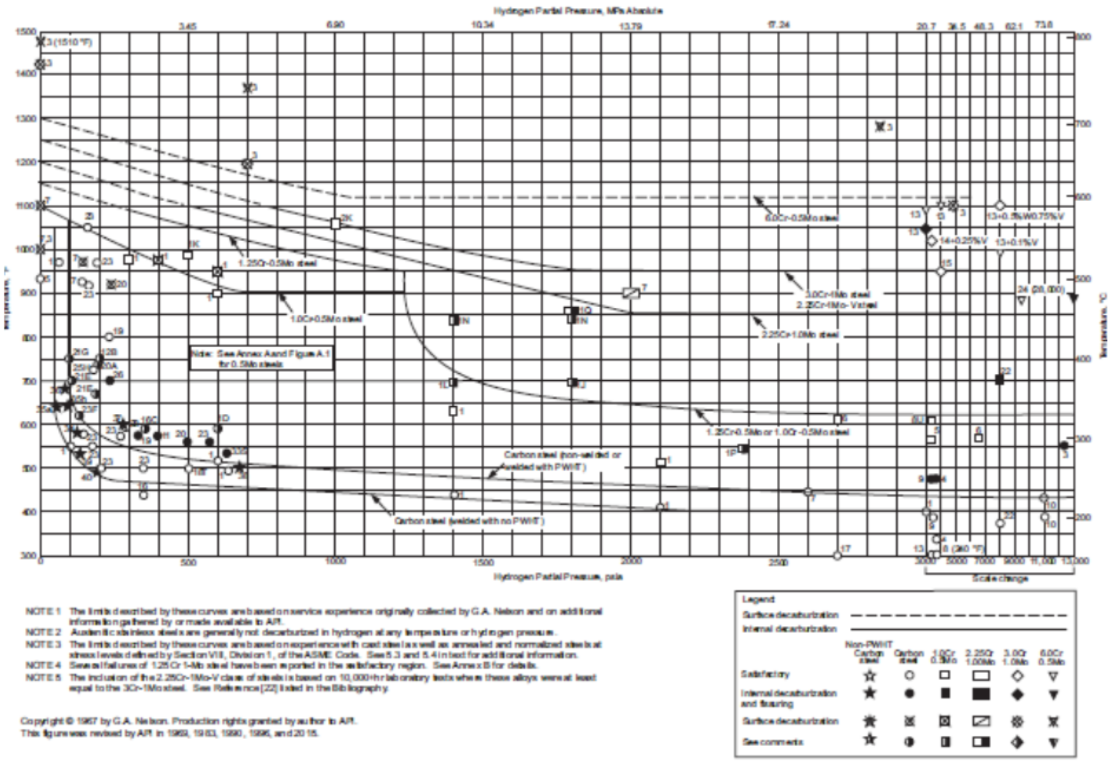

Figure 5.2 Operating limits for steels in hydrogen service to avoid HTHA (ref. API RP 941 Figure 1)

6. VGO MHC

6.1 INTRODUCTION

The following report summarizes audit findings for RDK VGO-MHC Unit (Mild Hydrocracker - 1500 series equipment). This unit treats streams from Lube oil/Furfural Units, FP 1&2, Flashed distillates and bottoms from both TC Units and form FP 1 and 2, essentially preparing the feed for FCCU. Refinery Process Handbook also mentions side streams from HV 6 and 7 but newer bloc diagram does not show such streams. This Unit reduces organic Sulphur and Nitrogen content and to some degree heavy metals in the feed stock to meet the specifications of the FCCU feed. Hydrogen needed in the process is supplied from a SMR type hydrogen plant and is supplemented by Reformer hydrogen.

Product of the unit is Vacuum Gas Oil for further cracking in FCCU for Mogas and Avgas production and naphtha stream for treatment at NHT. Streams with H2S gas and sour water are by-products, converted into elemental sulfur in SWS/Amine Unit and Sulfur Recovery Units.

Generally, corrosion rates in the unit are not excessive, at least not in recent years. One of the reason for low corrosion rates may be relatively low loading of the refinery resulting in lower throughout and lower concentration of corrosive compounds. This however may change if ISLA’s plans to process higher Sulfur and Nitrogen feeds in future are realized. Unit conversion capability is limited and to meet product specifications will downgrades in feed quality will also have to be limited. Notwithstanding the feedstock quality changes should be monitored, understood and included in the integrity monitoring plans.

First section of this report covers systemic findings, which are of more general nature and quite similar to the majority of the other Units, which have been analyzed. Since the inspection process is developed and administered by the same group only relatively small differences in the systemic issues has been found amongst the Units assessed during this review.

The Table 6.1 summarizes areas of concern based on the type of issue, such as short residual life, susceptibility to certain type of damage etc. Equipment and recommendations listed in this table should be addressed on priority basis.

6.2 THE MAIN INTEGRITY RISKS

Based on available data:

First integrity risk could be the condition of the cold end of the REACS (Reactor Effluent Air Coolers) E1502. Corrosion is not well controlled nor the inspection program able to assess their condition adequately. REAC corrosion is a weak spot of most hydrocracking units and should be receiving close attention. Corrosion in these systems can be localized and at times severe. The most frequent damage is caused by Ammonium Chloride salt deposits or Ammonium Bi-sulfide in high velocity and turbulence areas. Numerous failures have occurred in these REAC systems. Since information on the precursors to the corrosive compounds hasn't been available we could not quantify the corrosion risks. Water wash is commonly utilized to dilute or prevent deposition of the ammonium salts but it effectiveness depends very much on the injection system design and operation and wash water application and quality. Guidelines for design and operation of such systems are available. We did not locate comprehensive design data for this WW system. Example of targets for acceptable corrosion rates are shown below in Fig. 6.1

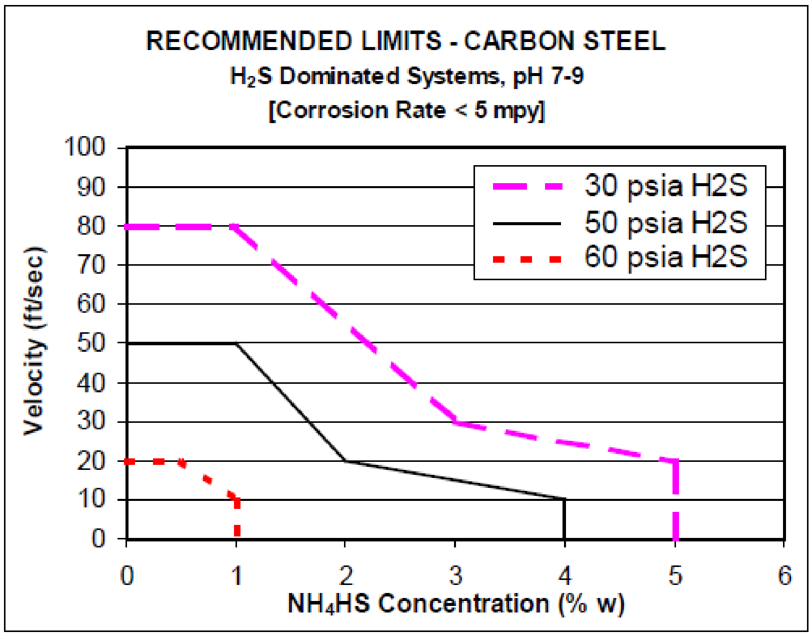

Figure 6.1 Targets for ammonium bisulfide corrosive parameters, acceptable corrosion rates

Inspection group appears not to have any responsibility for monitoring of the key parameters of this injection system. Also details of the WW system design have not been available in inspection. Corrosion is often localized and difficult to detect. Inadequate wash water system will not reduce the corrosion risk to the desired levels. Without having process data available we would estimate that the main risk would come from Ammonium chloride salts corrosion. Ammonium bisulfide concentration may not be high enough in this unit to cause severe corrosion but this is just "an educated guess".

Proper data are needed to assess corrosion risks in these systems accurately. For example of ammonium salt deposition curves refer to the Fig. 6.2 below. These are approximate; more flexible and more accurate models are available.

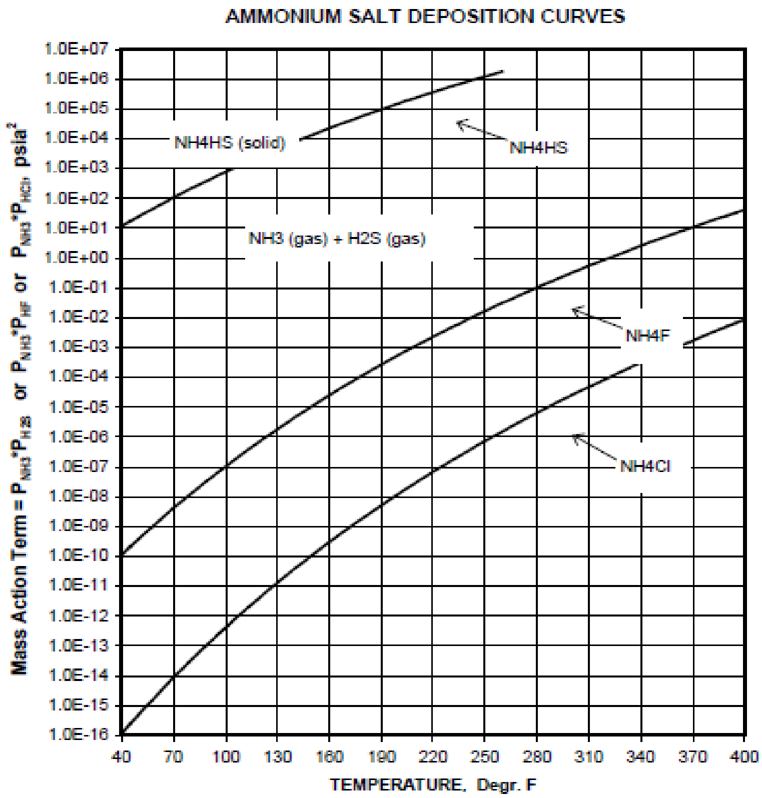

Figure 6.2 Ammonium Salts De-sublimation Curves

Second Integrity risk can be represented by V-1501 HP Separator, which operates in high hydrogen charging and corrosive environment. It is being patched with coatings of questionable effectiveness. (Inspection group is persuaded of the coatings effectiveness although this is probably unique approach. ED Technologies specialists are not aware of any other plant using similar coatings in similar services) Hydrogen. HIC cracking has been detected but its seriousness doesn't appear to be thoroughly assessed. Thorough inspection and FFP assessment of the vessel is recommended to ensure it is free of serious HIC damage and fit for service.

Other risks can be the generally poor performance of both furnace coils. Compared to the industry, replacement rates of the tubes are high. Some of the damage can again, be ascribed to the high sulfur pitch fired in theses heaters. Despite the high sulfur fuel used if the SS 347 material is delivered and installed in appropriate condition to its operating modes damage due to the PASC damage should be low. Closer attention should be paid to the damage mechanism as well as to the condition (chemistry and heat treatment) of the tubes installed. Methods to minimize PASC damage are available. Catastrophic damage (leak) in a tube may lead to a backflow and to emptying the reactor content through the heater, resulting in its destruction. We were not able to locate a check valve on the heater outlet (outstanding action!), which would be capable of preventing the back flow. Another caveat with these check valves is that they tend to foul and get stuck in open position even after a few weeks in operation. About 15y old study by SIOP of all Shell refineries resulted in finding over 60% of these valves stuck in open position. Both design and location of the valves is key to assure their function. These valves should be on critical valve list and inspected as frequently as necessary to assure that they are functional.

Also there is a possibility of ammonium salt deposits and corrosion already in the cold end of the E-1568. Corrosion history is spotty so mainly the chloride content should be monitored and related to the temperature profile of the exchangers. De-sublimation/ deposition temperatures of the salts can be assessed relatively accurately with modern models. This can be monitored and corrosion reduced or even prevented. More details on other equipment is listed in Table 1 below.

6.3 GENERAL COMMENTS

RECORDS & DOCUMENTATION QUALITY AVAILABILITY, MATERIAL LISTS OR MSDS (REPORTS, EQUIPMENT ANALYSIS, DRAWINGS ETC.)

6.3.1 Pressure Equipment (Vessels, exchangers, air coolers and heaters)

A) Inspection Sketches

Record keeping by ISLA inspectors is currently in form basic inspection observation notes, which are written into a SAP module and then inserted into an equipment file in paper form. Observations are summarized in TA reports. Observations available in the inspection files discuss mostly results of visual inspections. Wall thickness (W.T.) measurements if available are usually referred to as “satisfactory”, but sometimes without actual measurement record.

Since trending of wall thickness measurements is not done, quantitative estimates of residual life cannot be effectively done either. Measurements are sometime indicated on make-up sketches, however this doesn’t happen consistently and they are almost never trended. Older files show use of dedicated inspection sketches. These however do not show the open shell envelop to locate the CML accurately. System of centralized UT and other NDE program results appears not to be available for equipment such as pressure vessels, columns, heaters and heat exchangers. It is unclear how estimates of residual life are done with any degree of accuracy. In many (most?) cases inspection is not based on well understood corrosion or degradation mechanisms and how they relate to operating conditions. *Refer also to assessment of the Special Emphasis* Programs.

Without having standardized comprehensive system of inspection drawings / sketches dedicated to the NDE record it is in our opinion nearly impossible to assess progress of changes in equipment condition in a quantitative way and to predict residual life with a measure of accuracy or do the effective NDE planning. Most operators use sketches with level of detail corresponding to simplified GA drawing of equipment to identify areas of measurement or observed damage and repairs. In the ISLA system, we didn’t find standardized equipment inspection sketches, which would show the general configuration, materials, operating conditions and key appurtenances and, which could be used to define location of NDE measurement or specific damage. Also, we found in number of cases that inspection report from one SD is copied to another SD almost verbatim. Quality of the inspection could be improved by use of standardized inspection plans,

B) Bundle Inspection

Only visual inspection of bundles and tube ends is usually reported. In the VGO-MHC unit essentially no internal tube inspections is done using either borescopes, eddy -current, IRIS or similar quantitative techniques. Tube removal and splitting to assess condition are apparently also not practiced. No measurement trending is done during bundle inspection either. It is our opinion that accuracy of the bundle life prediction without doing quality internal tube inspections is expected to be low. This may lead to either unplanned leakage or premature replacements.

C) Fabrication and Material Records
Fabrication records such a drawings and design information (data sheets, calculations, welding and heat treatment procedures etc.) are available for some files only. It is also difficult to identify reliably actual materials of construction. Copies of the drawings are, if available, sometimes not legible. Good records should allow to retrieve basic information in matter of seconds.

D) Standardized Inspection Procedures
Records of inspections appear not to follow standardized procedures. Such procedures would be useful to ensure that the inspections are carried out consistently and thoroughly and the records and conclusions relevant for future planning.

> **Recommendation for Pressure Equipment:**
> Update or develop a system of standardized inspection sketches, and inspection procedures, which can be utilized for the purpose of planning NDE inspections, UT thickness measurements (TMLs and CMls) and repair definition. And TA. In case of piping this has been done and piping sketches have been prepared and are used for the above purpose.
>
> Wall thickness measurements should be kept in a computerized central record register/ data bank. Develop standardized data sheets which would summarize whatever relevant information can still be located in refinery archives and other sources, like personal files etc.
>
> Current standards for TA planning contain a major component of condition based decisions, i.e. equipment is included in the maintenance program bases assessment of its actual condition and the risk it represents for Operations. This is much more effective approach to plant efficiency compared to the simple time based inspection.
>
> E&D Technologies specialize in development of such plant inspection programs based on detailed corrosion analysis of process units. Proposals for or development of such inspection systems can be prepared for RDK management upon request.

6.3.3 Piping

In case of piping the PIRS (Piping Inspection Records System) this system uses inspection sketches discussed above, which show CML / TML locations. This is available for piping only however. The system is developed in adequate detail and is suitable to communicate measurement locations and areas requiring repairs o replacements. Results of piping wall thickness measurements are recorded in spreadsheets of the PIRS system (MS AXES based).

Corrosion rates are calculated and residual life estimated bases of simple arithmetic extrapolation of data. No other more complex data manipulations such as risk assessment or statistical evaluations are performed by PIRS.

CMLs are assigned based on historical experience without a benefit of corrosion analysis. This may lead to significant over inspection in areas where little or no internal corrosion takes place and under-inspection in areas of active corrosion. Also the system of queries and reports allowing analyzing data in different ways such as "what if…" type of queries is limited. No statistical evaluations or measurement quality assessments are available in this system.

Notwithstanding some of the shortcomings, implementation of PIRS has led to a very substantial improvement in piping reliability since the time it has been implemented.

While piping inspection programs are significantly more structured compared to the pressure equipment it still lags behind contemporary standards of risk based concepts and more complex evaluations of data.
Key component of piping inspection, exchanger bundles and also pressure equipment, is the knowledge of relevant corrosion mechanisms and parameters, which influence them. Such comprehensive analysis allows to focus on areas of active corrosion and distribute the inspection effort more effectively, i.e. help to prevent missing those areas, which require more intensive coverage and reduce inspection intensity in areas, where corrosion in not taking place.

The PIRS system has been claimed to cover now all key process piping systems. While its usefulness is undisputable the system still contains some errors and inaccuracies and would benefit form a QC review.

Recommendations for Piping:
Develop an inspection program based on assessment of active corrosion mechanisms and assessment of risk each such situation represents.

First step in development of knowledgeable based corrosion & Inspection system is assessment of individual process loops. Subsequent steps consist in implementation of the following programs:

1. Appropriate grouping lines and equipment into loops (development of corrosion loops and Material Selection Diagrams with all relevant information needed for corrosion analysis).
2. Corrosion assessment of the loops.
3. Development of parameters influencing corrosion and setting of integrity operating windows (IOWs).
4. Development of inspection/NDE programs for uniform and localized corrosion.
5. Development of inspection/NDE for dead-leg corrosion.
6. Inspection programs for injection/mix point corrosion.
7. Inspection/NDE of vents and drains (small connections)
8. Inspection of critical valves and check valves (similar to the RV inspection program)
9. Relief valves are covered by a separate basic inspection and maintence program, which is in place and appears functional but it has not been evaluated in detail.

6.3.4 CUI Programs

We have noted that since approx. 2015 the maintenance and inspection group are engaging in a more extensive piping external corrosion programs. It is likely that units, which have been shut down for turnarounds in 2016 and 2017 have their piping inspected and repaired. Since a comprehensive CUI program is not specifically defined in writing it is not clear what criteria are sued to decide on equipment repair and how effective such program is even though the plan for repairs of piping external corrosion for example in CD-3 area for the Spring 2017 TA appeared to be quite significant.

Development of specific inspection programs for corrosion under insulation (CUI) is in most plants know to E&D are usually carried out as parallel to the internal corrosion monitoring but separately administered programs. Most of the external corrosion detection can be done during operations and it is independent of operations. In case of RDK, where CUI is a major component of piping system repairs it would probably be useful to be able to separate the costs of maintenance due to external deterioration from that of internal deterioration so the improvements in design, protection or material changes and be analyzed based on their own merit. Details of such programs need to be developed.

6.3.5 TA Planning, Frequency of Equipment Inspections

TA Planning
TA planning appear to be almost exclusively time based, i.e. it is based on predetermined period. Commonly it appears to be a 4year interval between major TA. Sometimes it is extended to 6 years. Not all equipment is opened and internally inspected every SD. There has been no evidence pointing towards using condition based planning. This may lead to under inspection in some cases if the equipment is not effectively assessed, e.g. refer to the above mentioned relatively rare use of NDE methods. Comprehensive information/statistics on LOPC and unplanned outages have not been made available.

It is our opinion that the quality of the inspection programs does not consistently support extended internal inspection intervals if low LOPC frequencies and high availability factors for units are required. Also there is a safety aspect associated with extension of inspections.

Recommendations
Most refineries have converted to condition based or hybrid planning condition based combined with time based planning and risk assessment to determine optimum TA interval. Such programs offer the best reliability and lower program cost. It would be advantageous for RDK to develop such capabilities on ASAP bases. E&D Technologies specializes in implementation of such programs.

6.3.6 Onstream Inspection Programs (OSI Application)

From the available inspection reports, it would appear that almost all inspection is carried out during TA. Little systemic inspection is done during the run. While some hot components are more difficult to inspect on stream this could be optimized to increase the OSI component of the inspection programs to spread the work load more uniformly and provide fresher, more accurate data for maintenance decisions.

Recommendation:
Develop and implement an optimized OSI program

6.3.7 Use of contemporary NDE techniques to asses condition of equipment

It has been mentioned above that advanced NDE methods are being used sparingly. Methods such as guided wave, phase array (PAUT), tube inspection such as Eddy Current (ET), remote field eddy current (|RFT), Flux leakage (FL), internal rotating Ultrasonic Inspection (IRIS), Borescope, laser or white light., real time radiography, neutron back scatter, profile radiography, infrared scanning, etc. all these and other are available to assess condition of equipment more accurately.

Inspection reports show little evidence of sophisticated NDE method application. While not all NDE methods would be economically available on the Island but when considering the TA scope and schedule and the improvements use of optimized NDE can bring to it

6.3.8 Risk Assessments and Risk Based Inspection (RBI)

Risk assessment matrices have been developed but not used in the inspection program applications. Cursory review indicated that the assessment methodology used has been atypical leading to different result reached when other techniques are applied. This system is not usable in its current development. The plan is to implement RBI by the year of 2020,

> **Recommendation**: Accelerate the RBI development and application with targeted completion by 2018.

6.3.9 Inspection Performance Metrics and KPIs

There has been no evidence of quantified inspection performance measurement.

> **Recommendations**: Develop the basic inspection performance measurements in 2017

Table 6.1 VGO – MHC - Summary of Equipment Issues

Category	Equipment	Comment
Equipment with residual life of <5 yr	REACs: E-1502A,B,C,D	Corrosion in these air coolers is taking place but it is not well controlled. Process conditions leading to fouling and corrosion are not well controlled and probably not fully understood. Tubing is not inspected internally hence LOPC (loss of primary containment) incident risk is present. Based on average life the tubes it could be up for re-tube shortly. Tools for predicting and eliminating corrosions are nowadays available and can be applied. Internal inspection of tubes in this unit is recommended. Also external damage (people walking on air cooler tubes) needs to be prevented.
	F-1501 Charge Heater	The situation with the SS tubes in this heater is not entirely clear. Extensive PASC damage is claimed but not entirely proved. PASC is not common for this material and it should be preventable. Material temperatures are probably excessive. Cl SCC can also be a problem here. Soda Ash washing can result in Cl SCC if all precautions to prevent it are not taken. It is likely that tubes are overheated due to fouling. It can be due to operational problems or inadequate heater design (fire box sizing or burners). This is a high pressure / high risk heater. Internal leak may result in heater destruction if not protected by functioning check valve. See discussion above.

Table 6.1 VGO – MHC - Summary of Equipment Issues (cont'd)

Category	Equipment	Comment
Equipment with residual life of <5 y (cont'd)	F-1501 Charge Heater (cont'd)	Operations of the heater should be reviewed/ modeled using HTRI software models to find the weaknesses. Chronic refractory and casing damage is a result of fuel oil firing applicable to most heaters in the plant. Cumulative maintenance costs on this heater are likely very significant.
	F-1552-Fractionator Heater	This heater also suffers from severe overheating and bulging. This could be an integrity and fire risk. Same as above in case of the F-1501 but low pressure and lower risk situation, Proper design and operating reassessment should help to prevent most of these problems. Replacements in kind will not lead to an improvement.
	V 1564-Fractionator Pre-flash drum	This vessel works in corrosive environment. The causes for corrosion do not appear to have been analyzed/ included in the inspection files. Vessel has been replaced by one built in local shop but recommendation was made for replacement with a new vessel. This hasn't been done. Inspection not inspected since installation. Potential risk.
Equipment requiring inspection for environmental cracking	Stainless steel piping	Depending on type of insulation used for SS piping, this may result in CL SCC during SD periods. Asses the chloride content in the insulation Also SS drains in Rx effluent piping suffer from SSC and should be under surveillance. This depends on Cl loading of the feed and SD & SU procedures.
	V-1501 HP Separator	Vessel corroded and coated. Coating is regularly deteriorated= not effective. Cracking has occurred in the past. Old plate A212 B FBQ: susceptible material risk of HIC damage in the vessel. HP separators frequently suffer from this problem. Thorough FFP assessment of the vessel is recommended
	V-1502	Low pressure separator: Similar concerns to the HP separator V-1501 but less risk due to lower ppH2S.
	V-1555	Similar concerns to V-1502
	C-1553-Amine absorber	Corrosion may occur in case of high H2S loading (>0.5 mol H2S/mol of amine). Most corrosion would occur in the inlet area if exothermic heating is significant (in case of high loading). Higher than std. stress relieving temperature is required to prevent amine cracking. PWHT cycle temperature is not known. Inspect for amine cracking.
Equipment at Risk of HTHA	E-1568A- hot separator vapor/ rec H2 gas	Exchanger works possibly above the new API RP 941 curve. Review operating conditions in detail for possibility
	E-1551 – F/E exchangers	Alloy units… they don't need to be listed on the HTHA matrix as their resistance to HTHA is adequate.

Table 6.1 VGO – MHC - Summary of Equipment Issues (cont'd)

Category	Equipment	Comment
Equipment at risk of elevated temperature corrosion	Line from F1552 to C-1551 Line 59056B	This line is operating at around 370 C and it shows as being CS. PIRS shows relatively recent replacement. The line should be carefully evaluated and inspected. It is operating close to the range of maximum sulfiding corrosion rate.
Injection and Mixing point program	No program in place	It is industry standard to have injection and mixing points specifically identified and monitored as the areas can become location of increased localized corrosion. We recommend to implement such program.
Critical check valve program	No program in place	It is industry standard to have critical valves and check valves having safety or safeguarding function specifically identified and specific inspection/ maintenance program developed and applied. We recommend to implement such program.

7. FCCU Fractionation Unit

7.1 INTRODUCTION

This report summarizes the assessment findings for the RDK FP-2 FCC Fractionation Unit, which includes all equipment and piping at the point where the reactor effluent piping ties into the fractionation column, C-1, throughout the fractionation section, then up to the point where the piping leaves the plot limit and goes to the GT-7 unit and various downstream treaters. The FCC reactor effluent piping is covered in the FCCU reactor/regenerator report for this assessment. The fractionation section of the FCCU operates at low to moderate pressures (< 27 BARG), with temperatures ranging from ambient to 520°C (the reactor effluent to the fractionation column).The equipment and piping in the hotter sections of this unit can be susceptible to high temperature sulfidic corrosion. The cooler sections often tend to be susceptible to ammonium chloride and ammonium bisulfide corrosion, as well as wet H2S cracking.

Table 7.1 summarizes areas of concern. Equipment and recommendations listed in this table should be addressed on a priority basis.

7.2 THE MAIN INTEGRITY RISKS

Based on available data, the highest integrity risk in this unit appears to be in the slurry piping. As with many FCC units, this unit has carbon steel piping in the slurry system. This design anticipates that sulfur will be stripped out of the fractionator bottoms stream using stripping steam in the lower section of the fractionation column. It is apparent that this design is not effectively stripping the sulfur from the slurry prior to reaching the bottoms piping. This is resulting in significant amounts of high temperature sulfidic corrosion. Slurry piping is known to suffer from irregular corrosion, which is controlled by a Si content of the CS components. Low Si (<0.12%Si) results in significantly higher corrosion rates compared to higher Si materials. Components with less than 0.1%Si may suffer from rate which are 4 times or more greater than high Si components. The abrasive characteristics of some slurry stream tend to exacerbate this corrosion mechanism. The solutions to this issue can include improving the steam stripping of the process or up-grading the material of the slurry. Many refiners have opted to up-grade the material in the high temperature (> 260°C) slurry circuits from carbon steel to chromium-moly materials. If RDK choses this option, up-grading to 9Cr –1/2Mo rather 5 Cr is typically the preferred approach because of the marginal price difference and the significantly greater corrosion resistance of the 9Cr material.

Another high risk currently in the FCC Fractionator involves the fractionator overhead piping system, which is comprised of two 24” NPS vapor lines which reduce down to 16” branches at the first set of condensers. Premised on thickness data these two piping circuits are seeing significant corrosion. The thickness data shows that all seven 24" components which have CMLs had lost from 1.50 to 3.60 mm by the time of the last inspection of these CMLs (2009). If the corrosion has continued since 2009 at the same rates all six CMLs are currently below their designated renewal thickness of 6.0 mm. Even if one uses a much less conservative renewal thickness of 3.5 mm, all seven 24" NPS CMLs and three 16" CMLs (inspected in 2016) are approaching end of life. Also, both the intermediate reflux piping (Circuits 25066, 2566A and 25069) and the HCO piping (Circuits 25042 and 25046) are showing evidence of significant high temperature corrosion and may require some replacements soon. As with the slurry piping, up-grading the material in these piping circuits may be warranted.

7.3 GENERAL COMMENTS

This section of this report covers systemic findings, which are of a general nature and similar for majority of the units which have been analyzed.

TABLE 7.1 FCCU Fractionator Unit - Summary of Equipment Issues

Category	Equipment	Comment
Equipment with residual life of < 5 y	Top Reflux Cooler E-14A-D	2011 UT's have remaining wall ranging from 8.5 mm – 9.5mm. 11mm is nominal wall when new. Could not find 2011 UT sheet for E-14D. **Recommendation**: UT scan around corroded areas. Expect lace welding next T/A.
	LCO Reboiler E-3A	Last UT in our files is 1999. Channel head was partially strip lined in 2006. Remaining wall on CH maybe below min "t". In the file for E3 there is a fabrication drawing for a new CH labeled E3A. Was this CH purchased and installed on E3A? E-3A is in the Sulfidation program with no current UT's. **Recommendation**: Verify if new CH was installed. If it wasn't installed perform UT's at all monitoring points.
	E-17A/B	Not inspected for 16 years. (*Waiting on verification from Inspection whether missing or not inspected in 16 years.)* **Recommendation:** Perform a UT inspection of all CML's.
	Piping: The liquid draw off V-10, the 2nd Stage Accumulator, Circuit 25078	The liquid draw off V-10, the 2nd Stage Accumulator is showing corrosion on the 8" NPS components. CML 3 which was replaced in 2006 shows from its 2016 thickness data to be corroding at a rate of 0.300 mm/yr. At this rate it will reach its designated renewal thickness by 2020. **Recommendation**: Monitor this circuit closely and plan for a partial replacement.
	Piping: Pressure Relief, Circuit 25084	The 24" NPS components of this pressure relief line shows significant corrosion and are already below their designated renewal limit of 6.0 mm. Even though this line normally operates at less than 1 BARG, the minimum required thickness premised on relief conditions should be determine. While this is likely to be well less than its current designated renewal thickness, an analysis should be made of this system to determine an appropriate renewal thickness and assess the piping. It should be noted that the 10" NPS components in this circuit were renewed in 2012 and currently appear to be in satisfactory condition. **Recommendation**: An analysis should be made of this system to determine an appropriate renewal thickness and determine if the 24" NPS components should be replaced.

TABLE 7.1 FCCU Fractionator Unit - Summary of Equipment Issues (cont'd)

Category	Equipment	Comment
Equipment with residual life of < 5 y (cont'd)	Piping: 24" OH line off C-1, Main Fractionator, Circuits 2515A and 2515B	Premised on thickness data these two circuits are seeing significant corrosion. The thickness data shows that all seven 24" components which have CMLs had lost from 1.50 to 3.60 mm by the time of the last inspection of these CMLs (2009). If the corrosion has continued since 2009 at the same rates all six CMLs are currently below their designated renewal thickness of 6.0 mm. Even if one uses a much less conservative renewal thickness of 3.5 mm, all seven 24" NPS CMLs and three 16" CMLs (inspected in 2016) are approaching end of life. **Recommendation**: These two circuits should be re-inspected soon, with a likely at least partial renewal being required in the next 5 years.
	Piping: 24" NPS vapor outlet of V-7, the Fractionator OH Accumulator, Circuit 2517A	This circuit is comprised of 24" and 14" NPS components. 24' NPS CML 14 was already shown to have corroded to its designated renewal thickness of 4 mm in 2013. Other CMLs are also showing corrosion, but appear to have more life. **Recommendation**: Assess this circuit for at least a partial renewal.
	Piping: HCO Reflux piping, Circuit 25066	This circuit shows to have been renewed in 2006 and not been inspected since 2009. Premised on the 2009 thickness data this 10" NPS circuit has significant corrosion - as much as 0.60 mm/yr. Using this corrosion rate this circuit has already reached its designated renewal thickness. **Recommendation**: Inspect this circuit and plan for a full renewal soon.
	Piping: HCO Reflux piping, Circuit 25069	This circuit was last renewed in 2012. CMLs 3 and 8 on this circuit are showing significant corrosion. Only 6 of the 10 CMLs in this circuit have been inspected since the circuit was renewed. Premised on the 2016 thickness data they will be at their designated renewal thickness in the next five years. **Recommendation**: Verify the corrosion rates in this circuit and plan on possibly renewing the circuit within the next 5 years.
	Piping: HCO Reflux piping, Circuit 25066A	This circuit is the 10" NPS intermediate reflux from C-1, the main fractionator. This line was last inspected in 2009 and was showing significant corrosion at that time. If the high corrosion rates experienced between the time the circuit was renewed in 2006 and the 2009 inspection has continued, then the circuit is now below its designated renewal thickness. **Recommendation**: Verify the corrosion rates in this circuit and plan on possibly renewing the circuit within the next 5 years.

TABLE 7.1 FCCU Fractionator Unit - Summary of Equipment Issues (cont'd)

Category	Equipment	Comment
Equipment with residual life of < 5 y (cont'd)	Piping: Hydrogenated Castor Oil, Circuit 25042	This circuit is experiencing corrosion. In fact, the calculated corrosion rate premised on UT measurements taken is 0.60 mm/yr. At this rate CML 2 will be reaching its designated renewal in approximately 5 years. Other CMLs are showing similar, but slightly less corrosion. **Recommendation**: Inspect this piping within the next 3 years to determine its remaining life.
	Piping: Hydrogenated Castor Oil, Circuit 25046	This circuit appears to be experiencing significant corrosion. While there are only three CMLs on this circuit, all three show to be corroding at approximately the same rate, i.e., > 0.50 mm/yr. This circuit has not been inspected since 2009. At the calculated corrosion rates, this circuit has already corroded to below its designated renewal thickness. **Recommendation**: Inspect this piping to confirm the calculated corrosion rates premised on the 2009 thickness data. Plan on a likely renewal.
	Piping: Slurry, Circuit 25002	This 8" and 12" carbon steel piping is experiencing significant corrosion. The calculated corrosion rate on CML 3 is over 0.5 mm/yr. The last inspection was in April 2016. At these rates this piping system already has components which are below their designated renewal thicknesses. **Recommendation**: Consider replacing all this piping circuit. Due to the high corrosion rates being seen, consider using 9% Cr components for the replacement.
	Piping: Slurry, Circuit 25004	This piping circuit is experiencing significant corrosion (> 0.250 mm/yr). While the parts of this circuit which were renewed in 2006 and 2012 still have more than 5 years of remaining life, the components that were not renewed at that will likely require replacement soon. **Recommendation**: Consider replacing the components in this circuit which were not renewed in the 2006 and 2012 timeframe. Due to the high corrosion rates being seen, consider using 9% Cr components for the replacement.
	Piping: Slurry, Circuit 25002A	This 10" and 12" carbon steel piping is experiencing significant corrosion. The calculated corrosion rate on CML 1 is 0.328 mm/yr. The last inspection was in April 2016. At these rates this piping system will reach its designated renewal thickness in the next 1 to 2 years. **Recommendation**: Consider replacing all this piping circuit. Due to the high corrosion rates being seen, consider using 9% Cr components for the replacement.

TABLE 7.1 FCCU Fractionator Unit - Summary of Equipment Issues (cont'd)

Category	Equipment	Comment
Equipment with residual life of < 5 y (cont'd)	Piping: O.H. from V-99, Feed Surge, to C-1, Circuit 25250	The 10" NPS carbon steel piping components in this circuit appear to have significant corrosion. The last inspection in 2009 showed corrosion rates exceeding 0.400 mm/yr. Premised on the 2009 data this circuit has already reached its designated renewal thickness. **Recommendation**: Inspect this piping circuit and plan on at least a partial replacement soon.
Injection and Mixing point program		In general, the refinery does not have an effective, well-structured inspection program for injection and mixing points.
Critical check valve program		The refinery does not have a program for the identification and inspection of critical check valves.

8. Crude Distillation 3 Unit 1200/ CD-3, 2500, Wet Avtur Treatre, 1500 Gas Tail, 1600 Anine and Causitc Treatre, 1800/SWS

8.1 INTRODUCTION

The following report summarizes audit findings for RDK CD-3, Wet Avtur Tr, Gas Tail, Anine and Caustic Treater and the SWS based on the inspection records we had at our disposal. Figures 8.1 -

8.2 THE MAIN INTEGRITY RISKS

Based on available data:
Lap patches have been installed on multiple pieces of Fixed Equipment, both on the ID and the OD. In most cases, it's not known what the remaining wall is under the lap patch. Remaining wall maybe below the minimum required thickness or completely corroded away. Filet welds are not full equivalents of buttwelds for the same plate thickness. Lap patches set up additional mechanical and thermal stress fields around them. They should be designed by and installed under supervision of a specialist (Engineer) experienced in pressure vessel design and fabrication. No Wind Load calculations were found for the equipment after the lap patches were installed. Temporary lap patches may not be compliant with API-510. Found only one piece of equipment with a calculated min t in all of the inspection files. Minimum thickness should be evaluated for all components subject to deterioration.

THE SECOND MAJOR THREAT

Approximately 44 pieces of equipment in the CD-3 (Excluding NHT) are listed on the sites environmental cracking spreadsheet. Only four (V-1601,2, 3, 4) of those 44 pieces of equipment are being sandblasted and Wet Flourescent Magnetic Particle (WFMPT'd) for environmental cracking during the 2017 T/A. An additional 18 pieces of equipment are being blasted on the ID and coated, but no WFMPT. The 22 remaining pieces of equipment on the list are not identified as having anything done.

THE THIRD SIGNIFICANT THREAT

Overall condition of the Crude Heaters F-1201A-C internals. Major repairs every 1 to 4 years. Frequent repairs include tube replacements, refractory, hangers and supports, roof panels and casing. Design of the heaters should be reviewed and essential upgrades executed.

THE FOURTH SIGNIFICANT THREAT

CUI is run as an inspector driven spot inspection exercise. There isn't a prioritized listing based on process criticality, age, insulation type, etc. Most of Industry implements a CUI program as a stand-alone program with its own budget and resources. Industry strips everything on equipment being inspected that operates within the CUI temperature range. Industry does not do spot inspections.

8.3 GENERAL ITEMS

This section of this report covers systemic findings, which are of a general nature and similar for majority of the units which have been analyzed. It is similar to other units and it is covered in the general section of the Final Report.

Table 8.1 CDU- 3 - Summary of Equipment Issues

Category	Equipment	Comment
Equipment with a residual life less than 5 years	C-1205 HGO Drier Column	Lap patches were installed on the vessel OD due to CUI corrosion at insulation rings 1 and 2. The remaining wall at Ring 1 was 2.5 - 12.8mm and at ring 2, 2.0-13.0mm. Nominal wall for the shell is 11 and 14 mm in uncorroded areas. No dimensions were listed in 2010 inspection report for the corroded areas or if calculations were performed. A corroded area on top head at 2" nozzle was found and boxed in. The 2010 Post T/A recommendation was made for the replacement of the top head next T/A. 2017 T/A scope states to strip top head, de-rust, and inspect. **Recommendation**: short term recommendation -perform FFS, i.e. min t and wind loading calculations. Next T/A – remove and repair lap patches and repair top head. Since severe CUI was found a 100% CUI inspection should be performed.
	C-1207 Debutanizer Column	Write-ups don't reflect if min wall calculations were performed for internal pressure or wind loadings. The 2010 write-up stated that the top stiffener ring was heavily corroded – lace welded. The corrosion was moderate at stiffener rings 5&6 but lap patches were installed. Recommendations in write-ups to remove and replace next downtime. 2017, lap patch removal and repair not part of T/A scope. Without min wall calculation's this vessel should be considered as operating below min "t". **Recommendation**: Remove patches and perform weld buildup in corroded areas next T/A. Weld-build-up is required. Weld buildup of larger areas shall be engineered. Full encirclement lap patches maybe considered a permanent repair if they meet the requirements in API-510. Since severe CUI was found a 100% CUI inspection should be performed.
	C-1202 TCR Accumulator V-1207	Vessel is operating below calculation (1990) for min "t" of 8.6mm. 1995, carbon steel liner installed over corroded areas down to 7.4mm. Required "t" is 8.6mm and nominal is 14mm. 2017 T/A - Install 11 sqm of CS lining in bottom. No mention of lace welding in 2017 T/A scope. Vessel may still have < min "t" under new liner. In 2017 T/A scope to install new internal liner.

Table 8.1 CDU- 3 - Summary of Equipment Issues (cont'd)

Category	Equipment	Comment
Equipment with a residual life less than 5 years (cont'd)	C-1202 TCR Accumulator V-1207 (cont'd)	**Recommendation**: Perform a UT corrosion scan around corroded area that was lined. Remove strip liner next T/A, weld buildup corroded areas and re-strip line.
	Ejector Effluent Accumulator V- 1208	1995, 6.8sqm of carbon steel liner installed in bottom of vessel. No mention of liner in subsequent write-ups. Prior to lining some of the UT's found were 3.5 and 5.3mm and highs of 9.3mm. Nominal was 9.0mm when new. No weld buildup was documented. No further discussion in subsequent writeups that liner was removed. 2017 T/A work scope - Open and inspect and renew coatings. Have not received any additional T/A updates that might clear this item up. Liner is still installed over areas that are < min "t". **Recommendation**: Perform a UT corrosion scan around corroded area that was lined. It should be < min "t". Next T/A: Remove liner and lace weld wasted areas.
	E-1215A-O	The Crude column overhead condensers have had a significant number of re-tubes. The 2017 T/A work scope directs the 15 coolers to have cover plates removed for tube cleaning and inspection. The longest intervals have been 6 to 7 years excluding outliers that were out of service for extended time periods. Most re-tubes occur around 3 year intervals. Based on the write-ups it appears that the coolers are not always installed back in their original slot and there are spare A/C banks that are sometimes used. This reviewer verified with Site personnel that the equipment histories are tracked by the location, A through O – not by the specific item number. Re-tubed in 2010: A, B, D, F J, K. 2010 T/A recommendation -Retube next T/A, E-1215 I, M, O and renew headers on L – these four A/C's are in 2017 T/A letter for inspection. **Recommendation**: Start using the various NDE methods for tubular inspections. It would improve tubular reliability significantly. Several coolers will leak before next T/A. Review the Column overhead corrosion mitigation effectiveness and optimization, consider metallurgy upgrades for future re-tubes.
	E-1218B	Strip liner installed in 2004 may have been installed over remaining walls < min "t". **2002 (latest UT report in file) states "low thickness" and perforated off to the side. All other UT pts on the shell layout had thicknesses that were listed in that report.** Based on the data that we can access, this exchanger shell could be operating at less than min required "t". 2017 workscope plans to install a lap patch on the lower OD this T/A. Vessel will not be opened.

Table 8.1 CDU- 3 - Summary of Equipment Issues (cont'd)

Category	Equipment	Comment
Equipment with a residual life less than 5 years (cont'd)	E-1218B (cont'd)	**Recommendation**: Verify 2010 UT's. If external patch was installed plan to remove and make permanent repairs next T/A. If external patch was not installed perform a UT corrosion scan on areas with liner. Next T/A, remove strip liner and perform weld buildup in wasted areas. Reinstall internal liner or upgrade equipment alloy.
	Crude Heaters F-1201 A-C	All three Crude Heaters have extensive repairs every T/A. Has upgraded design for burners and possibly soot blowers been considered? Does routine burner maintenance occur? Consider upgrading tubes to 9 Ch, 1/2 Mo. 2017 T/A letter calls for partial tube renewals with 5 Ch, 1/2 Mo on wall tubes and 9%Ch, 1/2 Mo on roof tubes. **Recommendation**: Renew all tubes with 9 Chrome 1/2 Moly. Consider new or a better design of burners.
	Intermediate Residue Heater F-1202	The Intermediate Residue Heater has extensive repairs every T/A. Has upgraded design for burners and possibly soot blowers been considered? Does routine burner maintenance occur? Consider upgrading tube material to 9Ch, 1/2 Mo. Not in 2017 T/A letter. **Recommendation**: Renew tubes with 9 Chrome 1/2 Moly. Consider newer burners.
	Piping P72016	Pt 8 maybe < min "t" now. Recommendation: verify if Pt 8 was renewed this T/A or was it renewed just up to it as the T/A sketch depicts (which would miss pt 8 completely). If pt 8 was not renewed, perform a UT can around pt 8.
	Piping P72062	Pt 7 should be < min "t" by the end of this year. Pts 1, 2, 3, 4 and 6 were renewed this T/A. **Recommendation**: UT scan around PT 7.
	Piping General	16 iso's will be < min "t" within the next five years.
Caustic Cracking	Pre-flash Vessel V-1201	Caustic Cracking is a strong possibility. 2017 T/A work scope – inspect vessel and renew 2 - WOL's on vessel. T/A letter does not direct maintenance to PWHT new welds. Vessel was not PWHT'd when new. The 1989 failure report states to PWHT all future welds. More WFMPT should be performed next T/A to look for caustic cracking. 1977 report talked about caustic cracking in bottom section. **Recommendation**: PWHT all future weld repairs. Sandblast shell ID and perform WFMPT's on all welds next T/A.

Table 8.1 CDU- 3 - Summary of Equipment Issues (cont'd)

Category	Equipment	Comment
Equipment requiring inspection for environmental cracking		Approximately 44 pieces of equipment in the CD-3 (Excluding NHT) are listed on the sites environmental cracking spreadsheet. Of those 44 there are only four (V-1601,2, 3, 4) pieces are being sandblasted and WFMPT'd during the 2017 T/A. An additional 18 are being blasted on the ID and coated, but no WFMPT. The remainder of the list is not identified as having anything done. **Recommendation**: Coatings maybe an effective barrier for environmental cracking only if they stay intact, which they rarely do. Failed sections of coatings may be more prone to pitting or cracking (shift in polarization potential) I would consider this to be a questionable practice. If the risk is high, strip lining or concrete liner would be more effective. WFMPT should be considered next T/A. PTA (Polythionic acid) corrosion is not addressed in the environmental cracking list document. PTA has been mentioned in one report but never independently confirmed. No additional info found in any other write-ups. Several SS systems and components experience frequent cracks that maybe PTA. **Recommendation**: Evaluate the present of PTA. If confirmed develop decontamination procedures to prevent PTA.
Equipment at Risk of HTHA		HTHA is not an issue in the CD-3 Unit. NHT was reviewed by others.
Equip't at risk of elevated temperature corrosion (S or NAC		Thirty-one pieces of Fixed Equipment, including piping are listed in the Sites Sulfidation spreadsheet. Each piece of equipment is receiving periodic UT inspections.
Relief valve requiring inspection before next T/A		RV program is a time-based program. **Recommendation**: Implement one of the most commonly used programs for RV inspection. Most of the commercially available inspection programs do contain such modules. Recommendations can be made.
Injection and Mixing point program		Program not yet developed. **Recommendation**: Develop an injection/mix point inspection program as soon as possible.
Critical check valve program		Program not yet developed. **Recommendation**: Work with operations to identify Critical Check valves for the unit. Once list is developed create a Critical Check Valve inspection program.

9. FCCU R&R Unit

9.1 INTRODUCTION

The following report summarizes audit findings for RDK FCCU based on the inspection records we had at our disposal.

9.2 THE MAIN INTEGRITY RISKS

THE MAIN INTEGRITY RISK

V-5, Stripper - see E&D's Fitness for Service Assessment dated 2017. The biggest issue with the Rx is not knowing if Creep is or isn't present. E&D's report outlines steps to acquire Creep data among other items.

THE SECOND MAJOR THREAT

MK-56-58, Rx Overhead Line - 2012 UT reports shows 13 monitoring locations with thinning of 11.7 - 8.5 mm. Nominal Wall not identified in equipment folder. Most of the pipe ran 11.2mm to 12.1mm thickness at the last inspection in 2012. Inspection report is unclear if renewal was recommended or not. See Level 1 report comments. At next opportunity retake UT's to verify if erosion is continuing to take place.

THE THIRD SIGNIFICANT THREAT

MK- 42,43,45 CO/ Regen Overhead Line. Partial renewal in 2012. Cracks found almost every T/A since 1985 (2009 - OK). Average run times are two to three years. There is one run of nine years but suspect missing inspection data. V-4A/5, Rx/Regenerator – they are also considered to be a threat because of the extensive damage and repairs that routinely occur during your T/A's.

9.3 GENERAL COMMENTS

This section of this report covers systemic findings, which are of a general nature and similar for majority of the units which have been analyzed. It is covered in the general section of the Final Report.

Table 9.1 FCCU R&R Unit - Summary of Equipment Issues

Category	Equipment	Comment
Equipment having <5y Life or its Repair and Damage Rates Exceed Industry Average for the Type of Equipment	V3	Expect refractory repairs, crack repair at dipleg bracing, plenum and cyclone to plenum horns. Cracks at air grids. Inspect select nozzles from ID (see 2012 write-up) for cracks.
	V4A	Next T/A expect Refractory repairs, major repairs on Dip legs (probable renewal), Cyclone repairs, crack repair at dipleg bracing and plenum. Repair on Roo Cap and Chinese Hat. Verify that the patched liner in the top section was removed and repaired. If not what is size of the eroded area?
	V-5	See E&D Technologies Fitness for Service Assessment. Recommendation in the E&D Report. This vessel was in the 2017 mini T/A for excess catalyst loss. Not aware of what repairs were made. Bulging was first reported in 1982 and then again in1988 in more detail. 1985, Boat samples taken - no Creep damage, '90, Field Metallography said Creep was present, '91, Core samples and Field Metallography - inconclusive, '93, Creep evaluations did not reveal Creep. One report theorized that bulging could have come from an event in 1975 where the Rx Stripper reached 700C. 2012, 2 of 3 cyclones in service - OK, Dip Legs were patched due to erosion, Roo cap - hex repair, upper steam distributor renewed with A106 gr a, bottom distributor welded and re-drilled.
	CO /Regen OVHD Line MK – 42, 43, 45	Line renewed in 1985 with TP304SS. Cracks repaired in '88, 90, 99, 02, 06. 2006, deformation and bulging was found in vertical section just above MK-44. Repaired by welding two stiffeners on OD at Support Brackets MK-43/44. Cracking at plate sections of supports were found and repaired. 2009 - OK. 2012, some part/parts of the line were renewed due to sensitization. Cracks repaired in support rings. 2012 T/A recommendation: renew horizontal section. **Recommendation**: evaluate if lower section needs replacement as recommended in the 2012 T/A. Expect crack repairs during next T/A. Was not part of 2016 Short Stop. Has polythionic cracking been evaluated? Perform a stress analysis of piping?

Table 9.1 FCCU R&R Unit - Summary of Equipment Issues (cont'd)

Category	Equipment	Comment
Equipment having <5y Life or its Repair and Damage Rates Exceed Industry Average for this Type of Equipment (cont'd)	Rx OVHD line MK- 56-58	2012 UT reports shows 13 monitoring locations with thinning of 11.7 - 8.5 MM. Nominal Wall is unknown. Most of the pipe ran 11.2mm to 12.1mm thickness at the last inspection in 2012. **Recommendation**: verify if the OVHD Line renewal recommendation is expected to happen at the next T/A. If so, plan to renew these 13 sections next T/A.
	Rx standpipe MK – 5-7	Graphitization was identified in 2011 turnaround. Graphitization occurs in carbon steels and Carbon 1/2 Mo at temperatures ranging from 450C to 620C. If graphitization concentrates around weld zones, sudden failure of equipment may occur. Has Field Metallography been performed to confirm extent of damage? 2012, replaced loose refractory. 2017 Mini T/A calls for inspection via rope ladder. **Recommendation**: Plan for replacement next T/A. Consider material upgrade to at least 1.25% Chrome, 1/2 moly.
	Piping Catalyst 25223	Pt 3 will be < min "t" within 3 years Pts 5, 12 and 15 will be due < 5 years **Recommendation**: Inspect all UT points again. There are only a small number of piping iso's for FCCU R&R, seven catalyst isos and one fuel gas, torch oil etc. All other piping is listed under the Fractionator.
	Lift Pot and Y Riser MK-1,2	1990 failure analysis talked about Polythionic Acid Cracking occurring at hex that had detached from wall and shutdown at a later date. No further mention of PTA internal crack in any subsequent writeups – renewed? Next time the hex fails perform a crack inspection on ID surface at the Wye joint for Polythionic cracking.
	Stripper Standpipe MK-10 - 13	2012 - problems welding hex to wall due to coke residue. T/A recommendation - renew all hex and refractory next T/A. **T/A recommendation** - Renew hex and refractory.
	Feed Distribution nozzleMK-3	Every three to four years the nozzles are replaced.
	CO /Regen OHD Line Expansion Joint MK-44	Longest run to date without a leak is seven years, average run between leaks is three to four years. Bellows not inspected during 2016 Short Stop and doesn't appear to be in 2018 workscope.
	Stripper Lift Pot MK-8/9	From '85 to 2012 the Lift pot has been inspected eight times. The average interval between repairs is slightly less than 4 years.

Table 9.1 FCCU R&R Unit Summary of Equipment Issues (cont'd)

Category	Equipment	Comment
Equipment requiring inspection for environmental cracking		No equipment in the FCCU R&R is listed on the sites environmental cracking spreadsheet. PTA corrosion is not addressed on the sites environmental cracking list. PTA has been mentioned in one write-up and never confirmed. No additional info found in any other write-ups. Several SS systems and components experience frequent cracks that maybe PTA. **Recommendation**: Evaluate the presence of PTA. If confirmed develop decontamination procedures to prevent PTA.
Equipment at Risk of HTHA		HTHA is not an issue in the FCCU R&R Unit.
Equipment at risk of elevated temperature corrosion (Sulfidic or naphthenic acid		In general, the review of this unit did not disclose any significant deficiencies in the refinery's inspection program for detecting elevated temperature corrosion other than those noted elsewhere in this report.
Injection and Mixing point program		Special monitoring programs are not developed or implemented. Injection rates are not monitored by Inspection group
Critical Valve Monitoring program		Special programs for monitoring function of valves having impact on safety (other than RVs) are not developed or implemented. This covers valves like Check Valves or critical MOVs. RV Monitoring program is in place.

10. LVI-HF Unit

10.1 INTRODUCTION

This report summarizes the assessment findings for the LVI-HF unit (Low Viscosity Index Hydrofinisher). This unit uses Luboil feed (NND-40, NND-70, NND-650 etc.) from the Distilling and Luboil (DL) area and hydrogen from the Platformer unit. The products (LVI-40, LVI-50, LVI-450 etc.) are routed to storage.

Process Handbook indicates that this unit operates with high-pressures and temperatures (up to 142 bar and 375 °C). Feed is said to be delivered in batches. After preheating in feed/effluent exchangers and a fired heater it is passed through two three beds reactors, where the required conversions are achieved (i.e. desulphurization and de-aromatization). The reactor effluent, after preheating the feed, is cooled in an air cooler and then flashed off in a four separator system.

The gas is sent to the cold low pressure separator, while the liquid is preheated by the drier and fractionator bottom product and a hot oil heater and fed to the fractionator. In the fractionator flashpoint and viscosity of the product are corrected. After drying in the vacuum drier, the product is routed to its storage tanks at OPS, from where it is shipped out as final product.

The main damage mechanisms in this unit are Ammonium Chloride corrosion, HCl corrosion, Ammonium Bisulfide corrosion, Under-deposit corrosion and Hydrogen Embrittlement. Variability in batch composition may result in variable concentration of corrodents, which in turn may result in larger areas of the system be subjected to corrosion. Understanding of the variations are need to be able to locate zones of corrosion more accurately.

Table 10.1 summarizes areas of concern. Equipment and recommendations listed in this table should be addressed on a priority basis.

10.2 THE MAIN INTEGRITY RISKS

Based on available information:
The highest integrity risk in this unit appears to be HP Gas Air Cooler (E-1304). This cooler has a history of sludge depositing in the tubes and under-deposit corrosion, which leads to severe pitting and leakage. The wash water injection design needs to be understood in order to recommend design changes.

Another significant area of concern are the two Ejector Condensers (E-1323 A/B). The corrosion of the shell is caused by HCl formation. The method of pH control needs to be understood in order to recommend design changes. The tubes (cooling water) have a history of algae depositing and under-deposit corrosion. The cooling water treatment needs to be improved to prevent algae formation.

The main causes of pipe rejections in hydrocarbon service were, poor welds and CUI.

10.3 GENERAL COMMENTS

This section of this report covers systemic findings, which are of a general nature and similar for majority of the units which have been analyzed. It is covered in the general section of the report.
Main reactors should be assessed for potential of temper and hydrogen embrittlement.

10.3.1 RECORD KEEPING DOCUMENTATION QUALITY DOCUMENTATION AVAILABILITY, MATERIAL LISTS OR MSDS, (REPORTS, EQUIPMENT ANALYSIS, DRAWINGS ETC.)

PFD is not up-to-date. For example, vessels V-1301 and V-1302 are shown but these vessels were taken out of service.

No MSDs were available. The material selection of equipment was taken from the equipment construction drawings where possible. No comprehensive records were available that documented changes in material selection. In some cases material selection changes were found in inspection reports that were not otherwise available.

In case of piping, the PIRS system uses a system of inspection sketches to accurately communicate measurement locations and areas requiring repairs or replacements. The Criticality Analysis Matrix only partially captured piping systems. The PIRS piping data was used to make the list of piping systems complete.

A discrepancy was found between the materials data on the PIRS drawings and the PIRS database. All piping components identified as API 5L-B in the PIRS database are identified as A106-B on the PIRS drawings. Piping purchased under API and ASTM specifications may not always have identical chemistry.

> **Recommendations**: Develop a system of inspection sketches for equipment where inspection locations with their limiting values can be shown as well as clear description of material of construction of a given component.

Table 10.1 LVI-HF - Summary of Equipment Issues

Category	Equipment	Comment
Equipment with residual life of <5 y	HP Gas Air Cooler (E-1304).	This cooler has a history of sludge depositing in the tubes and subsequent under deposit corrosion, which leads to severe pitting and leakage. Likely corrodent are ammonium salts, Ammonium chloride specifically although understanding of specific operating conditions is needed to be able to determine the mechanisms more accurately). Operating conditions are not know to us and are not monitored by inspection. **Recommendation**: Relevant operating parameters need to be understood and wash water injection design and source needs to be re-evaluated. Using tap water (containing oxygen) can aggravate corrosion as well as increase Chloride stress corrosion cracking risks in the unit, recently retubed with SS316. Review by corrosion Engineer is needed in order to recommend operating and possibly design changes.

Table 10.1 LVI-HF - Summary of Equipment Issues

Category	Equipment	Comment
Equipment with residual life of <5 y (cont'd)	Ejector Condensers (E-1323 A and B)	The corrosion of the shell is caused by HCl formation. The tubes (cooling water) have a history of algae depositing and under deposit corrosion. **Recommendations**: The method of pH control needs to be understood in order to recommend operating and design changes. The water treatment needs to be improved to prevent algae formation.
Equipment requiring inspection for environmental cracking	separators V-1306, 1307, 1304	High pressure separators, cold and hot and hot hi pressure separators (V-1306, 1307, 1304) should be inspected by WFMP testing with high quality surface preparation around areas which are wetted by sour water; some vessels may not be PWHT. Both reactors (1977 vintage- second generation) should be assessed to confirm their pressurization and depressurization cycles and tendency for hydrogen and temper embrittlement, based on J and X-bar factors as per API RP 934-F or by expert evaluation.
Equipment at Risk of HTHA	E1302 A/B	Assess the E1302 A/B components for possibility of HTHA (Channels in particular) CS recycle gas line 64009 operates at 245 C: check for possibility of HTHA or sulfidic corrosion (borderline).
Equipment at risk of elevated temperature corrosion		In general, the review of this unit did not disclose any significant deficiencies in the unit inspection program for detecting elevated temperature corrosion other than those noted elsewhere in this report.
Equipment requiring Inspection for CUI	Dryer Bottom HE (E-1308 A and B)	In 2013 CUI was measured to be 2mm deep on shell. **Recommendation**: Check shell, coat and reinsulate.
Injection and Mixing point program		In general, the refinery does not have an effective, well-structured inspection program for injection and mixing points. LVI-HF has two wash water injection points: Upstream oh the Reactor Effluent Cooler (E-1303) and upstream of the HP Gas Cooler (E-1304). LVI-HF has two H2 mixing points: Fresh H2 Gas from the Platformer into stream #8, upstream of the Feed Surge Vessel (V-1308) and upstream of the Cold LP Separator (V-1307)
Critical check valve program		The refinery does not have a program for the identification and inspection of critical check valves.
PIRS discrepancies (example only)	PIRS 64043	The relief line from E-1302 to flare system is identified as A106-B on the PIRS drawing but as P-5 in the PIRS database
	PIRS 64008	Outlet E-1302A/B to E-1301A/B; Materials according to PIRS is 316L SS. Is this correct or is it A106-B?

11. Platformer Unit

11.1 INTRODUCTION

This report summarizes the assessment findings for the RDK Platformer Unit. Hydro-treated naphtha feed received from the NHT-2 is mixed with hydrogen-rich gas prior to preheating in the fired charge heater. Subsequently, the mixture is passed through the first reactor. Due to endothermic reactions, the mixture has to be reheated in the first interheater (fired) before entry in the second reactor, and again reheated in the second fired interheater before entering the third reactor. The reactor effluent is cooled by heat exchange against fresh feed and further cooled by air coolers and water coolers before passing to the product separator, where gas and liquid product are separated at high pressure. The majority of the flashed hydrogen-rich gas is recycled to the platformer feed, whilst the net make-gas is used in the hydrotreater and hydrodesulphurizer units.

The primary damage mechanisms typically seen in hot section of this unit i.e. in the charge heater / reactor section are: creep/stress rupture, creep embrittlement (MPC rated class 4 cracking in 1.25Cr steels, usually concentrated around stress riser locations), reheat cracking and potential for high temperature hydrogen attack. In the reactor effluent, cold section ammonium chloride or HCl corrosion can occur. CUI has also been known to be particularly aggressive in insulated equipment and piping located in cooler areas of the unit, typically downstream of the Reactor Effluent Charge Exchanger (E-1701 A-D) up to the Reactor Effluent Trim Cooler (E-1702 D-E) and downstream of the Stabilizer Feed Bottom Exchanger (E-1703 A-B) to the Stabilizer Overhead Condense (E-1706 A-B) until the equipment is no longer insulated).

Note on corrosion mechanism: an alumina-supported reforming catalyst requires moisture to activate the acid function and provide homogeneous chloride content over the whole catalyst bed. When the environmental atmosphere is too wet, however, chloride in the catalyst will be leached off and thus, deteriorate its effectiveness and corrosion is experienced in downstream location where water dew-point is approached. Usually the chloride content on the catalyst should be kept in the range of 0.9– 1.2 wt% for most bimetallic catalysts. To meet this requirement, an environment of 1–5 ppm of hydrogen chloride and 10–20 ppm of water should be provided in the circulating gas over the bimetallic reforming catalysts. Therefore, tight water control must be performed along with chloride control to maintain a proper chloride–water balance in the feed to assure catalyst function and at the same time prevent corrosion. Consult your catalyst provider for specific details.

Table 11.1 below summarizes areas of concern. Equipment and recommendations listed in this table should be addressed on a priority basis.

11.2 THE MAIN INTEGRITY RISKS

Based on available information:
The highest integrity risk in this unit appears to be the Reactor Effluent Cooler (E-1702 C1/C2 and E-1702 A1/A2 to a slightly lesser extent) and the Stabilizer O/H Condensers (E-1706 A/B).

The Reactor Effluent Air Cooler suffers from pitting corrosion. Re-tubing of E1702 B1 was scheduled for 2008, but the actual re-tubing could not be verified from the inspection records.

The bottom of the Stabilizer O/H condensers E-1706 A/B are heavily corroded, 6mm WT loss, the remaining wall (May 2013) was 11.1 min which is too close to the min required WT (10.9mm). Condensing acid water or chloride salts can cause severe corrosion. This location/ exchanger have been implicated in a few severe incidents in other plants.

11.3 GENERAL COMMENTS

This section of this report covers systemic findings, which are of a general nature and similar for majority of the units which have been analyzed. It is covered in the general section of the Final Report.

11.3.1 Record Keeping Documentation Quality Documentation Availability, Material lists or MSDs, (reports, equipment analysis, drawings etc.)

The material selection was not documented in Material Selection Diagrams and consequently it needed to be pieced together from the original data sheets and the inspection records. Changes in material selection which have occurred over time were hard to identify.

11.3.2 Piping

The refinery uses piping isometric drawings, which show CMLs (Condition Monitoring Locations). Measurements are recorded and trended using calculated CML average short and long-term corrosion rates and actual reading point short and long corrosion rates. Probabilistic methods of residual life determination are not used.

CMLs are assigned with little regard of actual corrosion mechanisms. This leads to significant over inspection in areas where internal corrosion doesn't take place and under inspection in areas of active inspection.

> **Recommendations:** Develop a condition trending system for equipment thickness measurements as that used for piping. Develop an inspection program based on assessment of active corrosion mechanisms and risk.

11.3.3 Discrepancies between PIRS dwg and PIRS DB

PIRS dwg	Service	Material on PIRS dwg	Material in PIRS DB
61002	Inlet Furnace F-1701	P12, 1Cr-½Mo	P11, 1¼Cr-½Mo
61003	Outlet Line Furnace F-1701	P12, 1Cr-½Mo	P11, 1¼Cr-½Mo
61004	Inlet Line Furnace F-1702	P12, 1Cr-½Mo	P11, 1¼Cr-½Mo
61005	Outlet Line Furnace F-1702	P12, 1Cr-½Mo	P11, 1¼Cr-½Mo
61006	Inlet Line Furnace F-1703	P12, 1Cr-½Mo	P11, 1¼Cr-½Mo
61007	Outlet Furnace F-1703 to R-1703	P12, 1Cr-½Mo	P11, 1¼Cr-½Mo
61008	Outlet R-1703 to E-1701A I E-1701C	P12, 1Cr-½Mo	P11, 1¼Cr-½Mo

Recommendation:
Confirm material used (P11 or P12). P11 has 0.5-1.0 wt% Si, while P12 has max 0.5 wt% Si. P11 has higher HTHA resistance (API RP 945) than P12. In case P12 is used, verify if the pH2, T operating point is located under the Nelson curve (integrity issue).

Table 11.1 Platformer Summary of Equipment Issues

Category	Equipment	Comment
Equipment with residual life of < 5 y	Charge Heater-2, F-1702	Re-tube based on tube lifecycle. Analyze heater operation (e.g. HTRI/Honeywell Unisim model or equiv. and optimize operation.
	Reactor Effluent Air Cooler (E-1702 C1/C2 and E-1702 A1/A2)	Tubes suffer from internal pitting. Many retubes, damage mechanism not documented (probably Cl based corrosion). All (6) AC HEs are parallel. C1 and C2 are the HEs with the highest corrosion rates and require retubing every 2-3 years). Inlet (PIRS 61009) and outlet (PIRS 61010) manifolds are none symmetrical leading to maldistribution of flow to the exchangers. The corrosion rate of the outlet piping PIRS 61010, CML #24, #7, #20, #21 is high (0.24-0.88 mm/y). Options are to redesign inlet manifold, add water wash or upgrade material.
	Stabilizer O/H Condensers (E-1706 A-B)	Replace shell, shell bottom heavily corroded 6mm, close to (11.1mm) min WT (10.9mm). These condensers had significant vibration issues, which seem to have been resolved (Sep-27, 2012 – vibration issues addressed by redesign exchanger Kooiman Apparaten, Sliedrecht, Holland). Exchanger was under designed, #tubes increased, but the exchanger is still under designed. Condensing acid water or chloride salts can cause severe corrosion. This location/ exchanger have been implicated in a few severe incidents in other plants.
	Hydrogen Relief KO Drum (V-1711)	Replace vessel. Deep pits (2013) through the shell and top head wall 1.5-5mm
	Water Seal Drum (V-1712)	Replace vessel. Significant corrosion (2013)
Investigate requirement for potential design change	1st and 2nd Reactor (R-1702 and R-1702)	Currently cold wall design. In 2010 R-1703 was changed to hot-wall (2.25Cr-1Mo) design. Specific reasons for the conversion not indicated. Unclear whether reasons for hot wall conversion exist for the other reactors as well (R-1701 and 1702)

Table 11.1 Platformer Summary of Equipment Issues

Category	Equipment	Comment
Equipment requiring inspection for environmental cracking		Review of this unit did not disclose any significant deficiencies in the refinery's inspection program for detecting environmental cracking in this unit. (Low sulphur feed)
Equipment at Risk of HTHA		HTHA is potentially an issue in the Platformer unit in the outlet piping of the Charge Heaters depending weather P12 (HTHA concern for 1Cr-0.5Mo) or P11 (no HTHA concern for 1¼Cr-½Mo) is used. This requires confirmation.
High temperature damage	Piping	Number of cracks have been reported in the high temperature sections of the Cr-Mo reformer piping. Usually this cracking occurs as result of so called creep embrittlement cracking (or class 4 cracking per MPC nomenclature). The causes can be multiple, including hydrogen effects or weld contamination by Se, but most often precipitation of fine carbides in the small grain section of HAZ resulting in strengthening & cracking due to creep/relaxation, which exceeds materials ductility at the fine/coarse HAZ interface. Depending on temper (strength) of the material, higher strength materials (CL II or III) show this ductility throughs faster and deeper than softer materials. Cracking usually occurs at stress concentration (notches) such as nozzles, re-pads, thickness change or poor quality welds at exposure times well over $10^{4\ hrs.}$ Repairs are possible but need to be of good quality. Reliability of this circuit will depend on the material used and on quality of the repairs (notch reduction). Other high temp material damage in these services can be metal dusting but this hasn't been reported.
Equipment requiring Inspection for CUI	1st and 2nd Reactor (R-1702 and R-1702)	The 2013 inspection reports for these two vessels noted external scattered pitting (CUI) and recommended completely stripping the shell and heads at the next turnaround for inspection and coating.
Injection and Mixing point program		In general, the refinery does not have an effective, well-structured inspection program for injection and mixing points.
Critical check valve program		The refinery does not have a program for the identification and inspection of critical check valves.

12. HV-6 Unit

12.1 INTRODUCTION

This report summarizes the assessment findings for the RDK HV-6 Unit (High Vacuum Unit 6). HV-6 is almost identical to HV-7.

The almost identical HV-6/7 separate the long residue ex CD-2B in several fractions of which some are used as raw material for the manufacture of various lube oil grades. The long residue is heated up in fired heaters to 380°C before going into the Distillation Column (C-1, previously named Vacuum Column DA-1). In this column, Vacuum Gasoil and about six distillate grades, so-called Neutralized Naphthenic Distillates (NND 1 s), (NND40, NND45, NND50, NND70, NND270, NND650), are drawn off.

12.1.1 Distillation Column (C-1, previously DA-1)

The Distillation Column (C-1, previously DA-1) comprises of a neutralization section where ADOS (caustic Soda, NaOH solution) is circulated in order to remove naphthenates. ADOS is routed to the ADOS diluent recovery units (ADRU) for the recovery of naphtenic acids diluted in neutral oil.

12.1.2 ADOS Section

Naphthenic acids present in the vacuum distillates are neutralized with continuous caustic soda injection (appr. 0.2% m/m) in order to meet a TAN specification of less than 0.05 mg KOH/g of the distillates produced. The ADOS section consists of a neutralisation section (trays #36 and #37), a wash section (trays #34 and #35), total draw of tray #38, a demister (York screen) between tray #33 and #34, M-deck between tray #38 and tray #39. The purpose of the wash section is to avoid entrainment of caustic into the distillates in the lube oil intermediate. The heaviest distillate produced (either NND 650 or NND 1100) is used as wash oil.

12.1.3 Fouling of the ADOS Section

Fouling of the trays in the ADOS section is unavoidable. Both crystallisation of caustic soda (when the temperature drops below 340°C) and coking of other components in the ADOS, promoted by the presence of caustic, result in fouling up of the neutralisation trays. When these trays get partially blocked the entrainment into the wash section will give fouling of the wash trays as well.

The sodium content of these streams increases from 3-5 ppm after start up to 25 ppm or higher. For NND 650, being a feedstock for LVI 450 production on the LVI-HF a sodium content above 5 ppm is considered unacceptable in view of de-activation of the catalyst.

The plan was to replace bubble cap trays with sieve trays (ease of maintenance). It is not clear whether this was actually done.

The primary corrosion mechanisms typically seen in HV-6 are high temperature sulfidic corrosion, naphthenic acid corrosion (commonly found in the upper sections and overhead of the fractionation system) and caustic corrosion in the ADOS section of Distillation Column. CUI has also been known to be particularly aggressive in insulated equipment and piping located in cooler areas of the unit.

Table 12.1 summarizes areas of concern. Equipment and recommendations listed in this table should be addressed on a priority basis.

12.2 THE MAIN INTEGRITY RISKS

Based on available data:

- **The highest integrity risk** in this unit appears to be Distillation Column (C-1, previously DA-1). This vessel has a long history of corrosion in the mid and bottom sections and corrosion behind the SS strip lining. Repair and replacement of trays #11-36 seems to be regular and also repair and replacement of trays #36-44 (ADOS section) seems to be regular. In 2007 severe corrosion of tray #11-38 and a through-wall crack below tray #38. Although the damage mechanisms are not documented, it is thought that the main damage mechanism is caustic cracking (trays) and sulfidic corrosion (behind strip lining).
- Another significant area of concern is the Feed Heater (BA-1). The amount of tube and refractory degradation is excessive.
- The shells of crude exchangers HE-4 (E-4), HE-5 (E-5), HE-6 (E-6), HE-7 (E-7) and HE-8 (E-8) suffer from quite severe Sulfidic and NAC.
- Ejectors J-1A, J-1B, J-2A and J-2B suffer from quite severe erosion corrosion.
- The main causes of pipe rejections in hydrocarbon service were, poor welds and CUI.

This section of this report covers systemic findings, which are of a general nature and similar for majority of the units which have been analyzed.

12.3 GENERAL COMMENTS

12.3.1 Record Keeping Documentation Quality Documentation Availability, Material lists or MSDs, (reports, equipment analysis, drawings etc.)

Tag numbers of coolers, exchangers and vessels on the PFD do not match tag numbers in inspection reports. Tag numbering system was changed at one point. PFDs are not up to date, it does not show most recent equipment compared with inspection reports.

No MSDs were available. The material selection of equipment was taken from the equipment construction drawings where possible. No good records were available that documented changes in material selection. In some cases material selection changes were found in inspection reports.

The original equipment data sheets were not available. The installation date is the date on the equipment construction drawings, as no equipment data sheet was available.

In case of piping, the PIRS system uses a system of inspection sketches to communicate measurement locations and areas requiring repairs or replacements. The piping section in the Criticality Analysis Matrix was not complete, the PIRS piping data contained 22 more line numbers.

> **Recommendations**: Develop a system of inspection sketches for equipment where inspection locations can be shown as well as clear description of material of construction of a given component.

12.3.2 Discrepancy between PIRS dwg and PIRS DB

PIRS dwg	Service	Material on PIRS dwg	Material in PIRS DB
04056	Crude, Inlet line R-2	P5, 5Cr-½Mo	API 5L-B

> **Recommendations**: Verify the piping material on PIRS dwg 04056. Material should be P5, 5Cr-½Mo. In case it is API 5L-B, pipe section shall be replaced with P5, 5Cr-½Mo.

Table 12.1 HV-6 - Summary of Equipment Issues

<table>
<tr><th>Category</th><th>Equipment</th><th>Comment</th></tr>
<tr><td rowspan="2">Equipment with residual life of <5 y</td><td>Feed Heater, BA-1</td><td>Tube renewal due to oxidation regular at each four year turnaround. Stainless steel roof tubes susceptible to high temperature degradation due to coke internal formation. The amount of tube and refractory degradation seems excessive.

Recommendation: Redesign burner configuration to optimize firing, heat distribution and avoid flame impingement. Consider upgraded refractory materials.</td></tr>
<tr><td>Distillation Column (Vacuum Column), C-1 (DA-1)</td><td>The overall condition of the column seems poor but insufficient accurate data is available to properly evaluate the condition of the column. The ADOS section was SS strip lined to resist NAC (1983). Pre-1990 the bottom dome was severely corroded and externally patched (covering ca. 1/3 of the circumference). Strip liner is cracked and the shell has been perforated (pinholes, likely sulfidic corrosion). Laminations were found in top section. Replacement of sections was recommended, however it is unclear if this was done.

The york screen is worked on each turnaround, including repairs to bubble cap trays below. Stripping section trays are often found cracked at each turnaround.

Recommendation:
Document the material selection of the column (need marked up GA dwg). Exact material selection is unclear. Sandvik 3RE60, duplex SS is used for sheet material (trays) in places, it is not clear where.

Perform FFP and Remaining Life Assessment analysis (API 579 or other) to understand the condition of the column.</td></tr>
</table>

Table 12.1 HV-6 - Summary of Equipment Issues

Category	Equipment	Comment
Equipment with residual life of <5 y (cont'd)	Distillation Column (Vacuum Column), C-1 (DA-1) (cont'd)	Confirm which bubble cap trays were replaced by sieve trays (if any) Evaluate improvements that can be made to the functioning of the ADOS system (or possibly blending). As it functions now material upgrade of trays may be required. Repair and replacement of trays 11-36 seems to be regular. Consider using 316 SS (instead of 410 SS) Repair and replacement of trays 36-44 (ADOS section) seems to be regular. Consider using duplex SS (instead of using 316 SS)
	Crude Exchangers HE-4 (E-4), HE-5 (E-5), HE-6 (E-6), HE-7 (E-7) and HE-8 (E-8)	The shells of the crude exchangers suffer from quite severe sulfur and NAC, in particular the nozzles. Recommendation: Develop a strategy to deal with NAC; improve caustic addition in DA-1, install liner, alloy up, blending of crudes.
	Ejectors J-1A, J-1B, J-2A and J-2B	Ejectors have a history of quite severe erosion corrosion. **Recommendation**: Consider material change to 316 SS
Equipment requiring inspection for environmental cracking		In general, the review of this unit did not disclose any significant deficiencies in the refinery's inspection program for detecting environmental cracking in this unit.
Equipment at Risk of HTHA		HTHA is not an issue in the HV-6 Unit.
Equipment at risk of elevated temperature corrosion (Sulfidic or naphthenic acid		Vacuum Column C-1 and the shells of crude exchangers HE-4 (E-4), HE-5 (E-5), HE-6 (E-6), HE-7 (E-7) and HE-8 (E-8) suffer from quite severe Sulfidic and NAC.
API 5L-B piping in sulfiding service		Sulfidation concern >260°C. API 5L-B has no min. Si content per API 5L. ASTM A106 min. Si 0.10 wt%. Desirable would be Si min. 0.15 wt% (per API RP 939-C, Figure C.1). The following lines are affected: PIRS 04016, Gasoil, Draw-off line from DA-1 to DA-4 (290°C); material is API 5L-B PIRS 04020, Gasoil, Draw-off line from DA-1 to DA-5 (305°C); material is API 5L-B

Table 12.1 HV-6 - Summary of Equipment Issues

Category	Equipment	Comment
Equipment requiring Inspection for CUI	Asphalt/NND40 Reboiler, R-2 (RB-2)	The 2011 the boiler structural supports were found to be severely corroded and unsafe. **Recommendation**: Check supports of C-3/C-4/C5 (stacked).
Injection and Mixing point program		The refinery does not have an effective, well-structured inspection program for injection and mixing points.
Critical check valve program		The refinery does not have a program for the identification and inspection of critical valves and check valves.

13. Fitness for Service Assessment of Stripper V-5 of FCCU

13.1 INTRODUCTION

The stripper V-5 vessel shows increase in diameter after suffering a few high temperature excursions prior to 1990. Circumference of the vessel has been increased at a rate of 6mm/year since 1990. The cause of the diameter change was not identified, therefore mostly visual inspections during the turnaround were relied on for assuring integrity of the vessel.

Based on the review of the inspection reports, it appears that ISLA might not have followed all the recommendations made in 1992. Also it is not known how many times the vessel might have been subjected to temperatures above the design values during subsequent years. At this time fitness for service integrity assessment can't be carried out in its full extent due to lack of information. Material properties including high temperature creep behavior and in particular complete history of past pressure and temperature excursions as well as future operating conditions need to be available to carry out complete fitness for service assessment. Mechanical integrity for continue-to-use of V-5 Stripper remains in question.

Since the vessel has prior damages such as bulging and carbide precipitation (from metallographic analysis), material degradation has likely occurred. Relevant embrittlement mechanism and weldability should be carefully assessed prior to attempting weld repairs. C-1/2Mo material is known to be prone to strain age embrittlement and other types of embrittlement. Several brittle fracture incidents were reported when hydrotesting after repair.

If the vessel is to continue to operate missing data need to be found or developed (e.g. appropriate material testing done) and the additional integrity assessment conducted.

A bulging was discovered from the stripper V-5 vessel during the 1988 FCCU turnaround (T/A). A core sample was supposedly cut from the bulged area and a remaining life assessment and metallographic assessment were conducted in 1990 T/A. Dimensional measurements showed that the bulging was generalized to all courses and all around the vessel. It was not certain that the deformation occurred as a result of creep damage throughout 34 years of operation or as a result of thermal excursions. Diameter of the vessel increases every time it was measured during the turnaround. Table below summarizes the findings related to stripper

Table 13.1 V-5 Summary of Equipment Issues

Date	Description	Comments
09/05/1972	A serious upset resulting in temperatures in excess of 700C for both the reactor and regenerator. High temperature was also occurred in the stripper resulted in 0.9% of bulge.	In 1989 inspection bulge was 2.1%
30/09/1975	A serious upset occurred in the main fractionator C-1 causing an internal fire. No damage was reported in the reactor and the stripper	
April/1985	Several cracks were found in nozzle welds of the stripper. It was reported that cracks were due to thermal fatigue and/or poor weld quality	Microstructural examination shows some spheroidized colonies but still very much in evidence as independent grains
October 1987	Electrical failure caused a back flow of air into the stripper resulted in internal fire, a hot spot and bulged area in the stripper.	This is only a hypothesis (never proven)
March/April 1988	Bulging on stripper was detected. A bluish surface color was observed from below the petroment liner to the top of the stripper and it was suggested that this was the result of burning of metal and overheating. 2% deformation was measured. The stripper was allowed to be returned to service but recommendation was issued for further investigation during 1990 T/A	Previous measurement was 0.9%, which means there has been 1.1% strain increase since 1972 measurement. There were significant microstructural differences depending on the exact location where it is examined. It is also claimed that such a comparison is not 100% valid. Definition of % strain was not defined. *It was reported that reinforced rings were applied in Course 4.
August, 1991	Original proposal for conducting creep testing was based on the assumptions the bulged area was highly localized. However, latest measurement revealed that bulging was general and wide spread. Double extrapolation method gave an estimated remaining life of 53.8 years, whereas statistical approach using the process data gave minimum life of 3.5 to 43 years.	Too much scatter makes the data not reliable and render useful life predictions. ISLA decided to continue to use it and relies on regular inspection in every turnaround. Assuming such an inspection is undertaken, design pressure 2.4 barg as a maximum allowable pressure and 515C was recommended as the maximum allowable pressure.

Table 13.1 V-5 Summary of Equipment Issues (cont'd)

Date	Description	Comments
December 1991	Predictions based on Monkman-Grant equation gave 2.6 years remaining life for the stripper.	Some original recommendations were not followed. Extensive metallographic analysis of broken pieces was not carried out. There are some discrepancies in comparison with the information originally provided to MSCM.
February 1992	INT-TETM-00035,91 report states that maximum operating parameters for the stripper should be maintained at a maximum pressure of 2.0 barg and maximum temperature of 510C. This is in disagreement with MSCM previous recommendations (MSCM Notes No. 91-7320) issued four months earlier with maximum pressure of 2.4 barg and max. allowable operating temperature of 515 C.	MSCM No-92-7360 Recommendations 1. Now that it has been shown that the results from accelerated creep rupture testing did not provide the much needed estimate of the remaining life of the stripper<u>, it is even more important to carry out the proposed inspection for the forth coming turnaround.</u> 2. Internal inspection shall be done as usual except that emphasis shall be placed to carefully inspect the welds from the inside surface including the use of crack detection techniques. 3. <u>In-situ metallography shall be done on selected spots. Emphasis shall be done in the HAZ of vertical welds and on nozzle welds.</u>

Since there were no supporting data nor evidence for the cause of bulging, ISLA decided to estimate remaining life of the vessel using metallographic method and post-exposure creep rupture testing. Three core samples were removed from the stripper to conduct an accelerated creep tests in an attempt to estimate remaining life assessment utilizing Larson-Miller parameter. According to a report issued on August 23rd, 1991, excerpts from the report are as follows:

1. Remaining life assessment based on 10 accelerated creep-rupture tests was not sufficiently accurate and precise to render useful practical information. Although a probabilistic approach was used to quantify the uncertainties and make effective use of inaccurate testing approach was used to quantify the uncertainties and make use of inaccurate testing results, the analysis produced remaining life

predictions in between 3.5 years and 43 years if the stripper is operated continuously at the design pressure and temperature.

2. Without a reliable remaining life estimate, we shall still depend much on future regular inspection results to eliminate the possibility of failure. This inspection, however, will have to be specially designed to detect creep failure problems.
3. No conclusive evidence has been found to suggest an imminent failure incident with the stripper.
4. Previous knowledge that is existence of shell bulging in the order of 2% and the uncertainty about the real causes of this bulging.
5. Since creep failure in this type of vessel is expected to be preceded by further bulging of the shell and/or cracking at the longitudinal welds, an inspection program is proposed which is intended for monitoring both aspects.

On the other hand, a report issued by MSCM (MSM Note No 92-7360) concluded that the data scatter and uncertainty was so large; therefore, there is no point on assessing the remaining life estimation based on creep test. Unreliability of the prediction will be even larger than normal if use is made of complicated procedures. Selected testing conditions were not adequately representing the operating conditions. There was consensus about the fact that the bulging in the stripper was the result of high temperature excursions rather than long term creep under near normal operating conditions. The memo also noted, however, “That is not to say that the stripper does not exhibit any creep damage but the failure of dangerous cracking is not expected to occur in the near future, certainly not before the forth coming turnaround. A thorough inspection is being completed again for the next turnaround, which is scheduled for 1993.”

Circumference measurements at the T/A since 1990 are shown in the Table below:

Table 13.2 Circumference measurement COURSE 4 at various years (based on Figure 4)

	1979	1988	1990	1993	1999	2012
Measured Length (mm)			14803	14825	14850	14935
Reported permanent strain (%)*	0.9%*	2.0%*				
Delta (mm)				22mm	25mm	85mm

- * no actual measured data were available except “reported creep strain” but it is not clear whether the permanent strain was due to creep or by other mechanisms.
- Original Circumference was reported in two different numbers (π*D = 4644* π = 14590mm, and 14559mm which was measured adjacent to the top/bottom head.
- Measurement condition was not fully described, therefore, accuracy of measurement is not warranted.

25.5 years have passed since the remaining life assessment and another report issued in 1992 claimed that the previous remaining life assessment was invalid. <u>It should be noted that the circumference has increased 132 mm between 1990 and 2012 on average of 6 mm per year and 6.5 mm per year increase between 1999 and 2012.</u>

At this moment it is not clear whether the increases in circumference has been mainly caused by additional temperature excursions, measurements errors, creep or combination of the above. From the data shown above indicated that the damage still exists and will not be restored unless it is replaced with a new material.

13.2 ENGINEERING ASSESSMENT

As noted in 1992 Report, the remaining life assessment performed in 1989-1990 should be invalidated for many reasons noted in the No-92-7349 report. One of the reasons is that the test condition is much higher than the operating condition. In such a case, it will be difficult to estimate reasonable remaining life by extrapolating the Larson-Miller parameter as shown in Figure 1 (Reference API 579 committee work Figure 13.5-2). A great deal of technology progresses have been made since 1991 regarding high temperature life assessment. (ref: Prager, M. " Development of Project Omega Method for the Life Assessment in the Creep Range" ASME PVP, 1994, Kim. DS & Mead, HE " Creep Remaining Life Assessment of Heater Tubes using Omega Method, ASME PVP 1999, API RP 579, 2007). American Petroleum Institute (API) Recommended Practice API RP 579 "Fitness For Service" and ASME "FFS-1" was published to estimate a more accurate remaining life assessment and testing. More realistic remaining life assessment can be made by utilizing the Omega method. In order to carry out the assessment, actual material data, process temperature and pressure should be given. Since no available data were provided, only sensitivity analyses were made to provide perspectives.

13.2.1 Design Condition

Material of Construction: ASTM A-204 Grade A (C-0.5Mo)

ID = 4600mm (181.10 in), **OD**=4644mm (182.83 in)

Nominal wall thickness = 22 mm (0.866 in)

Corrosion allowance = 9.5 mm (3/8 in)

PWHT: Yes (PWHT temp. unknown)

Design/operating pressure: 2.4kg/cm2 (34.1 psi)/1.29 kg/cm2 (18.3 psi)

Design/ original operating temperature: 525°C (977°F)/482°C(900°F)

Actual operating temperature: 510°C (950°F)

Date of Operation: November 1957

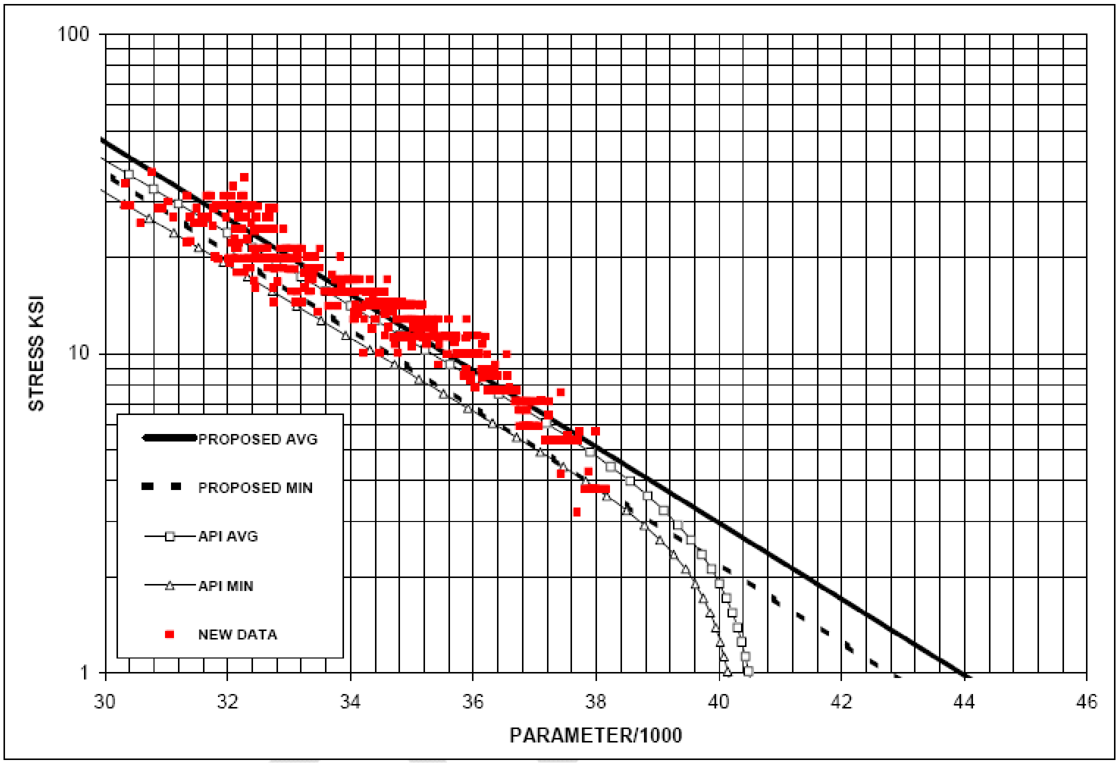

Figure 13.1 Inaccuracy of extrapolating L-M parameter at low stress range (ref: Figure 13.5-2 Larson-Millar Parameter of the Currently Employed API Curves Along With the Proposed Curves and New Data in US Customary Units: 2.25Cr-1Mo)

13.2.2 Parametric Study

Since no material creep data and operating history are available, FFS parametric assessment was conducted based on the assumptions noted below:

- Specific Omega data for ASTM A-204 Grade A (C-1/2Mo) was not available. Therefore, typical C-1/2Mo Omega data were used.
- No general metal wall loss i.e., FCA = 0.0
- Stress change due to diameter change was negligible.

Remaining life calculation was based on the equations shown below:

Determine remaining life (L) at the given stress level and temperature by utilizing creep rupture data for the material

$$^{n}L = \frac{1}{\dot{\varepsilon}_{co}\Omega_m}$$

where

$$\log_{10}\dot{\varepsilon}_{co} = -\left\{\left(A_o + \Delta_{\Omega}^{sr}\right) + \left[\frac{1}{460 + {}^{n}T}\right]\left[A_1 + A_2 S_l + A_3 S_l^2 + A_4 S_l^3\right]\right\}$$

$$\Omega_m = \Omega_n^{\delta_\Omega + 1} + \alpha_\Omega \cdot n_{BN}$$

$$\Omega_n = \max\left[\left(\Omega - n_{BN}\right),\ 3.0\right]$$

$$\log_{10}\Omega = \left(B_o + \Delta_{\Omega}^{cd}\right) + \left[\frac{1}{460 + {}^{n}T}\right]\left[B_1 + B_2 S_l + B_3 S_l^2 + B_4 S_l^3\right]$$

$$\delta_\Omega = \beta_\Omega\left(\frac{{}^{n}\sigma_1 + {}^{n}\sigma_2 + {}^{n}\sigma_3}{{}^{n}\sigma_e} - 1.0\right)$$

$$n_{BN} = -\left\{\left[\frac{1}{460 + {}^{n}T}\right]\left[A_2 + 2A_3 S_l + 3A_4 S_l^2\right]\right\}$$

$$S_l = \log_{10}\left({}^{n}\sigma_e\right)$$

13.2.3 Results of Sensitivity Assessment

Remaining life can be estimated more accurately when real material data and operating history are given. Since we could not find the relevant data, a sensitivity analysis was done for various temperature and pressure range. E&D Technologies developed a computer program to estimate the remaining life based on API 579. Results are shown in figures 2 and 3. As shown in the figures, plenty of remaining life is expected if the vessel is operated within the design limit.

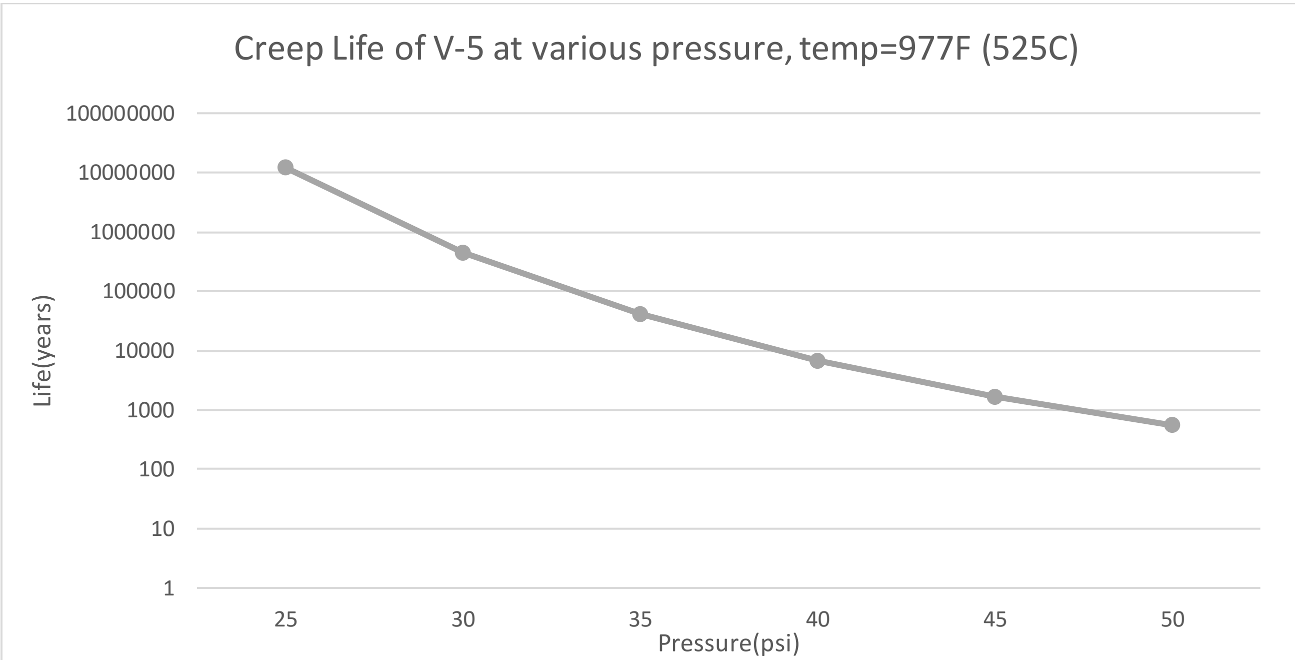

Figure 13.2

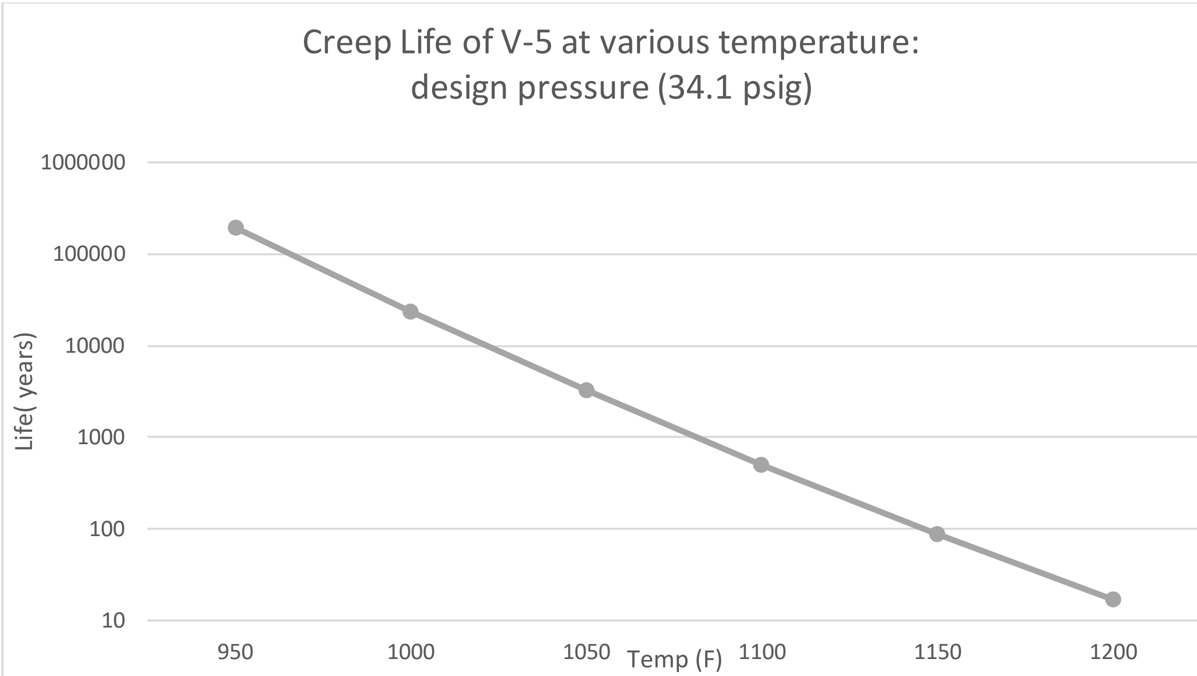
Creep Life of V-5 at various temperature:
design pressure (34.1 psig)
1000000
100000
10000
1000
100
10
Life(years)
950
1000
1050
1100
1150
1200
Temp (F)

Figure 13.3

13.3 CONCLUSIONS AND RECOMMENDATIONS

Based on reviewing the data provided by ISLA, we have made the following conclusions and recommendations:

1. Circumference of the vessel has been increased at a rate of 6mm/year since 1990. Remaining life assessment and integrity of the vessel cannot be done because of lack of material data as well as operating history.

2. Although metallographic assessment in 1992 indicated no evidence of creep and graphitization, further more detailed investigation should be conducted.

3. Based on the available data, it doesn't seem that ISLA followed all the recommendations made in 1992 shown in Table 13.1.

4. The integrity of V-5 stripper cannot be confirmed and more accurate assessment can be done if proper metallographic assessment and Omega sample testing is performed. Based on the information provided, I would recommend replace the Stripper with a new material which would allow flexibility of the future operation while maintaining reliability and integrity of the vessel.

5. Since the vessel has prior damages such as bulging and carbide precipitation from metallographic analysis, material degradation, weldability and embrittlement mechanism should be carefully examined prior to attempting weld repairs. C-1/2Mo material is known to be prone to strain age embrittlement and other types of embrittlement. Several brittle fracture incidents were reported when hydrotesting after repair (example picture attached).

6. Mechanical integrity for continue-to-use of V-5 Stripper is in question. Thorough integrity assessment should be conducted if the vessel is to continue to operate.

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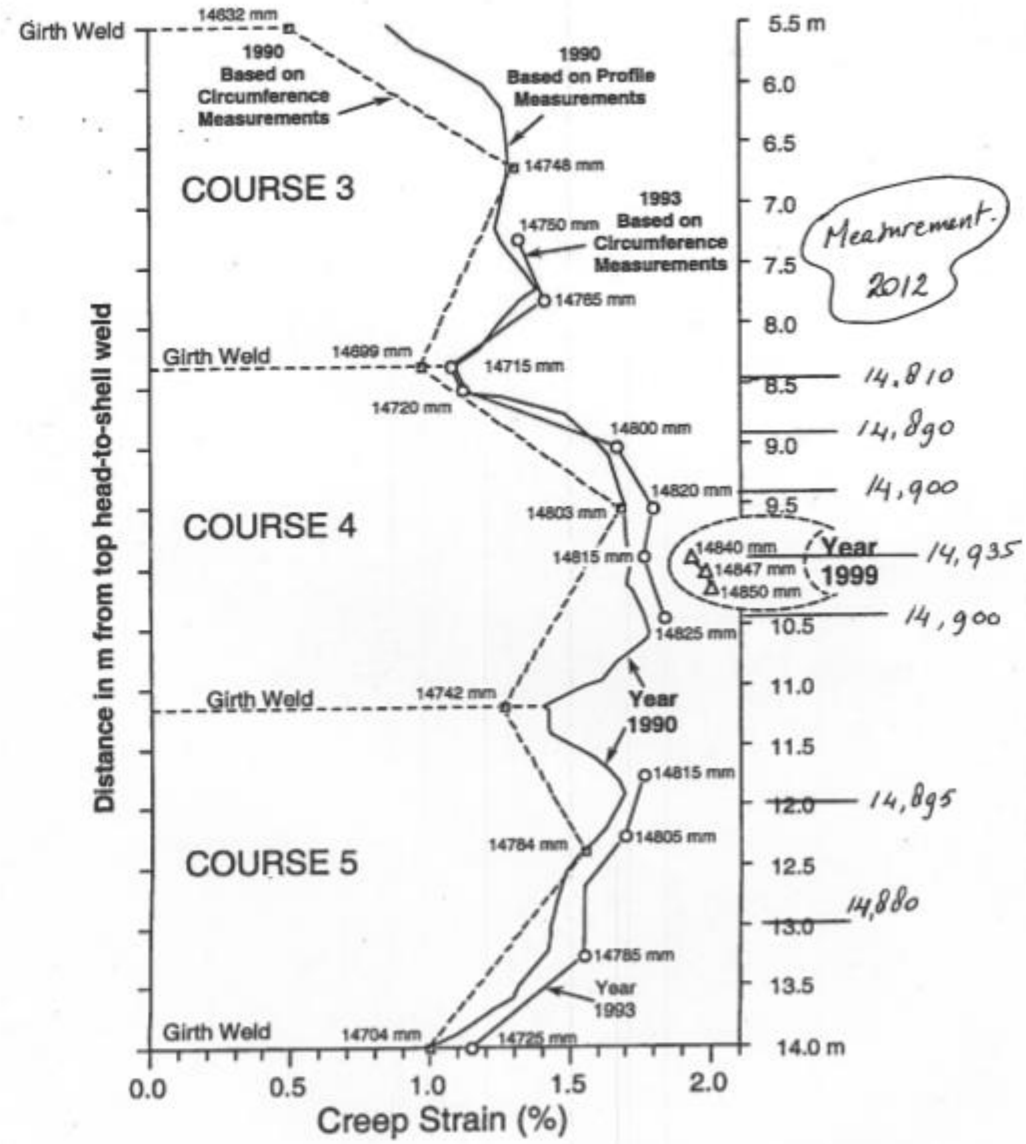

Figure 2. This is Figure 3.46 of the technical report INT-6024,1999. It shows the evidence of growth measured since 1990. Compared with the 1999 measurements, this represents a maximum of 0.28% growth in 9 years of service, equivalent to 0.031%/year creep rate.

Original circumference 14,559 measured adjacent to the top/bottom heads.

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Figure 13. 4. INT-6910, 1999