Application of IoT (Internet of Things) in the Monitoring and Control of Offshore Oil & Gas Production Platforms

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DECLARATION

I, Nkanyezi Samora Mqadi hereby declare that this research report is my own unaided work. It is being submitted for the degree of Master of Science in Engineering to the University of the Witwatersrand, Johannesburg. It has not been submitted before for any degree or examination to any other University.

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ABSTRACT

Internet of Things (IoT) is a new technological development in the oil and gas field, for both up upstream and mid/downstream industries. More stringent requirements with regards to process safety, optimisation, plant equipment health monitoring have pushed companies to investigate IoT for the improvement of their processes. IoT refers to a network of internet connected objects or devices for the purpose of collecting, exchanging data and taking automated actions (V. Hassija et.al., 2019). In the context of offshore oil and gas exploration processes, it refers to computers(control) systems that are interconnected in a network in order to access and process data for the purpose of monitoring and taking controlled actions on the production process, thus ensuring process safety and optimisation.

Due to the unfavorable operating conditions in which offshore oil and gas production facilities exist, companies are looking into the use of IoT in order overcome these harsh climatic and environmental offshore conditions, whilst making profits, with minimal or zero safety incidents. An IoT infrastructure and architecture typically consists of: measuring devices or transmitters, signal transmission protocols, control systems which process the collected data, networks which link the different data collectors and processors, and human machine interfacing, which allows end-users to access, interpret and make use of the data, for technical actions such as design, operation and optimisation.

Measurement technology is required to be robust and reliable in the harsh offshore production environment. Wireless technology such as virtual flow metering is on the rise in the offshore environment, as it uses less infrastructure (wiring and cabling) for measurements. Signal transmission protocols such as 4-20mA, 1-5 V, ethernet and modbus (foundation fieldbus) is still in use in, whilst radio frequency identification (RFID) and satellite telecommunications are on the rise, as it requires less infrastructure and allows for unmanned offshore production operations.

For processing the collected data, distributed control systems (DCS), programmable logic controllers (PLC) and emergency shutdown device (ESD) systems are used as standard control systems. These systems are powered electrically with 24 V DC or 110 V AC power supply. For subsea measurement technology, both 24 V DC is used for the transmitters and hydraulic power is used for pressure actuated isolation valves, in the gas and oil wells.

Subsea control actions are done in the master control system (MCS) and topside platform actions are done in the DCS.

For equipment health-monitoring, monitoring systems are implemented for predictive maintenance and abnormal situation management.

Opportunities for further investigation have been identified, in the areas of wireless monitoring, pipeline leak detection methods, advanced process control, alarm management, subsea and parameter estimation modelling.

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Table of Contents

LIST OF FIGURES

LIST OF TABLES

NOMENCLATURE

IoT	Internet of Things
RTMC	Real Time Monitoring and Control
mA	milli-Ampere
DC	Direct Current
AC	Alternate Current
PID	Proportional, Integral, Derivative
DCS	Distributed Control System
PLC	Programmable Logic Controller
MCS	Master (Marine) Control System
ESD	Emergency Shutdown Device
OPC	Object Linking and Embedding for Process Control
HMI	Human Machine Interface
GUI	Graphic User Interface
APC	Advance Process Control
KPI	Key Performance Indicator
LOPC	Loss of Primary Containment
WPSI	Well Process Safety Incidents
BOP	Blow Out Prevention
MWD	Measurement While Drilling
TEG	Tri-Ethylene Glycol
MEG	Mono-Ethylene Glycol
RFID	Radio Frequency Identification
PLDS	Pipeline Leak Detection System
RTTM	Real -Time Transient Method
HPU	Hydraulic Power Unit
EPU	Electrical Power Unit
AI	Analog Input
AO	Analog Output
SIL	Safety Integrity Level
HVAC	Heating Ventilation Air Conditioning
TUTU	Topside Umbilical Termination Unit
SUTU	Subsea Umbilical Termination Unit
VFM	Virtual Flow Metering

CHAPTER 1: INTRODUCTION

1.1 BACKGROUND

In the most recent years, there has been an increased focus in the application of IoT in the operation of Oil and Gas Offshore platforms. Traditionally downstream operations such as refineries have been leading in IoT, where telemetry, measurement and monitoring technology, and control system technology has been recognised to be integral in the design and operation of refinery units (Transportation Research Board, 2016). There are significant opportunities for the application of IoT, specifically, to improve functional safety, real-time monitoring and control for improved safety and optimisation of offshore facilities (subsea and topside operations).

With the most publicized and catastrophic incident of the Macondo well blowout and Deepwater Horizon mobile offshore drilling unit (MODU) explosion 3 in April 2010, there has been significant attention given to functional safety in offshore production facilities. Institutions such as the Bureau of Safety and Environmental Enforcement (BSEE) of the U.S. Department of the Interior have since requested in July 2014 that the Marine Board of the National Research Council (NRC) conduct a study advising the agency on the use of real-time monitoring (RTM) to improve the safety and reduce the environmental risks of offshore oil and gas operations (Transportation Research Board , 2016). Oil and gas companies now are focusing on the use of IoT, machine learning and the cloud for greater management of offshore (remote) facilities and tank collection sites so they can act in real-time as safety and regulatory issues arise (Transportation Research Board , 2016). In discussing IoT in oil and gas offshore facilities, specific critical areas need to be investigated in order to quantify the extent to which IoT is applicable and applied in this industry.

The areas of concern are: process safety, measurement and monitoring, communication and operations data transmission (telemetry), process control and control system technology. All these areas of concern can be categorised under the term IoT in the oil and gas offshore production platforms. The main drive behind developing IoT in this industry is primarily safety standards and regulations. Other requirements can be regarded as secondary. The main objective in an oil and gas production facility should always be the safety of both personnel and equipment.

Thus, developments in IoT technology should ensure that process safety requirements are achieved. Other objectives such process optimisation, predictive maintenance of equipment, are secondary and should be pursued once the safety of personnel, equipment and the environment, has been assured using IoT.

1.2 RESEARCH MOTIVATION

Recent focus in the offshore oil and gas industry has centered on the use of IoT in order to address areas such as process safety, equipment health monitoring and process optimisation in order to improve business performance. Companies are looking at how to improve functional safety, and improve the operational life of their equipment, monitor and control the exploration process better, whilst making profits and reducing costs.

IoT involves the ability to capture data, store and convert it to useful information which can be used for various objectives within the offshore exploration production process. The data could be used to improve automation-monitoring and control, equipment health monitoring, functional safety, and provide operational information which can be used for optimising operations and reduce safety incidents in a harsh offshore environment.

In the context of offshore oil and gas, this aspect of data capturing involves, measurement technology and digitalisation of the offshore process (drilling and gas production). This is currently a challenge in the offshore environment where the environmental conditions are harsher than onshore conditions and not easily suitable for standard measurement technologies, for process data capturing. Data capturing, and its optimal usage is critical in making technical, operational and business decisions, by companies.

Other challenges around the implementation of IoT technology in offshore production processes is transmission of the data, via specific communication protocols and the challenges which the different protocols present. The offshore environment is affected by environmental conditions which pose challenges such as signal interference, integrity and reliability.

Data reliability and integrity requires further investigations in the area of storage and access, via networks or the cloud. Other areas that require investigation, is the ability of the network hardware to integrate with IoT technology in offshore production processes. Automation hardware must be compatible to allow for seamless integration between network systems, thus enabling communication between control or automation systems.

IoT enables the capturing of data, its storage and transmission within a network, its usage and ultimately interfacing with the end-user. Human machine interfacing is critical in the development of an IoT solution as, the end-user must be able to interpret and understand the data which the IoT system is providing.

IoT provides immense opportunities for business enablement and performance, for offshore exploration processes. However, it must be understood and investigated thoroughly as to what are the requirements to have such a solution implemented. Existing infrastructure also must be compatible for IoT technology in order to realise the full benefit (V. Hassija et.al., 2019).

1.3 RESEARCH OBJECTIVES

The aim for this project is to investigate the use of IoT and particularly RTMC in the field of oil and gas production offshore platforms.

The research aims to investigate the application of IoT in Offshore oil and gas platforms by meeting the following objectives:

- Investigate the use of IoT to address process safety, production optimisation and equipment integrity and health
- Identify critical parameters (operation variables) for monitoring and control in drilling and production facilities in order manage and mitigate environmental and safety risks (e.g. to reduce the risk of well kicks, and blowouts)
- Investigate and analyse current measurement and monitoring technology with regards to their accuracy and reliability
- Investigate operations data retrieval and storage, transmission and communication protocols in offshore facilities

- Investigate the use of IoT in relation to condition-based monitoring and predictive maintenance for drilling and production equipment
- Investigate and study any limitations and challenges
- Propose a possible IoT and RTMC solution for a typical offshore platform (a case study)

This research report comprises of the following chapters:

Chapter 1: Introduction of offshore production platforms and the existing challenges, which necessitate the use of IoT in order to improve compliance to functional safety and regulations, improve equipment health and monitoring and optimise operations.

Chapter 2: Literature review to introduce offshore oil and gas production platforms, and definition of IoT and its application in the oil and gas industry.

Chapter 3: Method used for the investigation. A theoretical study and a practical investigation of an existing offshore platform. Critical parameter identification for monitoring and control, for both subsea operations and platform operations.

Chapter 4: Data collection, transmission and communications on an offshore platform.

Chapter 5: Design of an IoT solution for an offshore platform and proposals for additional solutions for enhancement of the control system solution. Discussion of the design and enhancements.

Chapter 6: Conclusions and Recommendations of IoT technology for offshore oil and gas platforms and recommendations for further investigations in the use of IoT in the offshore oil and gas platforms.

CHAPTER 2: LITERATURE REVIEW

As mentioned in the introduction section of report; to be able to investigate IoT in the oil and gas industry, specific areas need to be researched and understood within the industry. These are: process safety, equipment integrity and health, and process optimisation. These are the main objectives for oil and gas offshore facilities, and an effective IoT solution should be able address these operational objectives.

The literature study will first outline the oil and gas exploration industry process and followed by the IoT technology in the industry.

2.1 THE OIL AND GAS EXPLORATION AND PRODUCTION PROCESS

This section briefly describes the process involved in oil and gas exploration. Table 1 provides a summary of the principal steps in the process and relates these to operations on the ground (Joint Exploration and Production Forum/UNEP Technical 37, 1997).

Table 1: Summary of the exploration and production process (Joint Exploration and Production Forum/UNEP Technical 37, 1997)

Activity	Potential requirement on ground
Desk study: identifies area with favourable geological conditions	None
Aerial survey: if favourable features revealed, then	Low-flying aircraft over study area
Seismic survey: provides detailed information on geology	Access to onshore sites and marine resource areas Possible onshore extension of marine seismic lines Onshore navigational beacons Onshore seismic lines Seismic operation camps
Exploratory drilling: verifies the presence or absence of a hydrocarbon reservoir and quantifies the reserves	Access for drilling unit and supply units Storage facilities Waste disposal facilities Testing capabilities Accommodation
Appraisal: determines if the reservoir is economically feasible to develop	Additional drill sites Additional access for drilling units and supply units Additional waste disposal and storage facilities
Development and production: produce oil and gas from the reservoir through formation pressure, artificial lift, and possibly advanced recovery techniques, until economically feasible reserves are depleted	Improved access, storage and waste disposal facilities Wellheads Flow lines Separation/treatment facilities Increased oil storage Facilities to export product Flares Gas production plant Accommodation, infrastructure Transport equipment
Decommissioning and rehabilitation may occur for each of above phases	Equipment to plug wells Equipment to demolish and remove installations Equipment to restore site

Exploration Surveying

The first stage in the exploration of hydrocarbons in rock formations involves three major survey methods. These are namely: magnetic, gravimetric and seismic survey methods. The magnetic method involves measuring the variations in the magnetic field, which reflects the character of the rock as a function of present or available hydrocarbons. The gravimetric method involves the measuring of gravitation field at the earth's surface. Measurements are made on land and sea using aircrafts and survey ships respectively. The seismic survey method is the most common and relies on the differing reflective properties of sound waves to various rock strata, beneath the earth or ocean surfaces (Borthwick et al., 1997).

Exploration Drilling

After an explorative survey, the next step is to perform explorative drilling on an identified geological site. Explorative drilling is performed in order to confirm the presence of hydrocarbons, the thickness and the internal pressure of a gas or oil reservoir (Borthwick et al., 1997).

For land-based operations, a pad is constructed on the chosen site, in order to accommodate drilling and support services. Offshore operations can be performed using a various self-contained mobile offshore drilling units (MODU). The choice of a mobile offshore unit depends on water depth, sea-bed conditions and prevailing meteorological conditions (Borthwick et al., 1997).

Appraisal

After a successful explorative drilling stage, more wells are drilled to determine the size and the extent of the hydrocarbon field. The appraisal stage aims at evaluating the size and nature of the reservoir and confirm if further seismic studies are required (Borthwick et al., 1997).

Development and Production

After the appraisal stage is complete, where the size and nature of the oil field is confirmed, production wells are drilled. Multiple wells are drilled from a single pad in order to reduce land requirements and the overall infrastructure cost (Borthwick et al., 1997).

Each production well is drilled and prepared for production. Drill pipes are installed in each well, as well as blow-out preventers (BOPs) and control valves. BOPs are used to prevent well kicks and control valves are for regulating the pressure and subsequently the flow of the gas or the oil from the well (Borthwick et al., 1997).

Most oil and gas wells are initially free flowing, meaning the subsurface pressure is adequate to force the gas or oil to the surface of the well. After, long periods of operation, the subsurface pressure reduces and it is required to inject gas, water or steam into well, in order to increase its pressure and enable gas flow from the well. The injection of gas is performed via other drilled wells called injection wells, which are constructed or drilled adjacent to the main production wells (Borthwick et al., 1997).

Other well stimulation techniques are hydraulic fracturing and acid treatment in order to increase and enlarge the flow channels. The gas and the oil from the well are transported via pipelines to the platform production facility. The production facility processes the hydrocarbon fluids and separates oil, gas and water. The oil must usually be free of dissolved gas before export. Similarly, the gas must be stabilized and free of liquids and unwanted components such as hydrogen sulphide and carbon dioxide. Any water produced is treated before disposal (Borthwick et al., 1997).

Decommissioning and Rehabilitation

The decommissioning of onshore production installations at the end of their commercial life, typically 20–40 years, may involve removal of buildings and equipment, restoration of the site to environmentally-sound conditions, implementation of measures to encourage site re-vegetation, and continued monitoring of the site after closure. By their nature, most exploration wells will be unsuccessful and will be decommissioned after the initial one-to-three months of activity. It is, therefore, prudent to plan for this from the outset, and ensure minimal environmental disruption. Decommissioning and rehabilitation will subsequently, be simplified (Borthwick et al., 1997).

2.2 IoT DEFINITION AND ARCHITECTURE

IoT is simply a network of internet connected objects able to collect and exchange data. It can also be referred to a system of interconnected computing devices, mechanical and digital machines, objects that are provided with unique identifiers and the ability to transfer data over a network without requiring human-to-human or human-to-computer interaction (Bharadwaj, 2016).

A complete IoT system integrates four distinct components: sensors or measurement devices, connectivity, data processing/management service layer, and a user interface or application layer (Patel et.al, 2016).

2.2.1 Sensors, Measurement Devices and Actuators

In the context of the oil and gas offshore industry, measurement devices, refer to process instrumentation that is used to monitor and measure process conditions. Sensors or measurement devices provide information about the process. Physical and chemical process variables such as temperature, pressure, flow, level, speed, vibration, voltage, amperes, and frequency are all properties that define the status and condition of a process. These variables enable engineers categorise, define and model processes, for steady-state and dynamic conditions. These variables are used for process design, process control and other critical business decisions within an organisation.

2.2.2 Connectivity (Gateways)

Information from the process, is captured by instrumentation devices, according to a specified sampling frequency, which is typically every 1 second, 5 seconds or 1 minute, depending on the used control system network. This information is transmitted via different communication protocols to a cloud or a process control system network. These communication protocols can include, wireless communication, 4-20mA, 1-5 V, foundation fieldbus H1, 24V DC or 115V AC, satellite or ethernet.

2.2.3 Data Processing (Network or Cloud)

Data is captured and stored in a cloud or a control system network and processed. Processing can refer to using the gathered data to make corrective and optimisation decisions to the process. These corrective and optimisation decisions can specifically refer to the use of process control, where computer or software-based algorithms such as feedback control, logic-based or advanced control strategies are applied to act on the process.

2.2.4 User Interface

In IoT, the end-user is a vital. The end-user typically interfaces with the IoT application via a computer-based GUI or HMI and, in some cases via an alert text message or email. The purpose of the interface is to make available to the end-user important and critical information for decision-making.

Patel et.al, 2016, defines IoT using four levels; namely: smart device/sensor layer, network (communication layer), service support and application support layer and the application layer.

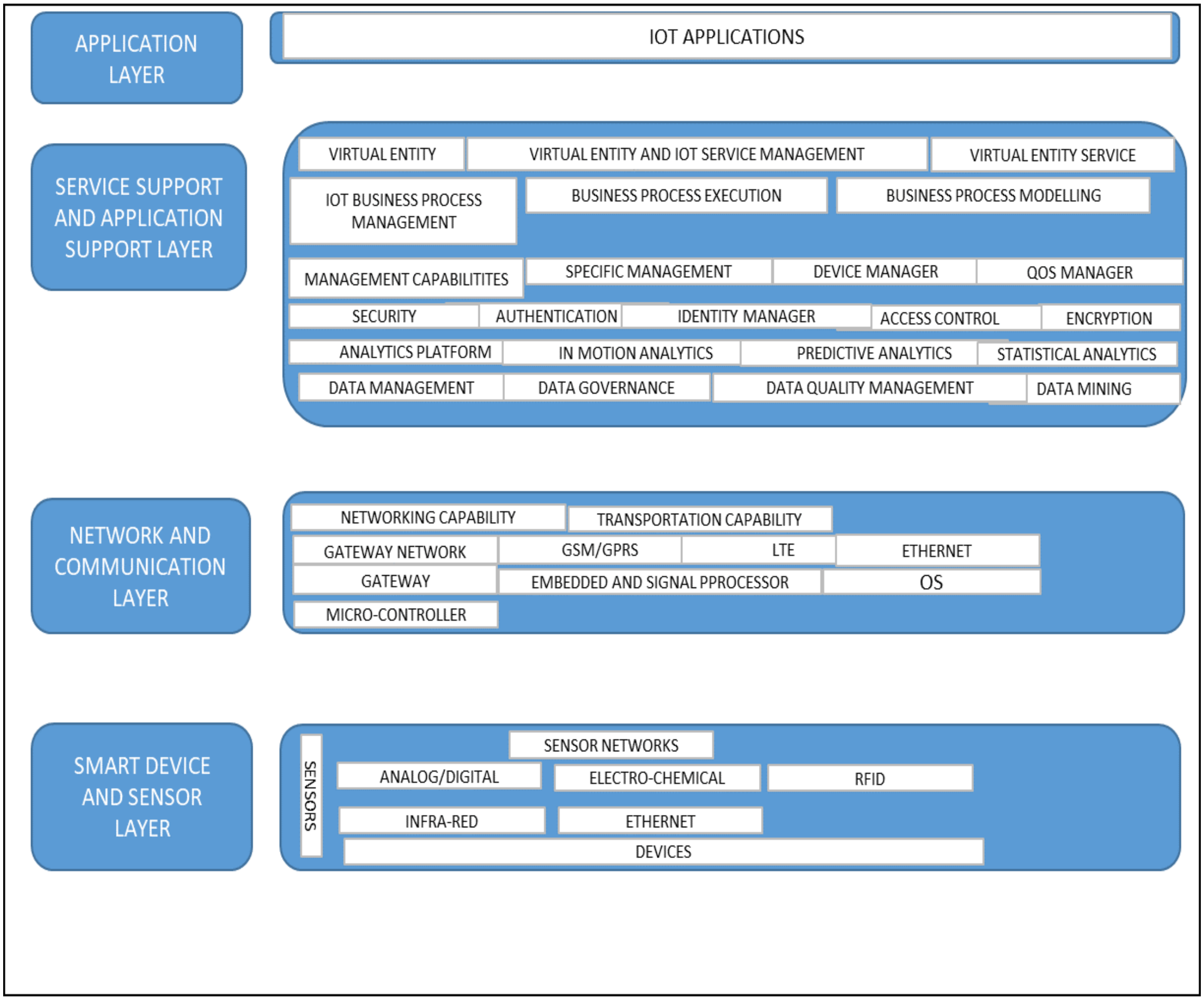

Figure 1: Typical IoT Architecture (Patel et.al , 2016)

An IoT architecture applied in the oil and gas industry, consists of measuring devices, networks, data processors and user-interfaces. Figure 2 indicates an IoT Wellhead monitoring system, with the different components connected to each other.

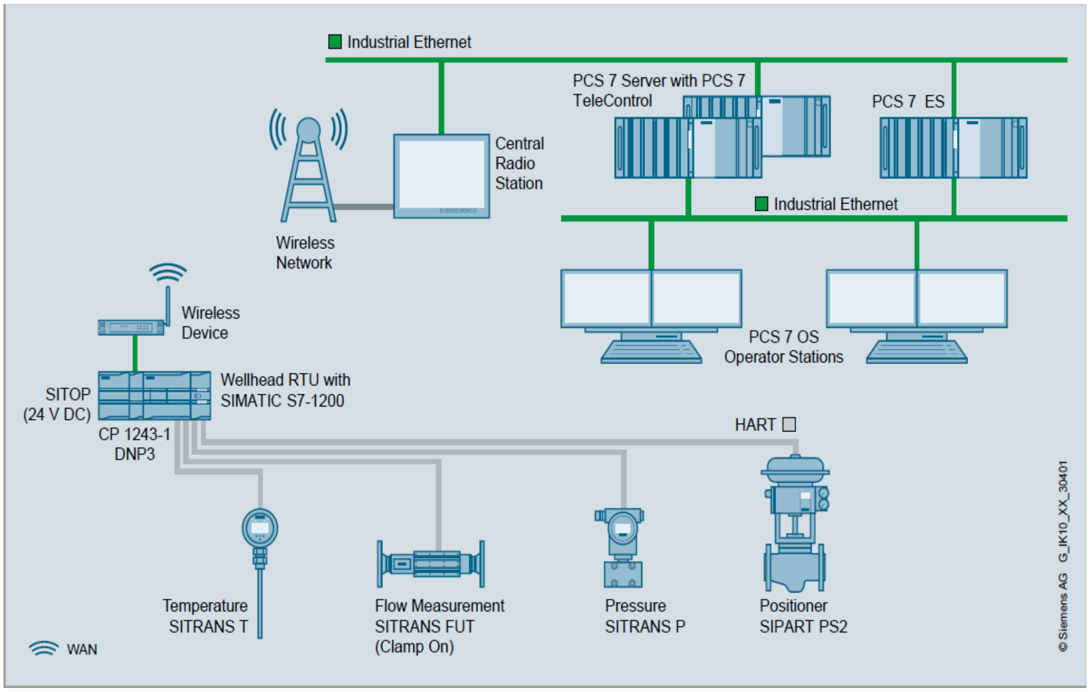

Figure 2: Application of IoT: Wellhead Monitoring via SCADA (Supervisory Control and Data Acquisition) (Siemens, 2016)

2.3 PROCESS SAFETY, EQUIPMENT HEALTH AND OPTIMISATION

IoT enables other aspects of oil and gas operations such as equipment health-monitoring. Equipment health-monitoring enables techniques such as predictive and preventative maintenance to be implemented before equipment catastrophic failures occur.

2.3.1 Categorisation of Safety Incidents in the Oil and Gas Platforms

The process safety indicator guidance published by a variety of organisations such as the American Petroleum Institute (API) in 2010 and the International Association of Oil and Gas Producers (2011) is enough to assist companies and regulators in preventing another Macondo type incident, given what is known about the causes of accidents. API RP 754 refers to the term Process Safety Events for its KPIs (Key Performance Indicators) and includes both incidents involving loss of primary containment (LOPC) as well as challenges to the system barriers in place to prevent LOPCs (Wilkinson, 2012).

There are four tiers of indicators presented in the form of a pyramid (Wilkinson,2012). At the top of the pyramid are losses of primary containment events of the greatest consequence. These are Tier 1 events. Tier 2 indicators are loss of containment events of less consequence than Tier 1.

At the bottom of the pyramid are those managerial and operating aspects of operating a facility which, if successful, should contribute to a safe facility. These are Tier 3 and 4 indicators and are intended for internal use at individual sites. API 754 recommends that leading indicators are appropriate for these topics.

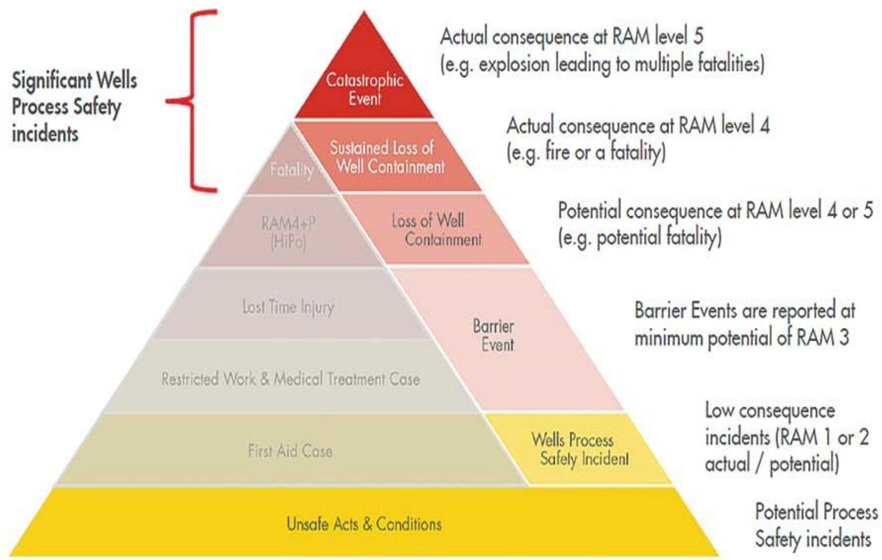

Figure 3: Categorisation of Safety Concern Indicators in the Oil and Gas Industry (Wilkinson, 2012)

The pyramid presents indicators in the form of a pyramid for both process and personnel safety. At the top of the pyramid are losses of primary containment events of the greatest consequence. At the bottom of the pyramid are well process safety incidents and barrier event for process safety (Wilkinson, 2012, Swuste et al.,2016).

Well process safety incidents (WPSI) are defined as incidents or unsafe conditions that may result in loss of well control or impairment of wellbore integrity. It includes any actual or potential unplanned or uncontrolled release of well effluents from assets or facilities operated by wells. WPSI may occur during the design, construction, operating, maintenance and abandonment phases. Examples include failure of the blowout preventer system (BOP), inaccurate pore pressure prediction, hydrocarbon leaks from pressure control equipment, mud return alarms disabled and inadvertent closure of BOPs (Wilkinson, 2012, Swuste et al.,2016).

Barrier events are defined as non-compliances with the requirement that all well operations shall be executed under the protection of at least two barriers for each potential flow path. Barrier events are a subset of WPSI and include failed or missing barriers. Barrier events occur when a well's physical barrier is lost, leaving only a single barrier remaining, e.g. BOP acting as a barrier following a kick (Khaled, 2017).

Oil well kicks and blowouts are other common operational events which can be catastrophic as already mentioned in reference to the Deepwater Horizon drilling rig in April of 2010, if proper IoT technology solutions, specifically RTMC are not implemented (Godhavn et.al, 2011).

Statistics indicate that typically every 100th kick results in one blowout. A blowout is an uncontrolled kick or uncontrolled influx into the wellbore. Kicks develop into blowouts for one or more of the following reasons (Godhavn et.al, 2011):

- Failure to detect potentially threatening situations during the drilling process
- Failure to take the proper initial action once a kick has been detected
- Lack of adequate control equipment or malfunctioning of the equipment

Pressure control systems are therefore enforced during drilling operations in order to prevent kicks which may result into well blowouts. Current detection methods oil well-kicks include the return flow meter (flow paddle) and the pit level indicator in the active mud tanks (Skalle, 2011).

2.3.2 Predictive Maintenance and Reactive Remediation

Predictive maintenance allows for early detection of indicators which could lead to catastrophic failures of equipment, loss of containment or unplanned shutdowns in oil and gas processing facilities. It is also used by oil and gas companies which have remote field operations. Most facilities are equipped with remotes sensors, such as level, pressure and temperature sensors which can transmit process information on an hourly basis in order to respond to potential issues.

IoT solutions such as tank level forecasting help manage and identify problems early enough to perform quick remediation solutions.

2.3.3 Data Storage, Transmission and Telemetry

Data is typically stored in a cloud or a historian data base, depending on the IoT solution in use. The cloud or the historian database connects to the other components of the IoT solution via the above-mentioned communication protocols.

The communication protocol implemented depends on the required corrective action to be taken. Safety corrective actions need to be made in real-time and thus the connection between the network (cloud) and the actuators or sensors is hardwired.

If the decision or the corrective action to be made is more for optimisation and will not affect the safety of the operation, then wireless or even telemetry solutions are employed.

2.3.4 Measurement and Monitoring in Oil/Gas Wells

Well stimulation (fracturing and acidizing), mud pumping, and well development (casing and cementing) are vital oil and gas processes that utilize pressure sensors for measurement and monitoring functions.

A measurement while drilling (MWD) method and apparatus for determining parameters of interest in a formation has a sensor assembly mounted on a slidable sleeve coupled to a longitudinal member, such as a section of drill pipe. When the sensor assembly is held in a non-rotating position, for instance for obtaining the measurements, the longitudinal member is free to rotate and continue drilling the borehole, wherein downhole measurements can be obtained with substantially no sensor movement or vibration.

The sensor assembly of the present invention can include any of the variety of sensors or transmitters for determining a plurality of parameters of interest including nuclear magnetic resonance measurements (Kruspe et.al, 2002).

2.3.5 Automatic Control and Functional Safety in Offshore Production

An offshore oil and gas production platform consists of control systems that are integrated into a network that allows for transmission of information and communication between the different systems. Each system performs a specific function for automatic control and safety functions.

These systems are the master control system (MCS),which operates the subsea wellhead, manifolds, chemical injectors, and other subsea equipment. The MCS is divided into two parts: subsea control systems (housed in the subsea equipment) and platform control systems. The other systems are the distributed control system (DCS), which controls the platform equipment and the emergency shutdown device (ESD) which performs critical safety functions.

The communication protocols between these systems are modbus TCP/IP, ethernet/IP and object linking and embedding for process control (OPC).

CHAPTER 3: METHODOLOGY

The methodology used is a qualitative approach, where an extensive literature survey has been conducted and an existing offshore oil and gas facility is investigated to evaluate the application of IoT. An offshore production platform was used as a case study for this investigation. The research that will be done can be broken down into the following steps:

3.1 THEORETICAL STUDY Vs. A PRACTICAL INVESTIGATION

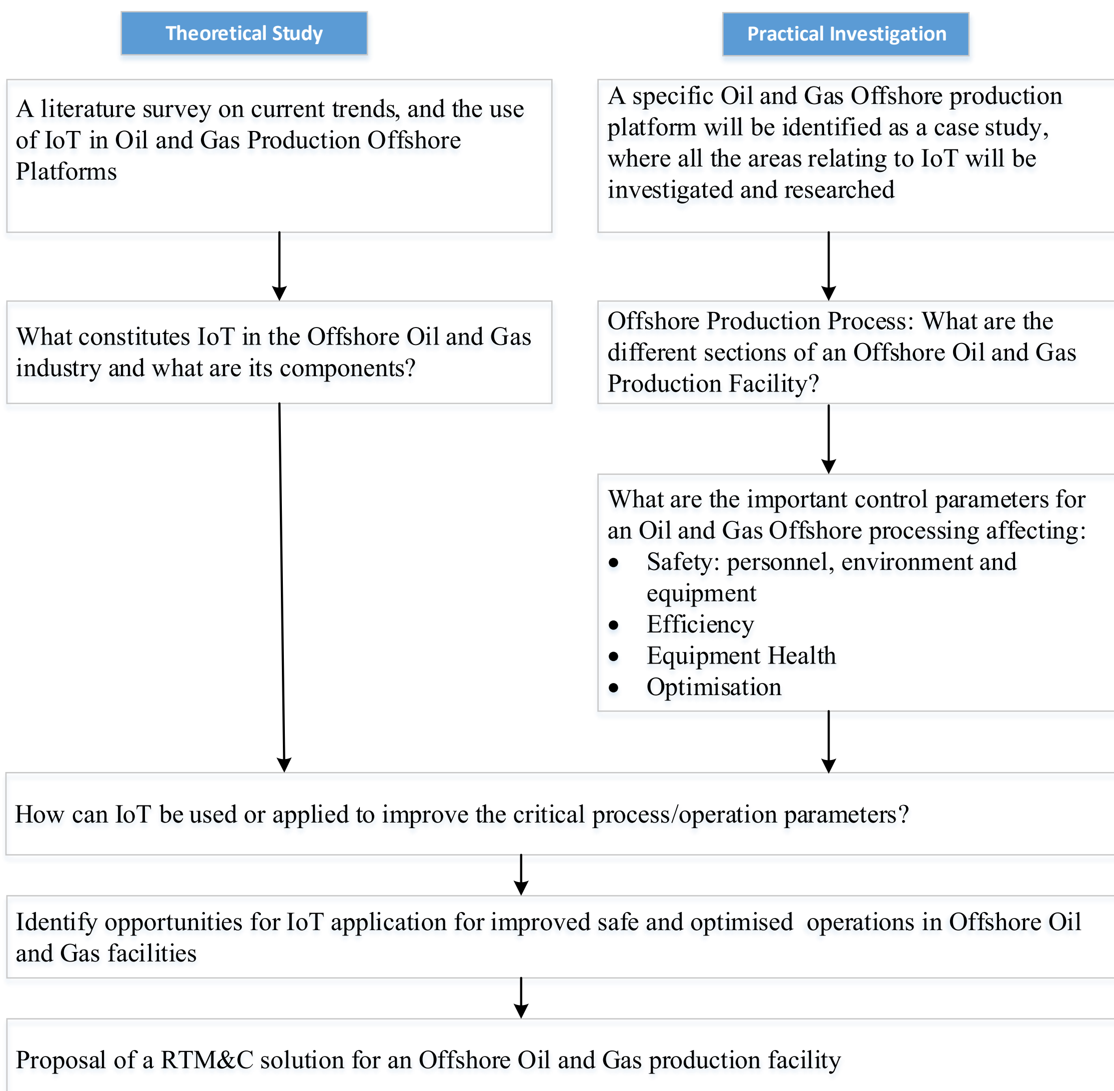

Figure 4: Theory vs Practical investigation Methodology

3.2 CRITICAL PARAMETERS IDENTIFICATION

The investigated offshore facility is a conventional fixed platform consisting of a well production section and an oil and gas separation section (PETROSA, 2019).

3.2.1 Well Production and Subsea Operations

During the extraction of the gas in wells, hydrocarbon gases mixed with condensate, flow from drilled gas wells in production pipes laid on the sea-bed. These pipelines are routed through metering skids which are sunk onto the sea-bed at the different well locations. These metering skids (manifolds) are equipped with subsea measurement technology (instrumentation) which is used to measure the flowing fluid's variables such as volume, pressure, temperature and flow.

This configuration of process pipelines combines into headers (main process lines) which then flow via risers to the offshore platform. Figure 5 shows a simplified flow diagram of this configuration.

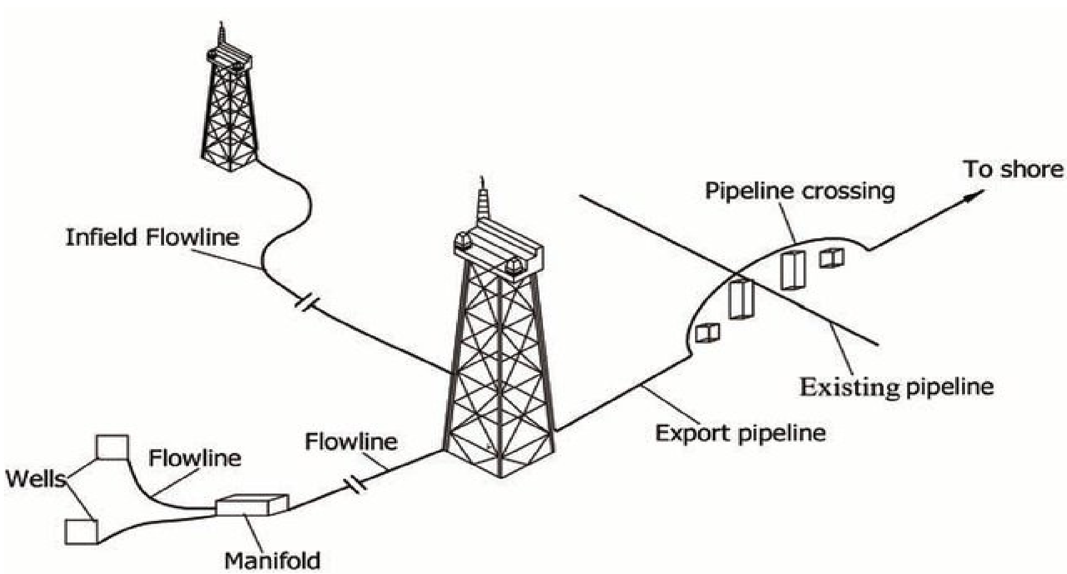

Figure 5: A simplified flow diagram of the subsea installation of flowlines and a platform (Guo et al., 2013)

Figure 6 shows how process lines are combined into a manifold to form a header. The header connects to the riser which feeds the separation platform with gas (or oil condensates).

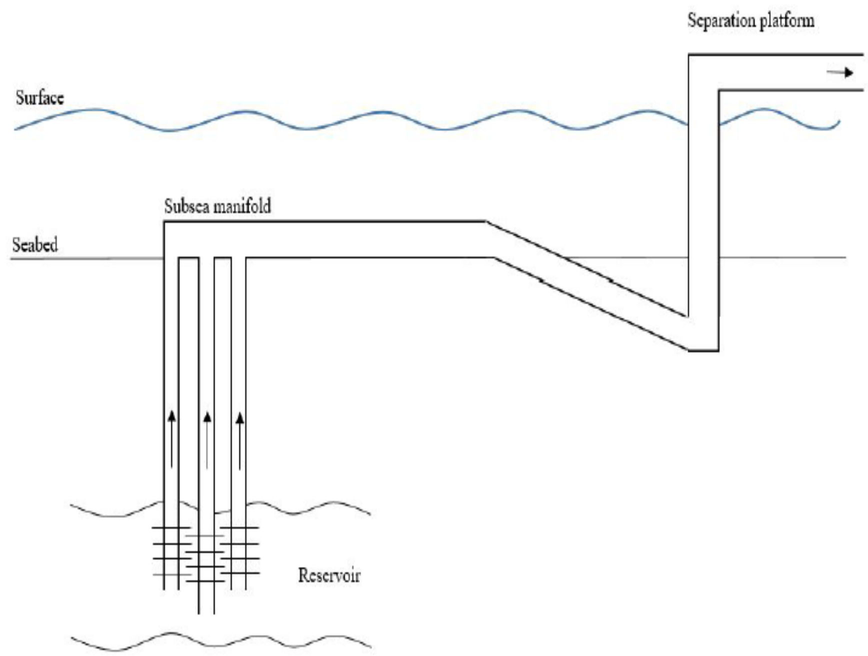

Figure 6: Subsea manifold and transportation pipelines to separation platform (Hansen et al., 2019)

One of the prominent problems affecting production in gas-wells is a phenomenon called liquid loading, which is the inability of the gas to remove liquids being produced in the wellbore and the hole drilled for the purpose of extraction of oil and gas. This occurs when the velocity (speed and direction) of the gas being produced drops below critical velocity. The produced liquid accumulates in the well, creating a static column of liquid. The liquid creates a back pressure against formation pressure that forms within the pores of a formation rock, increasing until the well ceases production (Peijun et al., 2015). For this reason, continuous measuring of the fluid pressure, flow density and temperature is critical.

The measured and monitored variables are: gas pressure, density, temperature and flow; and liquid density, pressure and flow. The measurement technology used for measuring the process variables are: subsea measuring devices mounted on skids.

3.2.2 Platform Operations

3.2.2.1 Gas System

The hydrocarbon gas is routed to the platform via risers. The purpose of the platform is to carry out separation of the gas from the condensates before the gas is compressed and routed to the on-shore facility for further processing into valuable products (i.e. fuels and chemicals).

Separation on the platform occurs via separation and knock-out drums. Heat-exchangers are used to ensure the correct temperature conditions of the hydrocarbons before entering the separation drums. Glycol contactors (absorption) are used to remove additional water after the separation drums (PETROSA, 2019). The well fluid arrives at the platform from the different wells at subsea conditions, which are between 12^0C and 80 ^{0}C and at pressures between 12 bar (g) and 15 bar (g). The well fluids flow into shell and tube heat exchangers and cooled to a temperature of about 20 ^{0}C. The fluids from the wells, are then routed to separator drums where, liquids, gases and some solids are separated. The exiting gas from these separators is then routed to a medium pressure compressor and compressed from 12.5 bar (g) to 30 bar (g). The compressed gas then enters a high-pressure compressor which compresses the gas up to 76 bar (g). After the compression to 76 bar (g), it is routed to the discharge knock out drum, and then routed to the glycol contactor where the gas is dehydrated by counter flowed tri-ethylene glycol (TEG) for the absorption of any possible water droplets that may have been carried over with the gas. TEG is recovered and recycled.

The gas from the TEG contactor, is routed through a chiller refrigeration system and routed to a low temperature separator where the final knock out occurs.

The gas then flows through the heat exchangers and before entering the metering skid, a chemical is added called dry gas. The function of this chemical additive is to absorb any possible water droplets and form a protective lining on the pipe line. The gas is routed through a metering skid where the gas is metered for volume at a pressure of 65 bar (g).

The gas is then routed via pipeline from the platform to the onshore facility. The pipeline pressure is monitored, and back-pressure controlled at 42 bar (g) by the onshore facility. Instruments are provided to monitor the total flow of export gas and condensate. The hydrocarbon and water dew points of the export gas are analyzed before export to ensure that there will be no hydrate formation of the export line (PETROSA, 2019).

The measured variables per equipment: separator level, pressure, temperature, pump pressure and flow. For heat exchangers, the measured variables are: inlet and outlet temperatures and pressures. For compressors: flows, pressure and temperatures are measured and monitored.

The measurement technology used are: temperature transmitters, pressure transmitters, flow transmitters and level transmitters.

3.2.2.2 Condensate System

The condensate collected from the separators is routed to the condensate water system used for oil separation. Mono-ethylene glycol (MEG) is also pumped from the platform to each of the subsea wells via the subsea pipelines. The MEG flows back through the pipelines with some of the gas and the condensate from the separators into the wells to prevent hydration of the pipelines flowing to the platform via the risers. This mixture of gas, condensate and MEG, can form slugs (multi-phase flow) in the pipes (PETROSA, 2019).

Multi-phase flows are not good for oil and gas pipelines. The slug flow causes undesired consequences in the whole oil production such as: periods without liquid or gas production into the separator followed by very high liquid and gas rates when the liquid slug is being produced (Jahanshahi, 2013). This is a problem that results into significant losses in the oil industry. The main one has been of economic order, due to reduction in oil production.

For this reason, the condensate is flowed into a slug catcher via level control and then rerouted to the MEG regeneration system for re-use (Havre et. al., 1999, Havre et.al., 2000, Havre et.al., 2001).

The measured variables are: separator level, pressure and temperature. For pump: pressure and flows are measured, and for heat exchangers, temperature and pressures are measured and monitored. The measured technology used are: temperature transmitters, flow transmitters, level and pressure transmitters.

CHAPTER 4: DATA COLLECTION, TRANSMISSION AND COMMUNICATIONS

The transmission of process information in an offshore facility is critical. This information is used by the control system, to perform corrective and safety functions or provide information related to equipment health (status) or condition.

Transmitters are used to provide information related to the physical and chemical properties of the flowing fluid. These are variables such temperature, pressure, flow, and level. Other important parameters, especially on rotating machinery such as compressors and pumps, include, vibration, motor speed, winding and bearing temperatures. Transmitters are mechanically connected/mounted onto the process lines in order to detect specific variables.

4.1 SUBSEA MEASURING TECHNOLOGY

Metering skids are lowered onto the seabed for the measuring of flow, temperature and pressure of the well fluids. The process lines from the well are connected to the metering skid on the seabed. The metering skid has flow, pressure and temperature transmitters mounted on it. As the well fluids flow in the process lines, they have these variables measured by the skid-mounted transmitters.

The transmitters mounted on the skid are electronic devices that are either loop-powered or powered from the control system in order to function. 24 voltage direct current (24V DC) is the normal power supply for transmitters to be able to measure a process variable. In other instances, transmitters that are loop powered are used. Loop powered transmitters do not require an independent power source to function/operate. In measurements, such as flow and level measurement, where variance in voltage does affect the functioning of the transmitter, loop-powered transmitters are used. Temperature measurements on the other hand rely on voltage difference in order to measure temperature, loop powered transmitters are not preferred, since the voltage changes as the process temperature changes.

4-20mA current is the standard communication protocol for transmitting process variables, from the process to the control system. For an example, in measuring volumetric flow in the subsea pipeline, the flow design of the gas will range from 0-140MMscf/day, this will mean, at maximum range, the milli-ampere signal will be 20mA and at turn-down (minimum range), the mill-ampere signal will be 4mA. At 70MMscf/day, the milli-ampere signal will be half of the range, which will be 12mA. This is how the process information is transmitted from the process pipeline to the control system, for monitoring and control.

The transmission of information from the transmitters to the control system is termed data collection and transmission. Data collection from the metering skids is transmitted through wiring cables which are combined into multi-core conduit of cables. The term normally used is the umbilical cord term, since this cord joins the subsea and platform control systems. The umbilical cord is a multi-core conduit consisting of hydraulic pipes as well as electric power supply cables from the platform controls to the subsea controls.

4.2 PLATFORM MEASURING TECHNOLOGY

Process measurements on the platform, are performed on the different equipment and process lines. These are temperature, level, flow, pressure and analytical measurements. The transmitters are connected to the control system, via junction boxes and multi-core cables which route the signals from the field to the control system, situated inside the control room.

Due to the harsh offshore environment, measuring technology is required to be robust, reliable and provide maintenance free operation for years. The following table provides generic information on the different process measurement technology, types and application.

Table 2 shows the different measurement technology and the application in the offshore production environment.

Table 2: Measurement Technologies in Offshore Facilities (ABB Measurement & Analytics,2017)

Measurement Technology		Offshore Application						
Variable of Measurement	**Type of Technology Used**	**Drilling**	**Wellhead &Manifolds**	**Separators**	**Water treatment and injection**	**Gas lift**	**Compression**	**Utilities**
Flow								
Diffential Pressure	Venturi		X	X		X	X	
	Orifice		X	X	X	X	X	X
	Subsea Venturi		X		X	X		
Coriolis	Coriolis meters	X	X	X	X	X	X	
Electromagentic flow meters	Electromagnetic flow meters	X		X	X			X
Vortex flow meters	Vortex flow meters			X	X			X
Variable Area flow meters	Variable Area flow meters			X	X			X
Swirls				X	X	X		X
Temperature								
Sensors		X	X	X	X	X	X	X
Transmitters	Thermocouples and Resistance Thermal Detectors(RTDs)	X	X	X	X	X	X	X
Pressure								
Absolute	Fluid's Density based measurements and Head difference	X	X					
Gauge	Fluid's Density based measurements and Head difference	X	X	X	X	X	X	X
Differential	Fluid's Density based measurements and Head difference		X	X	X	X	X	X
Analysers								
Hydrocarbons			X		X			X
Water					X			X
Level								
Magnetic		X		X	X			X
Radar		X		X	X			X

4.3 WIRELESS MEASURING TECHNOLOGY

Subsea virtual flow metering is used for estimating gas and water flow rates produced from the wells without measuring them directly. The technology uses data from the field, such as pressure and temperature measurement, as well as valve choke positions, to estimate the flow rates by implementing hydrodynamic multi-phase models and reconciliation algorithms. The virtual flow metering technology uses wireless transmission such as radio frequency identification (RFID) to transmit the estimated gas and water flow rates to the control system, where the flow rates can be used for monitoring and control.

4.4 COMMUNICATION PROTOCOL

Different protocols are used to communicate and transfer data between controllers and within the control system network. The identified communication protocols are: ethernet, modbus, and serial links, fiber optic, radio and satellite link connections.

4.5 NETWORK INTEGRATION

Gas and oil production from subsea wells to the surface processing facility, is controlled by an architecture of control systems. This integrated network architecture of systems consists of the following: distributed control system (DCS), emergency shutdown device (ESD), master control system (MCS), hydraulic power unit (HPU) and electric power units (EPUs). All these are configured in an architecture that facilitates proper communication and control. Figure 7 below shows the architecture of the used RTMC network system.

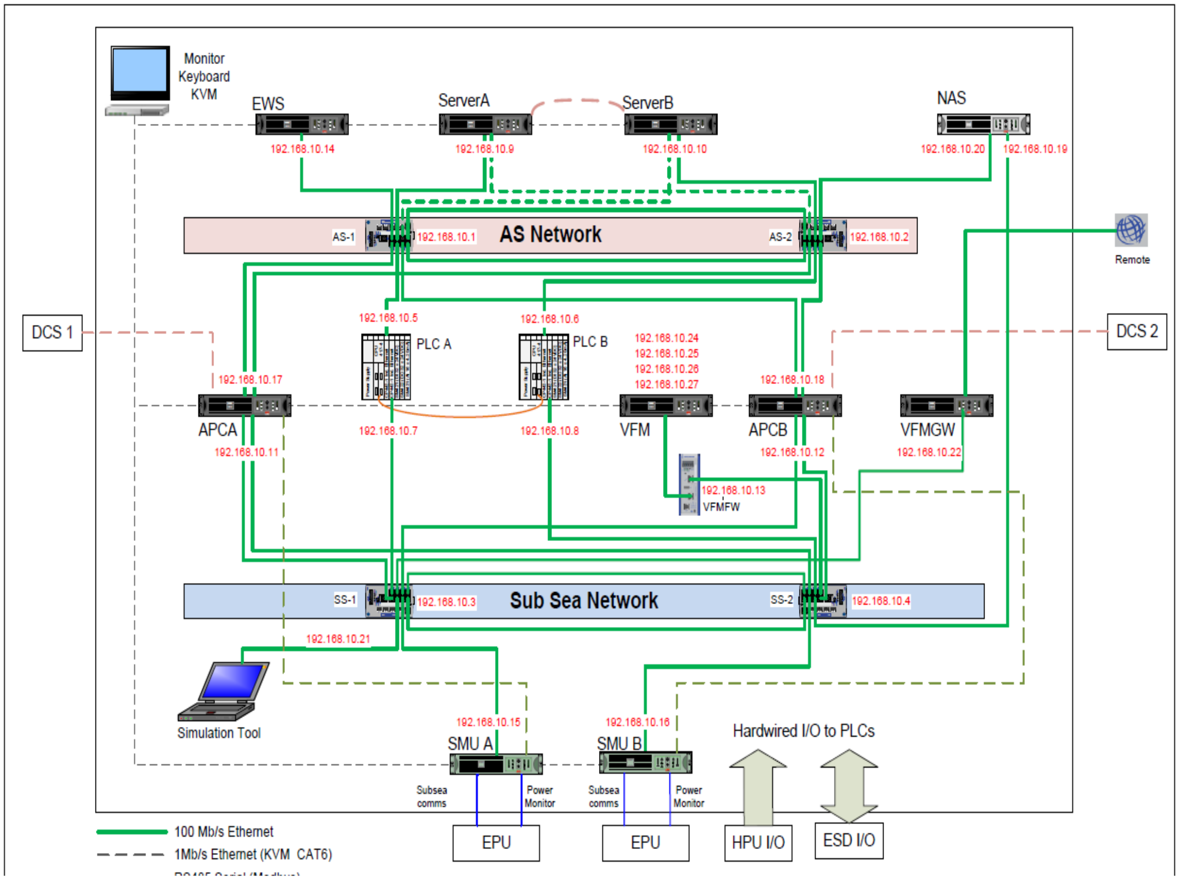

Figure 7: Used Network Integration. Drawing Indicating Control Hardware and the associated Gateways (A. Fadana., 2019, PetroSA)

4.5.1 Distributed Control System (DCS)

The DCS is the main control system, situated in the control room, where the entire offshore operation is monitored and controlled. It consists of marshalling cabinets, signal barriers, input and output cards and signal processors. It is the link between the field instrumentation and the operator stations, where the operation is monitored. Signals from the field, enter the control room and land in the marshalling cabinets via multi-core conductor cables. The 4-20mA signals flowing in the wires within the multi-core cables are then split and wired to the input cards, where the 4-20mA signals are processed and coded to binary language, which the DCS can interpret and use for control. Once interpreted by the DCS, it is then decoded into analog values, depending on the variable being measured.

If level in separator drum is being measured, which is normally measured from 0-100 % (engineering units), the 4-20mA signal once decoded in the DCS, is scaled such that, 4mA corresponds to 0 %, 8mA corresponds to 50% level and 100% level corresponds to 20mA.

All process variables such as, flow, level, pressure, density, pH, concentration in ppm (part per million, mg/l, percentage, mol/l etc.) are all transmitted to the DCS via the 4-20mA signal protocol. Temperature measurements use 1 to 5 mV for the transmission of the signal from the field to the DCS.

The DCS consists of range of different mathematical algorithms from which a selection can be made, depending of the application. The following algorithms can be found in the DCS:

- Signal scaling blocks
- Signal voting blocks
- Proportional, Integral and Derivative (PID) control with its variances such as, PID Feed Forward (PIDFF), PID External Reset Feedback (PIDERFB), PID Gap (PIDGAP)
- Logic blocks
- Summer blocks

Figure 8 shows an example of compressor pressure analog input into the DCS. Three pressure signals are wired into the DCS and are used in a voting logic block. The signal select logic block, selects which ever signal is applicable (i.e. highest or lowest) depending on the signal-select configuration.

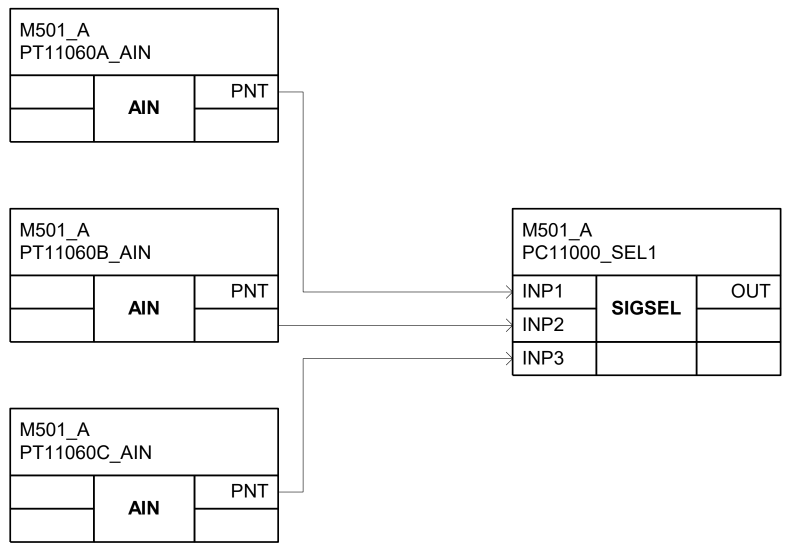

Figure 8: Compressor Suction Pressure Signal Voting (PETROSA, 2019)

Analog input (AIN) blocks are used to acquire the pressure measurements from the field. The values are scaled by the AIN blocks and passed on to a signal selector (SIGSEL) block. The SIGSEL block is configured to select the median value (SELOPT = 4) and make it available at its output (OUT) (PetroSA*,* 2019*)*.

The DCS (e.g. PID) ensures that the different variables are maintained at the desired set-points for optimal operation.

4.5.2 Emergency Shutdown Device (ESD)

The ESD is used to perform safety functions and protect the variables controlled by the DCS from exceeding their design limits. These limits could either be process, mechanical or material of construction limits. Process limits could refer to high discharge pressure in a compressor. It could refer to high level in separator drum, which if it overflows could potentially be a hazard to the offshore operation.

Mechanical limits could refer to temperature and pressure limits of a separator drum or a process line, which when exceeded could result to vessel or pipeline ruptures, leading to loss of containment, and possibly causing major hazardous incidents.

The ESD, like the DCS consists of inputs and output cards as well as signal processors. It also processes the signal that is measured from the field. The signal that is measured from the field is then compared to a safety limit, which is called a trip point, within the ESD. If the measured signal is equal to or higher than the high trip point, or less than or equal to the low trip point, the ESD performs a trip function by either closing or opening an independent final control element (e.g. a tight shut-off valve). The trip function is never a control or a regulatory function, but an isolation of a potential hazard function.

The two major differences between the ESD and the DCS, even though they are both control systems are:

- ESD performs trip functions whilst the DCS performs control (regulatory) functions
- The ESD safety integrity level (SIL) is ranked higher than the DCS. The ESD is required to be SIL 3 rated or SIL 4, whilst the DCS is ranked at a SIL of 1

International Electrotechnical Commission 61508 (IEC 61508) defines SIL ranking in terms of the failure rate of a hardware system. SIL 1 means, the DCS could potentially fail once in ten years and there could be failure of the input/output cards or the inability of the system to maintain and achieve the required set point. SIL 3 means, the ESD could potentially fail once in a thousand years, which means, when the system is required to trip it could potentially fail once in a thousand years. (Smith, D.J et.al.,2010, Gulland, W.G., 2000)

Table 3 indicates the used SIL levels based on their probability to fail whilst on demand (i.e. when required to function and perform the intended function).

Table 3: Table indicating the Safety Integrity Level Definition (Smith, D.J et.al.,2010, Gulland, W.G., 2000)

SIL Level	Probability of Failure on Demand (PFD)
1	Once in 10 years
2	Once in 100 years
3	Once in 1000 years
4	Once in 10 000 year

On an offshore platform, there are different ESD levels. These are levels 1 to 4.

Four levels of shutdowns are provided: Each level defines the degree of severity, which is a function of the nature of the incident and the anticipated risks. The levels of shutdowns are arranged on a hierarchy basis except for level 1, which is independent and local to the specific equipment in specific fire areas.

4.5.2.1 Level 1 (ESD-1) - Local Abnormality

ESD-1 covers the shutdown of services which do not affect the main production process or drilling operations. An equipment or package fault initiates the shutdown of that item or package with no knock-on effect on other equipment.

4.5.2.2 Level 2 (ESD-2) - Process Shutdown

Shutdown and isolation of the production process systems, including closure of the wellhead wing, master and pipeline riser valves will be initiated automatically due to a process abnormality, or may be manually initiated via the production control room with the ESD Level 2 push button.

The production process will also be shutdown (ESD Level 2) in the event of a loss of pressure in the instrument air system (IAS) or the HPU (Fadana, 2019).

4.5.2.3 Level 3 (ESD 3)- Staged Platform Shutdown

Confirmed detection of fire or gas in process areas or confirmed detection of fire or gas in specific non-hazardous utility areas will require various degrees of shutdown of the production facilities and either selective or total blow down. The exceptions will be fire or gas detected in the accommodation area and in those parts of the utility areas where no direct impact on the process system would be expected.

A Level 3 shutdown is initiated automatically or may be manually initiated from the production control room. The Level 3 push button will initiate the most comprehensive level 3 shutdown, equivalent to gas detected in a non-hazardous area. On initiation of a Level 3 shutdown, an ESD 3 indication lamp will be signaled in the air drive control room and a uniquely identifiable signal shall be transmitted to the drilling section, which will enable the drill crew to secure any open well and shut drilling down. It should be noted that a controlled shutdown of the drilling operations could only be done if electrical power is available. Since all topsides power will be isolated under certain Level 3 initiations, a controlled drilling shutdown will only be able to take place if the drilling power generator is already running or is subsequently started. This will enable drilling to secure the open - well and shut drilling down manually (Fadana, 2019).

All sub surface safety valves will be closed on a Level 4 shutdown and certain Level 3 shutdowns.

Drilling Level 3

(Drillers ESD Level 3 (Red) Shutdown) - Drilling Shutdown

Confirmed fire or gas in the drill rig, drilling module or drilling support module will require a shutdown of the drilling facilities. The shutdown sequence is initiated manually before any utilities can be shutdown. The manual push button that initiates the shutdown of the drilling facility is located on the rig floor and at the drilling supervisor’s office (Fadana, 2019).

Abandoning of the Platform

The ‘Prepare to Abandon Platform’ alarm siren is manually initiated via the push buttons located at all life boat stations, helideck and in the control room. The alarm siren is also confirmed verbally by an announcement given over the public address system. It is also displayed on the platform status lamps. Drilling will secure the "Open Well" manually and initiate shutdown of the drilling facility in response to a "Prepare to Abandon Platform" Alarm (Fadana, 2019).

4.5.2.4 Level 4 (ESD-4) - Total Platform Shutdown

This will be manually initiated only by Level 4 ESD push buttons located in the production control room and the life boat station. These will initiate operation of the sub surface safety valves for all production wells and in cases where a Level 3 shutdown has not already occurred, this will be started. Thus, all production facilities will be shutdown, isolated and blown down. All utility facilities will be shutdown, including main generators and the emergency generator. Emergency escape lighting and navigational aids will be maintained by self-contained batteries, until the cells are discharged.

If the fire water pumps are running, they will continue to do so. Whilst the ESD fire and gas system is operational, the fire pumps will be able to start automatically provided that no gas is present in the fire pump area or at the respective heating, ventilation and air-conditioning (HVAC) intakes. If gas is present in both fire pump areas, only local manual starts are possible (Fadana, 2019).

4.5.3 Master Control System (MCS)

The MCS is an electro/hydraulic multiplexed production and control system comprising of topside equipment for installation on the platform and subsea equipment for control and monitoring of remote wells and the associated subsea equipment. The MCS has a subsea component called wet controls and the dry-component called platform control.

The topsides equipment is connected to a topside umbilical termination unit (TUTU) which interfaces with the umbilical to supply chemical and hydraulic lines to the subsea wellheads.

The TUTU connects with the subsea umbilical termination unit (SUTU) fitted to each well location. The SUTU provides connections to the first termination station and onward transmission via jumpers to each SUTU and TUTU and terminates at the furthest termination station.

Interface between the platform and subsea terminations located at seabed are:

- MCS which of consists of programmable logic controllers (PLCs)
- HPU controlled by dedicated PLCs
- Electrical Power Unit (EPU) controlled by PLCs

Automated control actions are enabled by a network link between the MCS and the DCS to allow control room personnel operate subsea valves i.e. commissioning of subsea terminations as required. Tie-in interfaces to existing platform facilities are provided to the DCS, the ESD, the HPU and the EPU.

4.5.4 Hydraulic Power Unit (HPU)

The HPU provides hydraulic pressure to the isolation shut-off valves situated at subsea, for the purpose of isolating the processing facility from the well, in the event of an emergency. The HPU is controlled by a PLC.

4.5.5 Electrical Power Unit (EPU)

The EPU supplies power to subsea components such as the virtual flow meters (wet flow meters) and the subsea controls (MCS-wet controls). It is controlled by a PLC.

4.6 ELECTRICAL POWER SUPPLY

An EPU supplies 24 V DC power and 110 V to the subsea transmitters and safety control system (ESD). The EPU is supplied power from the platform electricity distribution network. The electrical cables also run through the umbilical cord system, thus connecting the subsea components and the platform components.

4.7 DATA STORAGE AND ACCESS

Data storage and access is implemented via historian data base servers, which connect to the control system network via ethernet and OPC. The historian data bases connect to the DCS, PLCs and the MCS (for both the subsea and top-side controls), via the network.

The data can be retrieved at different time intervals, ranging from 5 milliseconds to 5 minutes. Typically, on the DCS, the fastest data that can be retrieved is 5 seconds data, while for the compressors which are controlled by the PLCs, faster retrieval is possible, at 5 milliseconds.

Wireless technology can also connect to the historian data-bases computer servers via radio frequency identification and satellite communication.

CHAPTER 5: APPLICATION OF IoT SOLUTIONS TO AN EXISTING OFFSHORE PLATFORM FOR IMPROVED SAFETY AND PRODUCTION

In this case study of an existing offshore platform facility, the existing control system infrastructure has been investigated. The areas that are being investigated are: measurement variables and the associated measurement technology, controlled variables, communication protocols, different types of control systems, their network and connectivity.

The different process sections that have been identified and the associated equipment have been identified to have enough automation infrastructure to enable digitalisation and IoT implementation. The identified, existing infrastructure, that has been discussed above forms the backbone of an IoT solution for the offshore platform.

5.1 SUBSEA OPERATIONS

5.1.1 Virtual Flow Metering

For the subsea operations, the use of subsea virtual flow metering is advantageous. The use of subsea virtual flow metering would be for estimating gas and water flow rates produced from the wells without measuring them directly. The technology uses data from the field, such as pressure and temperature measurement, as well as valve choke positions, to estimate the flow rates by implementing hydrodynamic multi-phase models and reconciliation algorithms. Virtual flow metering uses wireless technology such as radio frequency identification.

5.1.2 Estimation Models and Algorithms for Unmeasured Parameters

The inability to install accurate and reliable instrumentation for the measurement of many subsea parameters provides opportunities in the subsea environment for parameter estimation algorithms and tools. These tools can be used to estimate many parameters which are currently not being measured during subsea operations. These estimation models could include models such as horizon estimation methods, Bayesian estimation, extended Kalman filtering, for estimating variables such as oil concentration in water from a separator drum. These estimation tools could then be tuned in order to fully represent the actual process dynamics.

The results from these parameter estimation tools can be used to provide information on the separation efficiencies between oil/gas and water and provide opportunities to implement improved control philosophies.

5.1.3 Pipeline Detection Methods for the Subsea Oil/Gas Pipe flow lines

In this case study, the investigated offshore facility would substantially benefit from the use and implementation of a subsea pipeline leak detection systems. A pipeline leak detection method is a safety technique used to identify leaks which would result into loss of containment. Such a system would ensure that mechanical failures such as, erosion and corrosion in pipes, are immediately detected and reported by the control system (Adegboye et.al, 2019).

There are different types of pipeline leak detection methods. They are:

- Compensated volume balance
- Pressure flow/mass balance monitoring along the pipeline
- Real-time transient method (RTTM)
- Negative pressure wave

The selection of the best leak detection method is based on the following criteria:

- Sensitivity
- Accuracy
- Reliability
- Robustness
- Leak Detection Location and Size
- Cost
- Response Time
- Complexity
- Maintainability

- Maintenance Support

The recommended pipeline leak detection method in this research work is the Real Time Transient Method, abbreviated as the RTTM pipeline leak detection system.

RTTM is widely regarded as the best pipeline leak detection method and can be used in the investigated offshore platform. The RTTM architecture includes field instrumentation such as flow, pressure and temperature sensors on the subsea pipes. Flow meters are installed at the inlet and outlet of each pipe. Flow metering is essential for mass-balance assurance during the operation, from one subsea location to another. Pressure and temperature transmitters are also installed along the pipeline route. The signals from the flow, pressure and temperature sensors would then be transmitted with fibre-optic or radio frequency telecommunications to the top-side MCS. They are then transmitted to the DCS where they would then be processed in the RTTM software installed in the DCS (Hansen et.al 2019).

Figure 9 shows a proposed basic architecture of a pipeline leak detection system, which can be integrated, with the IoT network of the offshore production platform.

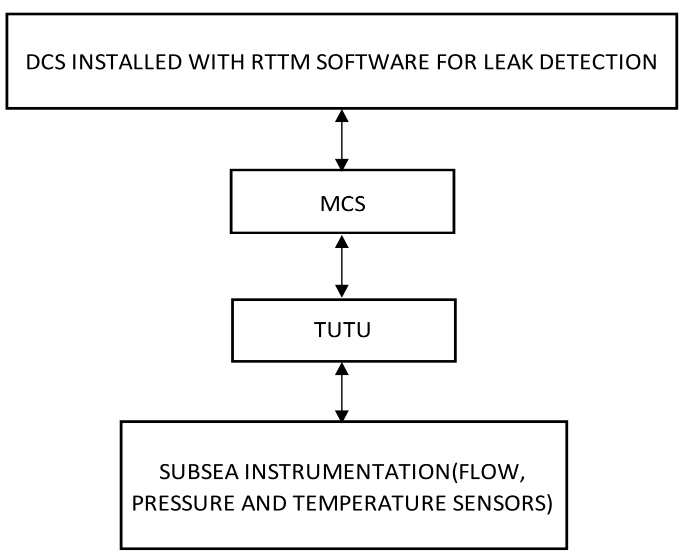

Figure 9: Proposed basic architecture of a RTTM pipeline leak detection system on an offshore platform

5.2 PLATFORM OPERATIONS

5.2.1 Predictive Maintenance on Rotating Equipment

Compressors and pumps are categorised as rotating equipment. This equipment requires condition or health status monitoring on a continuous basis to ensure safety and optimal operation.

Predictive maintenance is proposed where critical variables are monitored on a continuous basis. On both the medium- and high-pressure compressors, it is proposed to measure and monitor variables such as suction and discharge pressures, suction and discharge flows, winding temperatures, bearing temperatures, compressor speeds, and their vibrations. All these variables should have their operating ranges determined accordingly through design and operating reviews by the Technical and Operations teams.

Design and operation reviews can be conducted to set and determine the correct operating ranges and applicable high and low limits for each of the variables. Once these limits have been determined, alarm limits need to be determined for each variable. Typically for each variable the following limits need to be determined, measured and monitored, as indicated in Figure 10 below.

FLOW VARIABLE IN M3N/H

ENGINEERING UNITS OF MEASURE:

FLOW SENSOR OPERATING RANGE

HIGH OPERATING LIMIT	100
HIGH TRIP POINT	90
HIGH HIGH ALARM	85
HIGH ALARM	80
NORMAL "SAFE" OPERATION	21-79
LOW ALARM	20
LOW LOW ALARM	15
LOW TRIP POINT	10
LOW OPERATING LIMIT	0

Figure 10: Proposed design of operating ranges for a flow measurement, based on the design and operating conditions for Alarm Management

The monitoring of these limits and settings can either be done on a PLC or DCS system. These can then be monitored via a graphic user interface (GUI) or human machine interface (HMI).

The setting and monitoring of the variables on the equipment is the first step in implementing IoT, and predictive maintenance for rotating equipment. The second step is the use of such data for the prediction of undesirable behavior in the operation of these equipment.

Data trends can be set up and used to monitor process variables on each machine. These trends can indicate if that variable is approaching an unsafe operating region, and corrective actions can then be taken. The collected data can also be used in modelling the failure patterns on these machines. This means previous failures on the machines can be modelled by analyzing historical data, and the models can then be used to predict the same failures in the future.

These models can thus be used to prevent future catastrophic failures on machines, which lead to production downtime and losses, leading to profit losses.

5.2.2 Alarm Management

Alarm management is proposed in the design of IoT in offshore platforms to ensure that pre-determined ranges and alarm settings are correct and applicable for the day-to-day operation of the offshore platform. Alarm management allows for the evaluation of each alarm as it reports on the DCS when activated as a result of a process condition. Alarm management is implemented via a detailed step-by-step process called Alarm rationalisation, where nuisance or chattering alarms, stale alarms (alarms than have been active for more than 24 hours), are rationalized and evaluated if they are still applicable or if the pre-determined settings are still applicable or not.

Alarm rationalisation sessions involve all the necessary disciplines in an operations team. The involved disciplines are Process, Production, Process Control and Instrumentation, Mechanical Engineering disciplines. During the alarm rationalisation session, each alarm that reports on the DCS is evaluated and categorised accordingly. The intention of alarm management and subsequently rationalisation is to ensure that correct and useful alarming is implemented on the DCS, and that the control system is not 'flooded' with useless alarms which are not used by Operations.

Alarm management ensures that the Alarm system, which is part of the DCS is used efficiently and provides the necessary information to both the Operations and Technical teams.

5.2.3 Advanced Process Control (APC)

Model based or multi-variable control is used for the optimisation of multi-variable and interactive processes. The separation processes on the platform which has separation drums, and compressors provides an opportunity for multi-variable control, for the purpose of optimising the separation process. The control objective for the controller would be to maximise separation between the vapor and liquid (condensate streams) and maximise throughput (production).

The process that can be followed in implementing a model based or multi-variable controller is:

- Development of a model matrix where inputs (manipulated variables) are matched with possible outputs (Controlled variables)
- Step-testing of all the manipulated variables and obtaining models against responsive controlled variables
- Designing of a controller in an identified APC software package
- Deploying of the controller
- Tuning of the controller

5.2.4 Wireless Tank Gauging (Level Monitoring)

Use of wireless tank gauging can be used for measuring of separator tanks, as well as onshore tank levels. The wireless devices are installed on the specific equipment and the signals from the devices is transmitted wirelessly to the DCS via radio frequency identification (RFID) or satellite telecommunication. This process data can then be made available via the historian data base which accesses the different control systems (DCS, PLCs and MCS).

5.2.5 Wireless Equipment Monitoring

Wireless monitoring on compressors and other rotating equipment can be used for measuring of process conditions such as temperature, pressures, vibration, winding and bearing temperatures. These signals can be transmitted to the DCS via gateways for viewing, monitoring and can be used for predictive health monitoring.

5.3 DISCUSSION

Virtual flow metering for the subsea operations is proposed as a technology to be explored for measuring of the different oil and gas subsea flows. Virtual flow metering is useful since the oil and gas flows can be estimated and there is no requirement to have physically installed flow transmitters at subsea.

Pipeline leak detection system (PLDS) are also proposed where, the use of RTTM is recommended for the monitoring of any possible leaks in the gas lines. The information from the PLDS can be made available on the DCS and the historian database for the purpose of monitoring and taking the necessary corrective actions.

Monitoring tools for the purpose of predictive maintenance on rotating equipment are proposed. The information from these tools can be accessed from the process historian database via the control system through network gateways.

The predictive maintenance on the rotating equipment aims to assist the technical and operations team on predicting possible failures on equipment by using historical data and predict possible future equipment failures.

Alarm management aims to enhance the control system's effectiveness by rationalising alarms that are nuisance and unnecessary. This technique improves operations and enables production teams to focus on the relevant and the most important alarms during the operation.

Advanced or model-based control is proposed for the separation process, where the process is multi-variable and interactive. The aim of using advanced control would be to maximise throughput (production) and separation.

Wireless monitoring of process variables through radio frequency identification and satellite communication can be investigated further, particularly for unmanned offshore operations.

The proposed different components of an IoT system can be integrated together as indicated in Figure 11 below.

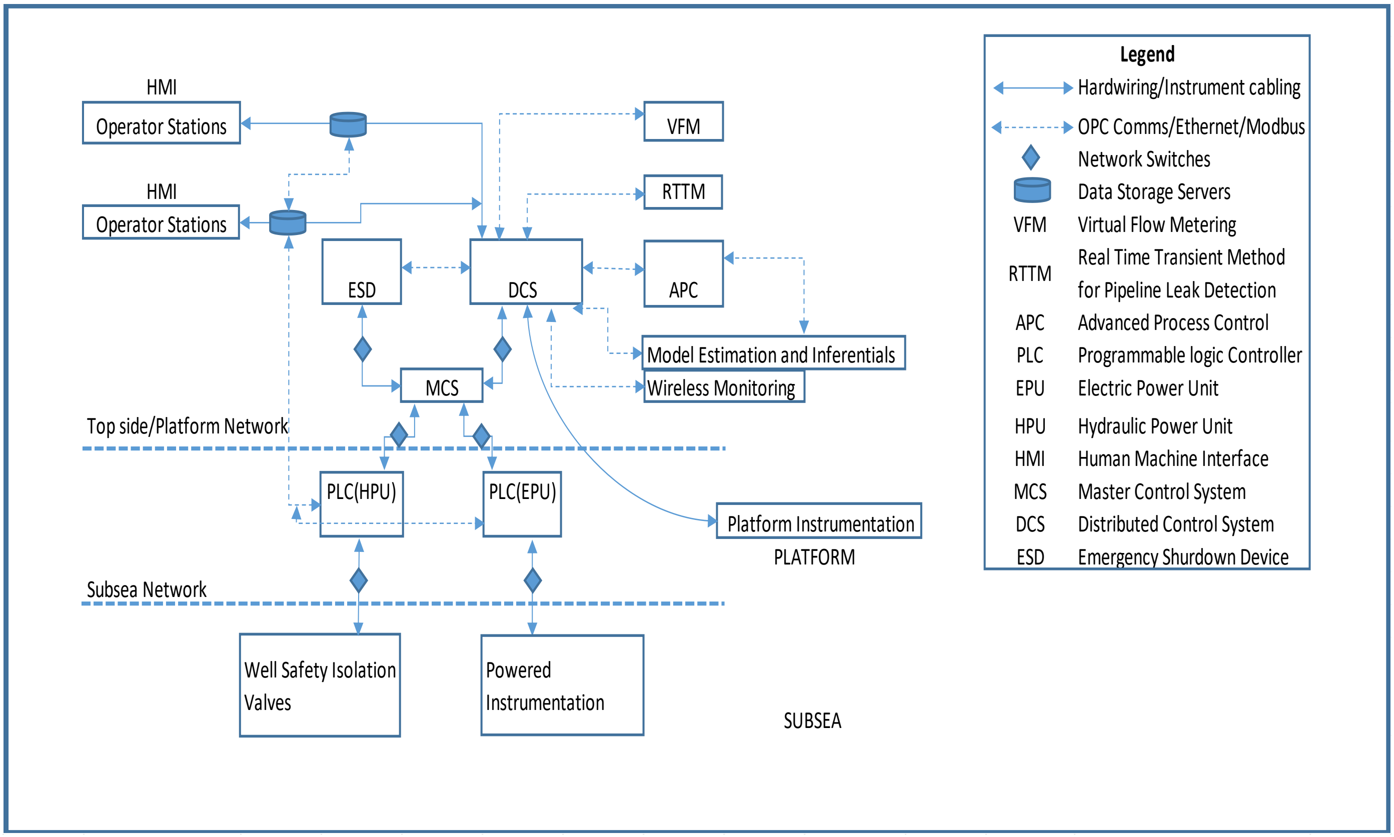

Figure 11: Proposed integrated control system network design for an offshore oil and gas production facility (ICSN)

CHAPTER 6: CONCLUSIONS AND RECOMMENDATIONS

6.1 CONCLUSIONS

The application of IoT in offshore production has been investigated through an analysis of an existing offshore production facility. The different sections of the offshore production facility have been identified. These are:

- Measurement technology, both wireless and those that make use of wire connectivity
- Data transmission protocols: 4-20mA, 1-5 V, ethernet, modbus
- Automation systems, such the DCS, PLC and ESD
- Networks
- Human machine interfacing

Through this investigation it has been identified that the upstream oil and gas industry, has made significant efforts in implementing IoT in offshore production facilities. Limitations in measurement technology, process safety, automation, data storage and transmission have been overcome through innovation, from both the academic and the industry fraternities.

A control system network solution which integrates all the different systems is also proposed for an offshore platform. The following control system enhancements are also proposed in order to improve operations, control and safety of an offshore production platform. These are:

- Virtual flow metering
- Estimation models and algorithms as inferential for unmeasured parameters
- Pipeline leak detection methods
- Predictive Maintenance on Rotating Equipment
- Alarm Management
- Advanced Process Control
- Wireless Tank Gauging (Level Monitoring)
- Wireless Equipment Monitoring

6.2 RECOMMENDATIONS

The purpose of this research has been to investigate the use of IoT in the offshore oil and gas industry, as well as propose improvements in the current IoT system. The investigation is inherently broad and requires a further detailed research in each of the identified areas. The next step in this topic is to investigate each of the following areas:

- Virtual flow metering
- Pipeline leak detection methods
- Wireless monitoring and control of equipment for safety and optimisation
- Subsea parameter estimations using adaptive modelling
- Advanced process control for increased separation and throughput
- Alarm management

Further investigation in each of the following areas will require the necessary resources (time, finance, laboratory equipment where necessary) from both the academic and industrial fraternities.

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