Prognostics and Health Management in the Oil & Gas Industry – A Step Change

Kenneth Moir[1], Octavian Niculita[2], and William Milligan[3]

[1]*Petrofac Oil & Gas, Bridge View, 1 North Esplanade West, Aberdeen, AB11 5QF, UK*
kmoir200@caledonian.ac.uk

[2]*School of Engineering and Built Environment, Glasgow Caledonian University,*
Cowcaddens Road, Glasgow, G4 0BA, UK
octavian.niculita@gcu.ac.uk

[3]*Howden Compressors, Old Govan Road, Renfrew, PA4 8XJ, UK*
billy.milligan@howden.com

ABSTRACT

A range of Process Hazard Analysis (PHA) tools are used throughout the Oil & Gas industry in hazard identification and analysis, to understand the effects to the system as a result of the hazards and to eliminate/reduce/mitigate the identified hazards. Prognostics and Health Management (PHM) is a life cycle concept introducing an integrated approach to the health management of a system through the design and operation cycles. Therefore, if projects can be developed within a PHM environment, this may lead to greater integration between the stakeholders, with the potential for a technically superior product developed with cost and efficiency savings. This paper demonstrates that functional analysis software applications can facilitate sensor set design to detect and isolate faults associated with the system's components and that those are comparable – with some manual adjustment – with the traditional approaches used in sensor set design. The results also show that a functional analysis approach is a viable tool in the PHA process i.e. it can generate FMECA reports and can be used to complement HAZOP studies. Finally using a PHM functional modelling application can benefit the main stakeholders in terms of demonstrating reliability, availability and maintainability of equipment whilst realising cost savings and improved efficiency.

1. INTRODUCTION

Prognostics and Health Management (PHM) is an integrated approach in managing the health of a system throughout the design and operation life cycle, refer to figure 1 below.
It is an approach that can facilitate the identification/definition of the hazards/functional failures that risk the health of the system and facilitates maintenance strategies, monitoring/diagnostics and failure prediction required to maintain the health of the system.

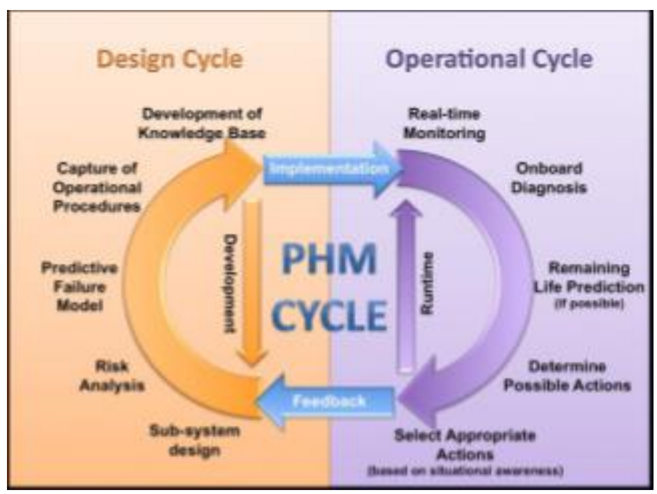

Figure 1. PHM Cycle (Stecki, Cross, Stecki and Lucas, 2012)

1.1 PHM in the Oil & Gas Industry

Prognostic models fall into three categories: data-driven; physics-based; hybrid of the two (Heng, Zhang, Tan and Mathew, 2009; Pecht, 2008; Lee, Wu, Zhao, Ghaffari, Liao and Siegel, 2014; Guillén, Crespo, Macchi and Gómez, 2016; Javed, Gouriveau and Zerhouni, 2017; Le Son, Fouladirad, Barros, Levrat and Iung, 2013).

The data-driven method utilises the data collated as part of the condition monitoring process to provide an indication of component/system failure and therefore predict the remaining time before the component fails (Pecht, 2008; Heng, Zhang, Tan and Mathew, 2009).

The model-based method requires that the physical system including the inter-relationship between subsystems are replicated in mathematical/physics-based models e.g. differential equations, transfer functions etc. (Pecht, 2008).

The hybrid method utilises both the data-driven method and the model-based method recognising that both methods have advantages/disadvantages and therefore the hybrid approach seeks to capitalise on the advantages from both systems.

The Oil & Gas industry typically adopts a data-driven prognostic approach as a first attempt in the development of a PHM capability, in conjunction with rigorous maintenance routines.

1.2 Aims and Objectives of the Paper

The aim of this paper is to demonstrate the use of PHM functional modelling software and its associated suite of software tools, to assess its applicability and suitability during the engineering design of an Oil-Injected Rotary Screw Compressor, with respect to existing process hazard analysis tools and existing methods of instrumenting a compressor prevalent in industry.

The objectives that are set for this paper are as follows: (1) Create a functional model of an Oil-Injected Rotary Screw Gas Compressor from standard engineering design drawings; (2) Identify key components of the system and analyse the effects of their functional failure and how the functional failure propagates throughout the system; (3) Analyse the sensor set assignments generated from the functional model and assess their suitability; (4) Compare the software tools available from a functional analysis/modelling application with the tools that are currently used in industry; (5) Identify the Stakeholders, their roles and responsibilities and interdependencies associated with the life cycle of an Oil-Injected Rotary Screw Gas Compressor throughout the design and operational phases.

1.3 Organisation of the Paper

The paper is organised and presented as follows: Section 1 provides a brief introduction to PHM in the Oil & Gas industry; Section 2 discusses the challenges in implementing a PHM approach; Section 3 briefly describes the operation of an Oil-Injected Rotary Screw Compressor; Section 4 discusses Functional Modelling/Failures; Section 5 analyses the functional failure analysis of key components of the system; Section 6 provides some concluding remarks.

2. PHM ANALYSIS IN THE OIL & GAS INDUSTRY - CHALLENGES & OPPORTUNITIES

There are several challenges in implementing a PHM approach in the Oil & Gas industry, which is heavily regulated at a national/international level and one where the operating/profit margins vary significantly depending on the geographical location of the facility. This next section discusses some of these challenges.

2.1 PHM, Maintenance and the Cost of Downtime

The costs associated with the production of oil and gas varies depending on the geographical location across the world. (McKinsey & Company, 2014) published a report indicating that over the course of the past 10 years, that operating and maintenance costs have increased by 10% per year. In the last 2-3 years, with the margins as tight as they are, operators typically resort to scaling back certain activities with new developments, small projects etc. usually being shelved. However, maintenance activities can also be delayed or scaled back e.g. planned shutdowns delayed or reverting to breakdown maintenance strategies. (McKinsey & Company, 2014) suggest that in the UK Continental Shelf, plant failure and unplanned shutdowns accounted for nearly 50% of overall losses and that planned maintenance shutdowns accounting for 25% of losses. (McKinsey & Company, 2014) identified three key performance related features: (1) The more efficient operators were far more likely to minimise planned downtime; (2) Reliability improvements due to lessons learned; (3) Embracing a culture within the workforce to take better care of the equipment that is in use 24/7.

The drive to cut operating and maintenance costs is pushing the agenda that is leading to the adoption of predictive maintenance strategies.

A study by (Kimberlite, 2016) cited in (GE Oil & Gas, 2016) suggested that by moving towards a predictive maintenance strategy, organisations can reduce unplanned downtime and still realise improved operational efficiency.

The (Kimberlite, 2016) study cited in (GE Oil & Gas, 2016) also noted that most of the operators included in their study used reactive or planned maintenance strategies and a much smaller percentage used predictive ones, refer to table 1 below. The table also details the percentage of unplanned downtime associated with each maintenance strategy.

As can be noted from the details in table 1, less than one quarter of the operators are using predictive/proactive maintenance strategies and they are reaping the benefits by having less unplanned downtime. Whilst the percentage values appear to be relatively small, if you translate the percentage difference into dollars, you get a different perspective.

Table 1. Maintenance Strategy vs Unplanned Downtime (Kimberlite, 2016) cited in (GE Oil & Gas, 2016)

Correlation between Maintenance Strategy and Unplanned Downtime		
Maintenance Strategy	Maintenance Strategy Operators %	% of Unplanned Downtime
Reactive	30	8.43
Planned	46	7.97
Predictive/Proactive	24	5.42

This is highlighted in figure 2 below. It has been estimated by (Kimberlite, 2016) cited in (GE Oil & Gas, 2016) that the financial impact of downtime associated with the maintenance strategy adopted and the cost differential is significant - $58M/$59M for the reactive/planned maintenance strategies compared with $24M for the predictive maintenance strategy.

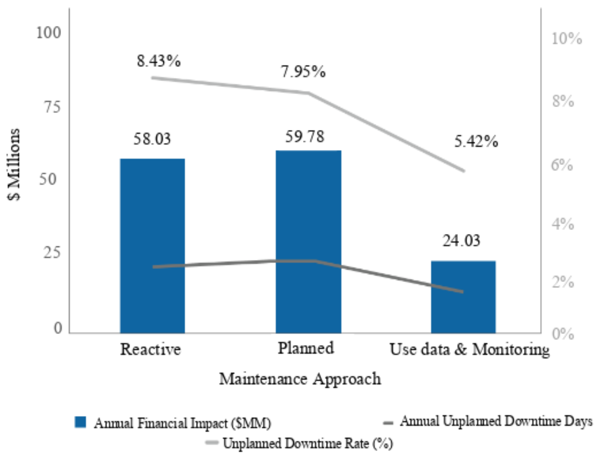

Figure 2. Costs of unplanned downtime (Kimberlite, 2016) cited in (GE Oil & Gas, 2016)

It appears to be evident that operators can make significant savings in terms of loss of revenue and lost days by adopting predictive/proactive maintenance strategies and reduce unplanned downtime.

2.2 Maintenance

Fundamentally, maintenance is the "combination of all technical, administrative and managerial actions during the life cycle of an item intended to retain it in, or restore it to, a state in which it can perform the required function." (British Standard, BS EN 13306:2010). (Dhillon 2002; Duffuaa, Raouf, and Campbell 1999) cited in (Ahmad & Kamaruddin, 2012) define maintenance "as a set of activities or tasks used to restore an item to a state in which it can perform its designated functions."

(Guillén, Crespo, Macchi and Gómez, 2016) summarise the various maintenance strategies and these are shown in figure 3 below.

Corrective Maintenance was one of the first strategies deployed in industry and it is often referred to as "Failure-Based-Maintenance", "Run-to-Failure" or "Breakdown Maintenance" (Jardine, Lin and Banjevic, 2006). Referring to the acronyms used in figure 3 for corrective maintenance, the following applies: FBM – Failure Based Maintenance; RTF – Run to Failure; BM – Breakdown Maintenance.

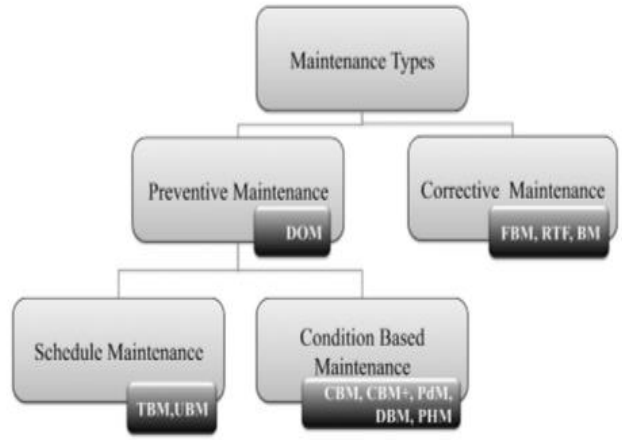

Figure 3. Maintenance Strategies (Guillén, Crespo, Macchi and Gómez, 2016)

Preventative maintenance strategies are designed to: prevent the failure based on time or usage (irrespective of condition); prevent the failure based on current condition; prevent the failure by analysing current condition with historical data; predict when the failure will be and then act in a timely manner to prevent the failure. The whole hypothesis for preventative maintenance is to implement the required maintenance actions to prevent equipment failure (Ahmad & Kamaruddin, 2012). Referring to the acronyms used in figure 3 for preventative maintenance, the following applies: DOM – Design Out Maintenance.

Scheduled Maintenance is defined in (British Standard, BS EN 13306:2010) as "maintenance carried in accordance with an established time schedule or established number of units of use". Referring to the acronyms used in figure 3 for scheduled maintenance, the following applies: TBM – Time Based Maintenance; UBM – Usage Based Maintenance.

Condition Based Maintenance (CBM) is defined in (British Standard, BS EN 13306:2010) as "preventative maintenance which includes a combination of condition monitoring techniques and/or inspection and/or testing analysis and the ensuing maintenance actions". CBM incorporates Predictive Maintenance and PHM amongst others. Referring to the acronyms used in figure 3 for condition-based-maintenance, the following applies: CBM –

Condition Based Maintenance; PdM – Predictive Maintenance; DBM – Detection Based Maintenance; PHM – Prognostics Health Management.

2.3 National/International Standards

The software suite of tools in a functional analysis/modelling application may include the feature to design a 'sensor set solution' to identify faults as part of the functional failure analysis process, however sensors required for control and safety functionality are determined by a range of national/international standards.

The standards applicable to an Oil Injected Rotary Screw Compressor are defined by the American Petroleum Institute (API) with the main ones being: (1) API619:2004 Rotary-Type Positive Displacement Compressors for Petroleum, Petrochemical and Natural Gas Industries; (2) API614:2008 Lubrication, Shaft-sealing and Oil-control Systems and Auxiliaries; (3) API670:2000 (R2003) Machinery Protection Systems

In addition to standards, the API also issue Recommended Practices which are similar to the standards i.e. they serve to provide the minimum requirements of the compressor package and they may form the basis for client/EPC specifications. The following Recommended Practices would apply: (1) API RP 500 Classification of Electrical Installations; (2) API RP 520 Sizing, Selection and Installation of Pressure Relieving Devices e.g. PSV's; (3) API RP 14C Analysis, Design, Installation and Testing of Basic Surface Safety Systems for Offshore Production Platforms.

API RP 14C is a recommended practice to facilitate the design requirements for offshore safety systems and includes wellhead systems, pressure vessels, compressors, pumps, heat exchangers, pipelines etc. It is a safety analysis process used to determine the safety concerns and requirements to protect process equipment. It provides recommended safety devices and locations for a typical compressor unit and provides specific requirements in terms of compressor suction/discharge pressure protection, temperature measurement, gas detection and shutdown valves.

2.4 Organisational Interfaces and Importance of PHM Requirements

To develop and implement any of the prognostic approaches mentioned in section 1, different types of data and information is required (Vachtsevanos, Lewis, Roemer, Hess and Wu, 2006). This information and data must be geared and contextualized towards a clear understanding and characterization of the failure and technical risk to specify the requirements for a PHM capability for an Oil-Injected Rotary Screw Compressor. It represents the output of several engineering disciplines being owned by various functional teams typically not part of the same organization. Please note that per the previous section, there are recommended standards and practices that system designers of such systems follow to tackle the event of a failure but they are only focused on specific parts or sub-systems in isolation. Only recently, a recommended practice targeting the reliability, technical risk and integrity management at the system/project level was published and it is now being adopted by the Oil & Gas community (Strutt & Wells, 2014). Although tailored for subsea equipment, many of the processes referenced in API-RP-17N are equally applicable to top-side equipment. During the development of this recommended practice, it was mentioned that the low figure of availability for equipment used in the Oil & Gas industry sector is because operators never asked specifically for reliability, subsequently this was not identified as a deliverable during the design process. If a system level PHM capability is to be developed for an oil-injected rotary screw compressor, our view is that it should be channeled through a cost-benefit-risk analysis and directly linked to FMECA or HAZOP, therefore direct access to operational reliability data is instrumental in setting the scene for the requirement capture phase (Saxena, Roychoudhury, Celaya, Saha, Saha, and Goegel, 2010). On the other hand, the availability of operational reliability is one of the main concerns raised by various OEMs throughout forums and workshops aimed at the design and development of condition monitoring solutions for Oil & Gas production and processing equipment. The PHM requirements should be split into requirements covering two main areas: Maintenance Management (ReqMM) and Integrity Management (ReqIM), refer to figure 4 below. Although all stakeholders: operators, OEMs, design/engineering services, maintenance and regulators should be involved in the discussions, we have found that the first set of requirements (ReqMM) are usually driven by the discussions between the Operator and the OEM, while the second set of requirements (ReqIM) must involve the Design/Engineering services and the Regulators with considerations for significant input from the OEM and Operator. The ReqMM should be targeting primarily cost through increased uptime, efficient maintenance, optimized lifecycle. The ReqIM are typically targeting the safety, reliability and efficient operations. Figure 4 below highlights the interfaces between the stakeholders associated with Maintenance Management and Integrity Management.

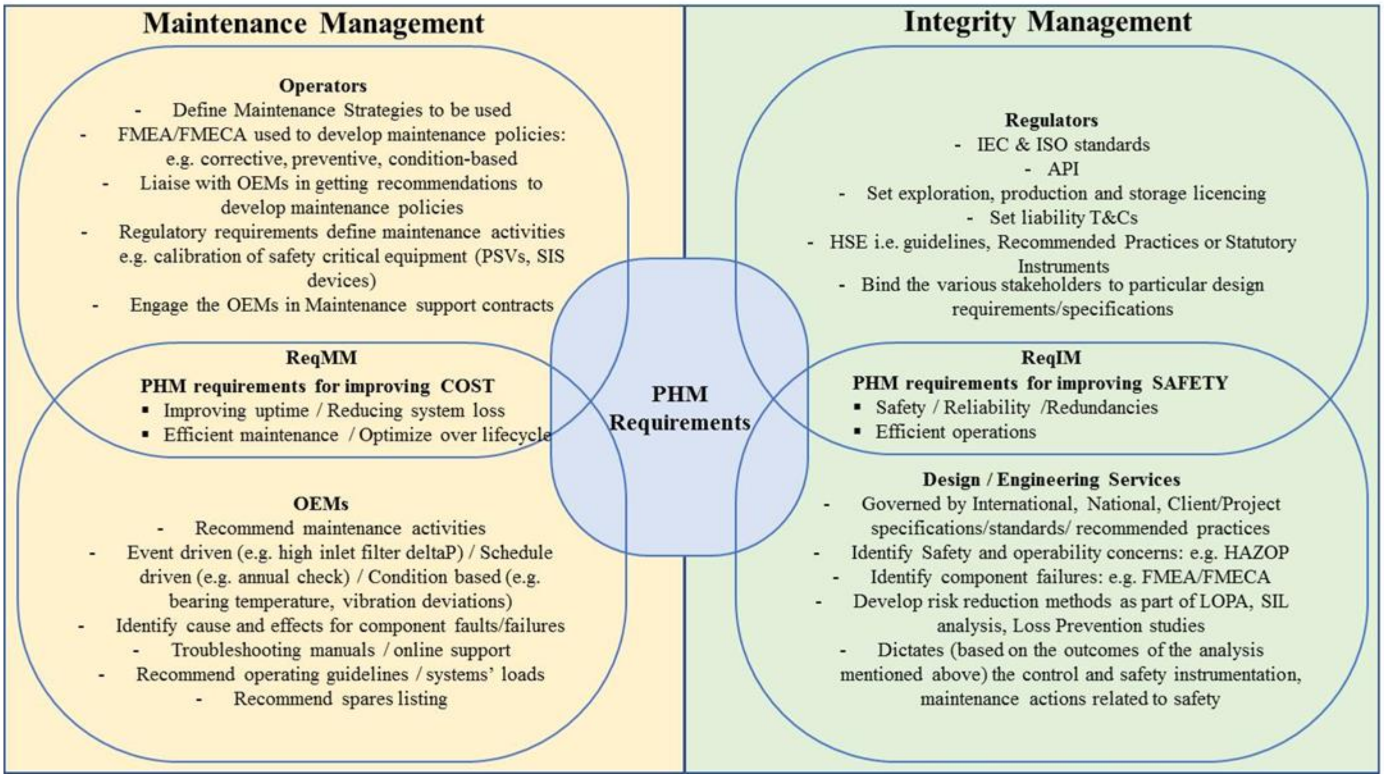

Figure 4. Stakeholder Interfaces

3. OIL INJECTED ROTARY SCREW COMPRESSOR FUNCTIONAL DESCRIPTION

The compressor used for reference in this paper is an Oil-Injected Rotary Screw compressor driven by an electric motor.

Prior to creating the functional model, used to identify functional failures and understanding the effects of these failures, an understanding of the function of the main components/processes of the compressor is recommended. This next section provides a brief description of the components and their process functionality.

3.1 Oil-Injected Rotary Screw Compressor

Rotary screw compressors operate on the principle of positive displacement (Stosic, Smith and Kovacevic, 2003) i.e. a volume of gas is drawn into the compressor casing via the suction/inlet port; the available volume is reduced, thereby compressing the gas; the compressed gas exits the casing at a higher pressure via the discharge port (Stosic, Smith and Kovacevic, 2011).

In an oil-injected compressor, lubricating oil is injected into the compressor casing via a dedicated port and mixes with the process gas. The lube oil forms a film between the lobes of the male/female rotors and is also used to lubricate the bearings, the mechanical seal, shafts and it also acts as a coolant i.e. it facilitates the heat absorption during the compression process. The lube oil is also used to operate the hydraulic slide valve mechanism to enable capacity control of the compressor.

3.2 Compressor Process Gas/Oil Systems

3.2.1 Suction Knock Out Drum

The suction Knock-Out drum is located upstream of the compressor inlet port and it is designed to remove any liquid droplets entrained in the gas flow prior to it entering the compressor casing. Coalescer elements are installed in the gas flow with entrained liquid dropping out by gravity, collecting in the bottom of the vessel – a level control system is used to control the liquid level in the Knock-Out drum. Dry gas is then routed to the compressor inlet port. Recycle gas is also routed to the suction Knock-Out drum from downstream of the gas cooler.

3.2.2 Rotary Screw Compressor

The rotary screw compressor consists of two helical rotors that mesh together, one rotor is referred to as the male rotor (driving) and the other is the female (driven). The male rotor is connected via a flexible shaft coupling to the electrically operated main drive motor. The male rotor contains four lobes which mesh with six flutes on the female rotor.

'Dry' hydrocarbon gas from the suction Knock-Out drum is routed through the inlet strainer, designed to remove solid particles, into the compressor casing at the compressor inlet/suction port. Lube Oil is injected into the gas stream and the gas/oil mixture fills the void between the helical rotors and as the rotors rotate, the meshing of the lubes/flutes reduces the area occupied by the gas/oil mixture which in turn causes compression of the gas/oil mixture. The compressed gas/oil mixture is discharged into the Primary Gas/Oil Separator and Oil Reservoir where gravity separation takes place.

The capacity of the compressor is controlled via a slide valve with the recycle valve used for fine tuning of the capacity control. The slide valve is operated hydraulically utilising lube oil.

3.2.3 Primary Separator and Oil Reservoir

As the gas/oil mixture enters the combined separator/reservoir, the gas expands and its velocity drops and as it does, the oil liquid drops out by gravity into the reservoir. The gas flow and any residual entrained oil flows through primary and secondary separators to remove all the oil content, which drops by gravity into the reservoir. Oil free gas is discharged from the separator and routed to the combined gas and lube oil cooler.

3.2.4 Gas Cooler

The gas is routed through a tube bundle and two fans are used to draw cold air up over the tube bundle to cool the process gas. The same fans are used to cool the lube oil which is routed through a separate tube bundle but within the same housing as the gas tube bundle. The gas cooler discharge temperature is controlled by varying the speed of the fans.

4. OIL INJECTED ROTARY SCREW COMPRESSOR FUNCTIONAL MODELLING

The MADe™ software application (version 3.7.1) shall be used to model the oil injected rotary screw compressor. The suite of tools available within this software shall allow me to model the flows of energy throughout the system e.g. pressure, flow, torque, angular velocity, electrical and therefore understand the effects of component functional failure to these energy flows.

4.1 Oil-Injected Rotary Screw Compressor (Gas) Model

A PFD of the system was created from a suite of P&ID's available from one of the OEM's that manufacture this type of compressor.

The functional model was focused on the forward flow of process gas and the recycle flow of Lube Oil.

4.2 Functions and Flows

Each component requires the assignment of functions and flows. The functions describe the operation of the component and what it does, they can be quite generic.

Modelling the inflows/outflows for each component is more detailed and forms the basis for functional failure analysis and the associated sensor set assignment designed to detect functional failure.

The flow of energy between components are mapped as inflows and outflows within each component. Figures 5 and 6 below detail the philosophy that is used in determining the inflows/outflows for the components used in the modelling of the compressor.

Simulation of a component failure is achieved by initiating a perturbation of the outflow in the direction of the components functional failure e.g. in the example of the valve in figure 5, a perturbation of High or Low Flow would be initiated to simulate a functional failure of the valve.

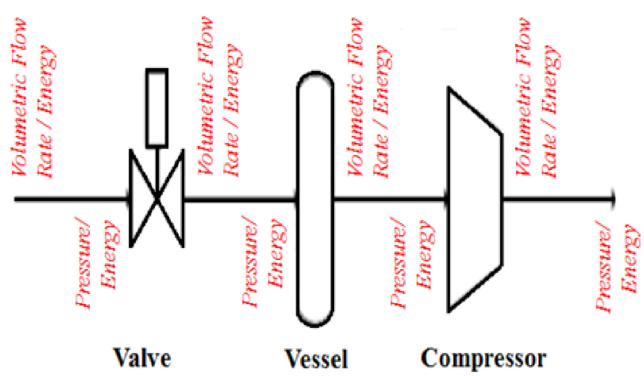

Figure 5. Energy Flows between Components – pipework, valve, vessel, compressor

The motor shown in figure 6 below, details a power source i.e. voltage for each electrically operated component with corresponding control signals e.g. start/stop, on/off.

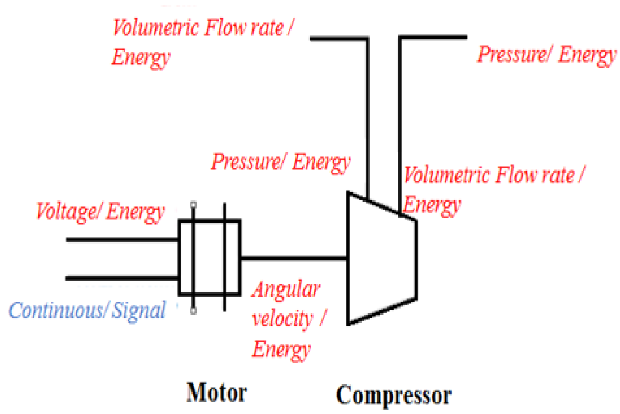

Figure 6. Energy Flows between Components – motor, compressor, pipework

The model also details the 'causal' relationships between the inflows/outflows in each component. This is essential when it comes to the analysis of component functional failure and how that failure propagates through the downstream connected components.

4.3 Failure Diagrams

For each component, corresponding failure diagrams were identfied, these map out the sequence of events leading to the component functional failure mode. The failure diagram details the following: causes, mechanisms, faults - that will result in a functional failure of the component. Standard definitions for these failure concepts are listed below.

1. Failure Cause – set of circumstances that leads to failure (British Standard, BS EN ISO 14224:2016)
2. Failure Mechanism – process that leads to failure. The process can be physical, chemical, logical or a combination thereof. (British Standard, BS EN ISO 14224:2016)
3. Fault – inability to perform as required, due to an internal state (British Standard, BS EN ISO 14224:2016)
4. Failure – loss of ability to perform as required (British Standard, BS EN ISO 14224:2016); termination of the ability of an item to perform a required function (British Standard, BS EN 60812:2006)

Data provided in the Failure Mechanism/Mode tables in OREDA Vol.1 taxonomy 1.1 was used to define component failure mechanisms where functional failure of a component is the failure of its outflow. The failure diagrams are developed by establishing correlations between faults and functional failures as well as the failure conditions for each component.

4.4 Component Functional Failure

The functional modelling software allows the user to identify key components for functional failure analysis, simulate a failure of the component and understand how that failure propagates throughout the system.
For the components selected for functional failure analysis with respect to the failure direction of the outflow - flowrate, pressure, electrical/mechanical energy outflow parameters were selected to decrease, whereas temperature could be selected for increase only or both increase and decrease. This selection is based on the functional operation of the compressor and the physics associated with these parameters.

4.5 FMECA

The functional modelling software application allows the user to perform a Failure Mode, Effects and Criticality Analysis and generate the reports. The criticality analysis is performed by determining the Risk Priority Number (RPN). Where the RPN is a quantitative measure of defining severity within the FMECA process as noted in (British Standard, BS EN 60812:2006) and is the product of Severity (S) x Probability of Occurrence (O) x Detection (D).
Industry generated FMECA Reports are considered as proprietary and therefore unavailable to individuals outside of the companies that generate them, therefore engineering judgement was applied when assessing the Severity, Occurrence and Detectability ranking values – the ranking values used in the functional model were based on tables 4,5 and 6 (British Standard, BS EN 60812:2006).

4.6 Selection of Components for Failure Analysis

The following documents were used for guidance when selecting components for functional failure analysis and sensor set design: (1) Offshore and Onshore Reliability Data (OREDA), 6th Edition, Volume 1 – Topside Equipment, 2015; (2) LOPA/SIL Reports provided by the Compressor OEM; (3) Components identified during the FMECA process with a higher Risk Priority Number (RPN).
(OREDA, 2015) defines failure as "The termination or the degradation of the ability of an item to perform its required function(s)". It further categorises failure into Critical, Degraded, Incipient and Unknown failures. Critical failures result in the instantaneous failure of the system/equipment which leads into a diagnostic mode to understand why. Degraded and incipient failures do not result in an instantaneous failure of the system but over time, if not attended to, the failure will deteriorate to the point at which the system fails. It is these two categories that are the focus of a PHM approach in terms of a maintenance strategy.
The LOPA/SIL report assessed several safety instrumented functions (SIF) to determine the Safety Integrity Level (SIL). Three SIF's were identified for SIL 2 categorisation:

Compressor Discharge Pressure High; Compressor Discharge Temperature High and Compressor Gas/Oil Pressure Differential Low. SIL can be defined as a relative level of risk reduction provided by a Safety Instrumented Function (SIF). It is a measure of the Probability of the Failure on Demand (PFD[2]) of the SIF and consists of 4 levels (1-4), 4 being the highest. The PFD's for SIL's 1-4 are: SIL1, 0.1 – 0.01; SIL2, 0.001 – 0.001; SIL3, 0.001 – 0.0001; SIL4, 0.0001 – 0.00001.

The FMECA report highlighted several component failures with severity rankings of 8/9: a fracture of the gas pipework; failure of the main drive motor; failure of the gas/oil pressure differential control valve and lube oil filter blockage.

Table 2 below details the four key components that have been initially identified for functional failure analysis and sensor set design.

Table 2. Components selected for Failure Analysis

Component	ID	Outflow Property	Perturbation	Failure Mechanism	Document
Inlet Gas Pipeline	3	Process Gas Pressure	Low	Leakage	OREDA
Main Drive Motor	8a	Torque	Low	Mechanical Failure	OREDA / FMECA
Lube Oil Supply Pump	17	Lube Oil Flow rate	Low	Mechanical Failure	OREDA
Gas Cooler Outlet Temperature	41	Process Gas Temperature	High	Mechanical Failure	OREDA

5. DIAGNOSTIC ANALYSIS

The Propagation Table is the main tool for analysing the model as it details the components selected for functional failure analysis and the effects of that failure as it propagates throughout the model.

A diagnostic analysis of the Propagation Table will identify the optimum number and associated location of sensors that will detect/isolate the component responsible for functional failure of the system.

With respect to selection of sensor sets with Ambiguity Groups, preference was given to sensor sets that offered a variance in the outflow properties used to determine failure e.g. pressure, temperature and flow vs only temperature or pressure & temperature. This provided a range of measurement techniques to confirm the detection of a functional failure of a component as opposed to just one measurement technique. This minimises common cause of failure and therefore increases availability of the system.

Table 3. Components selected for Failure Analysis

Analysis	No. of Components Selected for PHM Design Analysis	Best Possible Coverage	No. of Sensor Sets Generated/Analysed	Range of Sensors per Set	Ambiguity Groups	Components per Ambiguity Group
1	4	100%	72	4-7	NONE	N/A
2	5	60%	81	3-5	1	2
3	6	50%	38	4-6	1	3
4	9	55.56%	57	6-9	2	2/2
5	13	44.44%	51	5-8	2	2/3

A summary of the diagnostic analysis of the system are detailed in table 3 above.

Appropriate sensors were selected from the Sample Sensor Library within the software suite and assigned to the component outflows referenced in all sensor sets selected. Selection of sensor type/technology is detailed in table 4 below.

Table 4. Outflow Property vs Sensor Type/Technology

Outflow Property	Sensor Type/Technology
Pressure	Piezoelectric pressure sensor
Temperature	Resistive temperature device
Flow	Differential pressure device (Orifice Plate)
Torque	Rotary transformer (Strain gauge)
Angular Velocity	Toothed ring & pick-up

The detailed results from the analysis carried out are discussed in the next section.

5.1 Diagnostic Analysis #1

The functional model consists of 41 components and several sub-components, depicting the flows of process gas and lubricating oil used in the compressor package and their interdependencies, with the components/sub-components containing multiple inflows and outflows. The components referenced in Analysis #1 to #5 are detailed on the functional model – this is available upon request, as proprietary software is required to view the model. The functional model also details the location of sensors (small green circles) – these are based on Diagnostic Analysis#5, sensor set #37.

Referring to the lower section of the table in Appendix 1, it can be noted that as the number of sensors increases, the fitness score for the sensor sets decreases. This value is calculated in the software and is based on the coverage and the number of test points. The upper section of the table in Appendix 1 is the propagation table from the model exported to csv/excel.

The interpretation of the data is as follows – low pressure at (3) OR low mass flow rate at (4) OR (6) is indicative of a failure of the gas pipeline (3). Similarly, low torque at (8a) OR low angular velocity at (8b) is indicative of a failure of the main drive motor (8a). The same logic applies for failure of the lube oil supply pump and the gas oil cooler i.e. there is no ambiguity, one point of measurement clearly indicates the failed component.

The one notable exception is the detection of low pressure at component (11), in this scenario, a failure of the gas pipeline OR the main drive motor OR the lube oil supply pump i.e. the reverse OR logic to the ones described above. However, if low pressure is detected at (11) and (3), then the gas pipeline is the failure point; if low pressure is detected at

(11) and (16), then the lube oil supply pump is the failure point and so on.
The location of the measured variable differs in each of the sensor sets calculated and the locations of the sensors is detailed by the coloured squares in the table in Appendix 1. E.g. sensor set #17 consists of 1 x flow rate sensor, 3 x temperature sensors and one angular velocity sensor.

5.2 Diagnostic Analysis #2

In the second analysis, the Duplex LO filter low flow rate component was added – the table in Appendix 2 details the selected sensor sets for comparison.
The introduction of the fifth component also introduced one Ambiguity Group to the results, consisting of low lube oil flow in both the Lube Oil Supply Pump (17) and the Duplex LO Filter (26) – reference the rows highlighted in green in the table in Appendix 2.
The resultant of an Ambiguity Group is that functional failure of a component cannot be determined by the allocated sensors. Referring to the upper section of the table in Appendix 2, if you review the functional failures of components (17) and (26), you will note that no single point of measurement differentiates between these two component failures.
From the table in Appendix 2, it can be observed that low lube oil pressure (18) or low lube oil flow rate (10) indicate that the failure is either the LO Supply Pump or it is the Duplex LO Filter, but there is no singular point of measurement that can determine that it is one or the other.
The logic for the other 3 components remains as described in analysis #1 with similar logic for low flowrate (8c) and low pressure (11) e.g. low pressure (3) and low pressure (11) is indicative of a failure of the gas pipeline (3).
Comparing sensor sets 17 and 35 (4 sensors each), some trade-off should be considered – refer to the table in Appendix 2 upper section:

1. Sensor set #35 results in a gas pipeline (3) failure being detected further downstream (5) but low pressure detected at component (18) is failure of the LO pump or the LO filter.
2. Sensor set #17 results in a gas pipeline (3) failure being detected at the component itself, however a failure of the LO pump or the LO filter can only be determined by confirming that the gas pipeline or main drive motor have not failed – reference low pressure in component (11).

Comparing sensor sets 40, 57 and 75 (5 sensors each), similar trade-offs should be considered – refer to the table in Appendix 2 upper section:

1. The 3 groups offer different locations, flow properties and therefore sensor type to determine failure of the LO pump/filter ambiguity group i.e. temperature (27) and (8c) for sensor sets #40 and #75 respectively whilst flow (10) for sensor set #57.
2. Failure of the gas pipeline component (3) can be determined by different sensor types and locations i.e. sensor set #40 utilises pressure and flow at components (5) and (6); sensor set #57 utilises pressure at components (3) and (7); sensor set #75 utilises pressure and flow at components (3) and (4).
3. The differences between the measurement points for failure of the gas cooler are insignificant.

Sensor set #57's use of flow rate may sound a good option for detecting the ambiguity group's failure as the flow rate would deviate quicker than the temperature upon either component failing, however sensor set #75 utilises temperature measurement at the discharge of the compressor. Given that the discharge temperature control of the compressor is a key measured variable, then sensor set #75 may be the better option.
Sensor set #75 consists of 1 x mechanical/rotational torque sensor; 1 x pressure sensor; 1 x temperature sensor and 2 x flow rate sensors.

5.3 Diagnostic Analysis #3

In the third analysis, the TCV (32) low flow rate was added – the table in Appendix 3 details the selected sensor sets for comparison.
The introduction of the TCV added that component to the Ambiguity Group created in analysis #2 i.e. the group now consisted of 3 components, reference the rows highlighted in green in the table in Appendix 3 – low lube oil flow in the Lube Oil Supply Pump (17), TCV (32) and the Duplex LO Filter (26).
None of the 3 sensor sets were ideal as failure of the gas pipeline (3) was not detected until low flow at component (41), the gas pipeline (3) was embedded with other component failures and therefore requires 'NOT' logic to be applied e.g. using sensor set 36, low flow (41) and NOT low angular velocity and NOT {low flow (29) OR low flow (10) OR low temperature (8c)} = low pressure at component (3), refer to the table in Appendix 3 upper section.
Sensor set #36 would be the better option from those available. Sensor set #36 consists of 1 x angular velocity sensor; 2 x temperature sensors; 3 x flow rate sensors. There are no pressure sensors in this option, whereas pressure sensors are commonplace in compressor packages. For the ambiguity group, sensor set #36 offers flow and temperature measurement to confirm functional failure of the components in the group.

5.4 Diagnostic Analysis #4

In the fourth analysis, the TCV from analysis #3 was replaced by the compressor (8c) and the LO Separator/Reservoir (10), with high temperature and low flow rate selected for both these components - the table in Appendix 4 details the selected sensor sets for comparison.

By introducing the two additional components and selecting high temperature and low flow as functional failures in both, this resulted in an additional ambiguity group i.e. there were now two ambiguity groups:

1. Group 1 consisted of high temperature in the Oil-Injected Compressor (8c) and the LO Separator & Reservoir (10).
2. Group 2 consisted of low lube oil flow rate in the LO Supply Pump (17) and the LO Filter (26).

Referring to the table in Appendix 4, failure of components (3), (8a), (41) are easily detected/isolated by a single measurement i.e. low pressure (3), low torque (8a), high temperature (15) respectively.
Referring to the upper section of the table in Appendix 4, a loss of flow at component (8c) could be from a failure of components (3), (8a), (8c, temperature + flow), (10, temperature only), (17) or (26).
However, if I do not have corresponding failures – low pressure (3) or low torque (8a), those are ruled out leaving the two ambiguity groups – an increase in temperature at (8c) or (10) OR a loss of flow at (17) or (26).
A similar scenario exists with measurement of temperature at component (24), it could be from either of the ambiguity groups i.e. an increase in temperature at (8c) or (10) OR a loss of flow at (17) or (26).
In terms of the ideal sensor set from this analysis, all four sensor sets are suitable for the detection/isolation of components (3), (8a) and (41). For the four failures embedded in the two ambiguity groups, sensor set #32 utilises pressure, temperature and flow to detect/isolate the components whereas #21 only utilises pressure and temperature – therefore #32 is preferred to #21.
Comparing sensor set #32 with #55, both utilise pressure, temperature and flow to detect/isolate the components in the ambiguity groups but at different locations.
One could argue that despite having one less sensor, #32 is the preferred sensor set compared with #55. Pressure measurement at (7) provides no significant advantage to #55, whereas pressure measurement at compressor discharge pipework (9) is a key process parameter of the system and on this basis sensor set #32 would be the preferred option from this analysis.

5.5 Diagnostic Analysis #5

The modelling software does not assign sensors first, once a sensor set has been selected, appropriate sensors types can then be assigned. Further analysis was required to assess the locations where the standard design approach assigns sensors to understand how that affected system coverage, fitness, number of sensors and type of sensors. Therefore, components and functional failures were selected based on the location and type of sensors shown on the P&ID's supplied by the OEM. The table in Appendix 5 details the selected sensor sets for comparison.

The selected components resulted in two ambiguity groups:

1. Group 1 consisted of high temperature in the Oil-Injected Compressor (8c) and the LO Manifold (27).
2. Group 2 consisted of low lube oil pressure in the LO Pipeline (18) and LO Manifold (27) / low lube oil flow rate in the LO Filter (26).

Of the sensor sets detailed in the table in Appendix 5, #37 offers the best sensor spread despite the low percentage coverage available from all sensor sets, 7 process (gas & oil) sensors + 1 sensor for the motor assembly. It has three sensor types for identification of the ambiguity groups and the locations of the sensors determined by the functional analysis mirror very closely the locations determined by the standard design approach for pressure and temperature measurement specifically.
The maximum number of ambiguity groups achievable from this model is two. Increasing the number of components for functional failure analysis results in additional components being added to the existing ambiguity groups. As an example, if almost all the components in the model, pressure/flow/rotational outflows were selected for low failure whilst temperature outflows were selected for high failure, the analysis still produced two ambiguity groups with the temperature group containing 6 components and the lube oil group containing 16 components.

6. CONCLUDING REMARKS

This paper sought to compare the sensor set design based on the traditional engineering/design approach with a design based on the functional analysis of the system. Although analysis #1 returns sensor sets with 100% coverage, there are only 4 components selected for functional failure analysis. This however does not reflect the actual number of components that are critical in this system. Analyses #2 to #4 were designed to demonstrate the increased complexity in detecting/isolating functional failures as the size of the system for analysis is increased. This is shown by the creation and subsequent increase of Ambiguity Groups, the variation in the number of components within an Ambiguity Group and the complexity of the logic (as shown by the ±1 perturbations) in the excel exports of the Propagation Tables. In diagnostic analysis #5, the selection of components for failure analysis reflects those that in an actual compressor, are monitored by pressure, temperature and flow sensors for either control, shutdown or indication only purposes. None of the sensor sets in this analysis group provide a sensor set optimising locations and numbers, nor do they mirror those used in the actual compressor – which is a challenge for justifying the use of functional analysis for sensor set assignment when compared with the requirements set out in the API standards. It is possible to manually generate a sensor set, however this is not something that is explored in this paper.

Functional Analysis is not traditionally used in the oil and gas sector, either for compressor design nor the other key pieces of equipment in use e.g. subsea systems, however, it is a useful process in identifying risks and how those risks can propagate throughout the system with respect to the design function. Functional analysis is an automated process and can determine the system response to the functional failure of a component as the failure propagates throughout the system as mapped in the model, resulting in a detailed breakdown of the events that can lead to a functional failure of the system i.e. the Propagation Table. Functional Analysis software applications can present the data for further analysis, including FTA and RBD, where the latter can facilitate Functional Reliability (and Availability) Analysis of each component within the system. In addition to mapping out the propagation of functional failures and the subsequent identification of the components that pose a risk to the operation, reliability and availability of the system, a functional analysis can facilitate the critical analysis of the failure modes of the components that make up the system i.e. FMECA.

The traditional approach to performing a FMECA is very time consuming and requires a significant amount of manual data entry in the corresponding documentation, in addition to the time taken to decide/analyse all failures. Functional analysis software suites can generate the FMECA report most likely with less manual data entry, as many of the fields use default information from the model. A similar level of diligence is required in defining component failure, the cause of the failure and any effects/symptoms etc. whether the user is using a functional model or following the traditional approach. The advantage of using functional analysis and its internal software FMECA tool, is that everything is in the one database and therefore if changes are made to the model, e.g. modifications to a component's failure diagram, then the associated changes can be updated (i.e. O,S&D rankings) and the FMECA report re-generated.

In the current economic climate where performance criteria are measured in terms of safety, reliability, availability and maintainability of an asset, deriving many of the technical and managerial decisions associated with these criteria can be facilitated by utilising a model-based approach. Functional models facilitate management of assets with a suite of analysis tools e.g.: RBD, FMECA, FTA & RCM. By integrating these processes, which would otherwise be carried out in isolation, in a model-based system, many of the processes can be streamlined, standardised and automated. By deriving the reports from the functional model of the asset, this can lead to greater consistency in the reporting and decision-making processes, resulting in efficiency savings and potentially cost savings.

In terms of the benefit to stakeholders in embracing a functional analysis approach to the design/operation of a compressor package or any other form of industrial equipment, let me offer the following thoughts. The OEM's wish to promote their products in terms of increased reliability and availability whilst minimising maintenance costs, downtime etc. The Operator/owner demands a product whose reliability/availability ensures maximum productivity/uptime at the plant where the product is deployed and therefore a product that has verifiable reliability/availability data and requires minimum maintenance in terms of costs/downtime/spares is a key consideration. The design/engineering group may limit OEM's during the bidding process to those that possess verifiable reliability/availability data or have systems/processes in place, e.g. models of their system, that can capture this type of data. The OEM is best placed to define and create the system model, however will require collaboration with the operator/owner to obtain the necessary data that can verify the accuracy of the model that represents the operating conditions that the equipment is subjected to when in operation. The OEM may be able to perform functional analysis of their own product from a reliability/availability perspective but may require some form of collaboration or servitization arrangement with operator/owner to obtain MTTF/MTTR data as well as operational and maintenance test data. The operator/owner does not want a compressor package that is unreliable and requiring excessive maintenance intervention particularly if the OEM is required to deploy maintenance personnel to support the operator/owner's staff. This is going to be very costly over the life cycle of the compressor. It may appear to be in the interests of the OEM, however increased costs and unreliability will force the operator/owner to seek a more reliable compressor from a competitor. In the long run this will not be in the OEM's interests. If the OEM's can provide Health Management solutions including the ability to accurately predict the future health of their equipment, in addition to a more reliable and therefore more cost-effective package, then the interests of the manufacturers and the customers (operator/owner) are more closely aligned.

NOMENCLATURE

API	American Petroleum Institute
BM	Breakdown Maintenance
BS	British Standard
CBM	Condition Based Maintenance
DBM	Detection Based Maintenance
DOM	Design Out Maintenance
FBM	Failure Based Maintenance
FMEA	Failure Mode and Effects Analysis
FMECA	Failure Mode, Effects and Criticality Analysis
FTA	Fault Tree Analysis
HAZOP	Hazard and Operability

HSE	Health and Safety Executive
IEC	International Electrotechnical Commission
ISO	International Organisation for Standardisation
LO	Lube Oil
LOPA	Layer of Protection Analysis
MADe™	Maintenance Aware Design environment
MTTF	Mean Time to Failure
MTTR	Mean Time to Repair
OEM	Original Equipment Manufacturer
O, S & D	Occurrence, Severity & Detectability
PdM	Predictive Maintenance
PFD	Process Flow Diagram
PFD^2	Probability of Failure on Demand
PHA	Process Hazard Analysis
PHM	Prognostics and Health Management
P&ID	Piping and Instrumentation Diagram
PSV	Pressure Safety Valve
RAM	Reliability Availability and Maintainability
RBD	Reliability Block Diagram
RCM	Reliability Centered Maintenance
ReqIM	Requirements for Integrity Management
ReqMM	Requirements for Maintenance Management
RPN	Risk Priority Number
RTF	Run to Failure
SIF	Safety Instrumented Function
SIL	Safety Integrity Level
SIS	Safety Instrumented System
TBM	Time Based Maintenance
TCV	Temperature Control Valve
T&C's	terms and Conditions
UBM	Usage Based Maintenance

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BIOGRAPHIES

Kenneth Moir is an Instrument and Controls Engineer. He has an MSc in Applied Instrumentation and Control (GCU, 2017). His research work includes Functional Failure Analysis completed as part of his Master's Degree. He has worked extensively in the oil and gas industry as a practitioner of Instrumentation and Instrument Control Systems. He is a member of the InstMC and the IET.

Octavian Niculita is a Lecturer in Instrumentation with Glasgow Caledonian University. His current research interests include model-based diagnosis and prognosis, IVHM system design, IVHM tools capable of supporting the integration of IVHM and asset design for aerospace, maritime, and oil & gas (subsea) applications. Octavian has an extensive experience in Integrated Vehicle Health Management, having worked on applied aerospace projects funded by The Boeing Company and BAE Systems as a Research Fellow on his previous appointment with the IVHM Centre at Cranfield University. He is a member of the Prognostics and Health Management Society and the IET.

William Milligan is an Instrument and Controls Engineer with Howden Compressors. He has worked primarily on the design, testing and commissioning of screw compressor control systems within the oil and gas industry for the past 10 years. He is a member of the InstMC and the IET.

APPENDIX

Appendix 1	Diagnostic Analysis #1
Appendix 2	Diagnostic Analysis #2
Appendix 3	Diagnostic Analysis #3
Appendix 4	Diagnostic Analysis #4
Appendix 5	Diagnostic Analysis #5

Component	Flow Property	Failure	(3) Gas Pipeline (Process Gas - Pressure)	(4) Suction KO Drum (Process Gas - Mass flow rate)	(6) Inlet Strainer (Process Gas - Mass flow rate)	(8a) Main Drive Motor Assembly (Mechanical - rotational - Torque)	(8b) Flexible Coupling (Mechanical - rotational - Angular velocity)	(10) LO Separator & Reservoir (Thermal - Temperature)	(11) Gas Pipeline (Process Gas - Pressure)	(16) LO Pipeline (Lube Oil - Pressure)	(17) Lube Oil Supply Pump (Lube Oil - Flow rate)	(21) LO Pipeline (Thermal - Temperature)	(30a) LO Manifold (OE Bearing - Pressure)	(41) Gas Oil Cooler (Process Gas - Temperature)
(3) Gas Pipeline	Pressure (Process Gas)	Low (SS TR)	-1	-1	-1	0	0	0	-1	0	0	0	0	0
(8a) Main Drive Motor Assembly	Torque (Mechanical - rotational)	Low (SS TR)	0	0	0	-1	-1	0	-1	0	0	0	0	0
(17) Lube Oil Supply Pump	Flow rate (Lube Oil)	Low (SS TR)	0	0	0	0	0	-1	-1	-1	-1	-1	-1	0
(41) Gas Oil Cooler	Temperature (Process Gas)	Increase (SS TR)	0	0	0	0	0	0	0	0	0	0	0	1
Sensor Set Analysis	No. of Sensors	Fitness	Sensor Location											
Sensor Set 9	4	99.09%												
Sensor Set 17	5	98.86%												
Sensor Set 32	6	98.63%												
Sensor Set 69	7	98.40%												

Appendix 1 – Diagnostic Analysis #1

Component	Flow Property	Failure	(3) Gas Pipeline (Process Gas - Pressure)	(4) Suction KO Drum (Process Gas - Mass flow rate)	(5) Gas Pipeline (Process Gas - Pressure)	(6) Inlet Strainer (Process Gas - Mass flow rate)	(7) Gas Pipeline (Process Gas - Pressure)	(8a) Main Drive Motor Assembly (Mechanical - rotational - Torque)	(8b) Flexible Coupling (Mechanical - rotational - Angular velocity)	(8c) Oil Injected Compressor (Process Gas - Mass flow rate)	(10) LO Separator & Reservoir (Lube Oil - Flow rate)	(11) Gas Pipeline (Process Gas - Pressure)	(13) Gas Pipeline (Process Gas - Temperature)	(14) Outlet Valve (Process Gas - Temperature)	(15) Gas Pipeline (Process Gas - Temperature)	(18) LO Pipeline (Lube Oil - Pressure)	(27) LO Manifold (Thermal - Temperature)
(3) Gas Pipeline	Pressure (Process Gas)	Low (SS TR)	-1	-1	-1	-1	-1	0	0	-1	0	-1	0	0	0	0	0
(8a) Main Drive Motor Assembly	Torque (Mechanical - rotational)	Low (SS TR)	0	0	0	0	0	-1	-1	-1	0	-1	0	0	0	0	0
(17) Lube Oil Supply Pump	Flow rate (Lube Oil)	Low (SS TR)	0	0	0	0	0	0	0	-1	-1	-1	0	0	0	-1	-1
(26) Duplex LO Filter	Flow rate (Lube Oil)	Low (SS TR)	0	0	0	0	0	0	0	-1	-1	-1	0	0	0	-1	-1
(41) Gas Oil Cooler	Temperature (Process Gas)	Increase (SS TR)	0	0	0	0	0	0	0	0	0	0	1	1	1	0	0
Sensor Set Analysis	No. of Sensors	Fitness	Sensor Location														
Sensor Set 7	3	65.98%															
Sensor Set 17	4	65.75%															
Sensor Set 35	4	65.75%															
Sensor Set 40	5	65.53%															
Sensor Set 57	5	65.53%															
Sensor Set 75	5	65.53%															

Appendix 2 – Diagnostic Analysis #2

Component	Flow Property	Failure	(8b) Flexible Coupling (Mechanical - rotational - Angular velocity)	(8c) Oil Injected Compressor (Thermal - Temperature)	(10) LO Separator & Reservoir (Lube Oil - Flow rate)	(13) Gas Pipeline (Process Gas - Temperature)	(15) Gas Pipeline (Process Gas - Temperature)	(27) LO Manifold (Lube Oil - Pressure)	(28) Tee (Thermal - Temperature)	(29) Isolation Valve (NO) (Lube Oil - Flow rate)	(30a) LO Manifold (IE Bearing - Pressure)	(41) Gas Oil Cooler (Process Gas - Mass flow rate)
(3) Gas Pipeline	Pressure (Process Gas)	Low (SS TR)	0	0	0	0	0	0	0	0	0	-1
(8a) Main Drive Motor Assembly	Torque (Mechanical - rotational)	Low (SS TR)	-1	0	0	0	0	0	0	0	0	-1
(17) Lube Oil Supply Pump	Flow rate (Lube Oil)	Low (SS TR)	0	-1	-1	0	0	-1	-1	-1	-1	-1
(26) Duplex LO Filter	Flow rate (Lube Oil)	Low (SS TR)	0	-1	-1	0	0	-1	-1	-1	-1	-1
(32) TCV	Flow rate (Lube Oil)	Low (SS TR)	0	-1	-1	0	0	-1	-1	-1	-1	-1
(41) Gas Oil Cooler	Temperature (Process Gas)	Increase (SS TR)	0	0	0	1	1	0	0	0	0	0
Sensor Set Analysis	No. of Sensors	Fitness	Sensor Location									
Sensor Set 7	4	57.42%	■			■			■			■
Sensor Set 16	5	57.19%	■			■		■			■	■
Sensor Set 36	6	56.96%	■	■	■		■			■		■

Appendix 3 – Diagnostic Analysis #3

Component	Flow Property	Failure	(3) Gas Pipeline (Process Gas - Pressure)	(7) Gas Pipeline (Process Gas - Pressure)	(8a) Main Drive Motor Assembly (Mechanical - rotational - Torque)	(8c) Oil Injected Compressor (Process Gas - Mass flow rate)	(9) Gas Pipeline (Process Gas - Pressure)	(10) LO Separator & Reservoir (Lube Oil - Flow rate)	(10) LO Separator & Reservoir (Process Gas - Mass flow rate)	(13) Gas Pipeline (Process Gas - Pressure)	(15) Gas Pipeline (Process Gas - Temperature)	(22) Tee (Lube Oil - Pressure)	(23) TCV (Thermal - Temperature)	(24) Tee (Thermal - Temperature)	(26) Duplex LO Filter (Lube Oil - Flow rate)	(26) Duplex LO Filter (Thermal - Temperature)	(30b) LO Manifold (Lube Oil - Pressure)
(3) Gas Pipeline	Pressure (Process Gas)	Low (SS TR)	-1	-1	0	-1	-1	0	-1	-1	0	0	0	0	0	0	0
(8a) Main Drive Motor Assembly	Torque (Mechanical - rotational)	Low (SS TR)	0	0	-1	-1	-1	0	-1	-1	0	0	0	0	0	0	0
(8c) Oil Injected Compressor	Temperature (Thermal)	Increase (SS TR)	0	0	0	1	1	1	1	1	0	1	1	1	1	1	1
(8c) Oil Injected Compressor	Mass flow rate (Process Gas)	Low (SS TR)	0	0	0	-1	-1	0	-1	-1	0	0	0	0	0	0	0
(10) LO Separator & Reservoir	Mass flow rate (Process Gas)	Low (SS TR)	0	0	0	0	0	0	-1	-1	0	0	0	0	0	0	0
(10) LO Separator & Reservoir	Temperature (Thermal)	Increase (SS TR)	0	0	0	1	1	1	1	1	0	1	1	1	1	1	1
(17) Lube Oil Supply Pump	Flow rate (Lube Oil)	Low (SS TR)	0	0	0	-1	-1	-1	-1	-1	0	-1	-1	-1	-1	-1	-1
(26) Duplex LO Filter	Flow rate (Lube Oil)	Low (SS TR)	0	0	0	-1	-1	-1	-1	-1	0	-1	-1	-1	-1	-1	-1
(41) Gas Oil Cooler	Temperature (Process Gas)	Increase (SS TR)	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0
Sensor Set Analysis	No. of Sensors	Fitness	Sensor Location														
Sensor Set 4	6	61.59%	■		■	■			■		■					■	
Sensor Set 21	7	61.36%	■		■		■		■		■		■				■
Sensor Set 32	8	61.14%	■		■		■		■		■	■		■	■		
Sensor Set 55	9	60.91%	■	■	■	■		■		■	■					■	■

Appendix 4 – Diagnostic Analysis #4

Component	Flow Property	Failure	(5) Gas Pipeline (Process Gas - Pressure)	(7) Gas Pipeline (Process Gas - Pressure)	(8b) Flexible Coupling (Mechanical - rotational - Angular velocity)	(9) Gas Pipeline (Process Gas - Pressure)	(13) Gas Pipeline (Process Gas - Pressure)	(15) Gas Pipeline (Process Gas - Pressure)	(15) Gas Pipeline (Process Gas - Temperature)	(20) PDCV (Lube Oil - Flow rate)	(24) Tee (Thermal - Temperature)	(25) LO Manifold (Thermal - Temperature)	(26) Duplex LO Filter (Lube Oil - Flow rate)	(27) LO Manifold (Lube Oil - Pressure)	(41) Gas Oil Cooler (Lube Oil - Temperature)
(4) Suction KO Drum	Mass flow rate (Process Gas)	Low (SS TR)	-1	-1	0	-1	-1	-1	0	0	0	0	0	0	0
(7) Gas Pipeline	Pressure (Process Gas)	Low (SS TR)	0	-1	0	-1	-1	-1	0	0	0	0	0	0	0
(8a) Main Drive Motor Assembly	Torque (Mechanical - rotational)	Low (SS TR)	0	0	-1	-1	-1	-1	0	0	0	0	0	0	0
(8c) Oil Injected Compressor	Mass flow rate (Process Gas)	Low (SS TR)	0	0	0	-1	-1	-1	0	0	0	0	0	0	0
(8c) Oil Injected Compressor	Temperature (Thermal)	Increase (SS TR)	0	0	0	1	1	1	0	1	1	1	1	1	0
(9) Gas Pipeline	Pressure (Process Gas)	Low (SS TR)	0	0	0	-1	-1	-1	0	0	0	0	0	0	0
(18) LO Pipeline	Pressure (Lube Oil)	Low (SS TR)	0	0	0	-1	-1	-1	0	-1	-1	-1	-1	-1	0
(26) Duplex LO Filter	Flow rate (Lube Oil)	Low (SS TR)	0	0	0	-1	-1	-1	0	-1	-1	-1	-1	-1	0
(27) LO Manifold	Temperature (Thermal)	Increase (SS TR)	0	0	0	1	1	1	0	1	1	1	1	1	0
(27) LO Manifold	Pressure (Lube Oil)	Low (SS TR)	0	0	0	-1	-1	-1	0	-1	-1	-1	-1	-1	0
(41) Gas Oil Cooler	Mass flow rate (Process Gas)	Low (SS TR)	0	0	0	0	-1	-1	0	0	0	0	0	0	0
(41) Gas Oil Cooler	Temperature (Process Gas)	Increase (SS TR)	0	0	0	0	0	0	1	0	0	0	0	0	0
(41) Gas Oil Cooler	Temperature (Lube Oil)	Increase (SS TR)	0	0	0	1	1	1	0	1	1	1	1	1	1
Sensor Set Analysis	No. of Sensors	Fitness	Sensor Location												
Sensor Set 5	5	52.56%													
Sensor Set 12	6	52.33%													
Sensor Set 16	7	52.11%													
Sensor Set 37	8	51.88%													

Appendix 5 – Diagnostic Analysis #5