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Master's Thesis

Spring 2016

"An analysis of asset availability performance: a practical determination of well system reliability and maintainability"

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Stavanger, June 2016

Kai Petter Vika

Abstract

With decreasing oil prices, optimizing existing production is essential to generate as much revenue as possible. When the product sold decreases in value, more volume is required to maintain the revenue levels. Therefore, when oil prices are low, well availability is an important contributor to reaching revenue targets. A major international oil and gas company, with assets in NCS and UKCS, had a goal to better understand which failures impact their asset's well production availability. The goal of this thesis was to determine Company's assets' availability though practical system reliability and maintainability.

This was achieved by reviewing historic production performance data. When commencing this thesis, the goal was to obtain knowledge of how the offshore assets were managed to achieve well availability. It was believed that simple manipulations in excel would provide sufficient information to gain an understanding of how the wells are operated. However, as the thesis progressed, new discoveries were made which required further analysis, and most importantly it has been necessary to consider and recommend how to apply this historic insights to improve future performance.

With data collected from the company's performance database, PPIT. Based on the data, 1,854 production deferrals were issued during a period of nearly ten years for three separate assets. A total of 102 wells were included in the survey. A total of 822 service years were included in the review. *Well equipment failure* accounted for 40% of the production volume deferred, *platform priorities* accounted for 28% and *reservoir and well service* accounts for 32%.

Planned deferrals accounts for 17% of all production volume deferred. The total planned production volume deferred is 7 million BOE. Thus, 83% of the total production volume deferred is unplanned, which accounts for 35 million BOE. The total deferral duration was over 29,000 days, deferring 42 million BOE.

The reliability of the system is calculated using MTBF. The total MTBF, which includes planned and unplanned deferrals, for all assets is 0.45 years. This means that at any given time, any of the company's wells are, on average, expected to have deferrals twice a year.

The MTBF for equipment failure is 2.09 years. The main contributor to the low MTBF is the "Surface tree" equipment group. Additional equipment groups which causes low MTBF are the "DHSV" and "HPU/Logic" groups. "Intermediate completion" groups did not have any registered failures, this the MTBF is equal to the total service time.

The repair time to fix the system is determined by calculating the MTTR. The average MTTR for any deferrals for all assets is 16 days. The equipment average MTTR is 26 days. This is also expected, as the equipment MTTR is only unplanned deferrals.

The overall asset reliability is 61%. The industry average, compared to reliability data from WellMaster RMS, is 60%. This, on average, the Company's assets are according to the expected average. Asset 1 are below the expected performance average, whilst Asset 3 is above. Asset 2 has very low reliability and measures should implemented to increase the overall reliability.

As the components has a generally high reliability performance, altering component reliability will be less effective as the values are already high. Channing high values to higher values will not dramatically increase the availability of the system. Therefore, the focus should be on reducing the time it takes to repair the systems. If a component has high reliability, but is difficult to fix, the availability of the component may be relatively low. The following is highlighted;

- Efforts should be made reducing repair time for Cluster 2 equipment. If the repair time cannot be reduced, better maintainability of the equipment should be developed.
- To increase availability of the system, the initial focus should be on reducing the repair time of the components.
- A significant amount of the equipment has a reliability above 95%.
- Repair time has a big impact on the availability of a product.

Company has an overall good performance on the wells system availability. All the assets range between 84% and 93%. This is considerably higher than what was though prior to the commencement of this thesis. Even though Asset 2 is very low on reliability, it still manages to maintain a good availability of the wells. Thus, the maintainability of the wells systems is a very contributing factor in achieving the desired uptime of a well system.

Based on the information found in this thesis, the major contributor in reducing deferred production, and increasing the availability of a well system, is the maintainability of the wells. If the equipment has low reliability but has a relatively low MTTR, the equipment will remain available most of the time. Therefore, the equipment the company should focus on to improve well system availability is the equipment with high MTTR. A high MTTR will cause more production deferrals than a low MTBF. Therefore, measures should be made by Company to gather information related to how effective the company is at fixing failed equipment. This may be the most effective method to increase well availability.

For example, a possible way to increase availability is to install redundant systems on the TR-ASV to ensure continuous production. From this thesis, it was disclosed that the TR-ASV single failures caused large amounts of deferred production. By installing redundant system, deferred production can be lowered by tens of millions of dollars over a period of ten years.

Further, it was discovered that the managing of asset performance may be affected by discussions which are not directly related to the well itself. Asset 3 received a platform upgrade in 2012-2013, which has caused the production capacity on the platform to increase. Thus, all well failures cause a full system deferral. This yields less time to fix problems when they occur as the asset needs the production to perform as required. This causes a sub-optimum and "firefighting" environment.

However, overall, the Company has roughly industry average reliability for most assets. Company is relatively efficient at mending their failures. Thus, the availability of all the assets are reliability high. The high availability of the wells are thought to be due to the efficient maintainability skills of the organization. This thesis has proved that if the reliability of an item is poor, but easy to fix, the availability of the well system may still be high. Thus, Company should focus their time on reducing the maintainability of the system first.

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Abbreviations

- number

ASV – annulus safety valve, for this thesis interchangeable with TR-ASV

Avg. – average

BOE – barrel of oil equivalent

DHSV – downhole safety valve

g – system unreliability

GLV – gas lift valve

h – system reliability

IPC – installed production capacity

IPO – injection pressure operated, interchangeable with unloading GLV

KPI – key performance indicator

LL – lower limit

MTBF – mean time before failure, for this thesis interchangeable with MTTF

MTTF – mean time to failure, for this thesis interchangeable with MTBF

MTTR – mean time to repair

NCS – Norwegian continental shelf

pi – component reliability

PPIT – Production Performance Indicator Tool

qi – component unreliability

R(t) – reliability

RMS – reliability management system

S(t) – survival probability

TR-ASV – tubing retrievable annulus safety valve

UKCS – United Kingdom continental shelf

UL – upper limit

WBE – well barrier element

WBS – well barrier schematic

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1 Introduction

The purpose of this section is to provide an introduction to the thesis.

1.1 Preface

The purpose of this section is to provide an introduction to why the work is done.

A major international oil and gas company, with assets in NCS and UKCS, had a goal to better understand which failures impact their asset's well production availability. This was achieved by reviewing historic production performance data.

When commencing this thesis, the goal was to obtain knowledge of how the offshore assets were managed to achieve well availability. It was believed that simple manipulations in excel would provide sufficient information to gain an understanding of how the wells are operated. However, as the thesis progressed, new discoveries were made which required further analysis, and most importantly it has been necessary to consider and recommend how to apply the historic insights to improve future performance.

The data presented in this thesis is based on the best available assumptions and engineering judgement at the time.

1.2 Objective

The purpose of this section is to outline the objective of this thesis.

The objective of this thesis is to determine the well production availability of Company's assets though a review of historic performance data and use the information gained to recommend improvement potentials and focus areas. As part of the main objective, determining the portion of planned vs unplanned shut-ins is a necessary objective. In addition, other objectives are to determine;

- causes for shutting-in wells.
- bench marking of Company well reliability compared to industry average reliability.
- Company well component(s) availability.
- measures to increase availability.
- suggestions for improvement on data collection.

1.3 Method

The purpose of this section is to outline the method used for this thesis.

The method utilized for this thesis will be based on a practical interpretation of how the assets are managed by Company. The assessment will be generated based on the performance of the following tasks;

- Obtain deferrals related to three oil fields in the North Sea, for up to 10 years.
- Remove possible duplicates from this to ensure only one deferral is counted per fix.
- Code deferrals according to Exprosoft's WellMaster failure cause codes.
- Assign Equipment Level coding according to Company's "Well Equipment Failure Coding Hierarchy Rev 2 dated 23.08.2015"
- Enable excel coding to count occurrences, duration and volume deferred based on Exprosoft's WellMaster and/or Company well equipment coding.
- Calculate reliability data from PPIT information
- Generate a representative Company well system, and calculate the reliability of the well based on reliability data from Exprosoft's WellMaster RMS system.
- Compare the two reliability data findings.
- Calculate availability of Company assets

1.4 Delimitations

The purpose of this section is to define the limitations of the thesis.

1.4.1 Limitations of MTBF

All the data supplied for this thesis work is actual data recorded in Company's PPIT system. The data is calculated and converted into reliability data. All the calculated reliability data is presented as mean time between failure (MTBF). MTBF parameters only yields statistical results if the data from the PPIT system correspond to an exponential distribution where failure rate is constant and time is independent. Thus, MTBF, in this report, are merely a performance indicator and not a lifetime prediction. The MTBF is to not be interpreted as the expected lifetime of the component without failure (Molnes & Strand, 2009).

1.4.2 Data collection from PPIT

The data collected from Company's Production Performance Indication Tool (PPIT) span for nearly a decade. The author is of the opinion that it is highly unlikely that the process of collecting data has remained at a standstill for nearly a decade without any improvements to the process. Thus, certain processes KPIs have changed with respect to what and how the performance is reported.

It a challenging to capture these changes in the data set spanning over 30,000 rows of data. Therefore, the quality of the data input is assumed to be accurate and correct. However, one noticeable discovery of assumed change has been confirmed. It is related to how "Cyclic Wells" lost production is reported. It is assumed that his has changed over the years.

From 2006 up to, including 2010, eleven deferrals for Asset 3 were reported, all of which are deferred due to reservoir characteristics. These deferrals are similar in that they deferred large quantities of production and lasts over long periods of time. It has been confirmed that the reporting of these deferrals are not consistent with the current process, which was established in early 2011. For this reason, these deferrals have been taken out of the total deferral data set.

Furthermore, all deferrals properties are assumed to be complied by both a pre-defined drop-down list and free-text inputs. If there is a discrepancy between the values in from the drop-down list and free-text, the free-text information will supersede the drop-down list. The author assumes that the free-text is more accurate and specific than pre-defined values.

Assigning the deferrals failure mode and equipment level categorizations are preformed ex post facto. Therefore, all deferrals assigned values are done based on the authors best judgement at the time of performing the categorization. The author sought confirmation by reviewing in detail uncertain sets with the Company's asset engineers. However, due consistently large scale of data, it was impractical to confirm all the data.

1.4.3 Human errors

Due to the nature of the thesis, with over half a million data points and a lot of excel coding, there is always a chance of errors occurring. Multiple quality checks have been performed while coding and many potential errors has been adjusted. However, there will always remain some degree of error.

2 Background

The purpose of this section is to establish some background knowledge for the thesis. This section discusses the different types of well systems, its integrity and what shuts-in the wells. Further the section provides some theoretical background on the various techniques utilized throughout the thesis.

A global supply and demand imbalance sent the crude oil price from $120 per barrel to $30 per barrel in less than two years (NASDAQ.com, 2016) (Addison, 2016). The pain of tanking profits causes companies to search for cost savings and re-evaluate their break evens costs for projects (Addison, 2016). In the second half of 2015, twenty-two major projects were put on hold due to the lasting lower oil prices, resulting in reserves deferrals of seven billion BOE (Wood Mackenzie, 2016).

During the life cycle of a well, the well has multiple level phases as indicated in Figure 1 –from the initial planning of well to the abandonment of it (The International Association of Oil and Gas Producers, 2012). During the operational phase, each well has an anticipated production capacity which changes over time. The anticipated production capacity is referred to as an installed production capacity - IPC (O'Brien, 2016).

Figure 1 - Life cycle of well (The International Association of Oil and Gas Producers, 2012)

The IPC is the maximum production the well can produce. The IPCs are pre-defined value which is well dependent and often confirmed via wells test. If the well is shut-in, or has impaired reduced production, the well will not meet its IPC. When the production system does not meet the total IPC level, a production deferral is allocated against the well for the volume deferred – or suspended. The system's production output is continuously recorded (O'Brien, 2016).

During the Well Operational phase, a well is subjected to planned and unplanned shut-ins as shown in Figure 2. The planned shut-ins may be related to (O'Brien, 2016);

- maintenance activities
- well barrier element testing
- heavy lifts requiring wells to be shut-in and isolated
- drilling and completion activities of other wells
- planned scale squeezes

The un-planned deferrals may be further categorized in two groups; well equipment failures and well system impairments. A well equipment failure deferral is used when production critical equipment fail during operation (O'Brien, 2016).

The well system impairments creating unplanned deferrals may be related to (O'Brien, 2016);

- scaling
- chalk influx
- surface system pressure limitation
- solids
- temperature drop across choke
- BHP reduction

If a well is producing below its IPC, intervention work has to be performed to get the well producing according to its IPC again.

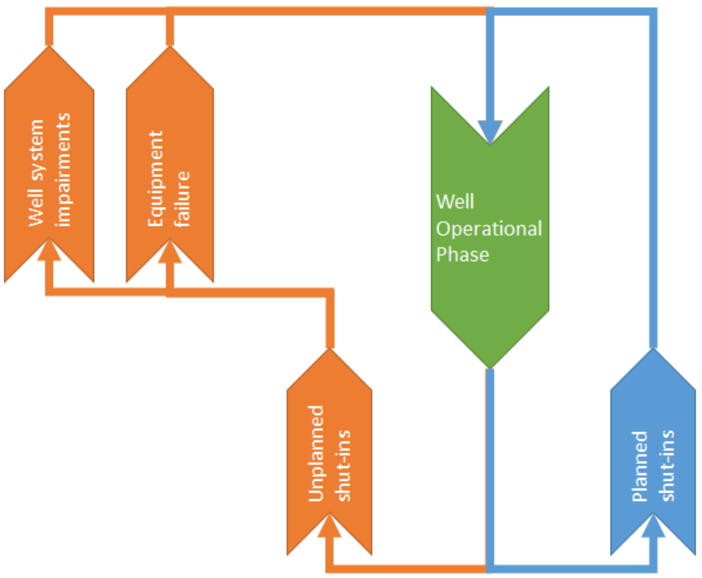


Figure 2 - Operational phase

2.1 Well systems

This section is intended to provide a basic understanding of what a well is and the different types of equipment associated with it. Also well integrity is discussed and focuses on what may shut-in a well.

2.1.1 Well types

In the most generic form, there are land wells and offshore wells. This thesis will focus on offshore wells. A well consists of a casing, tubing string, wellhead and x-mas tree. An offshore well is either a platform well or a subsea well. Platform wells have wellhead and x-mas tree on surface, also referred to as dry trees. A subsea well has the wellhead and x-mas tree on the seabed, which is also referred to as a wet tree (Odland, u.d.). For this thesis, the asset have dry trees.

For offshore, dry trees, there are two types of well functionalities; injection and production. Production wells produce fluids while injection wells are used to inject a medium into the reservoir (Corneliussen, 2006).

Production wells

A production well transports the reservoir fluids form the reservoir to the process facilities. A production well can produce oil or gas. An oil producing well will most likely also produce some degree of gas and water in addition to crude oil. A gas producing well is likely to produce some condensate and water in addition to natural gas. A production well is either naturally producing or on artificial lift (Corneliussen, 2006).

A well is naturally producing when the pressure in the reservoir is large enough to lift the produced fluids to surface. Over time, the pressure in the reservoir drops and the well requires additional lifting force to get the fluids to surface. Artificial lift systems add energy to the fluid column, which causes the fluid to lift to surface. The most common type of artificial lift in the North Sea is gas lift, and this is also relevant for the three assets. Other types of artificial lifts are rod pumps and electrical submersible pumps (Corneliussen, 2006).

Injection wells

There are three types of injection wells; water, gas and water and gas. The purpose of an injection well is to maintain the pressure in the oil reservoir. When a well is produced, the pressure in the reservoir decreases. By injecting water or gas into the reservoir allows for pressure increase in the reservoir which will allow for continuous production (Corneliussen, 2006).

For this thesis, only oil producing wells are considered in for this thesis.

2.1.2 Well integrity

Integrity can generally be defined as "adherence to moral and ethical principles" and "the state of being whole or undiminished" (Dictionary.com, LLC, u.d.). The adherence to moral and ethical principles is generally referencing expectations from the surrounding stakeholders, community, employees, shareholders and environment. It establishes a set of moral obligations in which the person, or company, is supposed to act responsibly to avoid disturbing or causing harm to others. Being able to act on these principles, and not reject any, allows the person, or company, to maintain a state of being whole and fulfill its integrity to the stakeholder.

NORSOK's definition of well integrity is "application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids and well fluids throughout the life cycle of a well" (NORSOK, 2013). In the practical application of integrity, it relates not only to the status of the well, being that all components are working well and thus the well has integrity, but NORSOK's definition also incorporates the appropriate support and organizational management to ensure integrity is accurate. The organization has responsibility of ensuring the competent personnel with the correct training is assigned to review and assess the integrity level of the well, system or operations. It is management's responsibility to ensure that the organization has integrity and competence to assess and assure integrity of the components they are assigned. Thus, it is the governing authorities' responsibility to asses and assure integrity of the companies assigned to perform and verify integrity (PSA Norway, 2016).

Integrity is therefore the moral and ethical principles developed to ensure that the companies reviews, assesses and assures integrity of not only hardware and software, but also the organization and its people. It is therefore the duty of the company to assess itself and to ensure everything is done correctly, every time. Then integrity becomes as Palmer describes; "I now know myself to be a person of weakness and strength, liability and giftedness, darkness and light. I now know that to be whole means to reject none of it but to embrace all of it" (Palmer, 2008). Thus, in order to keep integrity, a company should adapt Clive Staples Lewis' approach by "doing the right thing when no one is watching" (goodreads.com, u.d.).

One important principle of maintaining a wells integrity is built on well barrier elements (WBE). WBE is "a physical element which is in itself does not prevent flow but in combination with other WBE's forms a well barrier" (NORSOK, 2013). WBE's are components which are produces and tested according to industrial standards for the type of equipment. In other words, WBE are the components which make up the well.

A WBE is does not alone does not allow for reservoir fluids to reach surface, not does it control that production fluids. As Figure 3 indicates, having standalone WBEs will not contain the produced fluids. Therefore, standalone WBEs does not provide integrity.

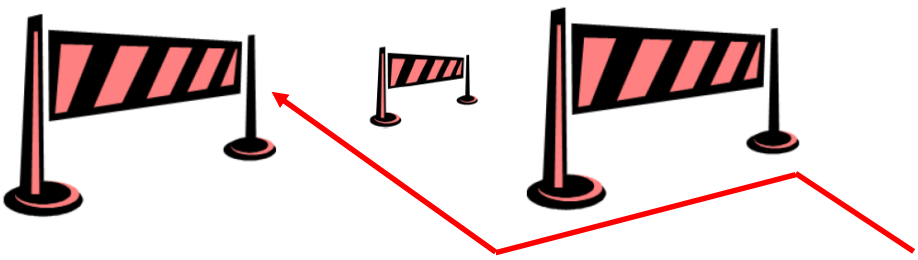


Figure 3 - Multiple WBE not in series

Integrity is gained by connecting multiple WBE's in series. Figure 4 shows how having multiple WBEs connected in series allow for containment of production fluids, which will make a well barrier. A well barrier is defined as "envelope of one or several well barrier elements preventing fluids from flowing unintentionally from the formation into the wellbore, into another formation or to the eternal environment" (NORSOK, 2013).

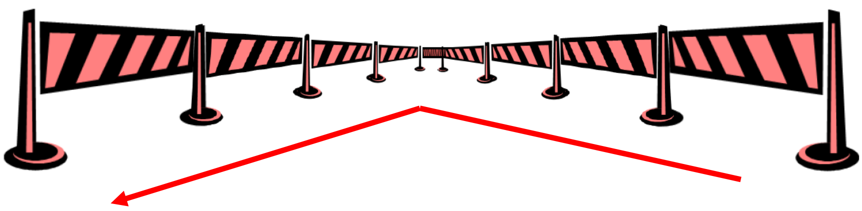


Figure 4 - WBE in series - a barrier

According to NORSOK (2013), a well barrier must be defined prior to commencing an operational activity. The well barrier must be verified and monitored. This is done to ensure that the necessary equipment to control the produced fluids are intact and can handle the hazard of the operation.

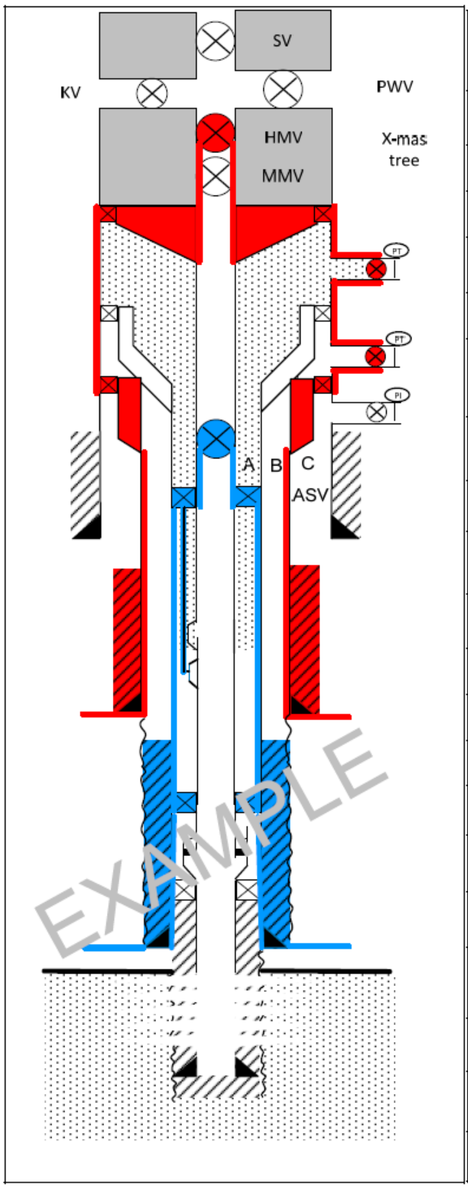
Further, NORSOK (2013) requires a well with access to reservoir pressure to maintain two independent mechanical barriers. This requires each well to maintain two independent barrier envelopes. These are commonly referred to as primary and secondary barrier envelopes. The production critical equipment is part of one of these envelopes, thus if a failure occurs in that type of equipment, the well had to shut-in.

2.1.3 Well shut-in

A production well can be shut-in, or have reduced production, for numerous reasons. A well shut-in can be related to uncontrollable reservoir issues, platform priorities or WBE equipment failure. This thesis will further discuss the WBE equipment failure, as the other two causes can be a large variety of different scenarios.

For the equipment failure to shut-in or impair production of a well, the failure has to put the equipment, environment or personnel in danger. All equipment failures do not automatically cause a well to shut-in. Equipment failures related to well barrier elements tend to cause shut-in the well.

NORSOK D-010 requires each operator to create and maintain a well barrier schematic (WBS). The WBS is an illustration of a well and its main barrier elements. The schematic visually differentiates between the primary and secondary barrier by colors. Below is a NORSOK example of a platform production well on gas lift with an ASV, where the GLV is not qualified.



Well barrier elements	EAC table	Verification/Monitoring
Primary well barrier		
In-situ formation	51	n/a after initial verification
Casing cement	22	n/a after initial verification
Production casing	2	Continuous pressure monitoring of B-annulus
Production packer	7	n/a after initial verification
Completion string component (CIV and CI line)	29	Periodic leak testing
ASV (including control line)	9	Periodic leak testing. AC ASV: xx bar/xx min.
Completion string (Between ASV and DHSV)	25	Periodic leak testing
DHSV / control line (including control line)	8	Periodic leak testing. AC DHSV: xx bar/xx min.
Secondary well barrier		
In-situ formation	51	n/a after initial verification
Intermediate casing cement	22	Daily monitoring of C-annulus
Intermediate casing	2	Daily monitoring of C-annulus
Intermediate casing hanger with seal assembly	5	Daily monitoring of C-annulus/ Periodic leak testing
Wellhead (A-annulus valve)	12	Periodic leak testing of valve AC: xx bar/xx min.
Wellhead (B-annulus valve)	12	Periodic leak testing of valve AC: xx bar/xx min.
Tubing hanger (body seals)	10	Periodic leak testing and continuous pressure monitoring of A-annulus
Wellhead (WH/tree connector)	5	Periodic leak testing
Tubing hanger (neck seal)	10	Periodic leak testing
Surface tree	33	Periodic leak testing of valves AC: xx bar/xx min.

Figure 5- Example of WBS (NORSOK, 2013)

Further, NORSOK D-010 defines a minimum set of requirement for an operational well. The standard requires "all valves, available testable seals and lines which are part of the primary or secondary well barriers shall have a maintenance program and be periodically tested to verify its function and integrity". NORSOK states that "Upon confirmation of loss of the primary or secondary well barrier, the well shall be shut-in and the remaining well barrier verified. Only activities related to the re-establishment of the well barrier shall be carried out on the effected well. Multiple well barrier failures on the same well shall immediately result in an alert to the emergency response organization". However, if the well poses a greater risk being shut-in, the well is allowed to keep production until the well barrier has been re-established (NORSOK, 2013).

In her 2014 master's thesis "New risk categorization system for well integrity – wells in operations", Kristine Naug Kostøl categorizes the possible leaks into two main groups – external and internal. Internal leaks do not leak to the environment or atmosphere. An example is a leaking DHSV. With the DHSV leaking, the reservoir fluid does not leak to the environment. External leaks are leaks outwards to the environment. Compared to internal leaks, external leaks are assumed to be more difficult to repair and control. Figure 6 - Possible leak paths shows the potential locations of these leaks. All leaks are leak past well barriers (Kostøl, 2014).

1. Internal leak – failure of the DHSV and x-mas tree valves.
2. External leak – leaking into the overlying formation and is contained.
3. External leak – same as above, but formation does not trap the pressure/medium.
4. External leak – leakage thru the wellhead and/or x-mas tree.

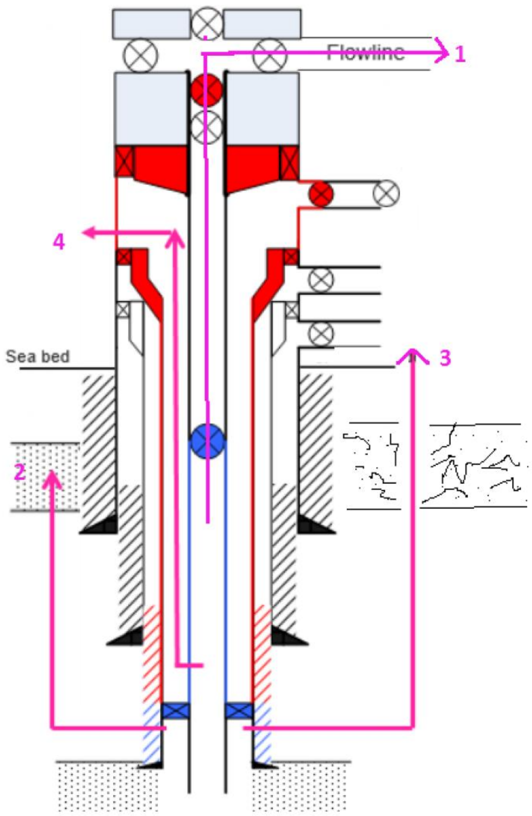


Figure 6 - Possible leak paths

Other possible leak paths, which may shut-in the well, are shown in The International Association for Oil and Gas producer's Figure 7. The figure identifies twenty-six possible leaks in a well –of which all fits into one of the four leak scenarios listed above.

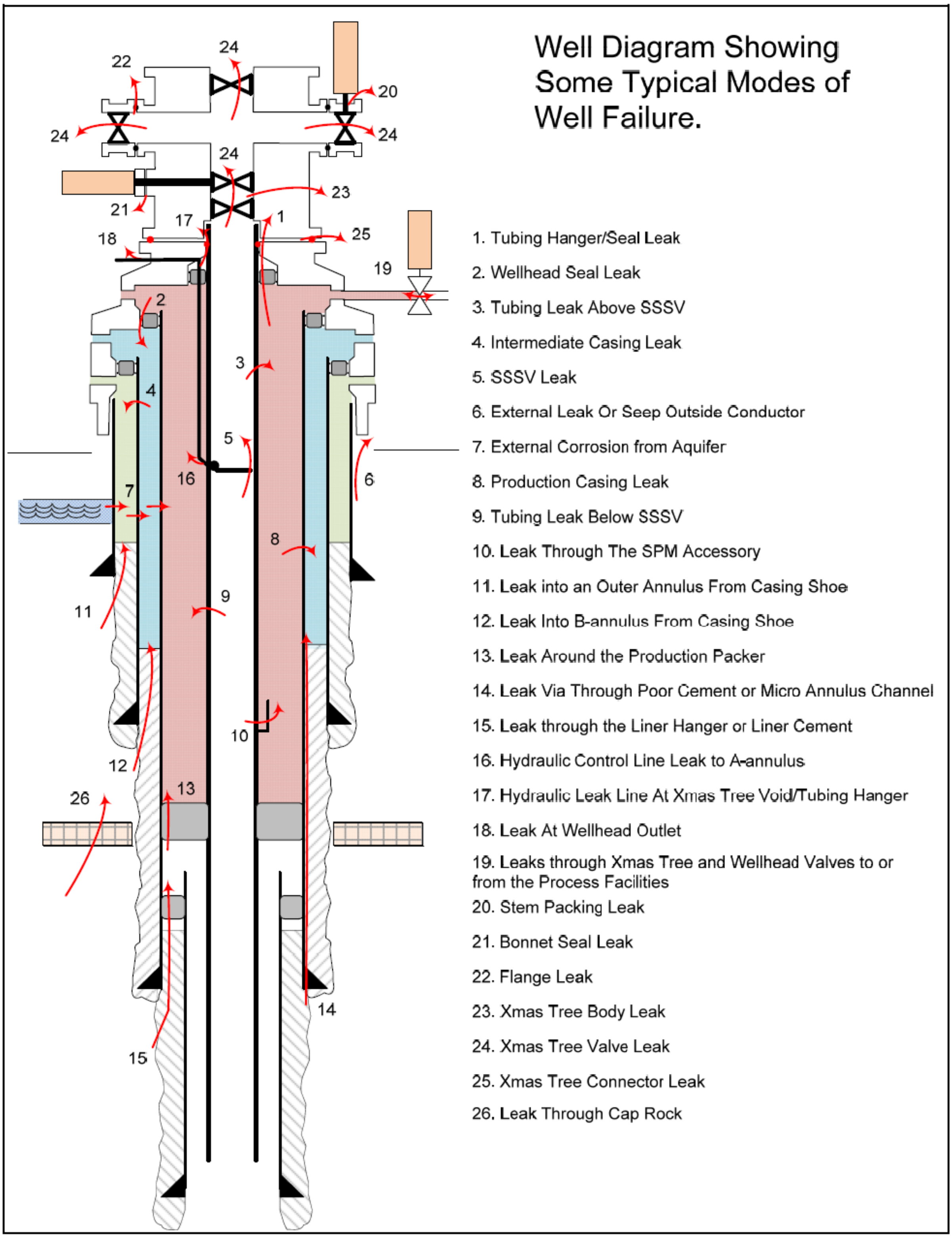


Figure 7 - Examples of possible leak paths in a well (The International Association of Oil and Gas Producers, 2012)

2.2 Literature review

This section is intended to provide basic methods of defining reliability, maintainability and availability. Basic methods of calculating the reliability and availability of components and systems will also be disclosed.

Over the years, there has been an increase focus on product and component reliability to avoid unwanted downtime. During the Korean war, the United States Department of Defense found that they spend two dollars per year maintaining every dollar's worth of electronic equipment. Over a lifespan of ten years, the maintenance of the equipment costs more than twenty times that of the purchasing costs. This yielded huge extra costs related to operability of the components (Aven, 1991).

Since the 50's and 60's, the industrialized countries are intensively concerned with reliability and risk management. Traditional values associated with reliability and risk management was to prevent harm to human life, environment and material assets. In later years, additional focus has been put to ensure production delivery from existing and planned production facilities (Aven, 1991).

The primary objective of reliability and risk management is to provide a basis for decision making. It is to ensure safety is taken care of systematically, and coordinated with work and activities to achieve and maintain the desired safety levels. Some of the objectives of reliability and risk management are to provide basis for (Aven, 1991);

- Prioritization between alternative solutions and actions
- Deciding whether reliability and risk are acceptable
- Evaluating profitability of a project
- Development safe and effective procedures for the operation and monitoring process or the equipment
- Undertaking a systematic description of undesirable event and their potential consequences
- Achieving improved system knowledge as a result of analysis of connection and interaction of the components in the system
- Developing competence and motivation for systematic safety follow-up

Asset management focuses on reliability and maintainability of a system. The reliability of the system is determined by reviewing equipment performance and system configuration. The maintainability of a system is determined by reviewing how much time is spent on downtime due to maintenance, personnel, mobilization delays and spare parts constraints. Combined, the reliability and maintainability gives the systems availability (DNV-GL, 2015).

The challenges with managing offshore assets are to maximize uptime and performance whilst minimize risk, downtime and cost. This is achieved by maximizing efficiency and reliability to increase production throughput at any given time. Further minimizing costs associated with manning, materials, maintenance, transportation and other activities which causes downtime. All this while achieving the necessary safety requirements enforced by governmental body and internal company policies (DNV-GL, 2015).

Asset performance is impacted by numerous activities related to market, operations, plant characteristics, maintenance and equipment reliability. Figure 8 shows additional contributors to the asset performance. In addition to unplanned downtime, which can be related to product reliability, planned shutdowns also impact the performance (DNV-GL, 2015).

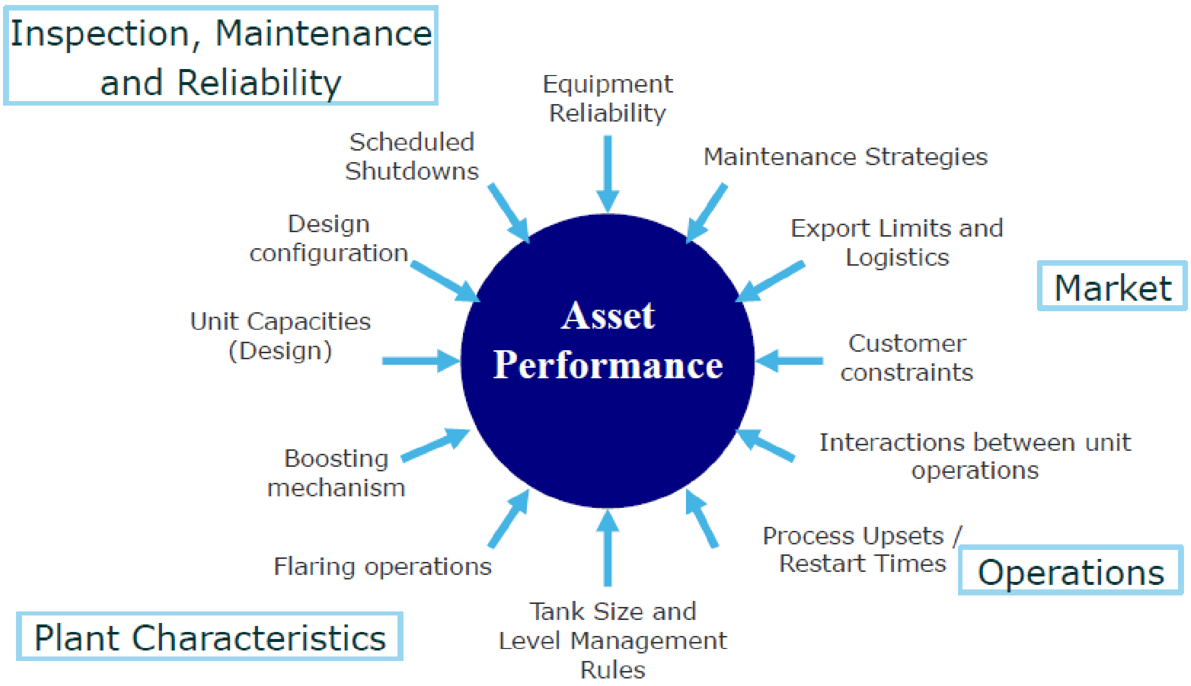


Figure 8 - Impacts on asset performance (DNV-GL, 2015)

Availability is a quantitative measure of the performance of an asset. Figure 9 shows how equipment performance and maintenance resources make the system uptime. Therefore, applying the theory of availability, the performance of an asset can be calculated (DNV-GL, 2015).

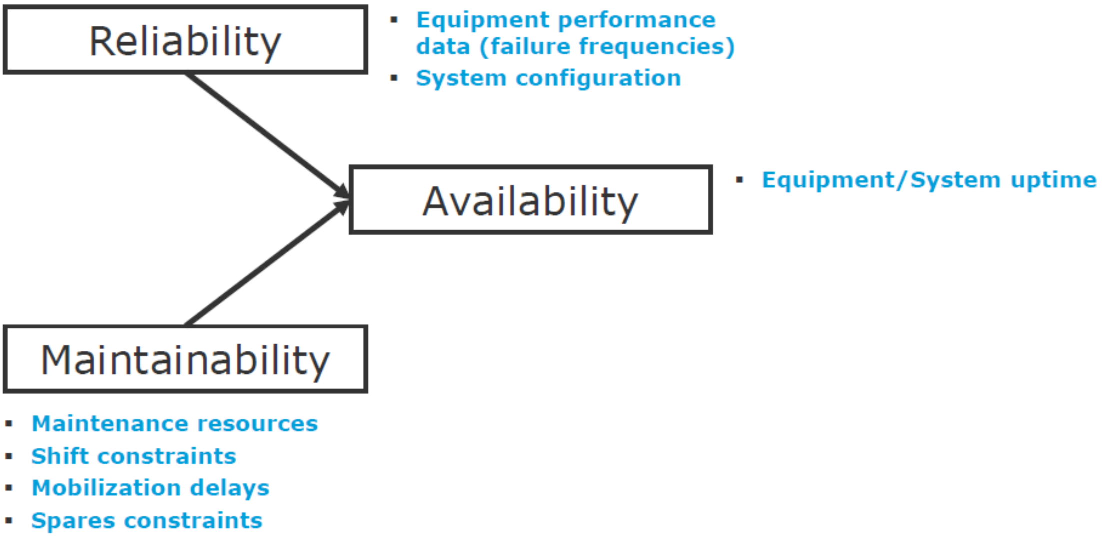


Figure 9 (DNV-GL, 2015)

A realistic measure of operational performance is system availability. If the system is unavailable due to failure, or routine maintenance, the consequence is the same –the system is not operational. As the system is not operational, the system does not provide the intended function (Liu, 2016).

The rest of this section will focus on how to determine a reliability, maintainability and availability of a system.

2.2.1 Component Reliability

The reliability of a component is the probability of the component working given a defined time period. Therefore, the unreliability of a system is the probability of the system not working given a defined time period. Reliability is defined in by NATO to be the "… ability of an item to perform a required function under stated conditions for a specified period of time" (NATO, 2001).

Figure 10 illustrated the statistical life cycle of a component and its mean time to failure. The lifetime of a component is classified into three categories, *Early Failures*, *Useful Life* and *Wear Out*. As each category has various failure rates, the failure diagram looks like a bathtub curve (DNV-GL, 2015) (Aven, 1991) (The International Association of Oil and Gas Producers, 2012).

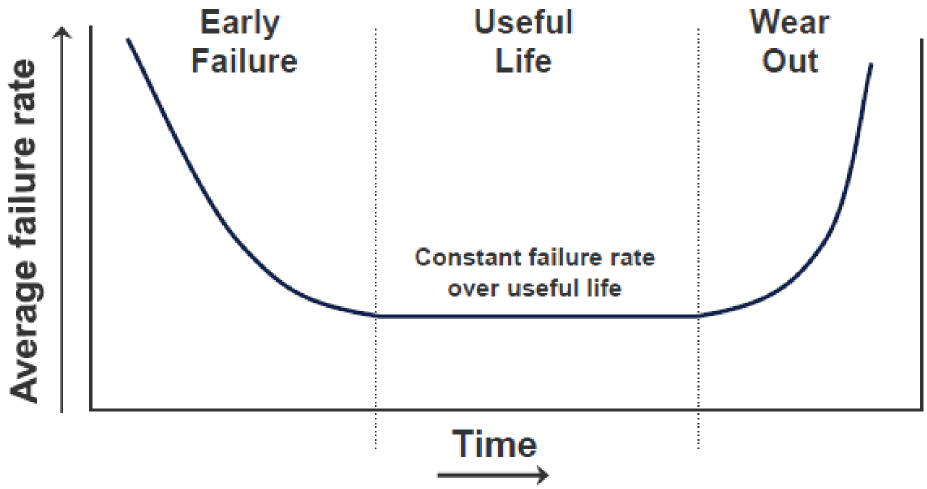


Figure 10 - Bathtub curve (DNV-GL, 2015)

Early Failure category experiences a decreasing failure rate. The failures are usually related to component quality (The International Association of Oil and Gas Producers, 2012). The quality issues may be related to manufacturing or design (Aven, 1991).

During the *Useful life* category has an approximately constant failure rate were the failure usually are due to normal in-services operations (The International Association of Oil and Gas Producers, 2012). Due to similar attributes, the exponential lifetime distribution, which also has a constant failure rate, is commonly used for calculating utilized to calculate the reliability of the systems (Aven, 1991). Therefore, the reliability predictions are generally based failure rates in during the *Useful life* category (DNV-GL, 2015). The work performed in this assumes all equipment is in the *Useful life* category.

Ware Out category experiences an increasing failure rate, where the failures usually are due to component ware and tare (The International Association of Oil and Gas Producers, 2012). These failures happen at the end of the components design life time (DNV-GL, 2015). Failure rates during the *Early Failure* and *Ware Out* vary with time and can be calculated using Weibull distribution (DNV-GL, 2015).

For the *Useful Life* category, constant failure rate distribution, the failure rate is expressed as λ. λ is expressed as an observed failure rate –the ratio of total number of failures to total cumulative observation time. It is the time it takes from realization of fault until item is reinstated for further utilization (DNV-GL, 2015).

Furthermore, according to Aven (1991), the lifetime, T, of an equipment type from the installation to the point it is no longer operable, i.e. it fails. Thus, F(t) denotes the lifetime distribution of T, as is expressed as;

$$F(t) = P(T \leq t)$$

Equation 1- frequency interpretation of probability (Aven, 1991)

Where F(t) is the expected potion of units that will fail within t units of time. T is the lifetime of the unit from installation until it fails. Thus, F(t) is expressed as;

$$F(t) = \int_0^t f(t)dt$$

Equation 2

The probability density function for exponential distribution is;

$$f(t;\beta) = \begin{cases} \frac{1}{\beta} e^{-t/\beta}, & t > 0, \beta > 0, \\ 0, & elsewhere \end{cases}$$

Equation 3 (Walpole, et al., 2012)

β is the time between failures, also referred to as mean time between failures (MTBF) (Walpole, et al., 2012). The failure rate λ is 1/β. By rewriting the equation above as a function of time and failure rate, the function becomes;

$$f(t;\lambda) = \begin{cases} \lambda e^{-\lambda t}, & t > 0, \\ 0, & elsewhere \end{cases}$$

Thus, by integrating the probability density function, the cumulative distribution becomes;

$$F(t) = \int_0^t \lambda e^{-\lambda t} dt = 1 - e^{-\lambda t}$$

Equation 4 (Walpole, et al., 2012)

Thus, lifetime T is exponentially distributed with parameters λ > 0 if;

$$F(t) = 1 - e^{-\lambda t}, \qquad t \geq 0$$

Equation 5 (Aven, 1991)

The reliability of the component is given by the survivor function R(t), This function is expressed as;

$$R(t) = P(T > t) = 1 - F(t)$$

Equation 6 (Aven, 1991)

Then, substituting the cumulative distribution, Equation 4, into the R(t) function;

$$R(t) = 1 - F(t) = 1 - \left(1 - e^{-\lambda t}\right) = e^{-\lambda t}$$

Equation 7 (Aven, 1991), (DNV-GL, 2015)

In Equation 7, t is the time duration given, or chosen, by the person performing the reliability calculations of the component. λ is the hazard rate of the component.

The failure rate, z(t), is the number of failures given a time interval. The hazard rate is defined as;

$$z(t) = \frac{f(t)}{R(t)}$$

Equation 8 (Aven, 1991)

By inserting the values from Equation 5 and Equation 7, h(t) can be re-written as;

$$h(t) = \frac{f(t)}{R(t)} = \frac{\lambda e^{-\lambda t}}{e^{-\lambda t}} = \lambda$$

Thus the exponential distribution is characterized to have a constant failure rate λ and time independent –making the failure rate is not dependent on the age of the component (Aven, 1991). Therefore, the reliability of the component is written as;

$Reliability = e^{-\lambda t}$, where, $\lambda = \frac{Number\ of\ failures}{Observationn\ time}$, t = service time

Equation 9 - Reliability of constant failure (Aven, 1991), (DNV-GL, 2015), (ITEM Software Inc, 2007)

2.2.2 System Reliability

The first step in analyzing the reliability of a system is to generate a reliability block diagram. The reliability block diagram captures the reliability structure of the system. This structure is independent of the failure or repair model (Klinger, et al., 1990). The diagram provides a structural relation between a system and its components (Aven, 1991).

When calculating a reliability block diagram, the components are assumed to be in one of two states; function state of failure state. The component if assumed to either be fully operational or fully failed. In binary, a fully operational system is given the value of 1, and a failed system is given the value of 0. Thus, if the equipment is partially failed, it must either be fully failed or considered operational (Aven, 1991). The calculations do not take into account partial failures. The offshore assets reviewed in this thesis is also assumed to be either in working or not working condition.

Aven (1991) assigns the following nomenclature for calculating the given reliabilities;

$$p_i = Reliability\ of\ component\ i$$

$$q_i = Unreliability\ of\ component\ i$$

$$h = Reliability\ of\ the\ system$$

$$g = Unreliability\ of\ the\ system$$

The sum of component reliability and unreliability, by definition, must equal one. Also, by definition, the reliability and unreliability of the system must equal one (Aven, 1991). Therefore, the following equations are given;

$$p_i + q_i = 1$$

Equation 10 (Aven, 1991)

$$h + g = 1$$

Equation 11 (Aven, 1991)

Utilizing the reliability block diagram, the reliability of the system can be calculated. The calculations are either done by series or parallel structure. More complex system has a combination of series and parallel structures within the same diagram.

Reliability of a series structure

Figure 11 illustrates a generic series structure. The reliability of a series structure of independent components is equals to the product of the components reliabilities (Aven, 1991). Therefore, all components must be functioning for the system to operate. For this thesis, the production critical components in a well are in series structure.

Figure 11- Series structure (Aven, 1991)

The reliability of a series structure is expressed as;

$$h = \prod_{i=1}^{n} p_i$$

Equation 12 - Reliability of series structure (Aven, 1991)

Reliability of a parallel structure

Figure 12 illustrates a generic parallel structure. The reliability of a parallel structure of independent components is equal one minus the product of the components unreliability. In a parallel structure, only one component has to work for the system to work.

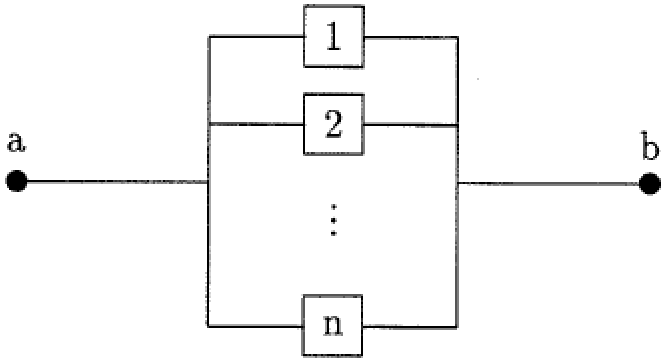


Figure 12 - Parallel structure (Aven, 1991)

The reliability of a parallel structure is expressed as;

$$h = 1 - \prod_{i=1}^{n} q_i = 1 - \prod_{i=1}^{n} (1 - p_i)$$

Equation 13 - Reliability of parallel structure (Aven, 1991)

Reliability of a complex structure

For system more complex systems, containing both series and parallel structures, the system can be viewed as smaller divisions in order to simplify the structure. Figure 13 illustrates a complex system containing both series and parallel structures. By singling out parallel and series structure and combining them into one sub-system allows for the diagram to be simplified. Aven (1991) provides the example below.

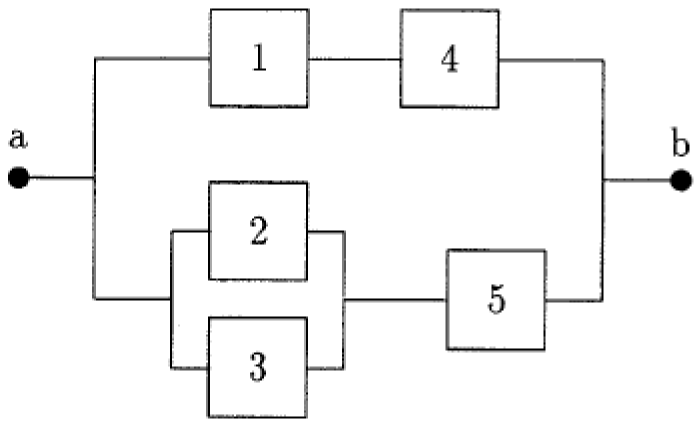


Figure 13 - Complex reliability diagram (Aven, 1991) (Aven, 2009)

To calculate the reliability of Figure 13 - Complex reliability diagram , the system must first be viewed as two parallel structures. The first structure is component 1 and 4, the second structure is component 2,3 and 5. The reliability of the upper structure can be calculated using series structure. The reliability of p_{14} therefore becomes p_1p_4 (Aven, 2009).

Furthermore, the lower structure has a combination of parallel and series. This can be calculated by first simplifying the parallel structure and its components 2 and 3 into a sub-system, and then use the combined reliability in series with component 5. The reliability of p_{23} becomes 1-q_2q_3. Then, p_{23} and p_5 are in series, and p_{235} becomes $(1-q_2q_3)p_5$. Then p_{14} and p_{235} are in parallel, which yields the final calculation $h_{12345} =1-[1-p_1p_2][1-(1-q_2q_3)p_5]$ (Aven, 2009).

2.2.3 System Maintainability

"System maintainability measures the ability with which a system is maintained to prevent failures from occurring in the future and restore the system when a failure does occur. The ultimate goal of a system operation is to make the system operational as far as possible…" (Liu, 2016). System maintainability is a design-dependent parameter that is developed to reduce downtime of the system; some components are repairable, others are not (Liu, 2016).

“System maintainability is the relative ease and economy of time and resources with which an item can be retained in, or resorted to, as specified condition when maintenance is performed by personnel having specified skill levels, using prescribed procedures and resources, at each prescribed level of maintenance and repair” (Liu, 2016).

For the purpose of this thesis, the two main categories for maintenance is proactive and reactive maintenance.

- Proactive maintenance, also called preventive or scheduled maintenance, is a systematic method of performing maintenance to prolong the system life and retain the system at a high level of performance. These activities include test, detection, measurements and periodic component replacements. Proactive maintenance is usually scheduled to be performed at given time intervals to prevent faults from occurs (Liu, 2016). An example of proactive maintenance choice would be to periodically grease annulus safety valves to avoid leaking valves.
- Reactive maintenance, also called corrective, breakdown, or unscheduled maintenance, is performed when a component has failed or no longer in operational condition (Liu, 2016). This causes downtime to the system and causes lost production. An example of this would be to wait for the annulus safety valve to leak before giving it attention. Then it can cause downtime to repair and obtain spares required to perform the job.

2.2.4 System Availability

The availability of system is “… portion of time in which a system, is in its operational or function stat under the specified environmental conditions” (Liu, 2016). The availability of the system is highly related to the reliability of the system. Reliability of a system is an essential characteristic as the availability will vary with the reliability. Reliability addresses random system failures and breakdown related to quality of design. Reliability failures are usually corrected with reactive maintenance. Therefore, as the reliability of a system increase, the system will become more available as it will be less prone to failures (Liu, 2016).

However, availability is more than just reliability. Availability is a more realistic measure of the overall efficiency, considering reliability and maintainability together. By implementing maintenance strategies, the components can be replaced or fixed before failure, minimizing loss of production due to component failures (Liu, 2016).

Availability of a system, in its simplest form, is the actual throughput compared with the potential throughput of the system. The system has a design max capacity, defined by limiting factors, and the availability is to which percentage if the capacity utilized. The availability then can then be calculated using Equation 14. For example, if a system pump can deliver 100 barrels of oil per day, but due to equipment malfunction the pump as to stop at given intervals as shown in **Error! Reference source not found.** , causing it to only deliver 90 barrels of oil per day, then the availability of the system is 90%.

$$Availability\ \frac{Actual}{Potential}\ x\ 100\%$$

Equation 14 - Availability (DNV-GL, 2015)

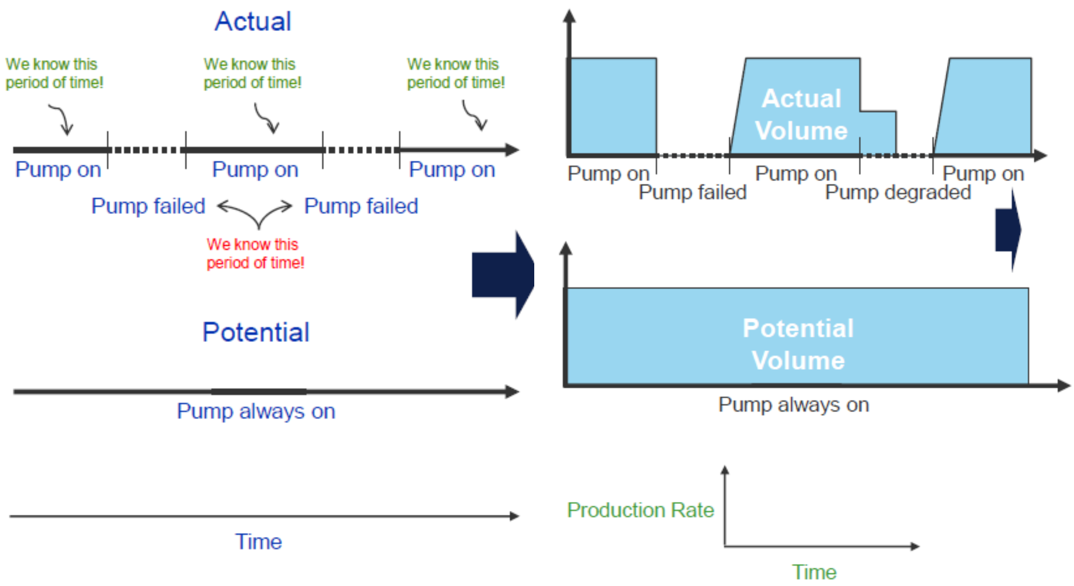


Figure 14 (DNV-GL, 2015)

With the pump malfunction, the actual achieved throughput is less than the potential throughput, given that the pump never stops. The volume lost due to the system not being 100% available is lost production. There are three different measures for availability;

Inherent availability (A_i). A_i is the probability that a system, when used under the stated conditions or design specified ideal environment, will operate satisfactorily at any point in time as required. A_i excludes preventative maintenance and other administrative delays such as logistical delays. A_i considers only random failure-induced maintenance actions (Liu, 2016). Thus, the A_i is expressed as;

$$A_i = \frac{MTBF}{MTBF + M_{ct}}$$

Equation 15 - Inherent Availability equation (Liu, 2016)

Achieved availability (A_a). A_a is the probability that a system will operate or function in a satisfactory manner in the ideal supporting environment. A_a is a more practical measure as it includes both corrective and preventative maintenance activities. The purpose of preventative maintenance will help avoid component failure from occurring (Liu, 2016). A_a is expressed as;

$$A_a = \frac{MTBM}{MTBM + \bar{M}}$$

Equation 16 - Achieved availability equation (Liu, 2016)

MTBM (mean time between maintenance) is the measure of maintenance time considering both corrective and preventative maintenance activities (Liu, 2016). MTBM is expressed as;

$$MTBM = \frac{1}{\lambda + f_{pt}} = \frac{1}{\frac{1}{M_{ct}} + \frac{1}{M_{pt}}}$$

Equation 17 - Mean time between maintenance equation (Liu, 2016)

Operational availability (A_o). A_a is the probability that the system will operate in a satisfactory manner in the actual operational environment, The actual delays within the system consist of both preventative and reactive maintenance and administrative delays. A_a gives a realistic and practical measure as it considers all aspects of system delay factors and reflects efficiency of the maintenance performed (Liu, 2016). A_a is expressed as;

$$A_o = \frac{MTBM}{MTBM + MDT}$$

Equation 18 - Operational availability equation (Liu, 2016)

The Table 1 lists the relevant maintenance time measures applicable in the three availability calculations.

Abbreviation	Name	Content
MTBF	Mean time between failures	Mean time between corrective maintenance activities
$\overline{M_{ct}}$ (MTTR)	Mean corrective maintenance time (Mean time to repair)	Corrective maintenance, as a result of failure; failure detection, diagnosis, disassembly, repair, reassembly, verification, etc.
MTBM	Mean time between maintenance	Mean time between all maintenance activities, both corrective and preventative.
$\overline{M}$	Mean active maintenance time	Weighted sum of $\overline{M_{ct}}$ and $\overline{M_{pt}}$
$\overline{M_{pt}}$	Mean preventative maintenance time	Preventative maintenance as scheduled maintenance, periodic inspection, servicing, calibration, overhaul etc. $\overline{M_{pt}}$ can overlap with $\overline{M_{ct}}$ and operational time
MDT	Mean maintenance downtime	$\overline{M}$ with logistical and administrative delays included

Table 1 - Relevant maintenance time measures (Sandborn, 2013)

Figure 15 provides a visual representation of availability in terms of the measures mentioned above. As defined above, if the system is operational it is given the binary value of 1. If it is failing it is given the value of 0. If the system has maintenance work performed on it, chances are the system is assumed to be not operational thus having a value of 0. From Figure 15, T_{ij} represents MTBF and MTBM whiles the component is operating. Dij represent the time required perform reactive maintenance – $\overline{M_{ct}}$ and $\overline{M_{ct}}$.

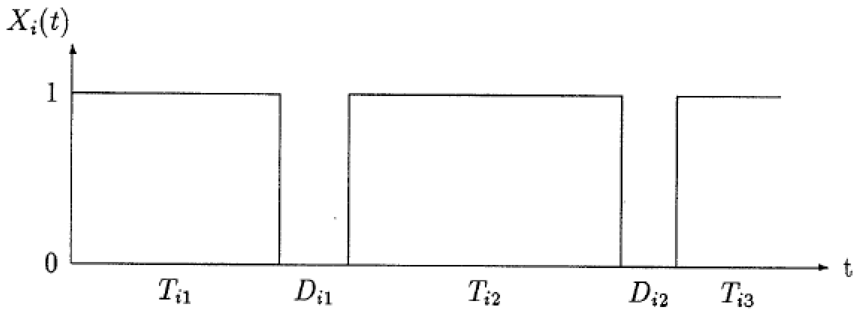


Figure 15 - Failure and repair process (Aven, 1991)

Then, mean time between failure is defined by ReliaSoft (u.d) and Aven (1991) to be;

$$MTBF = \int_0^\infty tf(t)dt = \int_0^\infty R(t)dt$$

Equation 19 (Aven, 1991) (ReliaSoft, u.d.)

By substituting R(t), which was calculated in Equation 11, into the equation, and solving;

$$MTBF = \int_0^\infty tf(t)dt = \int_0^\infty R(t)dt = \int_0^\infty e^{-\lambda t}dt = \frac{1}{\lambda}$$

Equation 20

As defined earlier, λ is the number of failures over a given observation time period. Therefore, the practical definition of the MTBF will be:

$$MTBF = \frac{observation\ time\ period}{number\ of\ failures}$$

Based on the equation above, mean time to repair (MTTR) will likewise be;

$$MTTR = \frac{observation\ repair\ time\ period}{number\ of\ failures}$$

For the purpose of this thesis, Inherent Availability will be utilized and expressed in a ratio of total observation time based on the data supplied for review. All preventative and proactive maintenance will be classified as non-equipment failure but will be logged as it does require downtime to the system. All reactive maintenance, administrative and logistical delays will be part of the MTTR time period.

3 Methodology

The purpose of this section is to describe the methodology used for this thesis. It will outline the required work to reach the objectives.

3.1 Objective

The purpose of this section is to describe how the objective will be achieved.

Figure 16 shows the flow path of information gathered and how it will be utilized to obtain the objectives. It shows what information is collected from PPIT system. It also indicated where Exprosoft's WellMaster will be incorporated into the calculations. Further, the diagram shows the anticipated output from the study.

The data obtained from the Company was collected from their Production Performance Improvement Tool – PPIT. The PPIT is the Company's upstream production deferral database. A production deferral is allocated against a well when there is a production shortfall compared to the installed production capacity (IPC). The IPC is the expected return, or max production, from the well. Therefore, production deferrals, in the PPIT system, are related to delayed production. (O'Brien, 2016).

Activities causing a production deferral may be either planned and unplanned. Planned activities may for example be heavy lifting or well intervention. Unplanned actions are often related to equipment failure, or well system impairments, causing the well not to produce or produce at reduced capacity. The PPIT system clearly identifies if the deferral is considered unplanned (breakdown work) or planned (planned work).

Further, the production deferral identifies deferral dates, deferred production volume and well number. A production deferral is issued each day the well is not producing. As a result, if an equipment failure occurs, and it takes twenty days to repair the equipment, twenty production deferrals are issued in the PPIT system against that well.

Each production deferral has a unique event index number, which, amongst other criteria, is used to identify total numbers of deferrals. Thus requiring data sorting, filtration and removal of duplicate deferrals to obtain the number of unique deferrals and to further calculate the duration and production deferred based per production deferral.

With the filtered data, all unique deferrals related to well equipment failures will be assigned a failure cause based on Exprosoft's WellMaster failure codes. This will allow for comparison on the different assumed failure causes of the well systems. The comparison will prove useful in order to obtain an understanding of what is going wrong in the well.

In addition, all the deferrals will be coded according to the company's *Equipment Level* categories. The *Equipment Level*s are a systematic categorization of the main components in a well. Implementing the *Equipment Level* code into the deferral data will identify which equipment groups are most prone to failure.

With the production deferrals coded with both failure cause and *Equipment Level*, the data can be grouped to calculate reliability of the equipment of the three fields. The reliability from the PPIT system will then be compared to the reliability gathered from Exprosoft's WellMaster RMS. Comparing the two results will then identify how the company assets perform compared to an average Exprosoft's WellMaster well. It is noted that this methodology was checked by Exprosoft and confirmed to be an appropriate approach.

Also utilizing the reliability data calculated, with the repair time collected from the PPIT system, the company well system availability will be identified. The asset's availability will give an overall performance indicator of the well systems.

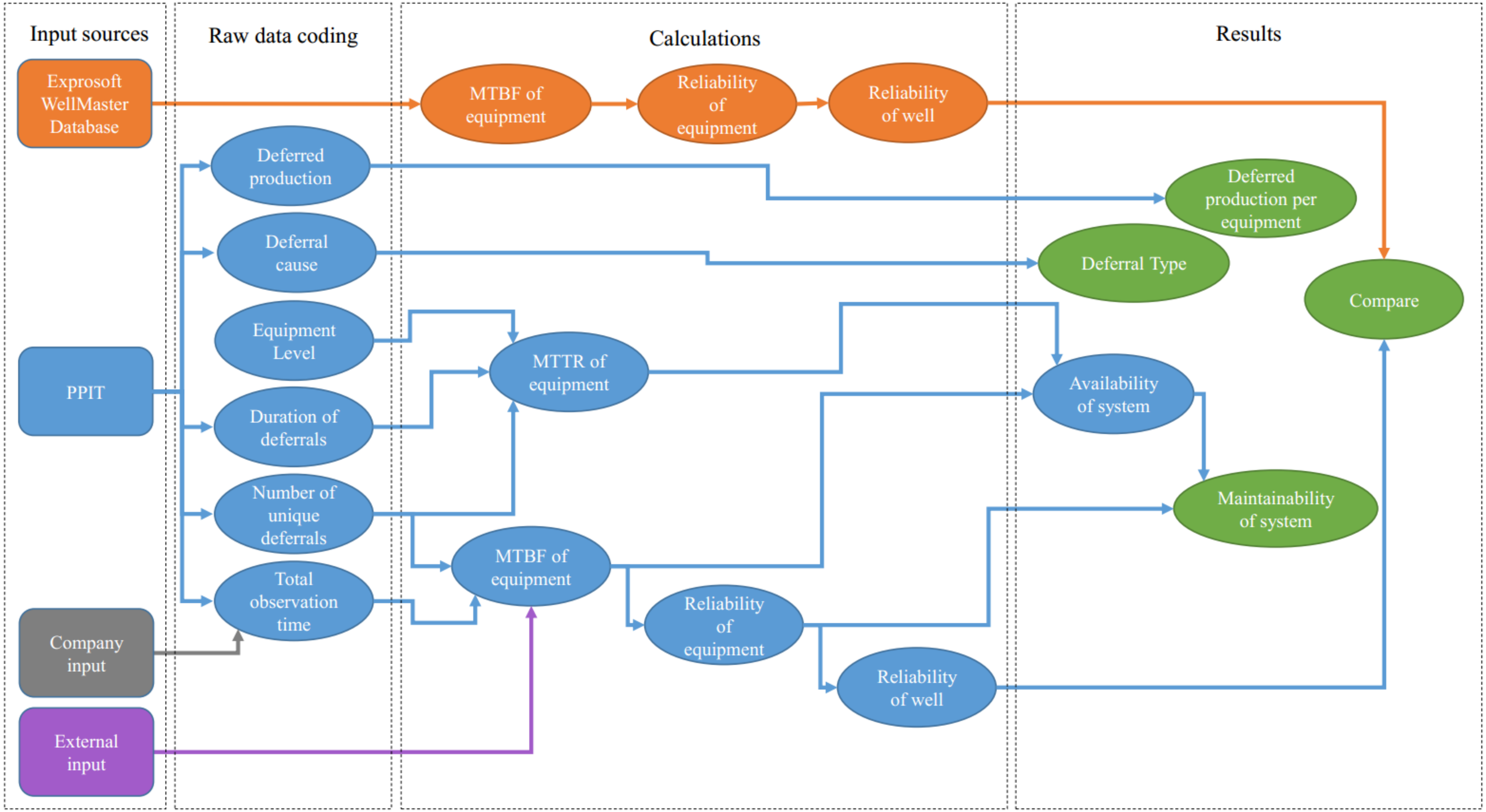


Figure 16 – Flowchart of thesis study

3.2 Raw data coding

The purpose of this section is to outline how the raw data will be handled and coded.

3.2.1 Data collection from PPIT

The data collected for this work is collected from Company's PPIT system. The data will be collected for up to ten years from three different offshore assets. The data is collected and compiled by Company.

The end date for the data collected determined to be February 21, 2016 for all three assets. The start date for the assets vary. The variation is related to when the asset came on line The starting dates are as follow:

- Asset 1 – January 1st, 2008
- Asset 2 – June 1st, 2006
- Asset 3 – June 1st, 2006

During this time period, a production deferral is placed when a well does not produce the expected quantity at a given day. The raw data was exported to a Microsoft Excel file. The data was compiled of over 31,000 rows with 18 columns, creating a total of over 500,000 data points. From the raw data, initial, un altered, performance data from the PPIT is presented in Table 2. From the table, the following should be highlighted;

- Total production deferrals – 31,102 ea.
- Total deferral duration – 27.6 years
- Total deferred production – 52.634 million BOE

Table 2 – Data collected from PPIT

Field	Number of deferrals entries	Start date	End Date	Duration (days)	Duration (years)	Deferred production (MBOE)
Field 1	4,878	01.JAN.2008	21.FEB.2016	2,974	8.14	10,329
Field 2	9,509	01.JUN.2006	21.FEB.2016	3,553	9.73	14,722
Field 3	16,715	01.JUN.2006	21.FEB.2016	3,553	9.73	27,583
Total	**31,102**	**-**	**-**	**10,080**	**27.6**	**52,634**

3.2.2 Determining unique production deferrals

Determining the number of unique production deferrals is important as it will define the frequency of deferrals occurring. It is also necessary in order to determine the time required to fix each deferral.

Split multiple layers of information

With over 31,000 production deferral entries collected from the PETI system, the deferrals will be sorted and filtered to determine the number of unique deferrals entries. In order to do so, the columns in the raw data set containing multiple layers of information will have to be divided up into separate columns. This will make the columns filterable and more searchable, which is an essential part to determining the total numbers of unique deferrals. Therefore, the first step in determining the number of unique production deferrals is to split these columns into multiple columns. Figure 17 shows how multiple layers of information is stored within one cell.

\Breakdown Work\Operability/Control\Slugging

Figure 17 - Example of data from PPIT system

As Figure 17 shows, multiple layers of information are compressed into the same cell. The common delimiter of information layers within the cell is “\”. In order to split this information into separate columns, Microsoft Excel’s “Convert Text to Columns Wizard” will be used.

The wizard will be used to ensure data is not missed or damaged during the transformation. When using the wizard, delimiters has to be chosen. The delimiter which will be used for this separation is “\”. Figure 18 shows how the wizard will be used. The figure also shows that “\” will be chosen as the delimiter factor.

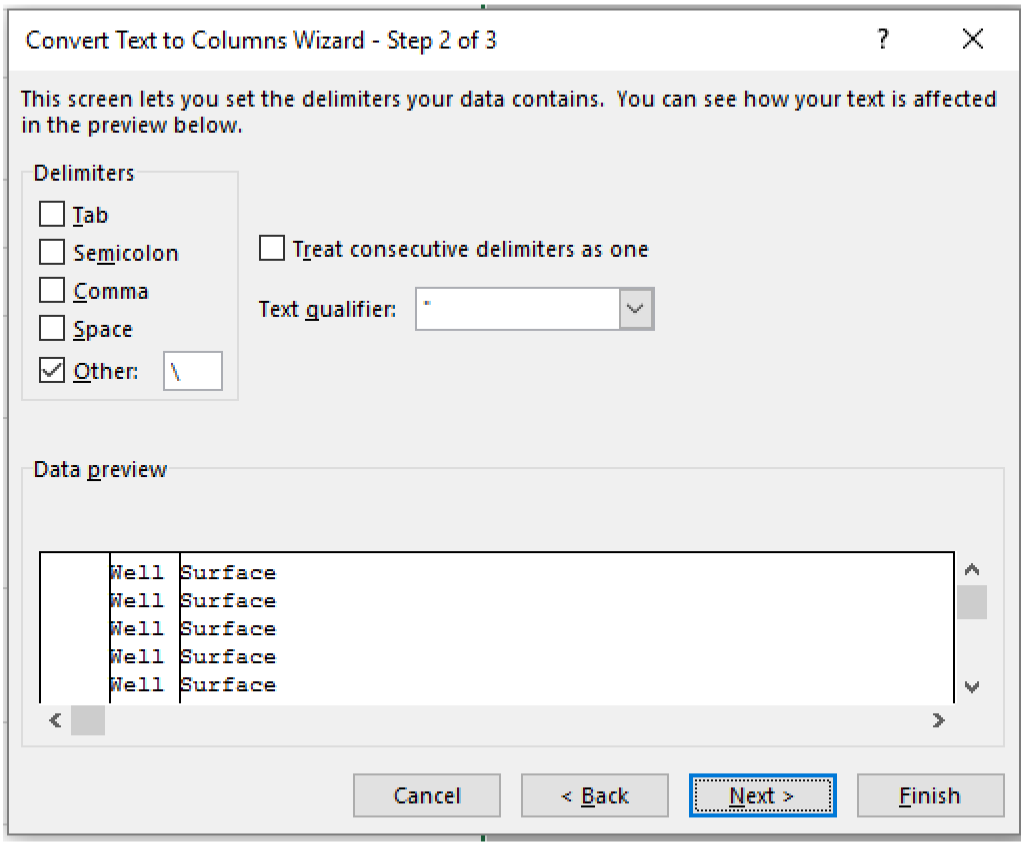


Figure 18- Convert Test for Columns Wizard in Microsoft Excel

Four columns contain multiple layers of data. These will be transformed into 13 columns. Thus, an additional 9 columns will be to the data set. Therefore, the new dataset will grow from 18 columns to 27 columns. Table 3 below shows the final columns and their headings. The headings containing sequential numbering, i.e. 1, 2, 3 etc., are the added cells utilizing the wizard.

Table 3 - Headings of data source from PPIT

#	Heading	#	Heading	#	Heading
1	Date	*10*	Equipment Source 3	*19*	Process Cause Description
2	Organizational Node	*11*	Planning Time Frame	*20*	Root Cause
3	Deferral Volume	*12*	Process Cause 1	*21*	Event Index
4	Initial Start Date	*13*	Process Cause 2	*22*	Event Description
5	System Source 1	*14*	Process Cause 3	*23*	Source Description
6	System Source 2	*15*	Process Cause 4	*24*	Work Order Reference
7	System Source 3	*16*	Human Cause 1	*25*	Shut Down
8	Equipment Source 1	*17*	Human Cause 2	*26*	Tag No
9	Equipment Source 2	*18*	Human Cause 3	*27*	Supplier Quality

Remove duplicates

After the information is presented in a searchable and filterable format, the next step in the process of determining the number of unique deferrals recorded is to remove duplicate entries against the same deferral. For this thesis, duplicate entries are defined as multiple entries towards the same fault or activity. Therefore, if it takes ten days to repair a fault, ten deferrals are registered in the system. However, there is only one unique deferral, which means there are nine duplicates.

In order to remove duplicates, criteria for determining what makes a duplicate has to be established. Since there is one entry per day the deferral is active, the data will always vary with each deferral entry. Therefore, both “Date” and “Initial Start Date” is defined as non-duplicate criteria. By removing these form, the criteria defining a duplicate, 25 categories required an exact match.

Microsoft Excel’s “Remove Duplicates Wizard” is used to remove the defined duplicates. The “Remove Duplicates Wizard” is used to ensure accurate removal of duplicates. Figure 19 shows the required criteria for removing duplicates. If the deferral match on the selected items below, then the deferral is considered a match.

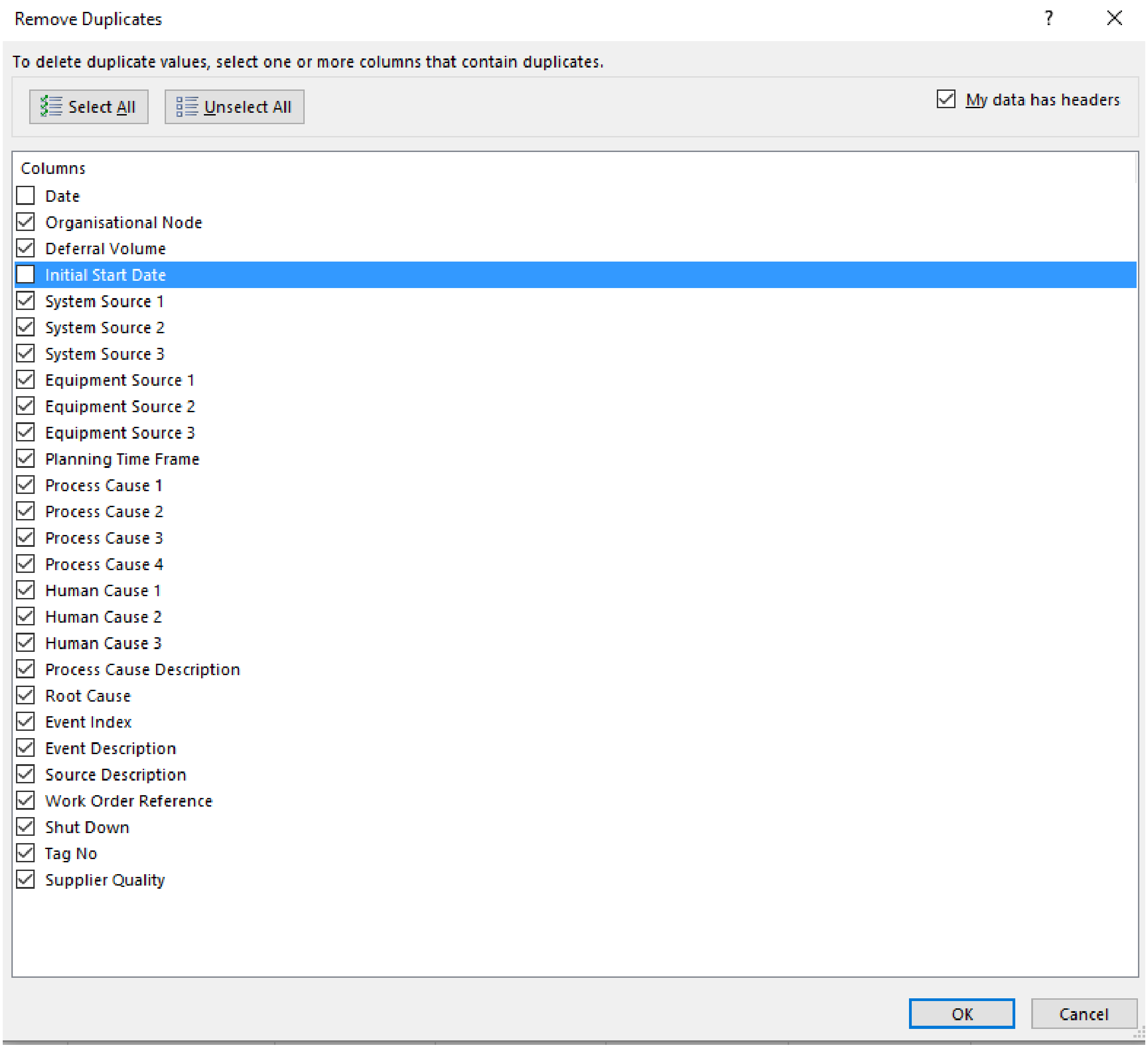


Figure 19 - Duplicate removal criteria

After the software removal of duplicates is complete, the list of deferrals will be dramatically shortened. Excel's "Remove Duplicates Wizard" does only detect exact matches. Small alteration within cells will therefore yield a non-exact match. Since some of the entries into the PPIT system are free-text, which allows the person input the text into the system to type what he/she desires, a manual review of the remaining deferrals had to be carried out. By sorting and reviewing similar lines. Since some of the data entry are free-text, small changes in wording will alter the values and remain undetectable for the software processing. The manual review identified small alterations of text choice which are similar in meaning, but not identical with respect for software recognition.

During manual review of the collected data, it is discovered that certain duplicates also existed under different event index numbers. These are deleted as only one occurrence of the continuous problem should be present.

In addition, certain deferrals are deleted. These deferrals were reported continuously, and are similar in both volume and duration, for a period of five years, up to and including 2010. According to Company, these are assumed to be incorrectly reported into the system. Therefore, they are taken out of this review (O'Brien, 2016).

After removal and removal of duplicate production deferrals, both by Excel and manual review, the total number of unique deferrals are 1,854. Asset 1 has 302 deferrals, Asset 2 has 792 deferrals and Asset 3 has 760 deferrals issued.

It is noted that this exercise in itself provides a very useful outcome to determine total number unique events, rather than total reported volumes.

Table 4 – Number of unite deferrals per asset

Asset	Number of unique deferrals
Asset 1	302
Asset 2	792
Asset 3	760
Total	**1,854**

3.2.3 Assigning failure mode and cause

With the number unique production deferral determined, and all duplicates removed, each deferral is assigned an assumed failure mode or cause. The failure mode and causes assigned will generate an overall picture of how it components fail. It may also provide information necessary to understand failure trends. The trends will guide in recommendations for improvements and implantation of solutions to solve reduce failure rate.

For this thesis, Exprosoft’s WellMaster Reliability Management System failure modes and causes were adopted and utilized. Table 5 lists the different failure modes and causes.

Table 5 - Exprosoft's WellMaster RMS Failure Mode and Cause Categories list

ID	Failure modes (complete list)	Safety critical	Failure type	Abbreviation
1	Fail to install	No	Installation failure	FTI
2	Fail to retrieve	No	Retrieval failure	FTR
3	Fail to close on demand	Yes	Operational failure	FTC
4	Fail to open on command	No	Operational failure	FTO
5	Leakage in closed position	Yes	Operational failure	LCP
6	Premature closure	No	Operational failure	PCL
7	Unacceptable closing time	Yes	Operational failure	UCT
8	Unacceptable casing wear	Yes	Operational failure	UCW
9	A-annulus to B-annulus communication	Yes	Operational failure	ABC
10	B-annulus to C-annulus communication	Yes	Operational failure	BCC
11	C-annulus to D-annulus communication	Yes	Operational failure	CDC
12	Leakage across seal	Yes	Operational failure	LAS
13	Leakage across packer	Yes	Operational failure	LAP
14	Well to control line communication	Yes	Operational failure	WCL
15	Control line to well communication	No	Operational failure	CLW
16	External leak	Yes	Operational failure	EXL
17	Premature disconnect	Yes	Operational failure	PRD
18	NOT USED			
19	Unknown	Yes	Operational failure	UNK

20	Incorrect position reading	Yes	Operational failure	IPR
21	Incorrect transducer reading	No	Operational failure	ITR
22	Incorrect flowrate reading	No	Operational failure	IFR
23	Hydraulic failure causing loss of safety critical functions	Yes	Operational failure	HFS
24	Electrical failure causing loss of safety critical functions	Yes	Operational failure	EFS
25	Incorrect detector reading	No	Operational failure	IDR
26	Loss of hydraulic redundancy without loss of functions	No	Operational failure	LHR
27	Premature opening	Yes	Operational failure	POP
28	Loss of electrical redundancy without loss of functions	No	Operational failure	LER
29	Stuck seal assembly	Yes	Operational failure	SSA
30	Stuck fully open	No	Operational failure	SFO
31	Stuck intermediate position	No	Operational failure	SIP
32	Stuck fully closed	No	Operational failure	SFC
33	Tubing to A-annulus communication	Yes	Operational failure	TAC
34	Reservoir to B-annulus communication	Yes	Operational failure	RBC
35	Reservoir to C-annulus communication	Yes	Operational failure	RCC
36	Hydraulic leak without loss of functions	No	Operational failure	HFN
37	Seawater leak without loss of functions	No	Operational failure	SFN
38	C-annulus to surface communication	Yes	Operational failure	CSC
39	C-annulus to ground water communication	Yes	Operational failure	CGC

40	B-annulus to surface communication	Yes	Operational failure	BSC
41	B-annulus to ground water communication	Yes	Operational failure	BGC
42	NOT USED			
43	Deferred production	No	Operational failure	DFP
44	Lost production	No	Operational failure	LOP
45	NOT USED		Operational failure	
46	Plugged/choked hydraulic control line	Yes	Operational failure	PHC
47	Plugged/choked chemical control line	No	Operational failure	PCC
48	Plugged/choked tubing	No	Operational failure	PTG
49	Collapsed tubular	Yes	Operational failure	CTG
50	Inadequate control line signal	No	Operational failure	ICS
51	Inadequate power	No	Operational failure	IPO
52	Surrounding to control line communication	Yes	Operational failure	SCL
53	Control line to surrounding communication	No	Operational failure	CLS

For this thesis, and for the data set provided, it is necessary to generate additional categories to supplement the WellMaster RMS Failure Mode and Cause Categories. WellMaster's codes are related to well equipment failing. It does not account for other indirect failures, such as reservoir issues or process failure. Table 6 shows the additional failure modes and causes.

Table 6 - Additional supplement categories for WellMaster RMS Failure Mode and Cause

ID	Failure modes (supplement to list)	Safety critical	Failure type	Abbreviation
54	Vibration/Clash/Proximity obstructions	Yes	Design Failure	VCO
55	Run to failure	Yes	Operational Failure	RTF
56	Corrosion	Yes	Design failure	COR
57	Well System Impairments	No	Operational failure	RES
58	No well specific equipment failure	No	Operational halt	NEF

Vibration/Clash/Proximity obstructions (VCO) is added to capture deferrals related to space constraints on the platform. Offshore surface wells have a tendency to rise a few centimeters when put on production. Therefore, it is important not to install instrumentation or other equipment too close to the wells when they are shut-in as they will move once becoming active. This is assumed to be safety critical as it may severely damage instrumentation, or other equipment, causing a system failure.

Run to failure (RTF) is added to the list to capture when the maintenance strategy is utilized. This was only utilized when the PPIT coding specifically stated that this strategy was utilized.

Corrosion (COR) is added to the list to identify where the failure related to wrongful material specification apply. This is considered a safety critical failure as it can, in some cases, cause external leaks to the topside surroundings.

Reservoir and Well System (RES) is added to the list to capture deferrals related to reservoir issues. The RES classification is not related to failure of equipment and is therefore not considered safety critical as it is manageable with existing systems for the well. An example of a RES classification is a cyclic well. A cyclic well causes lost production at some point in time, and thus it is logged in the system as a deferral. The RES category was further divide into additional sub categories. The additional subcategories are Asphaltenes, cyclic wells, fracking, chalk influx, lifting, logging, scale, slugging, solids production and undefined.

The **asphaltenes** category was implemented to capture deferrals specifically related to the production of asphaltenese from the reservoir.

The **cyclic wells** category was implemented to capture deferrals specifically related to cyclic well behavior. Cyclic wells are when the wells are producing form a time period, then stops producing for a period, before it starts, i.e. cyclic. The metadata in the PPIT system specifically defined the deferral cause as cyclic wells.

The **chalk influx** category was implemented to capture deferrals specifically related to chalk influx issues causing production to halt. The deferral was assigned this category when the deferral contained information related to chalk or influx.

The **lifting** category was implemented to capture deferrals specifically related to not being able to lift the liquids to surface. The deferral was assigned this category when the deferral contained information related to lack of lifting energy. Examples of working used in the PEID system are “pressure buildup required” and “low reservoir pressure”.

The **logging** category was implemented to capture deferrals related to logging activities of the reservoir. The deferral was assigned this category when the deferral contained information related to logging.

The **scale** category was implemented to capture deferrals related to scale issues. Such as scaling of production chokes and downhole safety valves.

The **slugging** category was implemented to capture deferrals related to production losses due to slugging in the production tubing. The slugging may be considered to be part of the lifting category, but if the deferral contained a version of the word slugging, it was put into its own category.

The **solid production** category was implemented to capture deferrals related to solids being produced from the reservoir. The deferral had to contain information related to the production of solids in order to be put in this category.

The **undefined** category was implemented to capture deferrals not matching any of the requirements above.

Platform deferrals (NEF), is a general category identifying all deferrals related to planned deferrals which in this case is not due to failure of equipment, or well system impairment. The NEF category was further divide into additional sub categories. The additional subcategories are drilling and/or completion related, heavy lifts, well barrier element testing and an undefined category.

> The **drilling and/or completion** category was implemented capture deferrals specifically related to drilling and completion activities. The metadata from PPIT is the defining factor if the equipment is coded with this subcategory.
>
> The **heavy lift** category was implemented to capture deferrals specifically related to heavy lifting operations. The category does not specify if the heavy lifts are related to completion of new wells or maintenance requirements. The heavy lifts were captured from the free-text fields in the PPIT system.
>
> The **well barrier element (WBE)** category was implemented to capture deferrals specifically related to verification of barriers. In order for the deferrals to obtain this categorization, the deferrals had to contain information in the free-text fields related to testing of barriers. Common terminology utilized for this sub group is testing. Periodic maintenance testing is also included in this group –the raw data shorthand notation; PM.
>
> The **undefined** category was implemented to capture deferrals not matching any of the requirements above.

Each deferral is assigned a specific code. This is done by the evaluating the information in the deferral. A deferral is assumed to be composed of both pre-defined values, selected from al list, and free-text fields. The free-text information is assumed to contain the most accurate information. Therefore, if there is a discrepancy between the information selected from a dropdown menu and free-text, the free-text trumps and is used. All the codes assigned are based on the best judgement at the time the code was assigned.

3.2.4 Assigning Equipment Level

After each deferral is assigned a WellMaster failure code, the deferrals which related to Well Equipment is assigned an *Equipment Level* code. Company has an existing *Equipment Level* nomenclature which will be adapted into this thesis. The *Equipment Level* exist in two categories; Level A and Level B. The Level A is high level system, whilst the Level B is more detailed to the component.

Each Level A consists of multiple level B. In order to implement this into the deferral data, the *Equipment Level*s is assigned an alphanumeric structure. The Level As are assigned an increasing number starting from 1. The Level Bs are assigned a single letter, following the alphabetic structure, starting with “A”. The Level Bs structure resets for every Level A category, thus yielding 1A, 2A, 3A, etc.

Implementing *Equipment Level* into the deferral will identify what equipment has failed. It will also allow for grouping equipment and reviewing failure trends. Further, it will allow for simple reliability calculations to be performed based on equipment type.

In Table 7, all the existing *Equipment Level* groups are shown.

Table 7 - Equipment Level - Company

Level A Equipment Source (All)		**Level B Equipment Source (All)**	
1	**Well Deferrals not related to specific well equipment**	**A**	**Well barrier element test, Heavy lift, injection limitation, etc**
2	Surface Tree (Dry)	A	Production Pressure/Temperature Sensor/Transmitter
		B	Choke
		C	Choke Actuator
		D	Production Wing / Kill Wing Valve
		E	Chemical Injection Valve
		F	Valve Actuator
		G	Upper Master Valve
		H	Lower Master Valve
		I	Swab Valve
		J	Tree Cap
		K	Penetrators (control line/ESP)
		L	Bottom Connector
		M	Pressure Containment Connection Seal
		N	Hydraulic Control Plumbing
		O	Tree Connection Flange
		P	Flowline
		Q	Ports and Fittings
3	Surface Wellhead (Dry)	A	Primary A to B packoff
		B	Secondary A to B packoff
		C	Lock down A to B packoff
		D	Control Line connection/device
		E	Back Pressure Valve

		F	Connectors
		G	Gas Lift Valve
		H	Ports and Fittings
		I	Upper Speed Head Connector - Pressure Containment Connection Seal
		J	Lower Speed Head Connector - Pressure Containment Connection Seal
		K	Annulus bleed-off systems
		L	**Cannot define**
4	Tubing Hanger (Dry)	A	Neck Seal
		B	NOT USED
		C	Hanger Body Seal
		D	Body Lock Down
		E	Control Line connection
		F	NOT USED
		G	Other
5	DHSV System	A	DHSV Flapper
		B	Tubing Isolation Valve
		C	Insert Safety Valve
		D	Flow tube
		E	**Cannot define**
		F	Seals
		G	Control Line
		H	VOID
		I	Exit block
6	Gas Lift System	A	ESD Valve
		B	ASV/H-SAS
		C	Control Line
		D	Exit block for the control line
		E	**Cannot define**
		F	**Envelope piping**
		G	Gas Lift Valve
7	Upper Completion	A	Chemical Injection Valve/Mandrel
		B	P/T Gauge
		C	PBR / Floating Seals
		D	Production Packer
		E	Production/Injection Tubing
		F	Downhole Flow Control (e.g. Valves)
		G	Dynamic Seal Assembly
		H	Injection Check Valve
8	Intermediate Completion Eqt	A	Intermediate Completion Packer
		B	Upper Zone Isolation device
		C	Lower Zone Isolation device

9	Lower Completion Eqt.	A	Liner Hanger
		B	Lower Completion Packer
		C	Formation Isolation Valve
		D	Sliding Sleeves (e.g. Flow Isolation)
		E	Float Equipment (Flow Check)
		F	Gravel Pack Sleeve
		G	Isolation Plug of Lower Zone
		H	Open Hole Zonal Isolation Packer
		I	Distributed Sandface Sensors (e.g. Temp/Press.)
		J	Distributed Sensor Fiber (Optical)
10	Sand Control System	A	Gravel Pack (Open Hole)
		B	Gravel Pack (Cased Hole)
		C	Cased and Perforated
		D	Frac Pack
		E	Stand Alone Screens
		F	Expandable Screens
		G	Openhole/Pre-drilled Liner
		H	Chemical sand consolidation treatment Eqt.
		I	Other
11	Casing	A	Surface Casing
		B	Intermediate Casing
		C	Production Casing / tubing
		D	Liner
		E	zonal isolation cement
		F	**Sustained casing pressure**

For this thesis, it is necessary to include an additional category to the list above. The 12th section of Level A equipment is added to capture faults related to automation, logic and HPU. The added category is an essential part of the emergency shut-down system on the platform, therefore it is thought necessary to group them in a separate group. Table 8 outlines the additional *Equipment Level* group.

Table 8 - Equipment Level

12	Automation, Logic, HPU	A	HPU
		B	HPU lines / solenoids
		C	Automation / logic
		D	Insufficient hydraulic oil

3.2.5 Categorizing deferral as planned or unplanned

Each deferral will further be categorized as a planned or unplanned deferral. This will be done by assuming all equipment failures are unplanned. Further, the additional “Process Cause” information was utilized to define planned or unplanned shut-ins. If the information was categorized as “Breakdown work”, the shut-in is assumed to be unplanned. If it is not unplanned, and not equipment failure, it is assumed to be planned.

3.3 Calculations

The purpose of this section is to outline what calculations will be performed.

3.3.1 Calculating duration and deferred production

After the unique production deferral is determined, and all duplicates removed, failure code and *Equipment Level* assigned, each deferral’s duration and production volume will be calculated. The unique deferrals will be coded in Microsoft Excel to accumulate the deferred production and duration. The raw data set is used to determine the total number of volume deferred and deferral duration. In order quality control the summations of the raw data, certain rows were delimited to be able to tag certain layers of the information.

In addition to delimiting of certain parts of the raw data, the failure codes assigned to the unique deferrals were transposed back into the raw data. If the failure code was not transposed back into the raw data, certain data points were not included in the overall unique deferral’s list, thus errors in the coding is discovered. This allowed for a manual check to verify that all unique deferrals were included. The failure codes were transposed utilizing a custom Excel coding. See Appendix for full disclosure of excel function utilized.

3.3.2 Calculating Mean Time Between Failure and Service Time Period

With each deferral assigned a failure mode and an *Equipment Level* group, the deferrals can be grouped and sorted. The mean time between failure (MTBF) can then be calculated for each *Equipment Level* group. The MTBF will be calculated utilizing the formula provided in the literature review;

$$MTBF = \frac{service\ time}{number\ of\ failures}$$

The MTBF is the time frequency of which a failure occur given a service time period. The number of failures will be collected from PPIT production deferrals. The service time will be the total time period in the PPIT system.

In order to determine the total service time, the number of recordable wells and their durations are required to be established. It is necessary to verify that Company's wells have been in operational phase for the service time listed in the PPIT. For example, if a platform has 10 wells, and each well has an observational period in the PPIT system for 9,5 years, then the total service time will be 95 years. Therefore, the following information has to be verified for all three assets:

- Generate a list of wells recorded in the PPIT system and confirming the types of wells with the company. Only wells with gas lift will count towards the service time required for gas lift equipment.
- Verify which wells were considered to be in the operational phase at the given PPIT start date. If any wells were not considered to be in the operational phase at the start date of the PPIT data set, then the difference in time shall be deducted from the service time.
- Verify which wells, if any, were plugged and abandoned, both permanently or temporarily, during the PPIT time interval. If they were plugged prior to the PPIT end date, then the difference in time shall be deducted from the service time.
- Verify which wells were re-completed during, and the durations of the re-completion, during the PPIT time interval. The re-completion time period shall be deducted from the observational period

For this thesis, the service time includes the time it takes to repair the failure. This is because the system is assumed to be in operational state, though not in a flowing state. The rest of the wells are still exposed to the operational conditions required and exposed to the environment.

3.3.3 Calculating Mean Time To Repair

Mean time to repair (MTTR) is calculated utilizing the formula provided in the literature review section. The formula is re-stated below.

$$MTTR = \frac{repair\ time}{number\ of\ failures}$$

The number of failures will be the total number of deferrals related to the specific equipment category. The repair time is the total time each deferral is active in the PPIT system per *Equipment Level* group. A failure is assumed active as long as it is in the PPIT system, thus a failure is assumed to be fixed at the last date of the deferral in the PPIT system. Therefore, if one deferral has five entries in the PPIT system, and there is one entry per day, it is assumed that the repair time required for that failure is five days.

3.3.4 Calculate reliability of component category

The reliability of an equipment group is determined from utilizing the following formula disclosed in Section 2.2.1.

$$Reliability = e^{-\lambda t}$$

λ is defined as number of failures per service time, which is the inverse of MTBF. The "t" is expected component lifetime or defined time period.

3.3.5 Calculating reliability of a well given PPIT input

The reliability of a well is calculated utilizing *Equipment Level* A component reliability data. For this thesis, the assumption is made that all *Equipment Level* A from the PPIT database are considered production critical components. This assumption is made on the basis that a deferral will not be issued towards the group of equipment if it did not cause a production deferral. Thus, they are production critical components.

Since all the *Equipment Level* A components are assumed to be production critical components, they are assumed to be in relying on each other for the well to produce. Thus, they are considered to be in series and the system reliability will be calculated utilizing a series structure, as defined in Section 2.2.2.

$$h = \prod_{i=1}^{n} p_i$$

3.3.6 Calculating reliability of a well based on WellMaster RMS data

In order to rate the reliability of Company wells, a generic typical gas lift production well is generated based on Company's *Production Failure Diagram*. The *Production Failure Diagram* is shown in Appendix E. Based on the diagram, critical components to ensure production uptime is categories. These components are listed in Table 9.

Table 9 - Critical well components

		Production Critical Components	WellMaster nomenclature
WellMaster Reliability Data	Production	HPU / logic	HPU (subsea)
		XMT cap	Tree connection
		Choke	XMT - Choke valve
		Swab valve	PSV
		Production wing valve	PWV
		Kill valve	KV
		Upper Master Valve	PMV
		Tree flange connection	Wellhead connector
		Wellhead	Wellhead
		Tubing hanger system	Tubing hanger vertical
		DHSV	TRSCSSV
		Unloading IPO	Unloading GLV
		GLV	Operational GLV
		DMY GLV	Dummy GLV
		Tubing string	Tubing
		Production packer	Production Packer
		Surface casing	Surface Casing
	Annulus	ESD Valve	AMW
		Tubing hanger system	Tubing hanger vertical
		Casing hanger	Not in Wellmaster
		Surface casing	Surface Casing
		Tubing	Tubing
		TR-SCASSV assembly	TRSCASSV assembly
		Production packer	Production Packer

All the components are considered to be production critical, meaning if one of them fail, the well has to shut-in and production is deferred. Since all the components have to be in working condition to produce any given well, all the components are in series. Therefore, the components are assumed to be in either fully working condition or in a non-working conditions. A series structure is calculated using the series formula defined in Section 2.2.2.

$$h = \prod_{i=1}^{n} p_i$$

The reliability data used for this calculation is collected from Exprosoft's WellMaster RMS data base. WellMaster collects information about well components from different types of wells around the world. The main focus of the data collection is the production string, casing string and wellhead and x-mas tree components. The data is collected for both wet and dry wellheads and trees. For the production string, the main focus is from the production packer up to the tubing hanger, and the lower completion equipment such as sand control equipment, inflow control valves (ICV) and full-bore isolation valves (FIV). For the casing string, it is the string itself as well as zonal isolation cement. For the wellhead and x-mas tree, reliability data for all components connected or installed directly on the wellhead and x-mas tree are collected. This excludes any surface equipment downstream of the well, i.e. when the well-flow leaves the PWV on the x-mas tree, choke valve is included, such as compressors and other production and process facility equipment not related to the well.

By generating a Company specific well, based on equipment which will cause deferrals, and populating it with WellMaster reliability data for this equipment, an industry expected average can be calculate for comparison. This will allow for comparison of Company performance and expected performance – were both datasets are based on actual performance.

3.3.7 Calculating availability of Company wells

With the mean deferral duration and reliability of the components calculated based on the PPIT system, the availability of the system can be determined. For this thesis, the availability is calculated as defined in Section 2.2.4, by the following equation;

$$Availability = \frac{MTBF}{MTBF + M_{ct}}$$

3.4 Analyzing results

The purpose of this section is to state that the calculated data will be analyzed.

The calculations performed in the earlier sections will be compared and analyzed in order to determine trends and current status. Comparing the availability of the wells and reliability of the wells will give an indication of how effective the Company is at maintainability. It will also give indications on which assets may require improvements. Depending on the outcome of the results, different scenarios may have to be evaluated.

4 Findings / Results

The purpose of this section is to present the results from applying the methodology described in Section 0.

4.1 Deferral types

The purpose of this section is to present the findings based on the different types of deferrals issued.

Table 10 quantifies the number of unique deferrals issued, the production volume deferred and the duration the deferrals were active. From the table, a total of 1,854 unique deferrals were issued, lasting over 29,000 days and with a total deferred production of over 42 million BOE. The following should be highlighted;

- Asset 1 has fewest deferrals, shortest duration and lowest production volume deferred.
- Asset 2 has the most deferrals, but it has the second longest duration and second highest production volume deferred.
- Asset 3 has second highest number of deferrals, but it has the longest duration and the highest production volume deferred.

Table 10 - Deferral overview

Asset	Number of unique deferrals	Total deferred production (MBOE)	Deferral duration (days)
Asset 1	302	10,330	4,878
Asset 2	792	14,723	9,509
Asset 3	760	17,007	14,953
Total	1,854	42,059	29,340

Table 11 shows the deferral distribution per asset for the time period. The PPIT data collection started in 2008 for Asset 1, thus the first two years are noted as zero.

Table 11 – Deferrals per asset per year

Prod. Deferrals	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Total
Asset 1	0	0	62	64	50	36	38	2	25	15	10	302
Asset 2	51	77	64	58	89	151	74	150	53	23	2	792
Asset 3	29	74	59	73	81	53	29	79	133	135	15	760
Total all Assets	80	151	185	195	220	240	141	231	211	173	27	1854

Chart 1 visually presents the data from the previous table. From the chart, the following observations should be highlighted;

- Asset 1 has seems to have a steady declining trend in number of production deferrals issued.
- Asset 2 has a considerably spike in deferrals in 2011 and 2013. It seems like a steady declining trend in number of production deferrals issued from 2014 to 2015.
- Asset 3 has a drop in deferrals in 2012, and then a steady increase in production deferrals issued for 2013, 2014 and 2015.

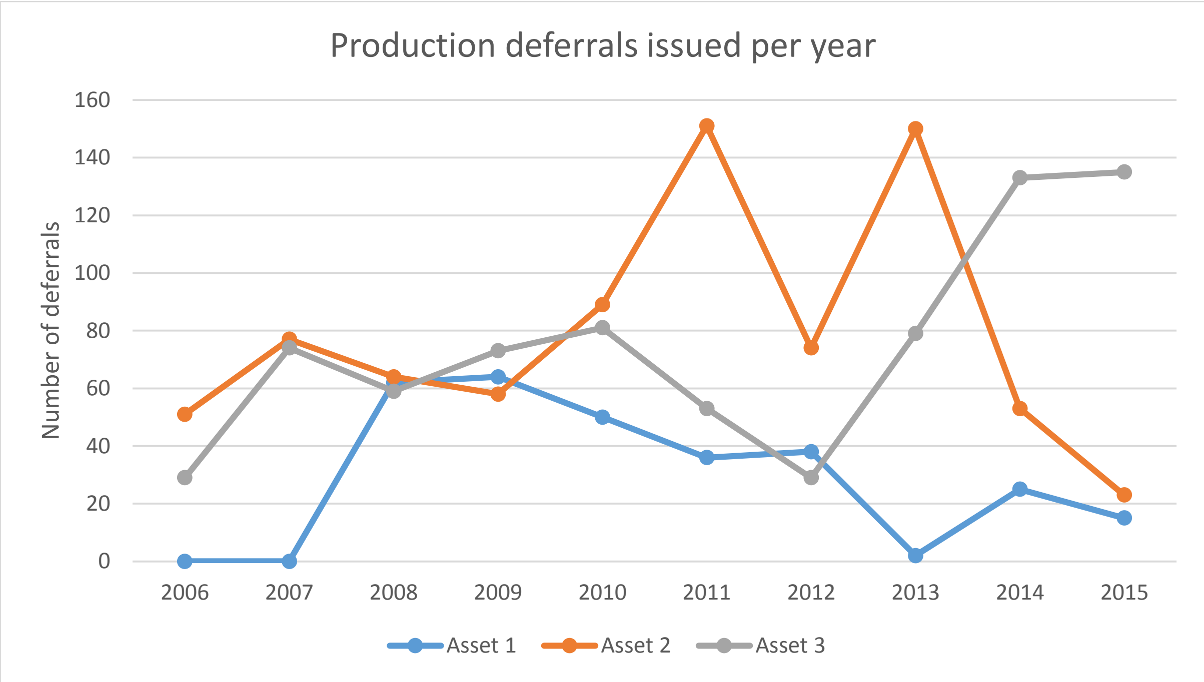


Chart 1 - Deferrals per asset per year

There are two categories of deferral types; planned and unplanned. For Company, the planned deferrals are mostly related to platform activities which causes the well to be shut-in. Unplanned deferrals are either related to equipment failure or reservoir and well-system impairments.

4.1.1 Equipment failure mode

Due to the nature of the data set obtained from the PPIT system, many assumption, and best engineering judgement were practiced when assigning failure modes on individual failures. The information in the data set is not informative nor accurate enough to ensure the correct failure mode was assigned. Therefore, the complete list of possible failure modes are not presented in the this thesis, and failure type till be implemented. A complete list of assumed failure modes assumed can be found in Appendix A.

However, though the data set was not informative enough for specific equipment deferrals, it is specific enough for top-level categorization of the failures mode. Three top-level groups of deferral modes emerged; *reservoir and well system deferrals*, *well equipment failure deferrals* and *platform deferrals*.

A deferral is assigned to the *reservoir and well system deferral* group when reason for issuing the deferral is related to reservoir issues. Issues can be, but not limited to, production of solids, scale, low bottom-hole pressure. A deferral is assigned to the *well equipment failure deferrals* when the deferral is issued due to well specific equipment failure. A deferral is assigned to the *platform deferrals* group when the reason for deferral is related to prioritization on the platform, such as heavy lifts and completion of other wells. It is also used when non-well specific equipment fails –like a multiple phase pump.

Failure cause by occurrence

Failure cause by occurrence is the number of unique deferrals issued per group. Table 12 shows the breakdown the three top-level failure modes. From the table, the following observations can be made:

- 21.5% of all deferrals issued are related to *well equipment failure*.
- 56.5% of all deferrals issued are related to *platform priorities* – which is mostly planned work
- 21.1% of all deferrals issued are related to *reservoir and well system* issues.
- Asset 1 has the lowest number of deferrals for all three categories
- Asset 2 has the highest number of deferrals for *well equipment failure* and *reservoir and well system* deferrals. It is second highest for the *platform priorities* category.
- Asset 3 has the second highest for *well equipment failure*, and the second highest for the other two categories.

Table 12 - Failure mode by occurrences

Asset	Well equipment failure deferrals		Platform deferrals		Reservoir and well system deferrals	
	Unique deferrals	% of sub-group	Unique deferrals	% of sub-group	Unique deferrals	% of sub-group
Asset 1	53	13.3%	165	15.8%	84	20.5%
Asset 2	196	49.2%	378	36.1%	218	53.3%
Asset 3	149	37.4%	504	48.1%	107	26.2%
Total	**398**	**21.5%**	**1,047**	**56.5%**	**409**	**22.1%**

Chart 2 visually represent the split between the three major groups.

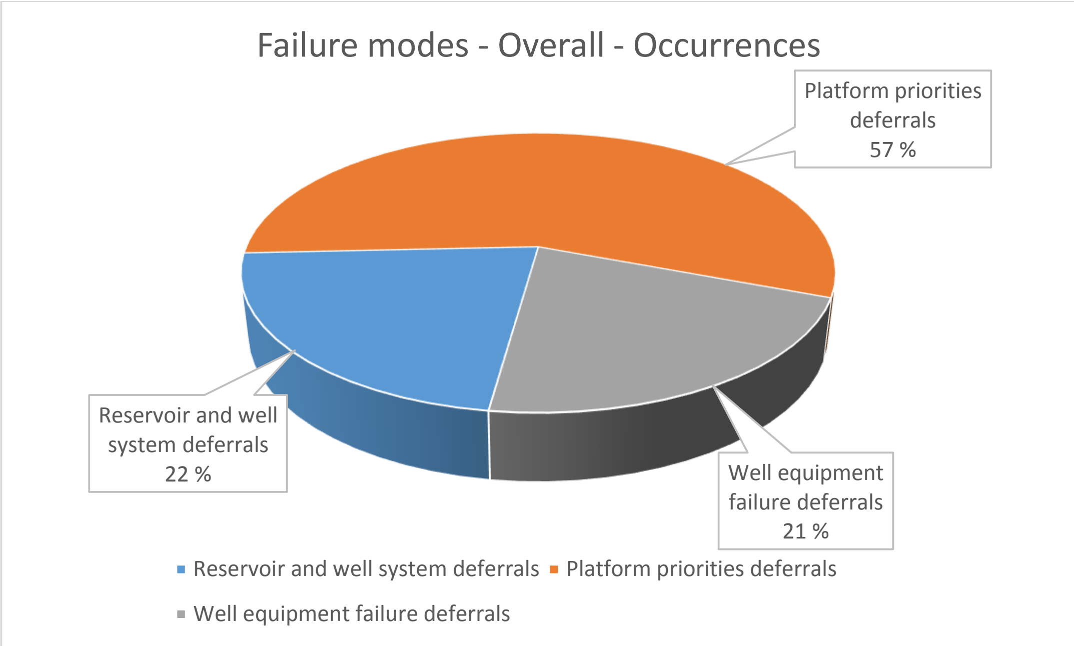


Chart 2 –Failure modes by occurences

Failure cause by duration

Failure cause by duration accumulates the total deferral duration per failure mode. Table 13 shows the breakdown of the deferral duration by the three top-level failure modes. From the table, the following observations can be made;

- 34.8% of the total deferral duration is related to *well equipment failure*.
- 21.7% of the total deferral duration is related to *platform priorities*.
- 43.5% of the total deferral duration is related to *reservoir and well system* issues.
- Asset 1 has the lowest deferral duration for all three categories
- Asset 2 has the second highest deferral duration for *well equipment failure* and *reservoir and well systems issues* and is the highest for the *platform priorities* category.

- Asset 3 has the highest deferral duration for *well equipment failure* and *reservoir and well systems* issues, and is the second highest in the *platform priories* category.

Table 13 - Failure mode by duration

Asset	Well equipment failure deferrals		Platform deferrals		Reservoir and well system deferrals	
	Duration (days)	% of sub-group	Duration (days)	% of sub-group	Duration (days)	% of sub-group
Asset 1	1,815	17.8%	1,479	23.2%	1,584	12.4%
Asset 2	2,858	28.0%	2,463	38.6%	4,188	32.8%
Asset 3	5,542	54.3%	2,433	38.2%	6,978	54.7%
Total	**10,215**	**34.8%**	**6,375**	**21.7%**	**12,750**	**43.5%**

Chart 3 visually represent the split between the three major groups.

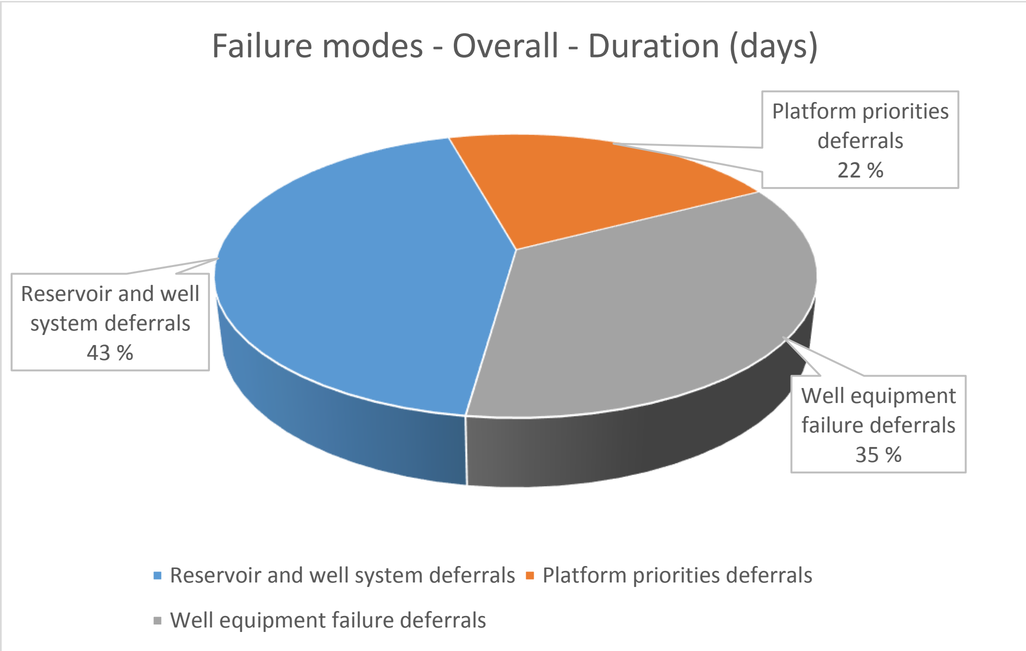


Chart 3 - Failure mode by duration

Failure cause by volume

Failure cause by volume accumulates the total deferral production volume per failure mode. Table 13 shows the breakdown of the deferral production by the three top-level failure modes. From the table, the following observations can be highlighted;

- 40.1% of the total deferred production volume is related to *well equipment failure*.
- 27.9% of the total deferred production volume is related to *platform priorities.*
- 32.0% of the total deferred production volume is related to *reservoir and well systems*.
- Asset 1 has the lowest deferral duration for all three categories.

- Asset 2 has the second highest deferred production volume for *well equipment failure* and *reservoir and well systems* issues and is the highest for the *platform priority* category.
- Asset 3 has the highest deferred production volume for *well equipment failure* and *reservoir and well systems* issues, and is the second highest in the *platform priority* category.

Table 14 - Failure mode by volume

Field	Well equipment failure deferrals		Platform deferrals		Reservoir and well system deferrals	
	Volume (MBOE)	% of sub-group	Volume (MBOE)	% of sub-group	Volume (MBOE)	% of sub-group
Asset 1	4,798	28.4%	3,151	26.9%	2,380	17.7%
Asset 2	5,874	34.8%	4,509	38.5%	4,339	32.2%
Asset 3	6,199	36.7%	4,063	34.7%	6,745	50.1%
Total	**16,871**	**40.1%**	**11,724**	**27.9%**	**13,464**	**32.0%**

Chart *4* visually represent the split between the three major groups.

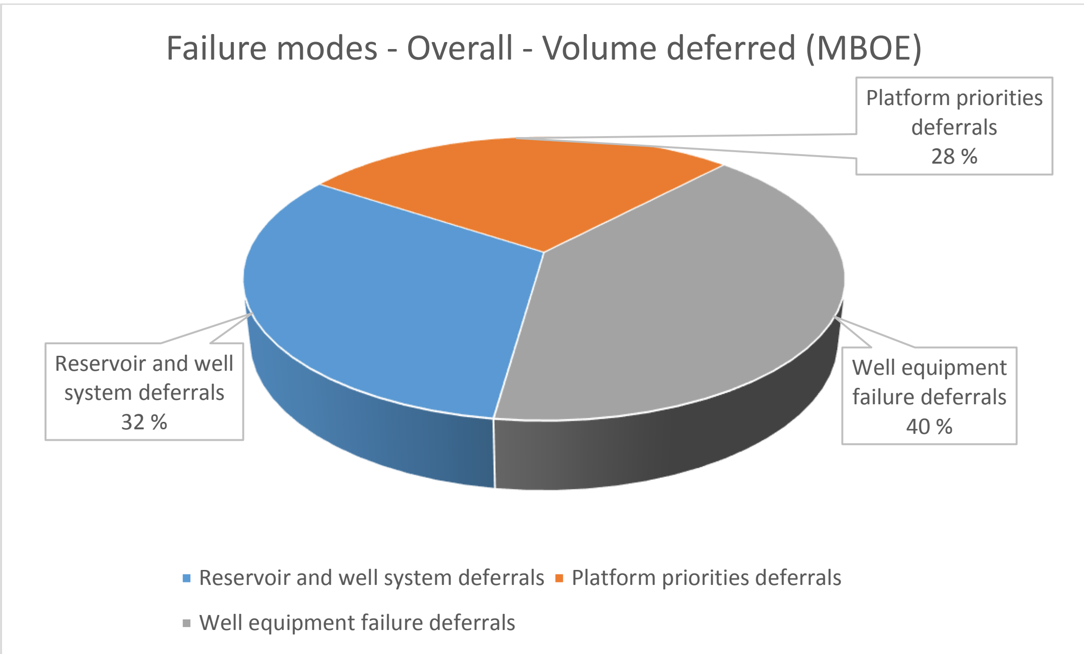


Chart 4 - Failure mode by volume

Table 15 shows the percentage of deferrals in the three categories side-by-side. By comparing deferral occurrences to duration and volume, the following conclusions can be made;

- *Well equipment failure* category is 21.5% of the occurrences, 34.8% of the duration and 40.1% of the volume. Thus, equipment failure last longer and defers more production volume than the average deferral.
- *Platform priority* deferrals account for 56.5% of the occurrences, 21.7% of the duration and 27.9% of the volume. Thus, deferrals in the undefined group lasts shorter and defer less volume than the average. Since deferrals related to platform priorities are mostly planned, it is expected that the deferral lasts for a short period of time.
- *Reservoir and well system* deferrals account for 21.1% of the occurrences, 43.5% of the duration and 32.0% of the volume. Thus, deferrals in this group lasts the longest and defers more volume than the average. It could be argued that this is expected as the *reservoir and well systems* failures are less common and potentially more difficult to rectify.

Table 15 - Failure mode overview of Assets by percentage

Field	Well equipment failure deferrals			Platform deferrals			Reservoir and well system deferrals		
	Unique Deferrals	Duration (days)	Volume (MBOE)	Unique Deferrals	Duration (days)	Volume (MBOE)	Unique Deferrals	Duration (days)	Volume (MBOE)
Asset 1	13.3%	17.8%	28.4%	15.8%	23.2%	26.9%	20.5%	12.4%	17.7%
Asset 2	49.2%	28.0%	34.8%	36.1%	38.6%	38.5%	53.3%	32.8%	32.2%
Asset 3	37.4%	54.3%	36.7%	48.1%	38.2%	34.7%	26.2%	54.7%	50.1%
Total	**21.5%**	**34.8%**	**40.1%**	**56.5%**	**21.7%**	**27.9%**	**22.1%**	**43.5%**	**32.0%**

Chart 5 is a visual representation and provides an overview of split of deferrals between the three assets.

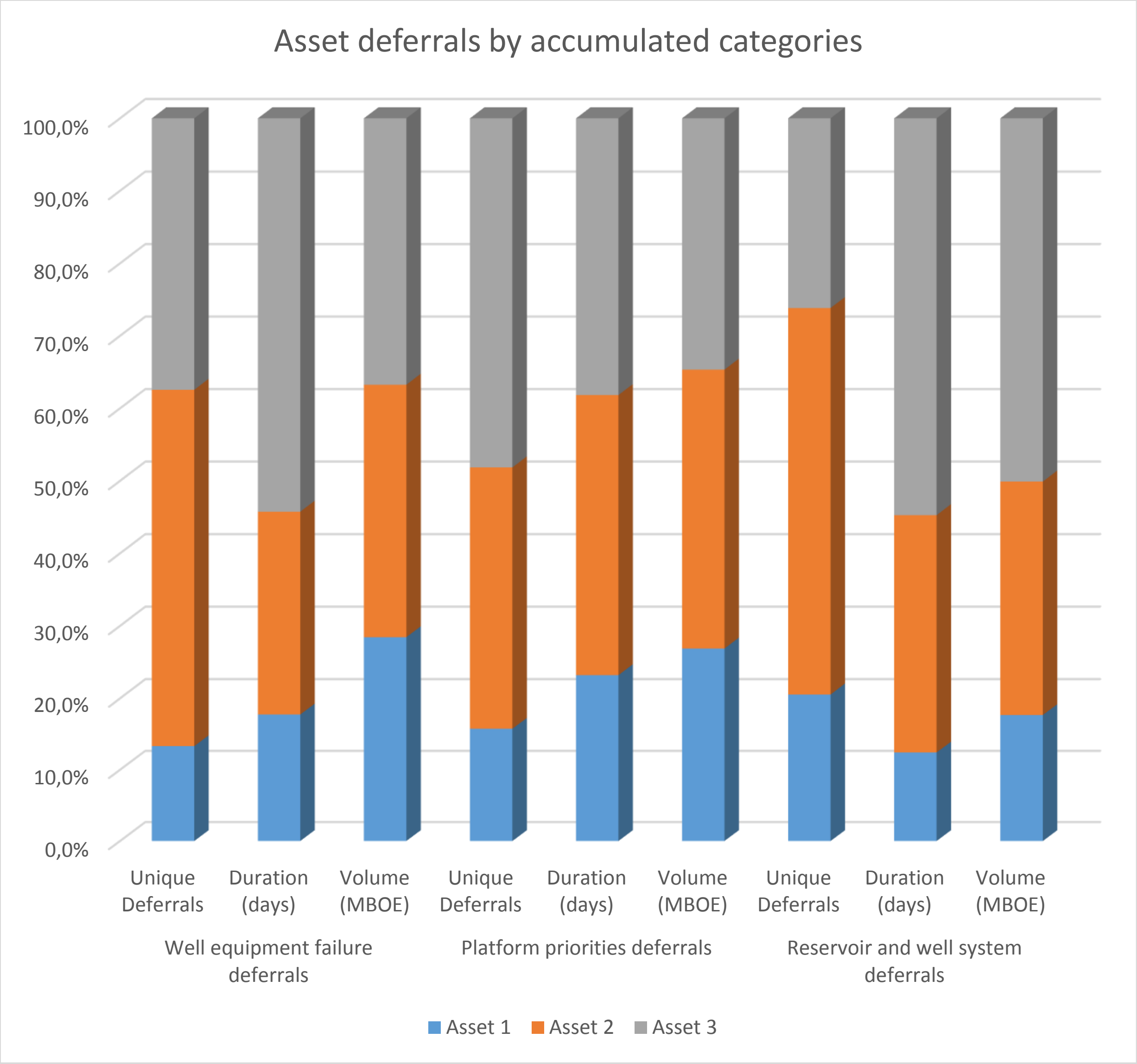


Chart 5 – Asset deferrals by accumulated categories

The *reservoir and well system* deferrals and *platform priorities* deferrals are further categorized as described in Section 3.2.3.

4.1.1.1 *Reservoir and well systems deferral group*

The *reservoir and well systems* deferral group was split into smaller sub-groups to further identify potential causes for deferrals. Table 16 shows the distribution of the sub-groups. From the table below, the following can be highlighted:

- Chalk influx is the biggest contributor in this group with respect to volume deferred.
- Problems lifting the production fluid and scaling are the amongst the top three causes for production losses in this group.
- Slugging also causes a significant amount of deferred production volume on one asset.

Table 16 – Reservoir deferral group for Asset 1

Issue	Occurrences	Duration (days)	Volume (MBOE)
Asphaltenes	23	705	873
Cyclic Wells	21	556	416
Fracking	9	257	183
Influx	19	4,240	4,456
Lifting	117	1,837	2,438
Logging	1	5	15
Other-r	39	1,027	951
Scale	125	2,843	2,253
Slugging	35	992	1,290
Solids	14	135	130
Total	**403**	**12,597**	**13,003**

4.1.1.2 Platform priority deferral group

The *platform priority* deferral group was split into smaller sub-groups to further identify potential causes for deferrals. Table 17 shows the distribution of the sub-groups. From the table below, the following can be highlighted:

- Drilling and completing related has few occurrences, but deferrers a significant volume.
- WBE testing has most deferrals and has a fair amount of volume deferred.
- Other-n is the biggest contributor. This group requires further analysis.

Table 17 – Platform prioities deferral group for Asset 1

Issue	Occurrences	Duration (days)	Volume (MBOE)
Drilling/Completion	33	1,058	2,024
Heavy Lift	134	253	381
Other-n	301	3,078	6,450
WBE testing	568	1,932	2,397
Total	**1,036**	**6,321**	**11,252**

The “Other-n” category captures the different types of deferrals related to the un-specified activities. These are activities such as well intervention, maintenance and installation of gas lift systems on one of the assets. As this category varies much from asset to asset, the further breakdown is asset dependent.

For Asset 1, the “Other-n” category was split into three categories presented in Table 18. From the table, the following observations can be highlighted;

- Maintenance account a high amount of occurrences, but duration and volume deferred are relatively low.
- Intervention accounts for few deferrals but account for large portions of durations and volume deferred.
- The general misc-n category is not of significant with respect to duration or volume deferred.

Table 18 – Breakdown of "Other-n" for Asset 1

Sub Category	# of deferrals	Duration (days)	Volume (MBOE)
Maintenance	54	80	218.4
Misc-n	39	244	360.0
Intervention	17	1006	1,785.5

For Asset 2, the "Other-n" category was split into four categories presented in Table 19. From the table, the following observations can be highlighted;

- Multiphase pump (MPP) accounted for a large portion of duration and volume deferred considering it only happened once.
- Maintenance accounts overall for a low potion of this group.
- Intervention is roughly 20% of the total volume deferred in this category for this asset.
- Misc-n is a larger portion for Asset 2 than it was for Asset 1.

Table 19 – Breakdown of "Other-n" for Asset 2

Sub-sub Category	# of deferrals	Duration (days)	Volume (MBOE)
Intervention	26	197	576.2
Maintenance	19	70	42.5
Misc-n	64	474	856.2
MPP	1	207	948.1
Total	110	948	2423.0

For Asset 3, the "Other-n" category was split into five categories presented in Table 20. From the table, the following observations can be highlighted;

- Gas lift (GL) installation accounts for large portion of the volume deferred.
- De-oiling is relatively high on volume deferred considering the low duration.
- Misc-n accounts for a large portion of the number of deferrals and duration. Volume deferred is relatively small considering the other two aspects.
- Intervention and IPC are generally low for this sub-group.

Table 20 – Breakdown of "Other-n" for Asset 3

Sub-sub Category	# of deferrals	Duration (days)	Volume (MBOE)
De-oiling	2	31	340.4
GL installation	2	127	810.8
Intervention	6	46	36.7
IPC	1	189	29.4
Misc-n	70	407	446.1
Total	81	800	1,663.5

4.1.2 Planned and unplanned deferral

Each deferral is categorized as a planned or unplanned event. For this thesis, all equipment failure deferrals are assumed to be unplanned. The unplanned category is divided into two sub-categories; *unplanned deferrals* and *well equipment failure deferrals*. Then the three categories of deferrals are; *well equipment failure*, *unplanned deferrals* and *planned deferrals*.

Table 21 presents the overall performance of planned vs unplanned deferrals for all of the Company's assets. From the table, *planned* deferrals account for 45% of all deferrals issued. It also accounts for 17% of the total deferred production and 15% of the total deferral duration. This indicates that 45% of all well shut-ins which occurred in the time period were planned. It also shows that 15% of the down-time was planned.

Furthermore, from the table, *well equipment failure* deferrals accounts for 21% of the total number of deferrals places, while it accounts for 35% of the deferral durations and 40% of the total production deferred. The *unplanned deferrals* group accounts for 34% the total number of deferrals places, while it accounts for 50% of the deferral durations and 43% of the total production deferred. This indicates that 55% of all well shut-ins which occurred in the time period were unplanned. It also shows that 85% of the down-time was unplanned.

In addition, from table, the overall average for *planned deferrals* are 8,500 MBE of deferred production and lasting 0.014 years. For the *well equipment failure* the average deferral is 42,400 BOE and lasting 0.070 years. The *Unplanned deferrals* average 27,100 BOE per deferral and lasing 0.065 years.

Table 21 – Planned vs unplanned deferrals

Type of deferral	All Assets							
	Number of deferrals		Deferred Production		Duration		Avg. per deferral	
	#	%	MBOE	%	Years	%	MBOE	Years
Well equipment failure deferrals	398	21%	16,871	40%	28.0	35%	42.4	0.070
Planned deferrals	833	45%	7,071	17%	12.0	15%	8.5	0.014
Unplanned deferrals	623	34%	18,117	43%	40.4	50%	29.1	0.065
Total	**1,854**		**42,059**		**80.3**		**22.7**	**0.043**

In addition, Table 21 also shows that 17% of the production volume deferred over the given time period is planned. This indicates the Company planned to defer seven million BOE of production over the given time period. It also shows that 83% of all of the deferred production was unplanned.

The deferred production varies between the three assets. Table 22 shows how the assets vary on production deferral. Form the table, the following should be highlighted;

- Asset 1 planned to defer 11% of the total deferred production –lowest of all assets.
- Asset 2 planned to defer 16% of the total deferred production –roughly average
- Asset 3 planned to defer 21% of the total deferred production, which is considerably more than the other two assets, and nearly twice that of Asset 1. Table 22 shows the production deferral for all assets.
- *Unplanned deferrals* group is very similar for all three assets, only ±2%.
- *Well Equipment failure* vary with ±10%. Asset 1 has the highest percentage, and Asset 3 has the lowest. Asset 2 is in the middle of the other two by percentage.

Table 22 – Production deferrals for all assets

Type of deferral	Asset 1		Asset 2		Asset 3	
	Deferred Production		Deferred Production		Deferred Production	
	MBOE	%	MBOE	%	MBOE	%
Well equipment failure deferrals	4798	46%	5,874	40%	6,199	36%
Planned deferrals	1180	11%	2,304	16%	3,587	21%
Unplanned deferrals	4352	42%	6,544	44%	7,220	42%
Total	**10,330**		**14,723**		**17,007**	

Comparing the percentages of each deferral type from Table 21, *planned deferrals* have a greater frequency of occurrences, while both the deferral duration and deferred production is considerably lower than the other two categories. Thus, the *planned deferrals* require less time and defer less production volume than the unplanned events. In other words, on average, a planned deferral costs less than the unplanned deferrals, which is as expected.

The *well equipment failure deferrals* are low in frequency, and the deferral duration and deferred production percentages are nearly twice as high as that of occurrences. Thus, the *well equipment failure deferrals* take longer and defer more production volume per deferral. The same if also true for the *Unplanned deferrals* group, but the differences between the groups are less. In other words, unplanned deferrals costs, in terms of lost production, and last longer than planned deferrals –as expected.

Asset 1

Table 23 outline the performance of Asset 1. From the table, the following is highlighted:

- 66% of all deferrals issued are unplanned.
- 34% of all deferrals issued are planned.
- 89% of all production volume deferred are unplanned.
- 11% of all production volume deferred are planned.
- Planned deferrals average 11,300 BOE per deferral and lasts 0.007 years or 2.5 days.
- Equipment failure deferrals average 90,500 BOE per deferral and lasts 0.094 years or 34.3days.
- Other unplanned deferrals average 30,000 BOE per deferral and lasts 0.053 years or 19,3days.

- Planned deferrals defer the least production volume and lasts the shortest time.
- Equipment failure defer the most production volume and lasts the longest.
- Asset 1 management planned to defer 1.2 million BOE in the given time period.

Table 23 – Production deferrals for Asset 1

Type of deferral	Asset 1							
	Number of deferrals		Deferred Production		Duration		Avg. per deferral	
	#	%	MBOE	%	Years	%	MBOE	Years
Well equipment failure deferrals	53	18%	4,798	46%	5.0	37%	90.5	0.094
Planned deferrals	104	34%	1,180	11%	0.7	5%	11.3	0.007
Unplanned deferrals	145	48%	4,352	42%	7.7	58%	30.0	0.053
Total	**302**		**10,330**		**13.4**		**34.2**	**0.044**

Asset 2

Table 23outline the performance of Asset 2. From the table, the following is highlighted:

- 64% of all deferrals issued are unplanned.
- 36% of all deferrals issued are planned.
- 84% of all production volume deferred are unplanned.
- 16% of all production volume deferred are planned.
- Planned deferrals average 8,100 BOE and lasts 0.019 years.
- Equipment failure deferrals average 30,000 BOE per deferral and lasts 0.040 years.
- Other unplanned deferrals average 21,000 BOE per deferral and lasts 0.041 years.
- Planned deferrals defer the least production volume and lasts the shortest time.
- Equipment failure defer the most production volume.
- Asset 2 management planned to defer 2.3 million BOE in the given time period.

Table 24 – Production deferrals for Asset 2

Type of deferral	Asset 2							
	Number of deferrals		Deferred Production		Duration		Avg. per deferral	
	#	%	MBOE	%	Years	%	MBOE	Years
Well equipment failure deferrals	196	25%	5,874	40%	7.8	30%	30.0	0.040
Planned deferrals	285	36%	2,304	16%	5.5	21%	8.1	0.019
Unplanned deferrals	311	39%	6,544	44%	12.7	49%	21.0	0.041
Total	**792**		**14,723**		**26.0**		**18.6**	**0.033**

Asset 3

Table 25 outline the performance of Asset 3. From the table, the following is highlighted:

- 42% of all deferrals issued are unplanned.
- 58% of all deferrals issued are planned.
- 79% of all production volume deferred are unplanned.
- 21% of all production volume deferred are planned.
- Planned deferrals average 8,100 BOE and lasts 0.013 years.
- Equipment failure deferrals average 41,600 BOE per deferral and lasts 0.102 years.
- Other unplanned deferrals average 43,200 BOE per deferral and lasts 0.120 years.
- Planned deferrals defer the least production volume and lasts the shortest time.
- Equipment failure defer the second most volume and last the second longest.
- Asset 3 management planned to defer 3.6 million BOE in the given time period.

Table 25 – Production deferrals for Asset 3

Type of deferral	Asset 3							
	Number of deferrals		Deferred Production		Duration		Avg.per deferral	
	#	%	MBOE	%	Years	%	MBOE	Years
Unplanned equipment failure	149	20%	6,199	36%	15.2	37%	41.6	0.102
Planned deferrals	444	58%	3,587	21%	5.7	14%	8.1	0.013
Unplanned deferrals - nonspecific	167	22%	7,220	42%	20.0	49%	43.2	0.120
Total	**760**		**17,007**		**40.9**		**22.4**	**0.054**

Summary of Planned and Unplanned deferrals

From summary of the three assets presented above, the following can be highlighted;

- *Planned* deferrals; on average, Asset 1 deferred the most volume per deferral
- *Planned* deferrals; on average, Asset 2 and 3 are very similar in deferred volume
- Asset 3 has the most *planned* deferrals issued
- Asset 3 *planned* to defer the most volume
- Asset 2 has the most *well equipment failure* deferrals
- Asset 2 has the most *unplanned* deferrals in total
- Asset 3, on average, uses the most time to fix *well equipment failure*, though Asset 1 is right behind.
- Asset 3, on average, uses the longest time to fix deferrals.

Chart 6 show the performance of the assets against the average of all the assets. The bar-graph is the average volume deferred, whilst the lines are the average duration. From the chart, Asset 1 has the highest deferral volume for *well equipment failure*. Further, Asset 1 is above average on both deferred volume for *planned deferrals* and *unplanned deferrals.*

Asset 2 is below average on both production volume deferred and deferral duration for all, except for *planned deferrals*.

Asset 3 is roughly on average for all three deferral types with respect to volume deferred. However, it is above average on deferral duration for all deferrals except for *planned deferrals*.

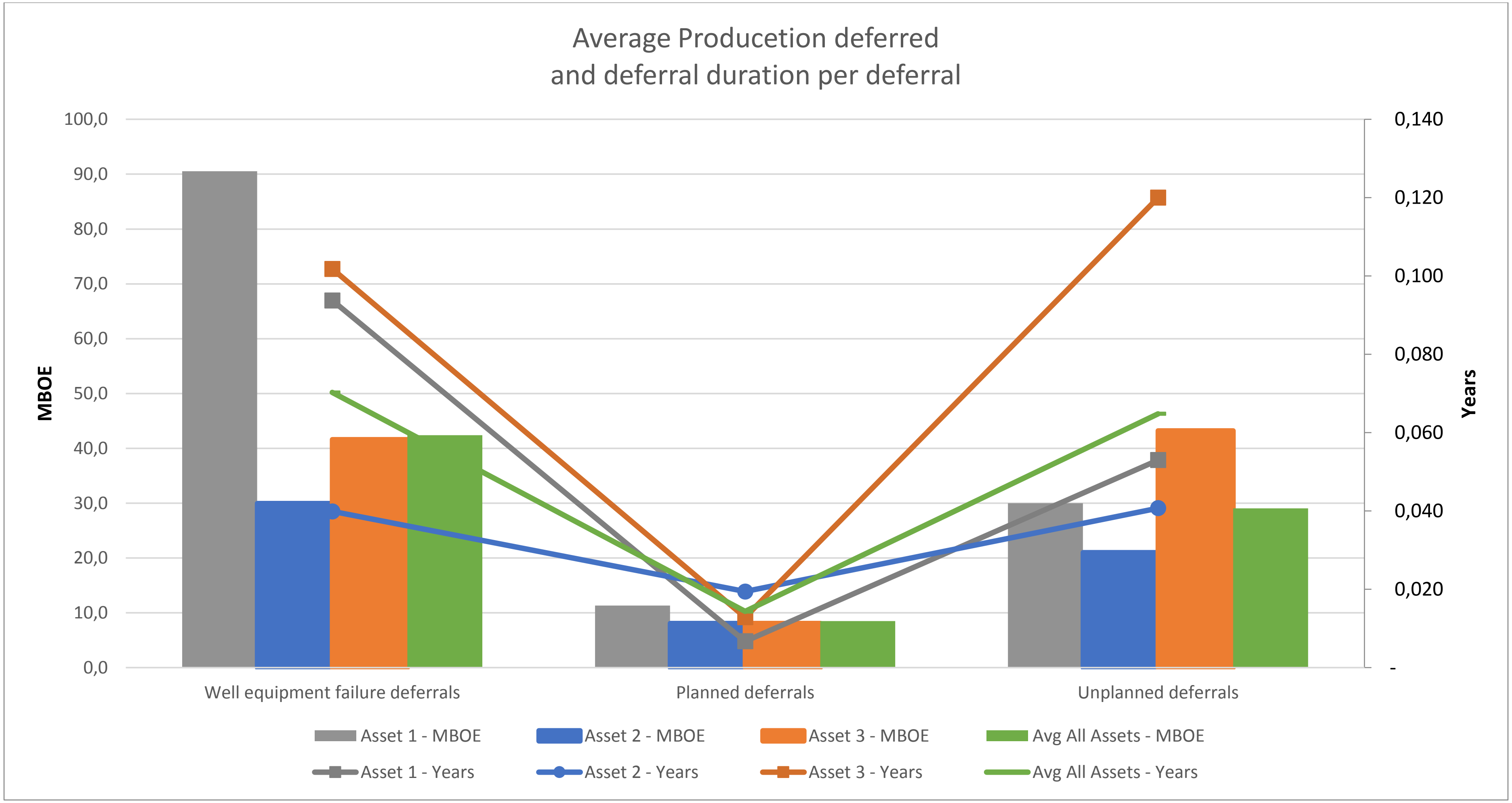


Chart 6 – Acerage production volume and duration deferrals

4.2 Unplanned Deferrals and Equipment Failures

The purpose of this section if to present the findings based asset performance according to Company PPIT system.

4.2.1 Number of Wells and Service Time

Table 26 shows the outline of number of wells per asset. In addition, the service time is shows presenting the total time the wells have been considered to be in operations. From the table, the following can be highlighted:

- Asset 1 and Asset 2 has roughly the same number of wells
- Asset 3 has 4-5 times the number of wells compared to the other two assets
- Total, 102 wells were analyzed.
- Total service time for all wells are 822 years.

Table 26 – Wells per asset

Asset	# of wells	Service time (years)
Asset 1	14	95
Asset 2	17	136
Asset 3	71	591
Total	**102**	**822**

4.2.2 Equipment Level

When assigning *Equipment Level* codes, it became evident that the deferrals did not contain the necessary information to assign Level B coding. Therefore, when assigning Level B coding, many assumptions and best engineering judgement was required. Thus, for this thesis, Level B will only be presented in Appendix B.

Table 27 shows the list of Level A components from each of the three assets are presented. In addition, a summary table identifies the overall performance of the assets. The first category number, "Well deferrals not related to specific well equipment" is the combination of reservoir and undefined deferral groups. These were discussed in section 4.1.1.1 and 4.1.1.2. This section will focus on numbers 2 through 12.

From Table 27, "Upper Completion" is a major contributor to combined deferred volume from all three assets. The combined deferred production accounts for almost half of the total deferred volume. Both Asset 2 and 3 are major contributors to this total. Whilst Asset 1 does not have the same loss in deferred production for this equipment group. In Appendix B, the overview of

Level B components indicate that the main issue with this equipment group is the control lines. This is assumed to be for the most part connection points, and not the control line itself.

The second highest equipment group which causes deferred production is number 5 –“DHSV systems”. Group 5 is a major contributor to equipment failure for Asset 1 and 2, as it accounts for nearly half of the deferred volume for each Asset. For Asset 3, the “DHSV system” accounts for nearly one sixth of the total deferred volume.

For Asset 1, the “Gas Lift System” contributes about one fourth of the total volume deferred. This is considerably larger portion and volume than the other two assets. In Appendix B, the level B group assumed to cause the biggest potion of deferrals is the ESD valve. This accounts for over one million BOEs of deferred production. As the table indicates, Asset 1 has the biggest losses in production due to this type of equipment failures. The last major contributor to overall lost production is the dry wellhead and x-mas tree groups, group number 2 and 3.

The other groups are relatively small in size compared to the four larger groups.

Table 27 – Defferal data per Level A equipment level for all assets

#	Level A equipment	Asset 3			Asset 2			Asset 1			Summary		
		# of deferrals , A3	**Duration (years), A3**	**Volume (MBOE), A3**	**# of deferrals , A2**	**Duration (years), A2**	**Volume (MBOE), A2**	**# of deferrals , A1**	**Duration (years), A1**	**Volume (MBOE), A1**	**# of deferrals**	**Duration (years)**	**Volume (MBOE)**
1	**Well Deferrals not related to specific well equipment**	611	25.77	10,807.7	596	18.21	8,848.5	249	8.39	5,531.6	1,456	52.36	25,187.8
2	**Surface Tree (Dry)**	40	1.39	682.9	71	0.85	359.3	16	0.21	201.3	127	2.45	1,243.4
3	**Surface Wellhead (Dry)**	7	0.58	148.5	9	0.18	209.9	1	0.00	0.9	17	0.76	359.3
4	**Tubing Hanger (Dry)**	6	0.90	396.7	2	0.05	10.7	1	0.04	30.4	9	0.99	437.8
5	**DHSV System**	20	2.19	927.2	50	3.08	2,252.5	10	2.21	2,708.9	80	7.48	5,888.6
6	**Gas Lift System**	9	1.39	380.4	15	0.49	54.3	10	2.16	1,463.8	34	4.04	1,898.6
7	**Upper Completion**	39	6.86	3,088.5	25	3.00	2,839.6	2	0.02	20.3	66	9.88	5,948.4
8	**Intermediate Completion Eqt**	-	-	-	-	-	-	-	-	-	-	-	-
9	**Lower Completion Eqt.**	-	-	-	-	-	-	2	0.19	290.3	2	0.19	290.3
10	**Sand Control System**	1	0.07	25.0	-	-	-	2	0.08	41.9	3	0.15	66.9
11	**Casing**	11	1.65	489.9	-	0.10	-	-	-	-	11	1.76	489.9
12	**Automation, Logic, HPU**	17	0.13	174.5	22	0.08	145.5	9	0.06	40.2	48	0.27	360.2
	Total (#2 through 12)	**150**	**15.17**	**6,313.7**	**194**	**7.82**	**5,871.7**	**53**	**4.97**	**4,797.9**	**397**	**27.97**	**16,983.3**

4.2.3 Mean time between failure

Mean time between failure (MTBF) is the total service time period over the total number of registered failures. From Table 10, the total number of unique deferrals registered in Company's system is 1,854 deferrals. From Table 26, the total observational period for all of the three assets is 822 years. Then, the overall MTBF is 0.45 years. In general, this means, that on average, each well is expected to close-in twice each year.

$$MTBF\_overall = \frac{822\ years}{1854\ deferrals} = 0.45\ years/deferral$$

From Table 12, the total number of equipment failure related deferrals is 398 deferrals. The service time period is the same, 822 years. Thus, the MTBF for well specific equipment is 2.09. A practical interpretation of this data is for each two wells, one well will experience equipment related deferrals during any given year.

$$MTBF\_equipment = \frac{398\ years}{1854\ deferrals} = 2.09\ years/deferral$$

Table 28 shows the MTBF calculated for each Level A equipment. From the table, the following can be highlighted;

- "Surface tree" equipment group has a general low MTBF
- "DHSV" and "HPU/logic" are considerably lower for Asset 1 and 2
- "Wellhead", "Gas lift system" and "Casing" are considerably lower for Asset 2
- "Intermediate completion" did not have any registered deferrals in PPIT, thus MTBF is the observed service time.

Table 28 – MTBF for all assets

MTBF (years)	Level A equipment level	Asset 1	Asset 2	Asset 3	Total
	Surface tree	5.9	1.9	14.8	6.5
	Wellhead	94.5	15.1	84.4	48.3
	Tubing hanger	94.5	136.2	118.2	91.3
	DHSV	9.5	2.7	29.6	10.3
	Gas lift system	9.4	1.2	6.5	24.2
	Upper completion	47.3	9.1	20.4	12.5
	Intermediate completion	94.5	136.2	591.0	821.8
	Lower completion	47.3	136.2	591.0	410.9
	Sand control	47.3	136.2	591.0	273.9
	Casing	94.5	12.4	42.2	74.7
	HPU / logic	10.5	9.7	42.2	17.1

4.2.4 Mean time to repair

The mean time to repair (MTTR) is the total deferral duration over the given number of failures. From Table 10, the total number of unique deferrals registered in Company's system is 1,854 deferrals. From Table 21, the total deferral duration is observational period for all of the three assets is 80.3 years. Thus, the MTTR for the a well is 0.043 years, which equals 15.8 days. On average, a deferral lasts less than 16 days.

$$MTTR\_overall = \frac{80.6\ years}{1854\ deferrals} = 0.043\ years/deferral = 15.8\ day/deferral$$

From Table 12, the total number of equipment failure related deferrals is 398 deferrals. Also from Table 12, the total deferral period is 28 years. Thus, the MTBF for well equipment is 0,070 which is 25,7 days. On average, an equipment failure deferral lasts less 26 days.

$$MTTR\_equipment = \frac{28\ years}{398\ deferrals} = 0.070\ years/deferral = 25.7\ day/deferral$$

Table 29 shows the MTTR for Level A equipment. From the table, the following can be highlighted;

- For all assets, “Casing” and “Upper completion” has the highest MTTR.
- For Asset 1, “DHSV” and “Gas lift system” has the highest MTTR.
- For Asset 2, “Upper completion” has the highest MTTR.
- For Asset 3, “Tubing hanger” has the highest MTTR.
- Surface tree has in general a low MTTR.

Table 29 – MTTR for all assets

	Level A equipment level	Asset 1	Asset 2	Asset 3	Total
MTTR (years)	Surface tree	0.013	0.012	0.035	0.019
	Wellhead	0.003	0.019	0.083	0.045
	Tubing hanger	0.036	0.052	0.181	0.110
	DHSV	0.221	0.060	0.110	0.093
	Gas lift system	0.216	0.020	0.073	0.119
	Upper completion	0.010	0.200	0.237	0.150
	Intermediate completion	-	-	-	-
	Lower completion	0.096	-	-	0.096
	Sand control	0.040	-	0.068	0.049
	Casing	-	0.009	0.118	0.160
	HPU / logic	0.006	0.006	0.009	0.006

4.2.5 Equipment Reliability

From Table 30, the component reliability for each asset is presented. From the table, and based on year 1, the following should be highlighted;

- For Asset 1, “Surface tree”, “DHSV”, and “Gas lift system” has a reliability of less than 90%. All three retain a reliability of over 80%.
- For Asset 2, “Surface tree” and “Gas lift system” are the only system with reliability lower than 90%. Both of them are considerably lower than the rest and have a reliability between 40% and 60%.
- For Asset 3, “Gas lift system” is the only system with reliability lower than 90%. This system has reliability of over 85%.
- Asset 3 has the highest system reliability
- Asset 2 has the lowest system reliability

Table 30 – Equipment reliability per asset

	Description	MTTF	λ	Reliability for time duration (years)									
				1		**5**		**10**		**15**		**20**	
				pi	**qi**	**pi**	**qi**	**pi**	**qi**	**pi**	**qi**	**pi**	**qi**
Asset 1	Surface tree	5.9	0.169	84.43%	15.57%	42.91%	57.09%	18.41%	81.59%	7.90%	92.10%	3.39%	96.61%
	Wellhead	94.5	0.011	98.95%	1.05%	94.85%	5.15%	89.96%	10.04%	85.33%	14.67%	80.93%	19.07%
	Tubing hanger	94.5	0.011	98.95%	1.05%	94.85%	5.15%	89.96%	10.04%	85.33%	14.67%	80.93%	19.07%
	DHSV	9.5	0.106	89.96%	10.04%	58.93%	41.07%	34.73%	65.27%	20.46%	79.54%	12.06%	87.94%
	Gas lift system	9.4	0.107	89.89%	10.11%	58.70%	41.30%	34.46%	65.54%	20.23%	79.77%	11.88%	88.12%
	Upper completion	47.3	0.021	97.91%	2.09%	89.96%	10.04%	80.93%	19.07%	72.81%	27.19%	65.50%	34.50%
	Intermediate completion	94.5	0.011	98.95%	1.05%	94.85%	5.15%	89.96%	10.04%	85.33%	14.67%	80.93%	19.07%
	Lower completion	47.3	0.021	97.91%	2.09%	89.96%	10.04%	80.93%	19.07%	72.81%	27.19%	65.50%	34.50%
	Sand control	47.3	0.021	97.91%	2.09%	89.96%	10.04%	80.93%	19.07%	72.81%	27.19%	65.50%	34.50%
	Casing	94.5	0.011	98.95%	1.05%	94.85%	5.15%	89.96%	10.04%	85.33%	14.67%	80.93%	19.07%
	HPU / logic	10.5	0.095	90.92%	9.08%	62.13%	37.87%	38.60%	61.40%	23.98%	76.02%	14.90%	85.10%
	System reliability (h_Asset 1) =	**1.7**	**0.58**	**55.85%**		**5.43%**		**0.30%**		**0.02%**		**0.00%**	
Asset 2	Surface tree	1.9	0.521	59.37%	40.63%	7.38%	92.62%	0.54%	99.46%	0.04%	99.96%	0.00%	100.00%
	Wellhead	15.1	0.066	93.61%	6.39%	71.86%	28.14%	51.64%	48.36%	37.11%	62.89%	26.67%	73.33%
	Tubing hanger	136.2	0.007	99.27%	0.73%	96.40%	3.60%	92.92%	7.08%	89.57%	10.43%	86.34%	13.66%
	DHSV	2.7	0.374	68.76%	31.24%	15.37%	84.63%	2.36%	97.64%	0.36%	99.64%	0.06%	99.94%
	Gas Lift System	1.2	0.822	43.94%	56.06%	1.64%	98.36%	0.03%	99.97%	0.00%	100.00%	0.00%	100.00%
	Upper completion	9.1	0.110	89.57%	10.43%	57.65%	42.35%	33.24%	66.76%	19.16%	80.84%	11.05%	88.95%
	Intermediate completion	136.2	0.007	99.27%	0.73%	96.40%	3.60%	92.92%	7.08%	89.57%	10.43%	86.34%	13.66%
	Lower completion	136.2	0.007	99.27%	0.73%	96.40%	3.60%	92.92%	7.08%	89.57%	10.43%	86.34%	13.66%
	Sand control	136.2	0.007	99.27%	0.73%	96.40%	3.60%	92.92%	7.08%	89.57%	10.43%	86.34%	13.66%
	Casing	12.4	0.081	92.24%	7.76%	66.77%	33.23%	44.59%	55.41%	29.77%	70.23%	19.88%	80.12%
	HPU / logic	9.7	0.103	90.23%	9.77%	59.81%	40.19%	35.77%	64.23%	21.40%	78.60%	12.80%	87.20%
	System reliability (h_Asset 2) =	**0.5**	**2.11**	**12.16%**		**0.00%**		**0.00%**		**0.00%**		**0.00%**	
Asset 3	Surface tree	14.8	0.068	93.46%	6.54%	71.29%	28.71%	50.83%	49.17%	36.23%	63.77%	25.83%	74.17%
	Wellhead	84.4	0.012	98.82%	1.18%	94.25%	5.75%	88.83%	11.17%	83.72%	16.28%	78.91%	21.09%
	Tubing hanger	118.2	0.008	99.16%	0.84%	95.86%	4.14%	91.89%	8.11%	88.08%	11.92%	84.43%	15.57%
	DHSV	29.6	0.034	96.67%	3.33%	84.43%	15.57%	71.29%	28.71%	60.20%	39.80%	50.83%	49.17%
	Gas lift system	6.5	0.154	85.76%	14.24%	46.40%	53.60%	21.53%	78.47%	9.99%	90.01%	4.63%	95.37%
	Upper completion	20.4	0.049	95.21%	4.79%	78.24%	21.76%	61.22%	38.78%	47.90%	52.10%	37.48%	62.52%
	Intermediate completion	591.0	0.002	99.83%	0.17%	99.16%	0.84%	98.32%	1.68%	97.49%	2.51%	96.67%	3.33%
	Lower completion	591.0	0.002	99.83%	0.17%	99.16%	0.84%	98.32%	1.68%	97.49%	2.51%	96.67%	3.33%
	Sand control	591.0	0.002	99.83%	0.17%	99.16%	0.84%	98.32%	1.68%	97.49%	2.51%	96.67%	3.33%
	Casing	42.2	0.024	97.66%	2.34%	88.83%	11.17%	78.91%	21.09%	70.10%	29.90%	62.27%	37.73%
	HPU / logic	42.2	0.024	97.66%	2.34%	88.83%	11.17%	78.91%	21.09%	70.10%	29.90%	62.27%	37.73%
	System reliability (h_Asset 3) =	**2.7**	**0.38**	**68.60%**		**15.19%**		**2.31%**		**0.35%**		**0.05%**	

From Table 31, the reliability based on all three assets are presented. From the table, and based on year 1, the fowling should be highlighted;

- “Surface tree” system is the only system with reliability lower than 90%.
- A considerable amount of systems has reliability of over 98%.
- The remaining has reliability between 90% and 98%, which should also be considered good.
- Overall asset performance is 61.6%.

Table 31 – Summary equipment reliability for all assets

	Description	MTTF	λ	Reliability for time duration (years): 1		5		10		15		20	
				pi	qi	pi	qi	pi	qi	pi	qi	pi	qi
Company Summary	Surface tree	6.5	0.2	85.68%	14.32%	46.18%	53.82%	21.32%	78.68%	9.85%	90.15%	4.55%	95.45%
	Wellhead	48.3	0.021	97.95%	2.05%	90.17%	9.83%	81.31%	18.69%	73.32%	26.68%	66.12%	33.88%
	Tubing hanger	91.3	0.011	98.91%	1.09%	94.67%	5.33%	89.63%	10.37%	84.85%	15.15%	80.33%	19.67%
	DHSV	10.3	0.097	90.72%	9.28%	61.46%	38.54%	37.78%	62.22%	23.22%	76.78%	14.27%	85.73%
	Gas lift system	24.2	0.041	95.95%	4.05%	81.31%	18.69%	66.12%	33.88%	53.76%	46.24%	43.72%	56.28%
	Upper completion	12.5	0.080	92.28%	7.72%	66.93%	33.07%	44.79%	55.21%	29.98%	70.02%	20.06%	79.94%
	Intermediate completion	821.8	0.001	99.88%	0.12%	99.39%	0.61%	98.79%	1.21%	98.19%	1.81%	97.60%	2.40%
	Lower completion	410.9	0.002	99.76%	0.24%	98.79%	1.21%	97.60%	2.40%	96.42%	3.58%	95.25%	4.75%
	Sand control	273.9	0.004	99.64%	0.36%	98.19%	1.81%	96.42%	3.58%	94.67%	5.33%	92.96%	7.04%
	Casing	74.7	0.013	98.67%	1.33%	93.53%	6.47%	87.47%	12.53%	81.81%	18.19%	76.51%	23.49%
	HPU / logic	17.1	0.058	94.33%	5.67%	74.67%	25.33%	55.76%	44.24%	41.64%	58.36%	31.09%	68.91%
	System reliability (h_Company Summary) =	**2.1**	**0.5**	**61.61%**		**8.88%**		**0.79%**		**0.07%**		**0.01%**	

4.3 Well Reliability

The purpose of this section is to present the well reliability data calculated.

4.3.1 Well Reliability related to Well Equipment Failures

If any of the Level A equipment groups fail, the well has to shut-in or have some impairment causing a deferrals. Thus, all Level A equipment groups are in series. The system reliability is therefore calculated by series structure. Figure 20 illustrates how the sub-systems are combined in a series structure.

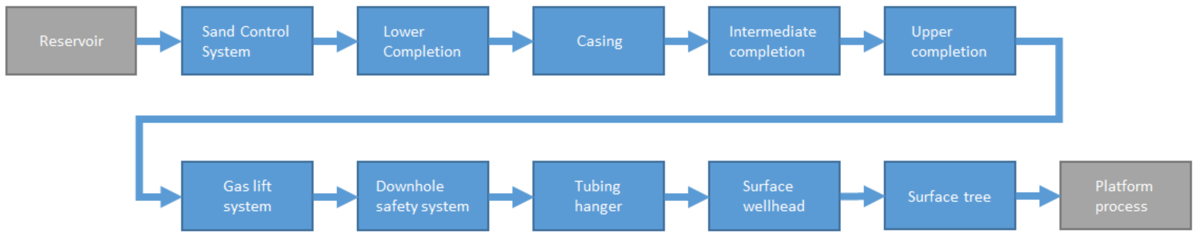


Figure 20 – Series structure of well components

With the data from the table above, the system's reliability is calculated utilizing the following equation:

$$h = \prod_{i=1}^{n} p_i$$

Therefore, to calculate the reliability of the given system,

h_asset = (p_sandcontrol) x (p_lower_compltion) x (p_casing) x (p_intermediate_completion) x (p_upper_completion) x (p_gl_system) x (p_dhsv) x (p_tubing_hanger) x (p_wellhead) x (p_tree)

The results from the system availability calculations are presented in Table 30. From the table, the following should be highlighted;

- system reliability of Asset 1 is 55.9%.
- system reliability of Asset 2 is 23.2%.
- system reliability of Asset 3 is 68.6%.
- Asset 1 and Asset 3 have more similar reliability than Asset 2.
- Asset 2 is less than half as reliable as the other two assets.

- The biggest variation between Asset 1 and 3 compared to Asset 2 is Asset 2's poor reliability of the "Surface tree" and "DHSV" groups.

4.3.2 Well reliability utilizing WellMaster data

As discussed in Section 3.3, generating a Company specific well, based on equipment which will cause deferrals, and populating it with WellMaster reliability data for this equipment, an industry expected average can be calculate for comparison. Based on the pre-defined generic well assembly, the WellMaster equipment reliability data can be collected. Utilizing WellMaster's reliability data, filters are available when calculating the reliability. The following filter options were applied to the WellMaster reliability calculations;

- *Fluid types: Produced oil and Produced oil with gas lift*; these were selected to only obtain information with respect to oil producing wells, and exclude reliability of injection and gas producing wells.
- *Reservoir pressure and temperature*: Conventional; this filters out application for high pressure (HP) and high temperature (HT). None of the wells form the PPIT system are assumed to be HP&HT wells.
- *Installation date range: From June 1st, 2001 up to February 21st, 2016*; the start date was chosen to be five years prior to the start of the PPIT data collected. This because all equipment logged on the first day of PPIT data set were installed prior to the given date. Thus, a date five years earlier was selected. The start date was selected based on the assumption that equipment becomes more reliable as time progresses, thus it was chosen not to utilize data from much earlier. The ends date was chosen to be the same as it is for the PPIT data base.

Table 32 presents the reliability data calculated using WellMaster. For the items assigned a MTBF of "0", no reliability data was available. As there are no specific data available for these equipment groups, they are assumed to be always working.

The HPU data is collected for subsea wells. The same is the XMT data. The rest of the data was calculated for surface wells.

From Table 32, the following should be highlighted;

- "HPU/logic" and "GLV" have the lowest MTBF.
- "DHSV" and "TR-ASV" have low MTBF compared to the other groups.
- "Production wing valve" has considerably lower MTBF than "ESD Valve", both are surface valve.
- "Production packer" has the highest MTBF of all components.

Table 32 – Generic Company well with WellMaster reliability data

		Production Critical Components	WellMaster nomenclature	MTTF (years)
WellMaster Reliability Data	Production	HPU / logic	HPU (subsea)	5.45
		XMT cap	Tree connection	306.38
		Choke	XMT - Choke valve	142.13
		Swab valve	PSV	0
		Production wing valve	PWV	91.45
		Kill valve	KV	0
		Upper Master Valve	PMV	54.97
		Tree flange connection	Wellhead connector	306.38
		Wellhead	Wellhead	0
		Tubing hanger system	Tubing hanger vertical	210.5
		DHSV	TRSCSSV	15.1
		Unloading IPO	Unloading GLV	116.71
		GLV	Operational GLV	7.06
		DMY GLV	Dummy GLV	358.94
		Tubing string	Tubing	358.71
		Production packer	Production Packer	676.61
		Surface casing	Surface Casing	0
	Annulus	ESD Valve	AMW	297.26
		Tubing hanger system	Tubing hanger vertical	0
		Casing hanger	Not found	0
		Surface casing	Surface Casing	0
		Tubing	Tubing	0
		TR-SCASSV assembly	TRSCASSV assembly	18.07
		Production packer	Production Packer	0

The "Tubing hanger system", "Surface casing", "Tubing" and "Production Packer" are required for both the "Production" and "Annulus" side. These values are color coded to reflect where they are listed twice in the Table 32. In order for the values not be duplicated, they are assigned the WellMaster RMS value in the "Production" section and the value of zero in the "Annulus" section and assigned.

Furthermore, to calculate the reliability of the components, the following pre-defined equation is utilized;

$$Reliability = e^{-\lambda t}$$

Where “t” is the timespan and λ failure rate, which is the inverse of MTBF. “t” is chosen to be one year for the calculations presented in Table 33. “pi” is the component reliability. “qi” is the component unreliability. More calculations with different timespans are presented in Appendix D.

Table 33 shows the reliability equipment based on WellMaster data. From the table, the following should be highlighted;

- “HPU” and “GLV” have component reliability of less than 90%.
- “DHSV” and “TR-ASV” have reliability of less than 95%.
- The well reliability is nearly 60%.
- Measures should be taken to review the components with low reliability to increase the overall reliability of the well.

Table 33 – Generic Company well reliability data

		Production Critical Components	WellMaster nomenclature	MTTF (years)	λ	pi	qi
WellMaster Reliability Data	Production	HPU / logic	HPU (subsea)	5.45	0.1835	83.24%	16.76%
		XMT cap	Tree connection	306.38	0.0033	99.67%	0.33%
		Choke	XMT - Choke valve	142.13	0.0070	99.30%	0.70%
		Swab valve	PSV	0		100.00%	0.00%
		Production wing valve	PWV	91.45	0.0109	98.91%	1.09%
		Kill valve	KV	0		100.00%	0.00%
		Upper Master Valve	PMV	54.97	0.0182	98.20%	1.80%
		Tree flange connection	Wellhead connector	306.38	0.0033	99.67%	0.33%
		Wellhead	Wellhead	0		100.00%	0.00%
		Tubing hanger system	Tubing hanger vertical	210.5	0.0048	99.53%	0.47%
		DHSV	TRSCSSV	15.1	0.0662	93.59%	6.41%
		Unloading IPO	Unloading GLV	116.71	0.0086	99.15%	0.85%
		GLV	Operational GLV	7.06	0.1416	86.79%	13.21%
		DMY GLV	Dummy GLV	358.94	0.0028	99.72%	0.28%
		Tubing string	Tubing	358.71	0.0028	99.72%	0.28%
		Production packer	Production Packer	676.61	0.0015	99.85%	0.15%
		Surface casing	Surface Casing	0		100.00%	0.00%
	Annulus	ESD Valve	AMW	297.26	0.0034	99.66%	0.34%
		Tubing hanger system	Tubing hanger vertical	0		100.00%	0.00%
		Casing hanger	Not found	0		100.00%	0.00%
		Surface casing	Surface Casing	0		100.00%	0.00%
		Tubing	Tubing	0		100.00%	0.00%
		TR-SCASSV assembly	TRSCASSV assembly	18.07	0.0553	94.62%	5.38%
		Production packer	Production Packer	0		100.00%	0.00%
		System reliability (h_WM) =		**1.95**	**0.5131**	**59.86%**	

To be able to better compare WellMaster data with the data collected from the PPIT system, the WellMaster data will be grouped according to the *Equipment Level A* groups defined earlier. The following WellMaster components were combined into the given *Equipment Level A* groups:

- Surface tree is made up of;
  - XMT cap
  - Choke
  - Swab valve
  - Production wing valve
  - Kill valve
  - Upper Master Valve
  - Tree flange connection

- Wellhead is made up of;
    - Wellhead
- DHSV is made up of;
    - DHSV
- Gas Lift System is made up of;
    - Unloading
    - GLV
    - DMY
    - ESD Valve
    - TR-SCASSV assembly
- Upper completion is made up of;
    - Production packer
    - Tubing string
- HPU/logic is made up of;
    - HPU/logic
- The following *Equipment Level A* groups did not have components found in WellMaster;
    - Intermediate completion
    - Lower completion
    - Sand control
    - Casing

All the components in each *Equipment Level A* group are assumed to be in series. Thus, the reliability of the new groups were calculated utilizing series structure. Table 34 presents the reliability of the new groups. From the table, the following should be highlighted;

- "Gas lift system" and "HPU/logic" are the only groups with reliability less than 80%.
- "DHSV" and "TR-ASV" have reliability of less than 95%.
- System reliability is nearly 60%.
- The grouping did not cause major alterations in reliability.

Table 34 – Generic Company well in Equipment Level A groups

Equipment Level A	pi
Surface tree	0.958
Wellhead	1.000
Tubing hanger	0.995
DHSV	0.936
Gas Lift System	0.809
Upper completion	0.996
Intermediate completion	1.000
Lower completion	1.000
Sand control	1.000
Casing	1.000
HPU / logic	0.832
Total	**0.599**

4.3.3 Survival probability

The survival probability, S(t), is the ratio of units which will remain in the functional state beyond a given time. These probabilities are frequently referred to as reliability estimates. These values can "… determine whether your product meets reliability requirements…" (Minitab, 2016).

The survival probabilities for the components from WellMaster can is calculated utilizing the survival probability tools of WellMaster. For this thesis, the survival probability is assumed to be the expected reliability of the component at the given time "t", where t = 1, and "t" is expressed in years. Thus the S(t) is the probability of the component remaining in operational state after the first year.

From well Master, applying the same filters as discussed earlier, the survival probabilities are presented in Table 36. From the table, the following should be highlighted;

- "DHSV" and "GLV" has S(t) of less than 90% over one year.
- The other components are in the mid to high 90%.

Table 35 – S(t) for Generic Company well with WellMaster reliability data

Acceptable reliability	S(t)
HPU / logic	1
XMT cap	1
Choke	0.982
Swab valve	1
Production wing valve	0.988
Kill valve	1
UMV	0.983
Tree flange connection	1
Wellhead	1
Tubing hanger system	0.998
DHSV	0.864
Tubing string	0.996
Unloading	0.992
GLV	0.793
DMY	0.998
Production packer	0.997
Surface casing	1
ESD Valve	0.981
Tubing hanger system	1
Casing hanger	1
Surface casing	1
Tubing	1
TR-SCASSV assembly	0.944
Production packer	1

In Table 35, the gray cells highlights that the system was unable to identify the survival probability. Therefore, the components are assigned the value of one. The other colors indicates where components are listed twice. This is the same color coding as utilized in earlier sections.

In order to compare these values to the *Equipment Level A*, values has to be grouped as in the previous section. These are combined with series structure. The S(t) for the *Equipment Level A* groups are presented in Table 36.

Table 36 – S(t) for generic Company well with Equipment Level A groups

Equipment Level A	S(t)
Surface tree	**0.954**
Wellhead	**1.000**
Tubing hanger	**0.998**
DHSV	**0.864**
Gas Lift System	**0.727**
Upper completion	**0.993**
Intermediate completion	**1.000**
Lower completion	**1.000**
Sand control	**1.000**
Casing	**1.000**
HPU / logic	**1.000**
Total	**0.594**

For this thesis, the S(t) is given upper level (UL) and lower level (LL) to generate an expected probability range for the components. The is chosen to be UL = +3% and LL = -3%. The percentage chosen for the bounds is a chosen number and may not be of statistical accuracy. Table 37 shows the assigned acceptance ranges for each *Equipment Level A* group.

Table 37 – Acceptance ranges for equipment groups based on WellMaster data

Equipment Level A	pi (WM)	S(t)	UL	R(t)	LL
Surface tree	0.958	0.954	98%	95%	93%
Wellhead	1.000	1.000	100%	100%	97%
Tubing hanger	0.995	0.998	100%	100%	97%
DHSV	0.936	0.864	89%	86%	84%
Gas Lift System	0.809	0.727	75%	73%	71%
Upper completion	0.996	0.993	100%	99%	96%
Intermediate completion	1.000	1.000	100%	100%	97%
Lower completion	1.000	1.000	100%	100%	97%
Sand control	1.000	1.000	100%	100%	97%
Casing	1.000	1.000	100%	100%	97%
HPU / logic	0.832	1.000	100%	100%	97%
Total	**0.599**	**0.594**	**61%**	**59%**	**58%**

From Table 37 , is shows that there is low difference between the WellMaster reliability (pi WM) and the S(t) of the generic well. This is as expected as both are generated from the same data set, thus should yield similar results. The only major difference is the lack of data on the "HPU/logic" category. Both "DHSV" and "Gas Lift System" differentiate, but all less than 10%. Thus the S(t) can be used synonymous with R(t).

4.3.4 Comparing reliability

The PPIT reliability data is compared to the reliability of the generic well calculated utilizing WellMaster data. The WellMaster well is assumed to represent an industry average well performance, as the data collected is based on input from operators around the world.

Table 38 compares Company reliability data to the defined acceptance criteria for reliability of the components. This is done by verifying if the Asset's reliability performance is within the expected range defined by UL and LL.

Table 38 – Comparing Company's assets to acceptance range

Equipment Level A	pi	S(t)	UL	R(t)	LL	All Assets		Asset 1		Asset 2		Asset 3	
Surface tree	0.958	0.954	98%	95%	93%	85.68%	Lower	84.43%	Lower	59.37%	Lower	93.46%	OK
Wellhead	1.000	1.000	100%	100%	97%	97.95%	OK	98.95%	OK	93.61%	Lower	98.82%	OK
Tubing hanger	0.995	0.998	100%	100%	97%	98.91%	OK	98.95%	OK	99.27%	OK	99.16%	OK
DHSV	0.936	0.864	89%	86%	84%	90.72%	Above	89.96%	Above	68.76%	Lower	96.67%	Above
Gas Lift System	0.809	0.727	75%	73%	71%	95.95%	Above	89.89%	Above	43.94%	Lower	85.76%	Above
Upper completion	0.996	0.993	100%	99%	96%	92.28%	Lower	97.91%	OK	89.57%	Lower	95.21%	Lower
Intermediate completion	1.000	1.000	100%	100%	97%	99.88%	OK	98.95%	OK	99.27%	OK	99.83%	OK
Lower completion	1.000	1.000	100%	100%	97%	99.76%	OK	97.91%	OK	99.27%	OK	99.83%	OK
Sand control	1.000	1.000	100%	100%	97%	99.64%	OK	97.91%	OK	99.27%	OK	99.83%	OK
Casing	1.000	1.000	100%	100%	97%	98.67%	OK	98.95%	OK	92.24%	Lower	97.66%	OK
HPU / logic	0.831	1.000	100%	100%	97%	94.33%	Lower	90.92%	Lower	90.23%	Lower	97.66%	OK
Total	**0.598**	**0.594**	**61%**	**59%**	**58%**	**61.61%**	**Above**	**55.85%**	Lower	**12.16%**	**Lower**	**68.60%**	**Above**

From Table 38, it shows that the component performance of Asset 1 is generally above or within the expected average, with two exceptions. Those are the "Surface tree" and "HPU/logic". With these two being lower than the expected range, the total performance of the asset is lower than the expected average.

The component performance of Asset 2 is worse than Asset 1. It has seven groups which are lower than average and four within the anticipated expected range. This results in an overall asset performance of lower than average. The major contributor here is the "Surface tree" at 59% and "Gas lift system" at only 44%.

The component performance of Asset 3 is the considered good. Only one component is performing lower than the anticipated average. Three are performing above average and the rest is within the anticipated expected range.

That means that Company systems, based on the PPIT data, and compared to the WellMaster data, is performing above the expected range.

The component performance of all assets are varying between all three categories. Two categories are above, six are within the range and three are lower than the average. This yields an overall performance of higher than the expected range and average.

4.4 System availability

The system availability of the assets considers the reliability and maintainability of the asset. Both the reliability data and maintainability data is collected from the PPIT system. Based on the data collected, the availability of the assets can be calculated. The availability is calculated by utilizing the following formula:

$$A_i = \frac{MTBF}{MTBF + MTTR}$$

Table 39 presents the results from the calculations. From the table, it shows that even though the reliability of Asset 1 and 3 were significantly higher than that of Asset 2, the well equipment availability of all assets are in the middle to upper 90th percentile.

From the table, the following should be highlighted;

The availability for Asset 1 is;

- Asset 1 obtained well equipment availability of 95.0%.
- Asset 1 obtained a non-well equipment availability of 95.9%.
- Asset 1 obtained a reservoir availability of 95.6%.
- Asset 1 obtained an overall availability of 87.6%.

The availability of Asset 2 is;

- Asset 2 obtained well equipment availability of 92.3%.
- Asset 2 obtained a non-well equipment availability of 95.3%.
- Asset 2 obtained a reservoir availability of 92.2%.
- Asset 2 obtained an overall availability of 82.5%

The availability of Asset 3 is;

- Asset 3 obtained well equipment availability of 96,3%.
- Asset 3 obtained a non-well equipment availability of 98.9%
- Asset 3 obtained a reservoir availability of 96.1%
- Asset 3 obtained an overall availability of 92.2%

Table 39 – Availability of company assets

		Level A Equipment Group	# of deferrals	Deferred production (MBOE)	Deferral duration (year)	λ	MTBF (year)	MTTR (year)	Availability (%)
Asset 1	Unplanned equipment failure deferrals	Surface tree	16	201	0.214	0.169	5.91	0.013	99.77%
		Wellhead	1	1	0.003	0.011	94.55	0.003	100.00%
		Tubing hanger	1	30	0.036	0.011	94.55	0.036	99.96%
		DHSV	10	2,709	2.207	0.106	9.45	0.221	97.72%
		Gas lift system	10	1,464	2.163	0.107	9.39	0.216	97.75%
		Upper completion	2	20	0.019	0.021	47.27	0.010	99.98%
		Intermediate completion	-	-	0.000	-	94.55	0.000	100.00%
		Lower completion	2	290	0.192	0.021	47.27	0.096	99.80%
		Sand control	2	42	0.079	0.021	47.27	0.040	99.92%
		Casing	-	-	0.000	-	94.55	0.000	100.00%
		HPU / logic	9	40	0.057	0.095	10.51	0.006	99.94%
		Unplanned equipment failure deferrals	53	4,797.9	4.97	0.561	1.78	0.094	95.0%
		Non-well equipment failure deferrals	165	3,151.2	4.05	1.745	0.57	0.025	95.9%
		Reservoir issues deferrals	84	2,380.4	4.34	0.888	1.13	0.052	95.6%
		Total	**302**	**10,330**	**13.4**	**3.19**	**0.31**	**0.04**	**87.6%**
Asset 2	Unplanned equipment failure deferrals	Surface tree	71	359	0.85	0.521	1.92	0.012	99.38%
		Wellhead	9	210	0.175	0.066	15.13	0.019	99.87%
		Tubing hanger	1	11	0.052	0.007	136.19	0.052	99.96%
		DHSV	51	2,253	3.080	0.374	2.67	0.060	97.79%
		Gas lift system	24	357	0.487	0.822	1.22	0.020	98.36%
		Upper completion	15	2,537	2.995	0.110	9.08	0.200	97.85%
		Intermediate completion	-	-	0.000	-	136.19	0.000	100.00%
		Lower completion	-	-	0.000	-	136.19	0.000	100.00%
		Sand control	-	-	0.000	-	136.19	0.000	100.00%
		Casing	11	129	0.104	0.081	12.38	0.009	99.92%
		HPU / logic	14	18	0.079	0.103	9.73	0.006	99.94%
		Unplanned equipment failure deferrals	196	5,874	7.82	2.085	0.48	0.040	92.3%
		Non-well equipment failure deferrals	378.00	4509.41	6.74	2.78	0.36	0.018	95.3%
		Reservoir issues deferrals	218.00	4339.07	11.47	1.60	0.62	0.053	92.2%
		Total	**792**	**14,723**	**26.0**	**6.46**	**0.15**	**0.03**	**82.5%**
Asset 3	Unplanned equipment failure deferrals	Surface tree	40	683	1.388	0.068	14.78	0.035	99.77%
		Wellhead	7	149	0.580	0.012	84.43	0.083	99.90%
		Tubing hanger	5	282	0.903	0.008	118.21	0.181	99.85%
		DHSV	20	927	2.193	0.034	29.55	0.110	99.63%
		Gas lift system	19	637	1.391	0.154	6.51	0.073	98.89%
		Upper completion	29	2,832	6.864	0.049	20.38	0.237	98.85%
		Intermediate completion	-	-	0.000	-	591.04	0.000	100.00%
		Lower completion	-	-	0.000	-	591.04	0.000	100.00%
		Sand control	1	25	0.068	0.002	591.04	0.068	99.99%
		Casing	14	545	1.654	0.024	42.22	0.118	99.72%
		HPU / logic	14	120	0.131	0.024	42.22	0.009	99.98%
		Unplanned equipment failure deferrals	149	6,199	15.17	0.374	2.68	0.102	96.3%
		Non-well equipment failure deferrals	504	4063	6.66	0.85	1.17	0.013	98.9%
		Reservoir issues deferrals	107	6745	19.10	0.18	5.52	0.179	96.9%
		Total	**760**	**17,007**	**40.9**	**1.41**	**0.71**	**0.054**	**93.0%**

Based on the information gathered from PPIT, the combined availability of the Company's well equipment is 96.7%. This yields a high percentage of well equipment available for production. The following data is gathered from the Company's performance;

- Combined Assets obtained well equipment availability of 96.7%.
- Combined Assets obtained a non-well equipment availability of 98.6%
- Combined Asset obtained a reservoir availability of 95.3%
- Combined Assets obtained an overall availability of 91.1%

Table 40 – Overall availability for company assets

	Level A Equipment Group	# of deferrals	Deferred production (MBOE)	Deferral duration (year)	λ	MTBF (year)	MTTR (year)	Avaiability (%)
Summary – Unplanned equipment failure deferrals	Surface tree	127	1,243	2.453	0.155	6.47	0.019	99.70%
	Wellhead	17	359	0.758	0.021	48.34	0.045	99.91%
	Tubing hanger	9	438	0.991	0.011	91.31	0.110	99.88%
	DHSV	80	5,889	7.480	0.097	10.27	0.093	99.10%
	Gas lift system	34	1,899	4.041	0.041	24.17	0.119	99.51%
	Upper completion	66	5,948	9.878	0.080	12.45	0.150	98.81%
	Intermediate completion	-	-	0.000	-	821.78	0.000	100.00%
	Lower completion	2	290	0.192	0.002	410.89	0.096	99.98%
	Sand control	3	67	0.148	0.004	273.93	0.049	99.98%
	Casing	11	490	1.758	0.013	74.71	0.160	99.79%
	HPU / logic	48	360	0.268	0.058	17.12	0.006	99.97%
	Unplanned equipment failure deferrals	398	16,871	27.97	0.483	2.07	0.070	96.7%
	Non-well equipment failure deferrals	1,047	11,724	17.45	1.274	0.78	0.017	98.6%
	Reservoir issues deferrals	409	13,464	34.91	0.498	2.01	0.085	95.3%
	Total	**1,854**	**42,059**	**80.3**	2.255	0.44	**0.04**	**91.1%**

Chart 7 shows how the MTBF effects reliability and availability of the total system. As the MTBF increases, so do the reliability and availability of the system. The chart shows how little impact a fluctuating MTBF and R(t) has on the overall Availability of the system. Thus showing that Availability is more than just reliability of equipment.

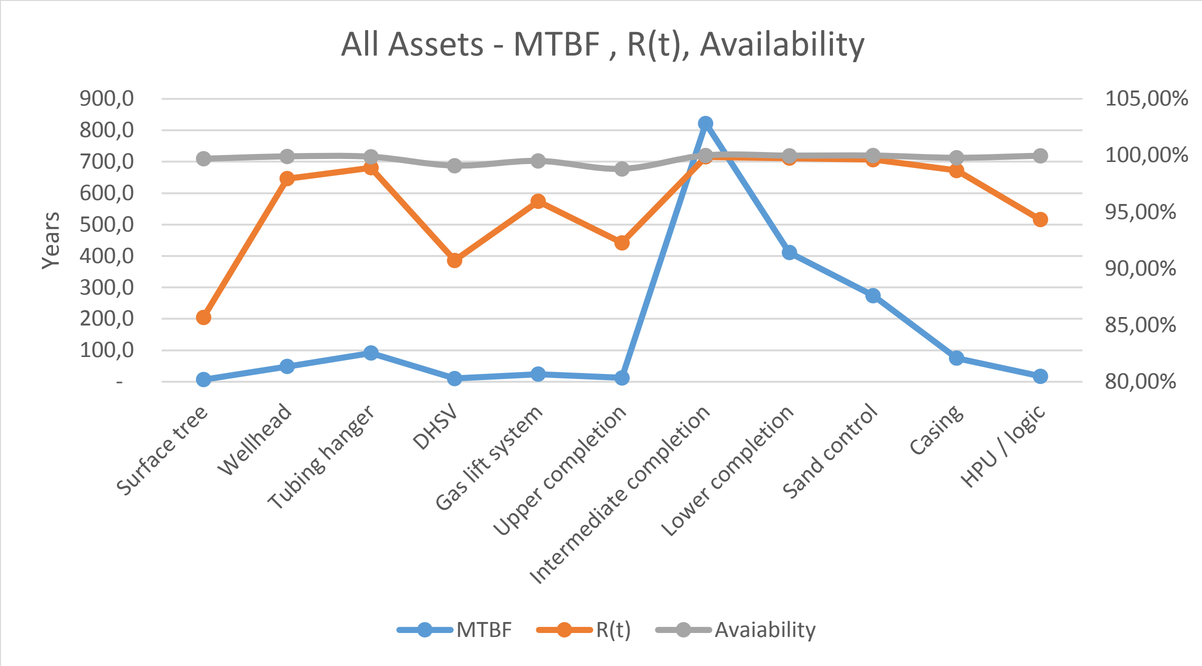


Chart 7 – All assets – MTBF, R(t), Availability

Chart 8 shows how the MTBF and MTTR effects the availability of the system. MTBF is based on left axis, and the other two on the right axis. For "Intermediate Completion", it shows how low MTTR and high MTBF yields the highest Availability.

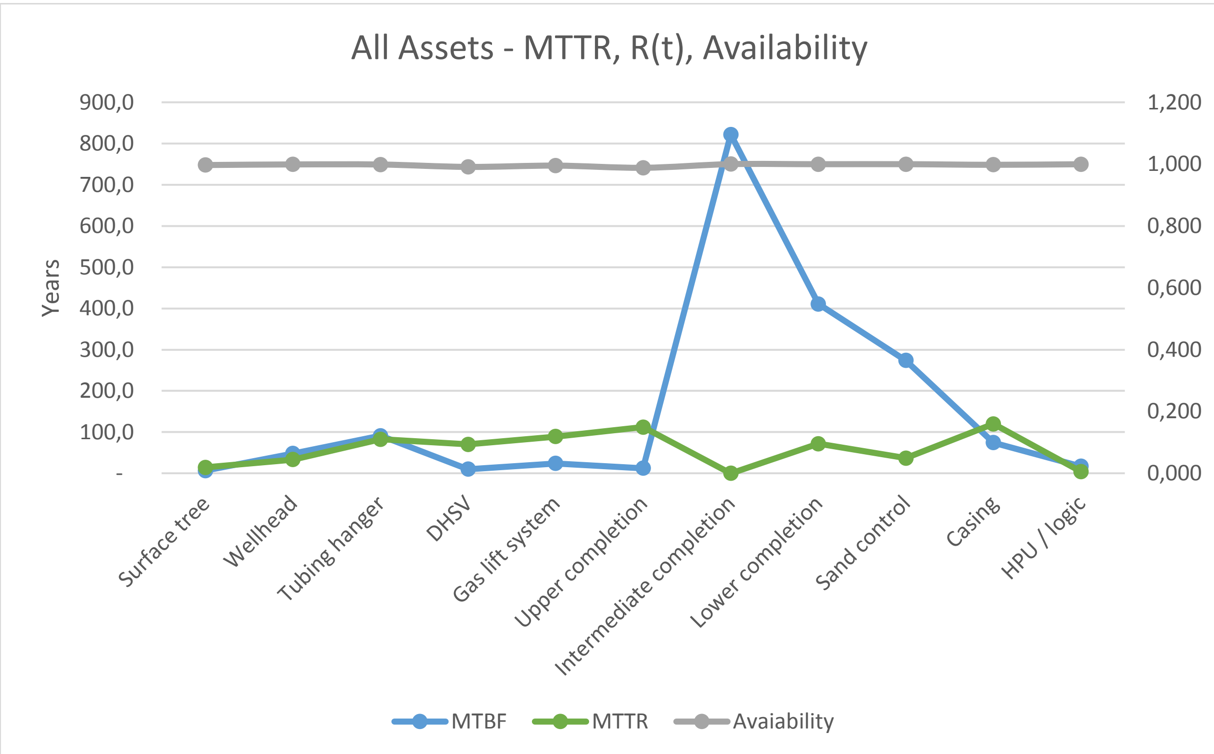


Chart 8 – All assets – MTTR, R(t), Availability

Chart 9 shows how the MTBF, MTTR and pi effects the availability of the system.

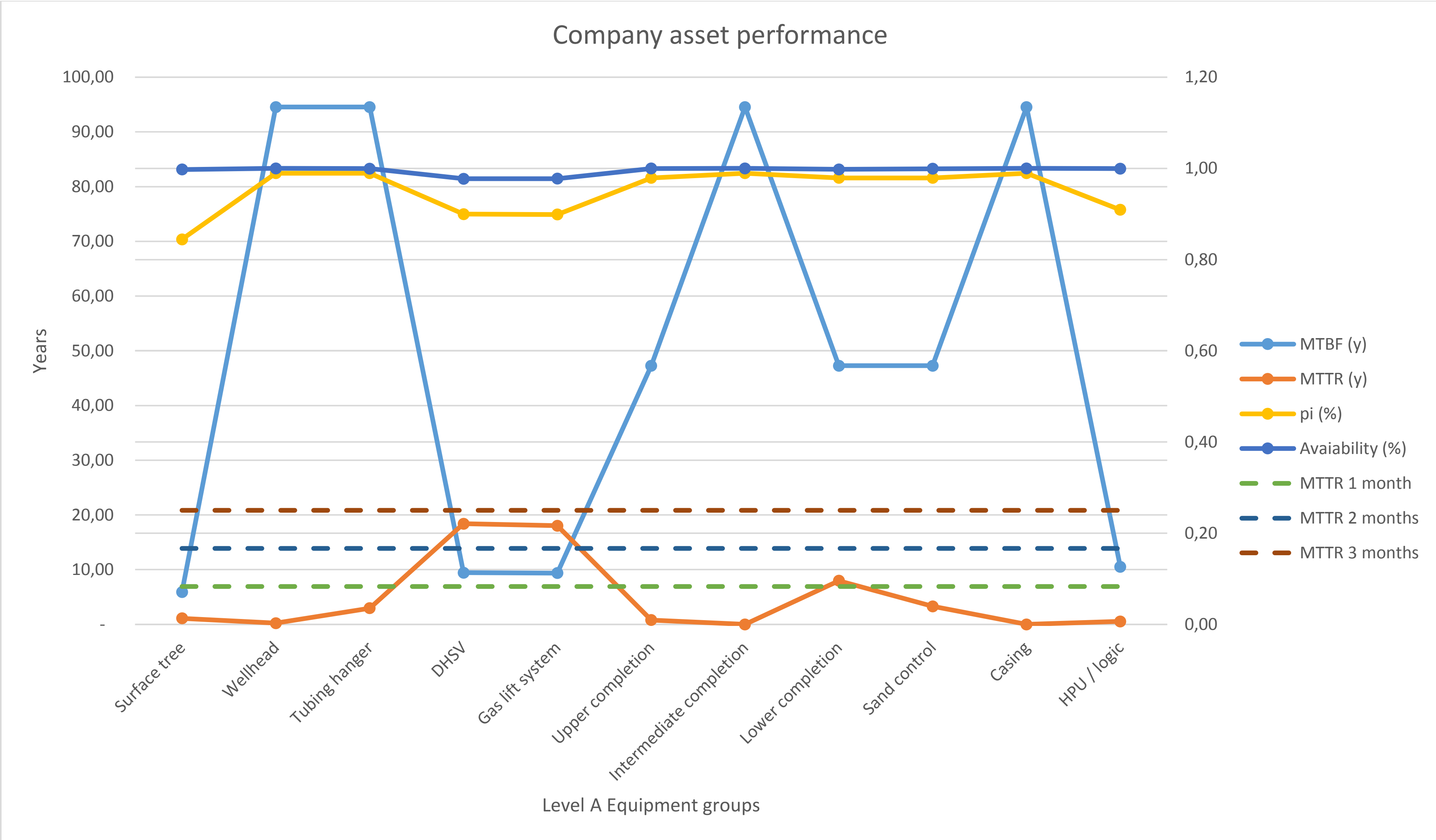


Chart 9 – Company asset performance

From the graphs above, the following observations can be made of how the MTBF and MTTR affects the Availability of a well.

Table 41 – Summay table of relationship between MTBF, MTTR and Availability

MTBF	**MTTR**	**Availability**
Increases	Decreases	Increases more
Increases	Constant	Increases
Increases	Increases	Depends
Constant	Decreases	Decreases
Constant	Constant	Constant
Constant	Increases	Decreases
Decreases	Decreases	Depends
Decreases	Constant	Decreases
Decreases	Increases	Decreases

5 Discussion of results

The purpose of this section is to discuss the findings presented in Section 4.

5.1 Deferral type – what shuts-in a well?

The purpose of this section is to discuss the types of shut-ins of well Company has experienced.

From section 4, two main groups of deferral types are the type of shut-in and deferral cause type. For the type of shut-in, it is either planned or unplanned shut-in. The types of causes of deferral is wither equipment failure, undefined and reservoir deferrals. This section will discuss the different outcome from the two groups of deferrals.

5.1.1 Planned vs Unplanned deferrals

For the shut-in type deferrals, it has been disclosed that a high percentage of the shut-ins percentage, by production volume deferred, are unplanned while a lower percentage of the production deferred is planned. From Table 21, 11% of Asset 1's deferred production volume is planned. For Asset 2 and 3, the planned deferred production volume is 16% and 21%.

Comparing the percentages of deferred production volume, a possible conclusion could be that Asset 3 plans to shut-in their wells more than the other two assets. Since the percentages is a ratio of unplanned vs planned deferrals, is it possible that Asset 3 just have less unplanned deferrals compared to the other two assets?

It is fair to assume that deferral due to unplanned shut-ins should be higher than planned shut-ins, as the operator only shuts-in the production when it is necessary. Based on the percentage of deferred volume per asset, it shows that the different assets operate with different ratios of planned vs unplanned deferrals. Asset 1's planned deferral ratio is half of that of Asset 3. Asset 2 is roughly the expected average as presented in Section 4.

From Table 42, Asset 3 defers on average 370,000 BOE yearly. Asset 2 defers on average 240,000 BOE yearly, while Asset 1 is nearly half of that at 145,000 BOE per year. As above, one possible conclusion could be that Asset 1 is outperforming Asset 2 and 3. But is this a correct conclusion?

From the same table, Asset 2 and 3 defers nearly 8,000 BOE on average per planned deferral. Asset 1 defers 11,300BOE on average per planned deferral. This is considerably more than the other two assets.

In order to compare the numbers, the number of available wells per asset has to be considered. As presented in Table 26, Asset 1 has 14 wells, Asset 2 has 17 wells and Asset 3 has 71 wells. Then Asset 1 defers on average 10,400 BOE per well per year, while Asset 2 defers 14,000 BOE. Asset 3 defers 5,200 BOE per well per year. Then Asset 3 is considerably lower than the other two assets.

Table 42 – Asset deferral performance per well

Asset	# of wells	Total Planned Deferrals	Total Planned Deferred Volume	Total Planned Deferral Duration	Average deferred volume per deferral	Average deferred volume per year	Average deferred volume per well per year
Asset 1	14	104	1,180	8.14	11.34	144.87	10.35
Asset 2	17	285	2,304	9.73	8.08	236.85	13.93
Asset 3	71	444	3,587	9.73	8.08	368.78	5.19

Comparing the percentages listed above with average deferral production per well, Asset 3 has higher ratio of planned deferrals, but it has the lowest production deferral per well. As the percentages are high, and deferrals per well are low, this indicates that Asset 3 does not have more planned deferrals, but it has less unplanned deferrals than the other two assets. Since Asset 3 has less unplanned deferred production, the planned deferred production is higher per percent, but not per volume per well.

The PPIT does not provide an overall view of the expected production output from the assets, it is difficult to conclude which asset actually defers the most volume in percentage based on the expected production. However, based on the information provided, Asset 3 plans to defer less volume per well than the other two assets. Asset 2 plans to defer the most per well of the three assets to perform activities in and around the well area.

5.1.2 Type of equipment failure

From Table 12, it shows by volume deferred, that 40% of all deferred volume is related to well production critical equipment failure. Further it shows that 32% of all production volume deferred is related to reservoir issues, such as scaling and low reservoir pressure. The same table also shows that 28% of all deferrals are related to other priorities, such as well barrier element testing and failure of production equipment. Therefore, 60% of the time the well has to shut-in, or reduced flow is not due to equipment failure of well equipment.

However, 28% of deferrals are also related to intervention work. Intervention work is often related to changing out downhole equipment or maintenance on surface equipment. Changing out topside or downhole equipment is most likely related to failure of equipment. Then the question is raised; is there a deferral for the failed equipment the intervention will change out? The assumption can be made that there is not a deferral for the equipment failure, as they would not need to defer the well twice, i.e. one for the equipment failure and one for the intervention.

Then the question becomes; why is there not a deferral for the equipment failure? By definition, a deferral is issued if it shuts-in the well. If the equipment failure does not cause the well to shut-in, it is deemed not production critical, then why change-out the equipment? If there are two deferrals issued, the production volume deferred is inaccurate as it will have been reported twice for the same well. Intervention deferrals, while planned, should be linked to the equipment failure it replaces, thus making the actual intervention deferral an unplanned deferral.

Though the above assumption is not always true, it is likely to be true in some cases. In addition to the above assumption, one reason why equipment failure does not have a deferral against it can be related to it not actually causes the well to shut-in. As discusses in the literature review section, NORSOK will allow the operator to continue to flow the well, if a well barrier has failed it's test, if it is assumed to be safer to produce than to shut-in the well. Thus, for some failures the well many continue to be produced until the failure can be fixed.

Performing this analysis ex post facto, relying on coding and assigning groups based on best engineering judgement at the time may yield inaccurate outcome. Therefore, Company should review how they address interventions in their PPIT system, as this accounts for xx percent deferral. There should be ways to easily identify if this work is related to well equipment failure, trouble with reservoir, preventative and reactive interventions and process equipment failure. Some of these are thought to be in place, based on the review of the raw data, but are inconsistent and does not match the free-text. Therefore, Company should review of how they are utilized and provide adequate training to ensure conformity and increase the quality of the data collected.

5.2 Reliability, Maintainability and Availability of systems

The purpose of this section is to discuss the relationship between Reliability, Maintainability and Availability of systems.

From the literature review, Availability is a combination of the reliability and maintainability of the system. As presented in Section 4, the reliability of Asset 1 is 56%, Asset 2 is 12% and Asset 3 is 69%, with an overall average reliability of 62%. This is calculated by interpreting the data from the PPIT system. The reliability is related to the time-interval between each system/well failure.

The maintainability of the system is calculated by interpreting other information found in the PPIT data set. By assuming that a deferral is placed for each day the deferral is active, the total duration of the deferrals can be calculated and a mean time to repair is obtained. This explains how long it took for the deferral to clear, i.e. fix or replace failed equipment. The MTTR is a performance indicator for how efficient Company is at attending their deferrals.

The two combined makes the availability of Asset 1 is 88%, Asset 2 is 83% and Asset 3 is 93%. vary from 83% to 93%, with an overall average performance of 91%. Comparing these to Reliability, there is a huge gap between reliability and availability. How is it possible to have such poor reliability and yet so high availability?

The goal of any operational company is to maximize on the uptime whiles minimizing the downtime. In other words, maximize the MTBF and minimize the MTTR. Chart 10 shows a generic graph utilizing an increasing MTBF and decreasing MTTR.

Chart 10 demonstrates the generic relationship between MTBF and MTTR. It is clear from the graph that the availability reaches 80% reasonably fast, and the latter 20% stretches over a longer period requiring bigger difference between MTBF and MTTR.

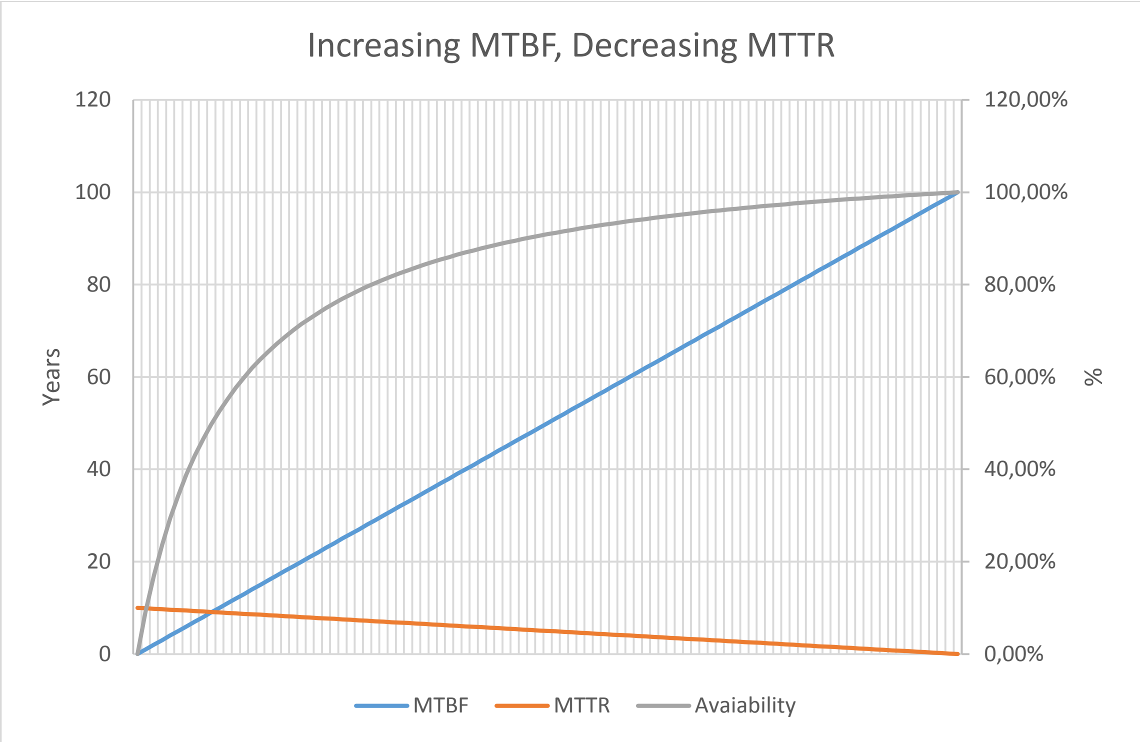


Chart 10 – Increasing MTBF and decreasing MTTR

Practical example

A practical interpretation of the relationship between reliability, maintainability and availability can be explained by using a car as an example. A car has certain components which has to work for the car to be in operational condition. One of these components is the car's spark plugs. The car is assumed to have four spark-plugs for the combustion engine to ignite and provide energy for propulsion. It also has four suspensions for a smooth and comfortable ride. Both groups of components are required for the car to operate. All components within the group has to be fully functional for the car to operate.

Case 1 - Assume the person has to change all four sparkplugs once a day. Then it is safe to assume that the sparkplugs have poor reliability. Changing all the sparkplugs takes less than half an hour and has to be done at a workshop. The workshop return trip is a half hour. Since the changing of the sparkplugs takes little time, having to change the sparkplugs daily will most likely not cause the person to lose the ability to utilize the car on a normal basis. With some simple planning, the person should be able to do everything he/she wants during a day. Therefore, poor reliability compiled with effective maintenance yields high availability.

Case 2 – Assume the person has to change all four suspensions once a day. Then it is safe to assume that the suspensions have poor reliability, just like the sparkplugs. However, changing the suspension takes around four hours and has to be done at a workshop –the same as in Case 1. This means that the person has to drive to the workshop once a day, and wait four hours each day, to be able to continue to use the car for the next 24 hours. This would obviously inconvenience the person as he/she would not have access to the car as much. Therefore, poor reliability complied with less effective maintenance yields lower availability.

Case 3 – The person has to perform both Case 1 and Case 2. This would further decrease the time the car is available during a 24 hour period.

In Case 1, the person may be able to learn how to change the plugs and perform this task at home. By keeping the right tools, obtaining the right skills and keeping a stock of parts, the person can easily change the sparkplugs to avoid having to drive to the shop each day to perform the work.

For Case 2, changing the suspensions may be difficult to do at home, therefore he/she may keep on relying on the service provided by the workshop. Since the person has to rely on the workshop, he/she should review the process with the workshop to try and identify areas of improvement. Managing to cut the repair time in half by implementing better planning and more efficient executions has a significant impact on the availability of the car.

To prove this, simple availability calculation, defined in the literature review, is performed. Availability is actual performance over potential performance. In this case performance is time the car is available for normal use.

For Case 1 – with workshop;

- Actual time: 24 hours - 0.5 hour – 0.5 hour = 23 hours
- The potential is 24 hours.
- Thus, the availability of the car is 96%.

For Case 1 – without workshop;

- Actual time: 24 hours - 0.5 hour = 23.5 hours
- The potential is 24 hours.
- Thus, the availability of the car is 98%.

For Case 2 – without workshop changes;

- Actual time: 24 hours - 0.5 hour – 4 hour = 19.5 hours
- The potential is 24 hours.
- Thus, the availability of the car is 81%.

For Case 2 – with workshop changes;

- Actual time: 24 hours - 0.5 hour – 2 hours = 21,5 hours
- The potential is 24 hours.
- Thus, the availability of the car is 90%.

Assuming the financial cost is the same for both the improvements suggestions, which should the person pick for Case 3 if he only could choose one? In Case 1, the improvements only increased the availability of the car with 2%. In Case 2, the improvements increased the availability by nearly 10%. Since Case 1 breaks often, but it is simple to fix, the improved version, cutting the repair time by 50%, only yields 2% increase. In Case 2, the repair time is much longer, therefore cutting it by nearly 50% increases the availability by nearly 10%.

From this example, one can appreciate that if the equipment breaks often, but is easy and fast to fix, there is little to gain from trying to improve the efficiency. However, if the component breaks often and it is more difficult and time-consuming to fix, there are more to gain from planning for the repair and investing in improving the repair. Therefore, lowering already low repair time provides little value for the availability of the system

This also applies to other assets, like Company's Asset 1, 2 and 3. Chart 11 shows the reliability of the equipment versus the time it takes to fix it. Cluster A consists of equipment which has lower reliability than 80%, which means that the expected frequency of failures are relatively high. Cluster A is only Asset 2 components, and the three components are;

- Gas lift system
- Surface tree
- DHSV

Cluster B has components which has reliability over 80%. This cluster will be further analyzed.

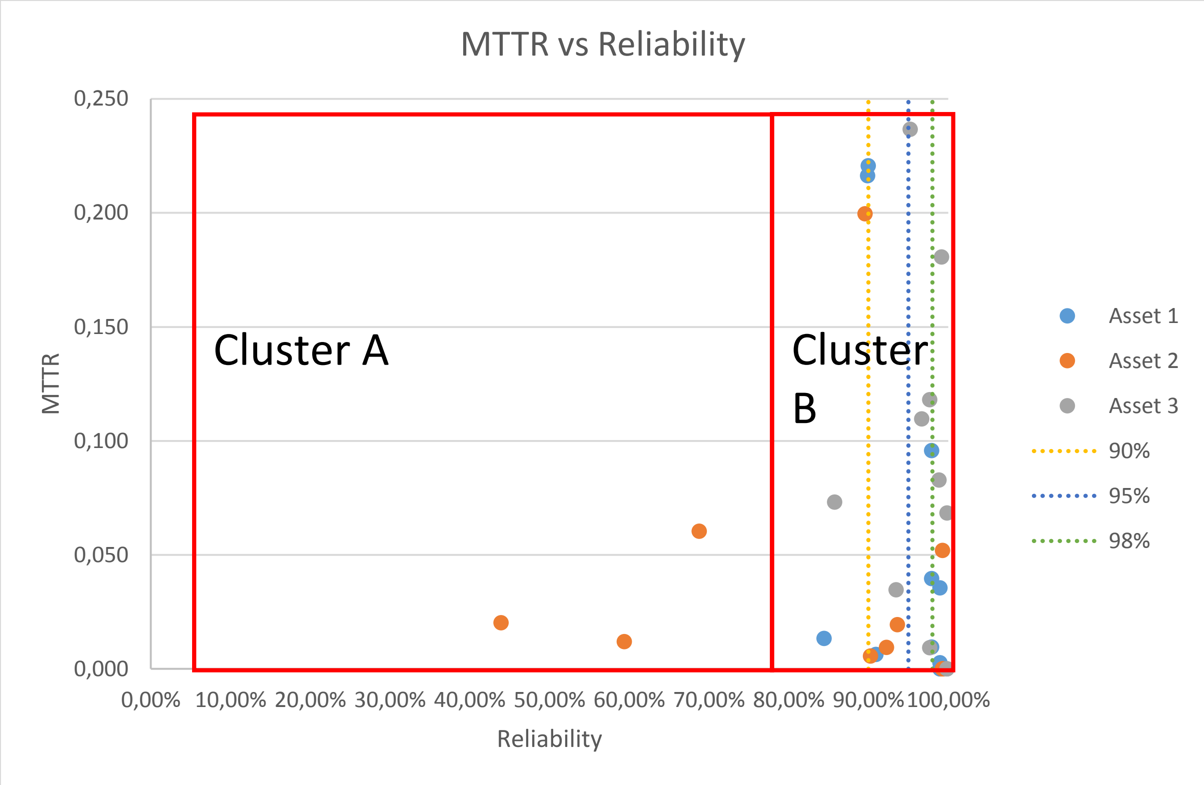


Chart 11 – MTTR vs Reliability for all assets

Furthermore, Cluster B is further divided into four clusters;

- Cluster 1 – low reliability, short repair time
- Cluster 2 – average reliability, long repair time
- Cluster 3 – average reliability, short repair time
- Cluster 4 – high reliability, low repair time

Therefore, equipment in Cluster 4 is the best performance for the equipment as it will have few failures with low repair time. Cluster 3 and 1 are relatively ok clusters, as it has low time to repair. Cluster 2 is the worst cluster to be in as it is prone to failure reliability often and the repair time of the equipment if long.

Chart 12 shows the application of the four clusters. It clearly shows that there are components in the Cluster 2 category, which means they take a long time to fix.

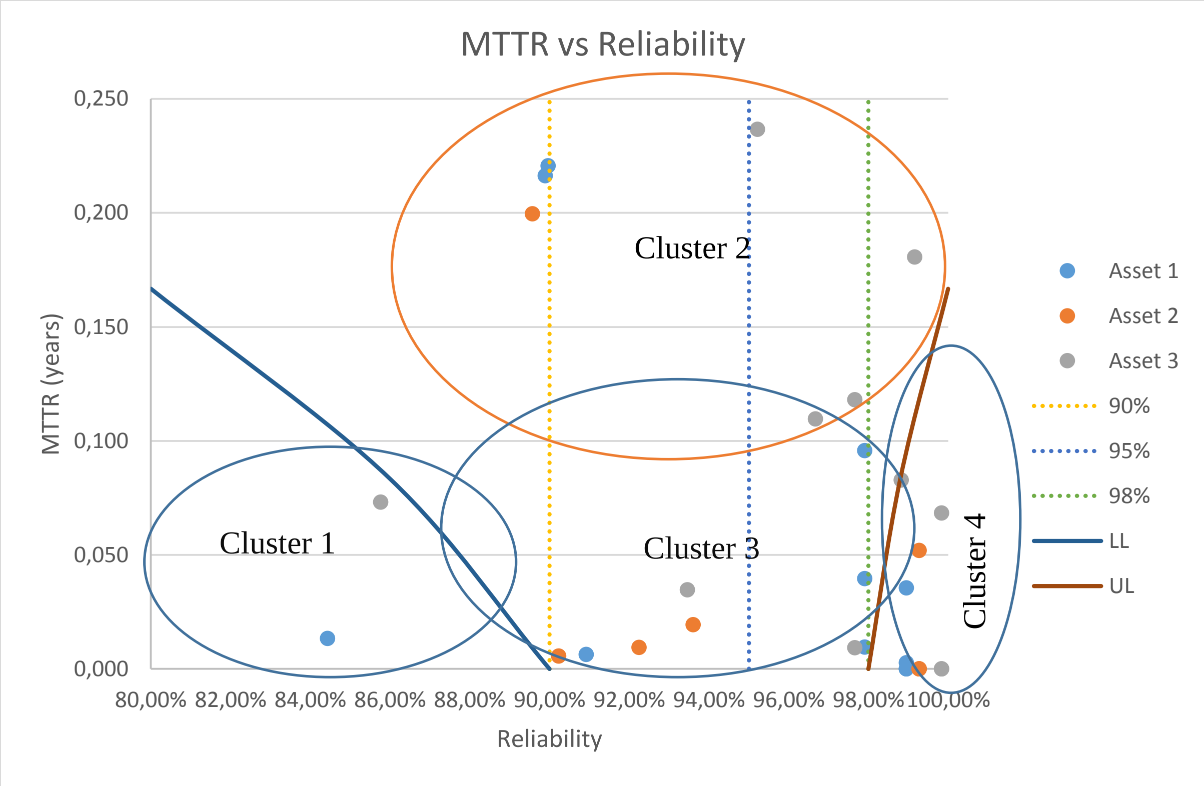


Chart 12 - MTTR vs Reliability for all assets

Cluster 1 consists of;

- Asset 1; Surface tree
- Asset 3; Gas lift system

Cluster 2 consist of;

- Asset 1; DHSV, Gas lift system, HPU/Logic
- Asset 2; Upper completion
- Asset 3; Tubing hanger, DHSV, Casing

Cluster 3 consists of;

- Asset 1; Upper completion, Lower completion, Sand control, HPU/logic
- Asset 2; Wellhead, Casing, HPU/logic
- Asset 3; Surface tree, HPU/logic

Cluster 4 consists of;

- Asset 1; Wellhead, Tubing hanger, Casing
- Asset 2; Tubing hanger, Intermediate completion, Lower completion, Sand control
- Asset 3; Wellhead, Intermediate completion, Lower completion, Sand control

Chart 12 shows the performance of all the Equipment Level A groups compares to the MTTR the systems. From the graph, it clearly shows that certain systems have low reliability and low MTTR. That means that the system fails often, but they are, on average, fixed reasonably quick.

Other have medium reliability with varying MTTR. Same as for the earlier, the system with lower MTTR are fixed reliably quick, thus not causing too much lost production. However, there are sections which have 99% reliability and a high repair time –three months for some. These should be reviewed and have appropriate plans in place for maintenance and repair.

The last group has high reliability with relatively low MTTR. As long as the reliability is high, the MTTR is low, the availability of the system is good.

This compares to the "Car" case discussed above, Cluster 1, 3 and 4, where all have relatively low repair time, are the same as discussed in Case 1 above. Lowering already low repair time will not add much value to the overall availability of the system. Cluster 2 compares to the Case 2 discussed above. Longer repair times can be reduced to see a greater increase at the availability of the system.

As the components have a generally high reliability performance will make it less effective to alter, as changing already high values to higher values will not dramatically increase the availability of the system. Therefore, the focus should be on reducing the time it takes to repair the system. This because if a component has high reliability, but is difficult to fix, the availability of the component may be relatively low.

From the discussion above, the following should be highlighted;

- Efforts should be made reducing repair time for Cluster 2 equipment. If the repair time cannot be reduced, better maintainability of the equipment should be developed.
- Time is better spent on fixing repair time of a system.
- To increase availability of the system, the initial focus should be on reducing the repair time of the components.
- A significant amount of the equipment has a reliability above 95%.
- Repair time has a big impact on the availability of a product.

5.3 Production deferrals

The purpose of this section is to discuss management scenarios which may cause increased, or decreased, production deferrals.

A well, or system of wells, has an expected production output per day. When the system of wells are not able to produce the expected output, a production deferral is placed towards the system to make-up the difference. A production deferral is allocated against a well system when there is a production shortfall compared to the installed production capacity (IPC). The IPC is the expected production output, or max production, from the well (O'Brien, 2016).

If a system of wells are expected to produce 10,000 BOE per day, and it only produces 9,000 BOE, a production deferral is placed for the 1,000 BOE missing production output. A production deferral is therefore issued for the quantity of production not met. But what makes certain well systems more prone to production deferrals than others? How can it be managed? And can decisions along the lifetime of a field influence the number of deferrals issued? These questions will be answered through a series of simple examples, explaining how certain decisions will influence the level of production deferrals.

The following nomenclature is used:

- Well production capacity – is the maximum production throughput the wells can produce.
- Production process capacity – is the maximum about of produced fluids the process facilities on the platform can handle.
- Expected production output – is the IPC of the wells. For this section, this is either the same as well production capacity or production process capacity, whichever is less, as one of the two will be the bottleneck of the system.

5.3.1 Case A – Well production potential > Production process capacity

Case A, if Platform A has 10 wells, of which all wells are producing wells. Each well has its own well production capacity. Table 43 shows the potential production capacity of each well is listed.

Table 43 – Case A platform production

Well	Potential Well Production capacity (BOE/Day)
A-01	1,300
A-02	1,200
A-03	900
A-04	800
A-05	1,100
A-06	1,150
A-07	1,250
A-08	1,000
A-09	700
A-10	600
Total	**10,000**

From Table 43, the potential well production capacity of the platform is 10,000 BOE per day. For this case, the production process capacity of the platform is 8,500 BOE per day. This means that the platform's process system can handle less than the what the wells can potentially produce. Since the production process capacity is the limiting factor, at 85% of the potential well production capacity, the expected production is equal to the production process capacity at 8,500 BOE per day. Since the production process capacity is85% of the potential well production, each well is choked back to produce at 85%. Thus, the production profile of the wells are presented in Table 44.

Table 44 - Case A platform production

Well	Potential Well Production Capacity (BOE/Day)	Expected Production Output (BOE/day)	Difference (BOE/day)
A-01	1,300	1,105	195
A-02	1,200	1,020	180
A-03	900	765	135
A-04	800	680	120
A-05	1,100	935	165
A-06	1,150	978	173
A-07	1,250	1,063	188
A-08	1,000	850	150
A-09	700	595	105
A-10	600	510	90
Total	**10,000**	**8,500**	**1,500**

The table above quantifies the 15% the well is chocked back. The Figure 21 is a visual representation of the table above.

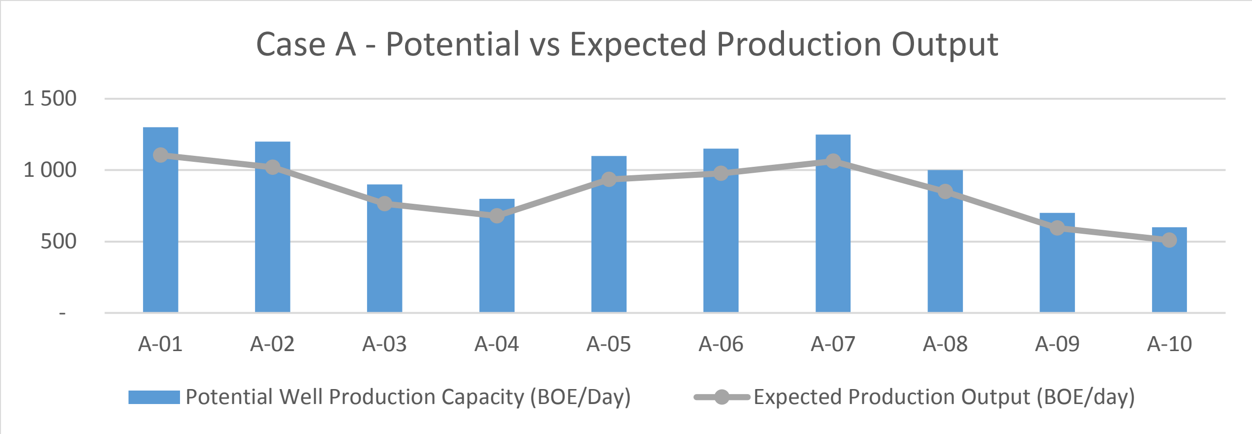


Figure 21 - Case A platform production

Figure 21 shows that the expected production output is less than the potential well production capacity. Figure 22 shows the accumulated potential vs expected production output is presented. From the graph it is clear that the potential always is above the expected, yield that the wells are not producing at 100%.

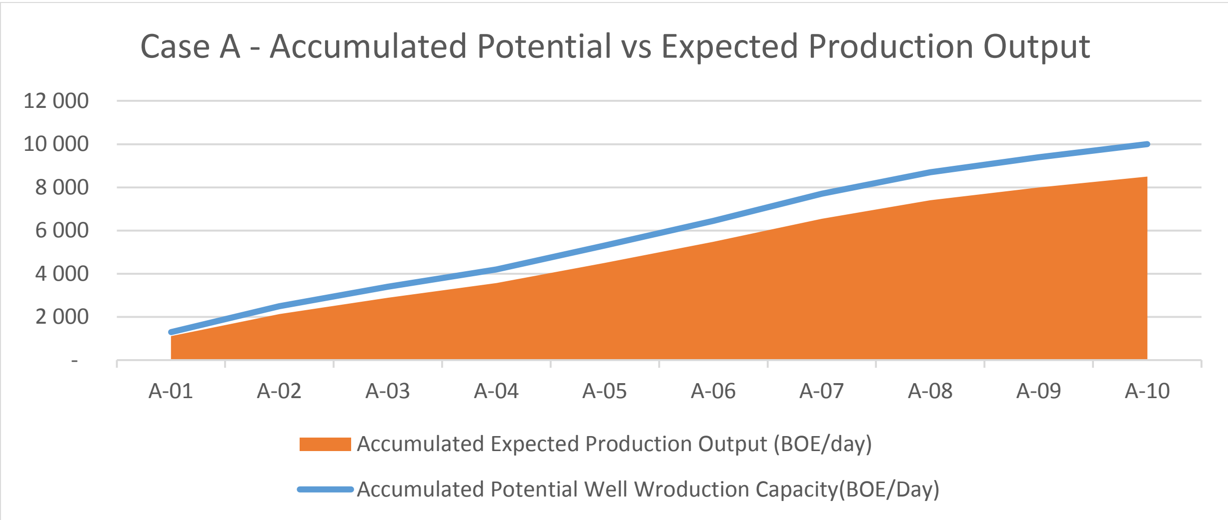


Figure 22 - Case A platform accumulated production

Over time, wells are required to shut-in due to various causes. What would happened if A-07 was shut in? Per definition, will a production deferral be issued? If A-07 shuts-in, the platform loses the 1,063 BOE per day of actual production. It loses an additional 187 BOE per day of additional potential well production capacity.

However, since all wells were producing at a reduced rate, 85%, that means there are potential production which is not being utilized for anything. The total additional well production capacity was 1,500 BOE per day. If the full potential of A-07 is taken out, 1250 BOE per day, the new total additional production is still 250 BOE per day over the expected production output. This means that the platform will still be able to make the expected production output.

Since the production process capacity is less than the potential well production capacity, when A-07 shuts-in, the other wells will just boost their production to 97% per well keep 8,500 BOE per day. Therefore, per definition, a production deferral will not be placed towards A-07. The platforms new well production profile is presented in Table 45.

Table 45 - Case A platform production with closed well

Well	Potential well production capacity (BOE/Day)	Actual well Production profile (BOE/day)	Actual well Production profile (BOE/day) **(A-07 closed)**
A-01	1,300	1,105	1,263
A-02	1,200	1,020	1,166
A-03	900	765	874
A-04	800	680	777
A-05	1,100	935	1,069
A-06	1,150	978	1,117
A-07	1,250	1,063	-
A-08	1,000	850	971
A-09	700	595	680
A-10	600	510	583
Total	**10,000**	**8,500**	**8,500**

With A-07 closed, the remaining 9 wells has to produce at 97% to maintain the target production rate. This is feasible as the production process system is still the bottleneck. That means that even with one well closing, the platform will not lose any of the production output, which means it will still generate the required revenues for the share and stakeholders. A visual representation of the table is presented in Figure 23.

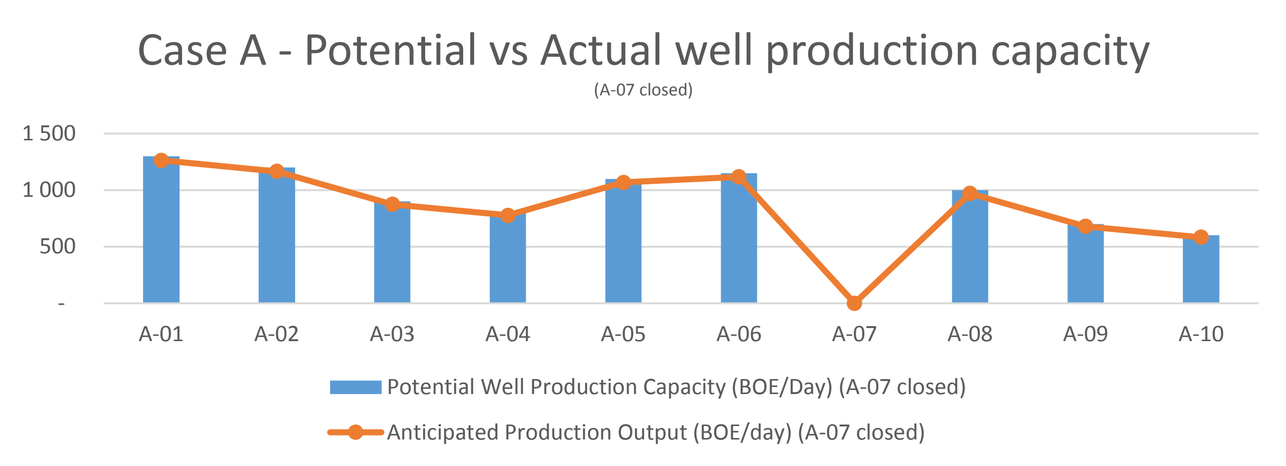


Figure 23 - Case A platform production with closed well

Figure 24 shows the accumulated expected production output vs the well potential output. It visually shows that the platform will be able to produce at the expected rate without one of the best producing wells available. The same is shown in the chart below, as the accumulated potential is still slightly higher than the accumulated expected production output.

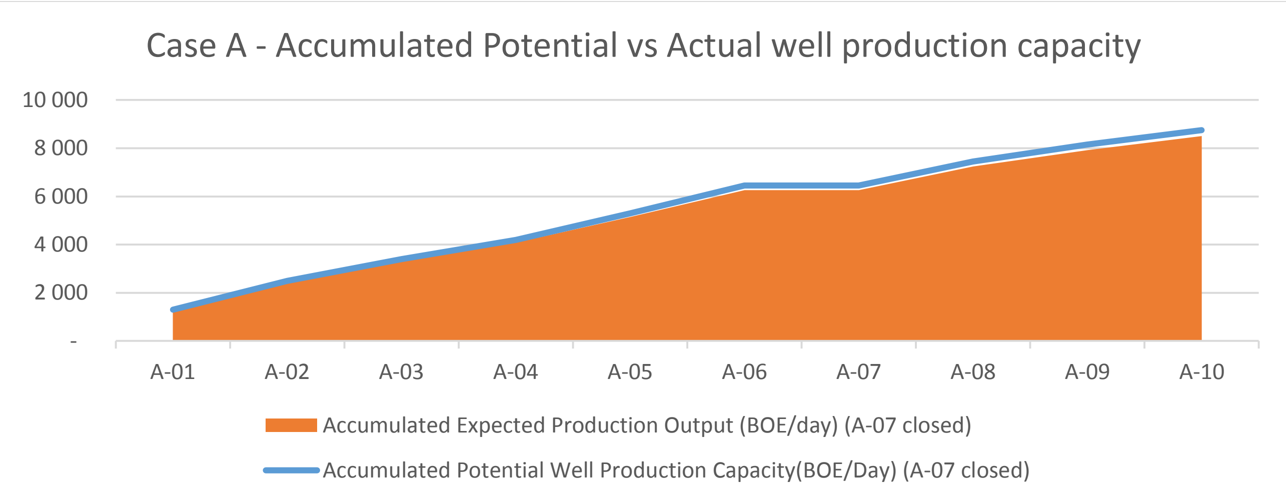


Figure 24 - Case A platform accumulated production with closed well

Since the expected production output can still be met, even with one good producing well inactive, may give the management for the platform some leverage when it comes to repairing and fixing broken components. This may allow the platform to perform a proper assessment of the failure and to plan for repairs to take place. It may avoid extra costs related to quick fixes which may only be temporary. Alternatively, there may be no work performed on the well, as it would cause additional production to be yielded.

5.3.2 Case B – Well production potential < Production process capacity

What happens when the production process capacity exceeds the well production potential? Utilizing the same well production potential as in Case A, but increasing the production process potential with 50%, to a total of 12,750 BOE per day, how will this affect the performance of the platform?

Case B has a production process capacity exceeding the potential well production capacity, meaning the process facility offshore is able to handle more produced fluids than the wells can produce. This means that the bottleneck of the system then becomes the production capacity of the well. As with all assets, it is safe to assume that stakeholder and shareholders want as much as they can get out of their wells. Thus, the expected production is therefore the maximum production the well production can deliver – 10,000 BOE per day. Table 46 shows that the potential well production output becomes the expected production output.

Table 46 - Case B platform production

Well	Potential Well Production Capacity (BOE/Day)	Expected Production Output (BOE/day)	Difference (BOE/day)
A-01	1,300	1,300	-
A-02	1,200	1,200	-
A-03	900	900	-
A-04	800	800	-
A-05	1,100	1,100	-
A-06	1,150	1,150	-
A-07	1,250	1,250	-
A-08	1,000	1,000	-
A-09	700	700	-
A-10	600	600	-
Total	**10,000**	**10,000**	**-**

From the table above, it shows that there is no difference between potential and expected production output. Figure 25 is a visual representation of the table above, indicating that the potential equals the expected output.

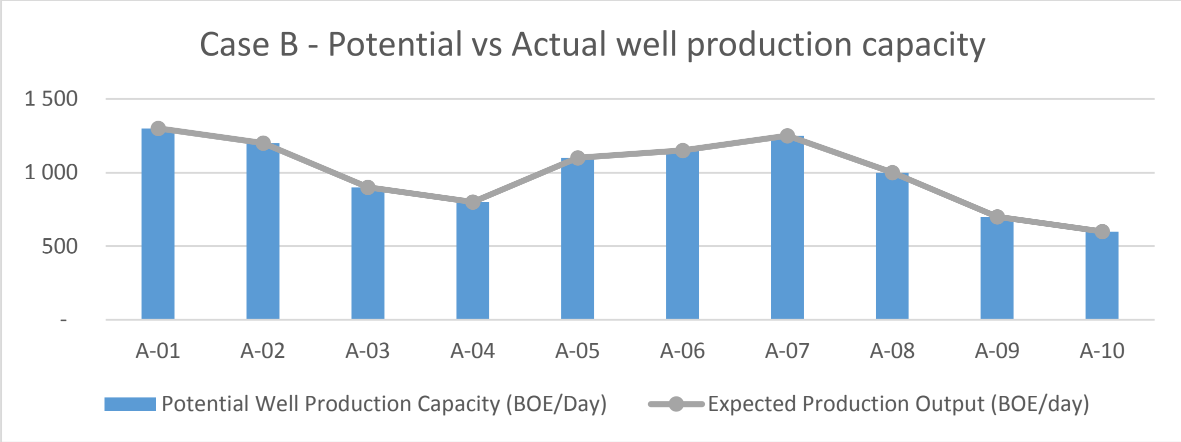


Figure 25 - Case B platform production

Figure 25 shows that the potential well production is the same as the actual production process capacity, thus the wells has to be online at all times to make the expected production output. Figure 26 shows that the accumulated potential production equals the accumulated actual production, given that all wells are online.

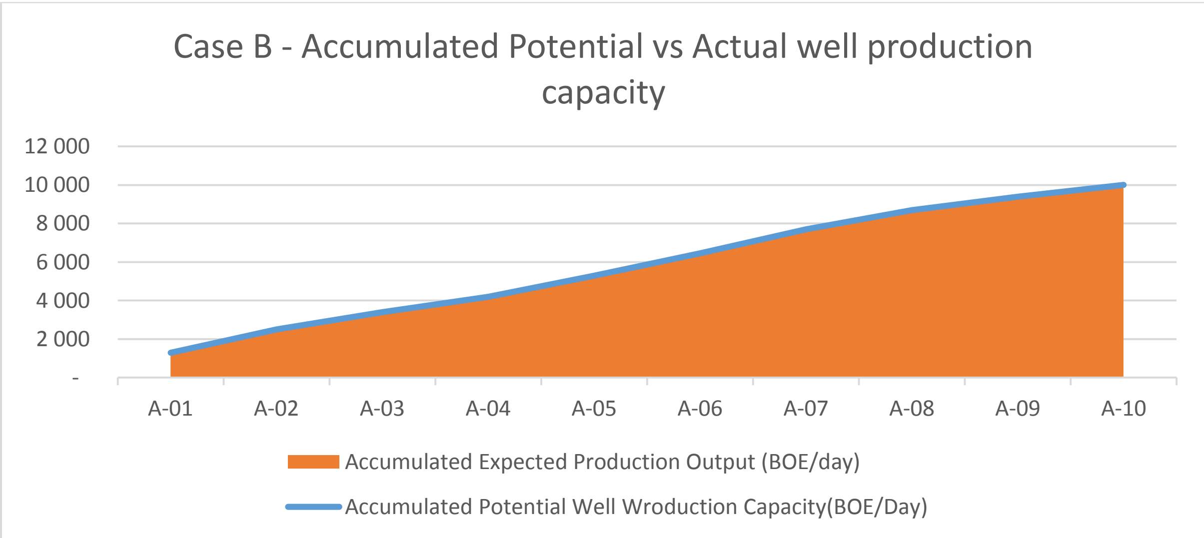


Figure 26 - Case B platform accumulated production

As in Case A, what happens now if a well has to shut-in? Since the potential well production is the expected production output, there will be a gap between actual output and expected output. Using the same example as before, if well A-07 shuts-in, the platform loses 1,250 BOE per day. The new production profile is presented in the Table 47.

Table 47 - Case B platform production with closed well

Well	Potential Well Production Capacity (BOE/Day) (A-07 closed)	Expected Production Output (BOE/day) (A-07 closed)	Difference (BOE/day) (A-07 closed)
A-01	1,300	1,300	-
A-02	1,200	1,200	-
A-03	900	900	-
A-04	800	800	-
A-05	1,100	1,100	-
A-06	1,150	1,150	-
A-07	-	1,250	(1,250)
A-08	1,000	1,000	-
A-09	700	700	-
A-10	600	600	-
Total	**8,750**	**10,000**	**(1,250)**

As the table shows, the potential well production capacity is 1,250 BOE per day less than the expected output. Figure 27 is a visual representation to indicate the deferred production.

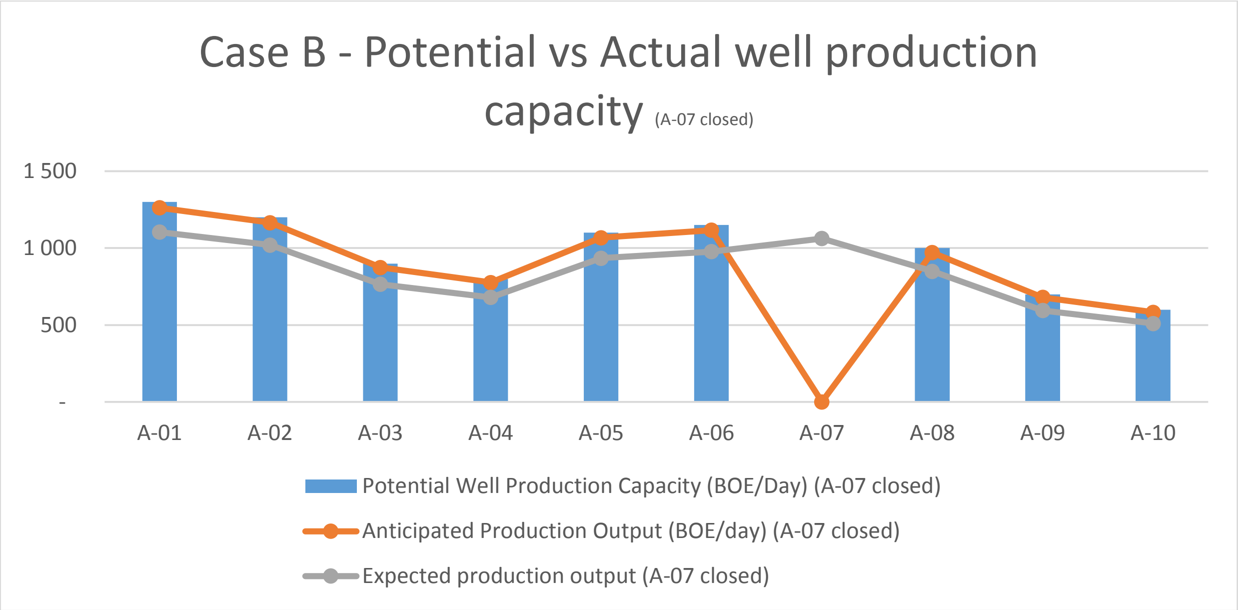


Figure 27 - Case B platform production with closed well

The graph above clearly shows the difference between the expected output from A-07 and the potential and anticipated output. Figure 28 shows that the accumulated potential and anticipated production output are both less than the expected production output.

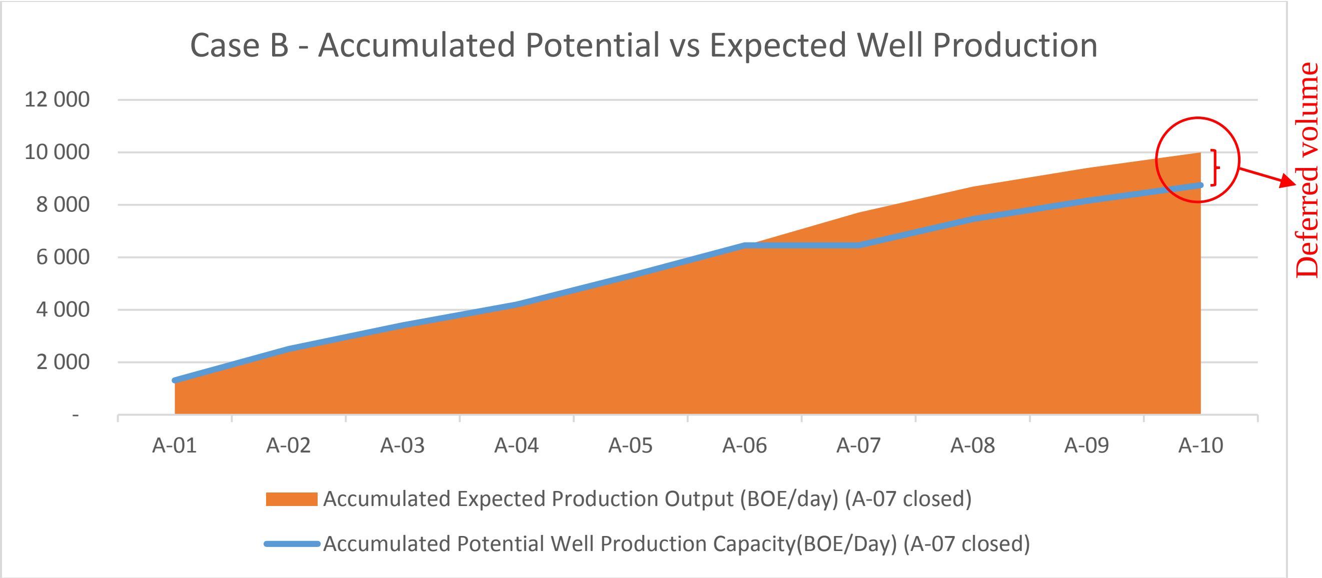


Figure 28 - Case B platform accumulated production with closed well

Figure 28 indicates the lacking production volume expected with the well shut-in. Since the actual output value will be less than the expected value, the volume has to be deferred. This is reported by issuing a production deferral against the platform, and in this case A-07, indicating that it is not able to produce as expected. From Table 47 it shows that the deferred volume will be 1,275 BOE per day.

Therefore, if a well has to close in Case B, the operator has to act quickly to get the well back on production to avoid production deferrals. If one has to be performed quickly, it might stress the organization if it has not planned for that kind of failure or shut-in. This may cause a sub-optimum solution and a "firefighting" environment, which may yield unwanted extra cost as it might be very urgent.

3.1.1. Case A vs Case B

If the production process capacity is the limiting factor, Case A, the platform may be able to produce though some wells has to individually be shut-in or chocked back due to numerous reasons. It allow for production targets to be met and give necessary breathing-room for operators when or if a failure occur. Case A is often the case for new installation, where the wells are able to produce more than the platform can handle.

The downside with Case A is that if one well goes down, the company does not need the well to meet the target. A plausible scenario is that the company chooses not to fix the well, as it is not necessary. Over time, the well will continue to degrade. Eventually, over time, the cost of bringing the well back online is too high, and then the well is completely ignored and the well production potential is removed from the platform potential, as it is not needed.

What happens if an Asset transition from Case A to Case B? Then all the shut-in wells are required to make the new production target. This probably means the old wells has to be fixed at a high cost as the state of the wells has been ignored for some time. Is this part of the cost-benefit analysis performed prior to deciding to temporarily shut-in a well? These are questions an operator should consider and find the answer to, prior to neglecting the well as it is “not required to meet production goals”.

Case B is more feasible for older fields, where over time the process facilities has to be upgraded or changed out, and the potential production capacity declines. If the company invests in a process facility which is able to handle more than the wells can produce, it may create a situation where the platform is going to struggle to meet their production goals. The expected production output would then become, as in Case B, the maximum well production capacity. Thus, if one well shuts-in, the production target will not be met – Case B.

The upside of this is that the operator most likely has to get the well back online if it is shut-in. The downside is also that the operator has to fix the well, and they will most likely not be given the appropriate time necessary to properly assess the situation. Fixing wells in a hurry can lead to the assessment of what went wrong to be incorrect. Alternately, it could lead to fixing more than what is required, as they do not have time to find the root cause. All these yield a higher operational cost than necessary.

If the price and size increase with the process facility’s capacity, the decision makers should defiantly consider what impact a bigger facility has on the daily operations of the platform. If the cost increase is negligible, they should still consider the implications it has on the daily operations. If the well has to be fixed quickly every time, the cost associated with the deferred production and equipment/service purchase may be of considerable value.

It is not as clean cut as presented in this discussion. Many aspects go into the decision on how to run a platform. The intention of his discussion is just to highlight that increasing process capacity may not be only positive. There may be hidden costs related to time-constrains when not being able to meet the required production output.

5.3.3 Company comparison to Case A and Case B

How does these two theories apply to Company assets? As presented in Section 4, Chart 13 shows the deferrals issued per year for all the assets. Asset 1 shows a reliably steady number of deferrals issued each year. For 2013 and to 2015 the numbers are lower than anticipated. According to company's website, appraisal wells were drilled in this time period, which may mean that less production wells were available in the operational phase, thus less deferrals issued.

Asset 2 shows two peaks in production deferrals issued in 2011 and 2013. The remaining years show a relatively stable number of production deferrals being issued. For Asset 3, the graph shows clearly a drop in number of deferrals issued in 2012, before showing an increasing trend for production deferrals for Asset 3 in 2013, 2014 and 2015. What caused this increase in production deferrals?

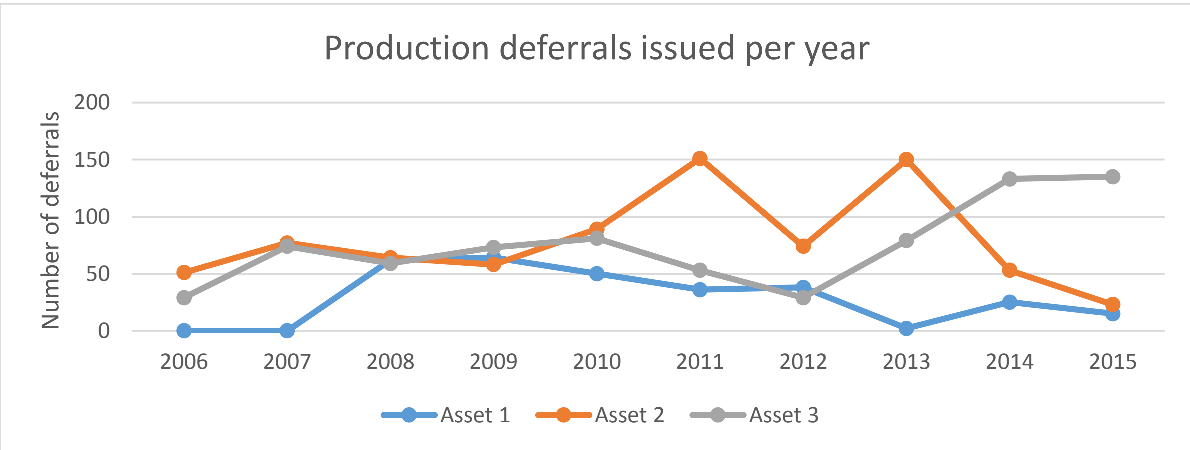


Chart 13 – Production deferrals per year for all assets

The rest of this section will discuss how this relates to Asset 3. Asset 3 was chosen as it is the biggest asset in terms of number of wells and production volume deferred. However, the asset contains less deferrals per well than any of the other two assets. As a result, Asset 3 was chosen to discuss why and maybe estimate how this may change over time.

Asset 3

For Asset 3, Company installed a new production facility in 2012. It was ready for production in early 2013. The new production facility replaced the old facility that was originally installed in the 1980's. According to the company website, the new production facility installed has a production capacity of 120,000 BOE and 4 mmsm^3 per day.

According to the company's website, the asset is expected to produce 35,000 BOE and 1 mmsm^3 per day. This yields a large over-capacity in the production process facility. The graph below illustrates this difference. It clearly shows the gap between what is expected to produce and the capability of the newly installed production process facility.

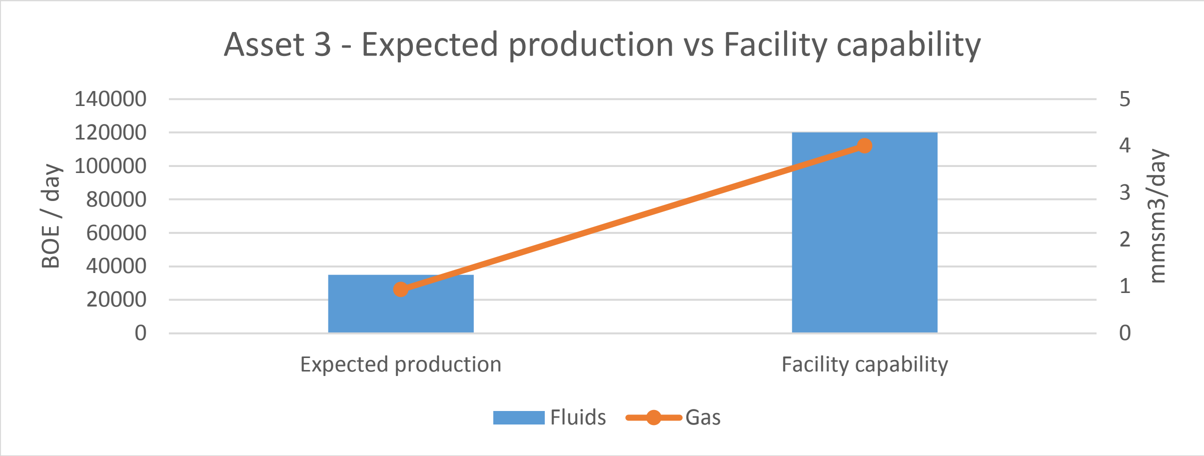


Chart 14 – Asset 3 expected vs facilility capacity production

According to company's website, the original process facility had a larger capacity than the new installed. The reason for this can be that most fields experience a higher production of fluids in the early life of the field, reaching a plateau production capacity. After a few years, the production declines and continues to decline until the field is shut-down (Odland, u.d.). Thus, the larger capacity process facility may be fit for purpose. In addition, it is assumed that the process facility declines over the years, and since the 1980's the facility has degraded. As it degrades, the available capacity also declines. This may explain why there are less deferrals issued prior to commissioning the new process platform as discussed earlier.

From the table presented in Section 4, it shows that 362, out of 760, production deferrals were issued from 2013. Since the duration of 2016 is only one and a half month, 362 deferrals were issued the last three years. This accounts for 48% of the total deferrals issued. The other six and half years accounts for 52% of all deferrals issued.

Therefore, based on the information found on the internet which correlates to how the number of deferrals were issued, it looks like Asset 3 transition from Case A to Case B in 2012 – 2013. Thus, it is expected that the number of deferrals will remain high for Asset 3, as the well production capacity is not likely to reach the production process capacity. Therefore, the expected production output will be the maximum well production capacity for the lifetime of this field.

5.4 Replacement barriers

The purpose of this section is to discuss options pertaining to failed barrier elements which causes production deferrals.

As discussed in earlier sections, if a failure occurs in a production critical component the well is shut-in and production is deferred. The production deferred can be quantified into monetary values and potential lost revenue can be calculated. Efforts can be made to reduce lost revenue by increasing the production availability of wells. The production availability of wells are increased by decreasing the downtime required to fix or replace failed components.

Based on the generic Company well composed in Section 4, utilizing the WellMaster reliability data, four equipment groups stand out as having low reliability; gas lift valves, including unloading valves, DHSV, TR-ASV and HPU. As the HPU is a platform specific issue, compensating measure or override options may be available. As this is not specific to well equipment, it will not be discussed in this section.

In general, if the equipment has low to medium reliability and low repair time, the total deferred production volume is not as significant as equipment with high repair time. Tubing retrievable gas lift valves, including the unloading valves, are assumed to easily changeable. Thus, they will not be a further part of this discussion.

Both the DHSV and TR-ASV are larger components requiring more work to repair. The DHSV is accessible for repairs though tubing interventions. Thus, when the DHSV fails, intervention can be performed to repair/replace the system. Interwell's IDHSVC (Interwell, u.d.) can replace a damaged DHSV. In addition, is seal areas are damaged, swell packers can be installed (PTC, u.d.). Since are replacement alternatives for the DHSV, it will not be further discussed in this section.

Due to the nature of the design, the TR-ASV is not accessible for repair though intervention. As such, TR-ASV cannot be repaired or replaced. The rest of this section will discuss possible contingencies to the TR-ASV and the possible financial impact.

According to WellMaster, a MTBF/MTTR of a TR-ASV is 18 years. A practical application of this is; if a platform has 20 wells with TR-ASV installed, at least one TR-ASV failure will occur, on average, each year. Since the TR-ASV cannot be repaired or replaced, the operators must plan for TR-ASV failures.

5.4.1 Company TR-ASV failure

From the data collected from Company PPIT, Asset 3 had two TR-ASV failures in 2014. According to Company *Production Critical Diagram*, the TR-ASV is considered a production critical component. Thus, if the component fails, the well is shut-in and the production is deferred. The financial implications of these two analyzed further.

The combined production deferral for the two TR-ASV failures was nearly 270,000 BOE. The average production deferral duration, MTTR, for the two failures were 0.42 years. According to Statista.com, the average crude oil price for the last ten years is 85 USD per barrel. For this section, an average oil price of 40 USD is selected. The reason for choosing a lower oil price is to reflect the current market oil price, which is between 30 USD and 40 USD per barrel.

With oil prices of 40 USD per barrel, the total lost revenue for Asset 3, due to the two failures are nearly 11 million USD. In addition to lost revenue comes the cost of actually replacing the barrier to resume production. It is assumed, due to the long lead time of nearly 5 months, attempts were made to flush and clean the system prior to proceeding with replacement options.

According to Company's website, Asset 3's 45 active producing wells are expected to produce nearly 35,000 BOE per day. This averages 775 BOE per day per well. In order to generate a conservative estimate, for this section, the average expected production per well is lowered to 500 BOE per day.

Further, the average duration for replacing the failed TR-ASV barrier for the two wells may be considered high. Therefore, to generate a conservative estimate, it is estimated that replacing the barrier will take 3 months, instead of 5 months. Each month is assumed to have 30 days.

Thus, for this section, each TR-ASV failure costs the company 1.8 million USD in lost revenues. This, of course, assumed that the well is put back on gas lift production.

From the data collected, Asset 3 has twenty-five wells which require gas lift. Thus, twenty-five wells with TR-ASV installed. As two TR-ASV's has already failed, it is assumed that Asset 3 has twenty-three TR-ASV reaming in operational condition.

Applying the WellMaster MTTF for TR-ASV of 18 years, it is feasible to assume that at least one TR-ASV will fail per year for the next 10 years. Thus, the assumed lost revenue for the ten years are 18 million USD. Is there a way to reducing the deferred revenue?

5.4.2 Redundant equipment for TR-ASV

One option to reduce the deferred revenue is to install a redundant system to the TR-ASV. One such system is PTC's MSAS system. A typical MSAS system consist of a check valve, hydraulic actuator and a spacer spool to house the actuator. The MSAS valve is installed in the VR profile of the wellhead, whilst the actuator and spacer spool is installed between the wellhead and AMV. Thus, the MSAS system is installed in series between the AMV and TR-ASV, adding an additional barrier to the gas injection side of well production. Figure 29 shows a typical MSAS system.

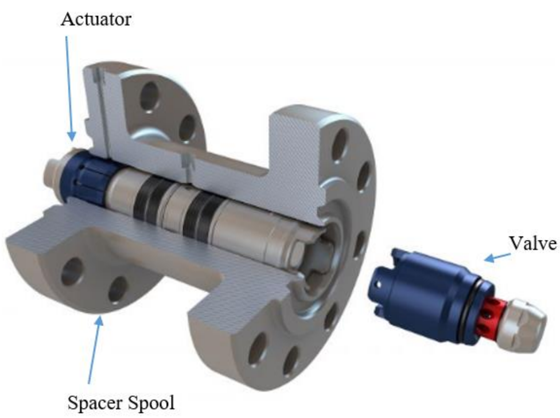


Figure 29 – Typical MSAS system (www.ptc.as)

The valve is a check valve and is a normally-closed valve. The hydraulic actuator is also a normally-closed system, which means it will operate when energized. The hydraulic actuator is energized through hydraulic pressure. When the actuator is energized, it moves pistons to energize the valve. When the valve is energized, the vale is in an open position and allows bidirectional flow.

However, if the hydraulic energy is not present, the valve will be closed, but the check-valve function of the valve is still operable. Thus, the valve will open in the flow direction of the injected gas. This will allow gas to be injected into the annulus and avoid over pressuring the gas injection line. When gas injection into the annulus stops, the check valve will close and seal against annulus fluids.

5.4.3 Costs of installing redundant TR-ASV system

If the MSAS is part of the original well design, costs for retrofitting gas injection lines, updating P&IDs and removing clashes offshore are saved. The actual cost for retrofitting a MSAS is unknown. For this study, it is assumed that the cost for retrofitting MSAS on a well is 70,000 USD per system.

Installation time and MTTR

In discussions with PTC's Operational Coordinator, Bjarne Miljeteig (Miljeteig, 2016), the expected installation time for the MSAS is very low. If the system is installed during well completion, the installation time required is one shift. If the system is installed for retrofit, it can vary from one to five shifts as it depends on when and how the access if obtained. Most installations usually are one to two shifts. This time is also considered applicable for equipment change-out due to failure. Therefore the intervention time for MSAS is considered very low.

Due to the low intervention time required, and assuming that Company has spares in stock, the time requires to repair an MSAS failure is one month. This is from the failure has been discovered to it has been repaired. This time estimate allows for three weeks onshore planning and one week of operational activity offshore.

For this section, an MSAS installation, and/or re-installation, is estimated to take one week. With 500 BOE/day being deferred, the total deferred revenue becomes 0.14 million USD per MSAS installation. For an MSAS failure, due to the accessibility of the equipment, it is assumed that a failed system can be replaced within one month. Then the deferred revenue becomes 0.60 million USD per MSAS failure.

MSAS reliability

PTC is enrolled in Exprosoft's vendor RMS, and from there the MTTF for a MSAS system is 38 years. The equipment and personnel cost for purchasing and installing MSAS offshore is assumed to be 85,000 USD.

How to handle TR-ASV failures

Interpreting Exprosoft's WellMaster MTTF for TR-ASV to be 18 years, and considering two failures occurred the last two years, it is not a question of, if, but when the next TR-ASV fails.

Thus, Company has four ways of addressing TR-ASV failures;

1. Do nothing – meaning the well will not be put back on gas lift production.
2. Re-complete – very expensive and may costs in excess of 100 million USD.
3. Reactive approach – replace barriers upon TR-ASV failure.
4. Proactive approach – install replacement barriers for all TR-ASVs to avoid deferred revenues.

Alternative 1 and 2 is not what happens in practice. Thus, option 3 and 4 will be further discussed.

5.4.3.1 Reactive approach

A reactive approach would be installing an MSAS when TR-ASV failure occurs. In addition to the estimated revenue loss due to deferred production, additional cost to retrofit and replace the failed TR-ASV barrier will apply.

The costs and revenue losses related to a TR-ASV failure are:

- Deferred/lost revenue for 10 TR-ASV failures = 18 million USD
- Equipment cost for replacement barrier – 85,000 USD per system, 10 system = 0.85 million USD
- Retrofit wellhead for installation – 70,000 USD per system, 10 system = 0.70 million USD
- Failure of replacement barrier, one per 38 years of service = 0.2 million USD

Deferred production due to MSAS failure over time period = 1 million USD

Year	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Number of operating TR-ASV	23	22	20.8	19.6	18.6	17.5	16.6	15.7	14.8	14.0	13.2
Avg. TR-ASV failures per year	1.3	1.2	1.1	1.1	1.0	1.0	0.9	0.9	0.8	0.8	0.7
Number of operating MSAS	1	2	3	4	5	6	7	8	9	10	11
Avg. MSAS failures per year	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.3	0.3
MSAS Equipment CAPEX	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2
Deferred revenue due to MSAS install	0.0	0.0	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0
Deferred revenue due to MSAS failure	0.0	0.0	0.0	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.2	-0.2
Deferred revenue due to TR-ASV failure	-2.3	-2.2	-2.1	-1.9	-1.8	-1.7	-1.6	-1.6	-1.5	-1.4	-1.3
Savings/loss	**-2.4**	**-2.4**	**-2.3**	**-2.2**	**-2.1**	**-2.0**	**-1.9**	**-1.9**	**-1.8**	**-1.7**	**-1.7**
Accumulated savings/loss	**-2.4**	**-4.8**	**-7.1**	**-9.3**	**-11.4**	**-13.4**	**-15.3**	**-17.2**	**-19.0**	**-20.7**	**-22.4**

Table 48Table 48 shows the cash flow related to expenses or losses related to installing redundant barrier for failed TR-ASV. The table shows that in 2016 there are twenty-three TR-ASVs operating, and in 2026 there are thirteen. Further, it shows the average TR-ASV failures expected based on the constant failure rate.

The table shows that in 2016 there will be a requirement for one MSAS system installed, and in 2026 there will be a total of eleven. Further it shows the estimated failure rate of the MSAS system given the constant failure rate.

The table also shows the anticipated revenue losses due to equipment failure and expenditures for purchasing replacement equipment. From the table, in 2026, the TR-ASV failures will have cost 22 million USD in lost revenues and procurement of new equipment.

Table 48 – Reactive barrier replacement costs

Year	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Number of operating TR-ASV	23	22	20.8	19.6	18.6	17.5	16.6	15.7	14.8	14.0	13.2
Avg. TR-ASV failures per year	1.3	1.2	1.1	1.1	1.0	1.0	0.9	0.9	0.8	0.8	0.7
Number of operating MSAS	1	2	3	4	5	6	7	8	9	10	11
Avg. MSAS failures per year	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.3	0.3
MSAS Equipment CAPEX	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2
Deferred revenue due to MSAS install	0.0	0.0	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0
Deferred revenue due to MSAS failure	0.0	0.0	0.0	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.2	-0.2
Deferred revenue due to TR-ASV failure	-2.3	-2.2	-2.1	-1.9	-1.8	-1.7	-1.6	-1.6	-1.5	-1.4	-1.3
Savings/loss	**-2.4**	**-2.4**	**-2.3**	**-2.2**	**-2.1**	**-2.0**	**-1.9**	**-1.9**	**-1.8**	**-1.7**	**-1.7**
Accumulated savings/loss	**-2.4**	**-4.8**	**-7.1**	**-9.3**	**-11.4**	**-13.4**	**-15.3**	**-17.2**	**-19.0**	**-20.7**	**-22.4**

Chart 15 shows the cash-flow diagram for table above. As the accumulated line indicates, for each year the TR-ASV failures costs the company money in form of deferring production and procuring new equipment.

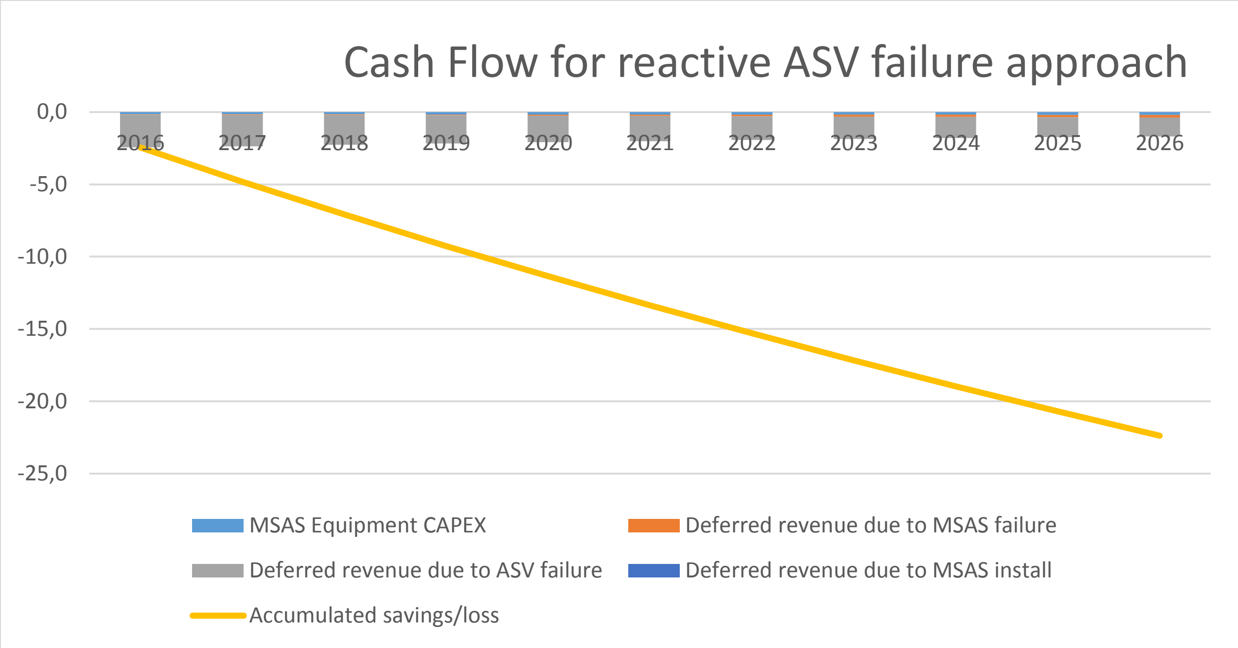


Chart 15 - Reactive barrier replacement costs

5.4.3.2 Proactive approach

The proactive approach to TR-ASV failures are to install a redundancy system to the all the TR-ASVs. The estimated costs associated with a proactive approach is;

- Equipment cost for replacement barrier – 85,000 USD per system, 23 system = 2 million USD
- Retrofit wellhead for installation – 70,000 USD per system, 23 system = 1.6 million USD
- Deferred production due to MSAS installation – 3.2 million USD
- Failure of replacement barrier, one per 38 years of service, 23 systems per = 0.6 million USD
- Deferred production due to MSAS failure over 10 years = 4.4 million USD

It is assumed that if the well already has MSAS installed, and the TR-ASV failed, the well can continue to produce. Therefore, the potential loss of revenue due to TR-ASV failure becomes a saving when redundant systems are installed. Then over a period of 10 years, a total of 19.6 million USD is saved. **Error! Not a valid bookmark self-reference.** shows the cash flow related to continuous production with MSAS when a TR-ASV failure. From the table, it shows that by 2021 the accumulated revenues are nearly 1 million USD is saved. By 2026, the proactive approach has potentially saved 7 million USD in revenues. These savings are after the assumed deferrals and equipment associated costs have been deducted.

Table 49 – Proactive barrier replacement costs in USD

Year	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Number of operating TR-ASV	23	22	21	20	19	18	17	16	15	14	13
Avg.TR-ASV failures per year	1.3	1.2	1.2	1.1	1.0	1.0	0.9	0.9	0.8	0.8	0.7
Number of operating MSAS	25	25	25	25	25	25	25	25	25	25	25
Avg.MSAS failures per year	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
MSAS Equipment CAPEX	-3.6	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1
Deferred revenue due to MSAS install	-3.2	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1
Deferred revenue due to MSAS failure	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4
Saved TR-ASV deferred revenue	2.3	2.2	2.1	2.0	1.9	1.8	1.7	1.6	1.5	1.4	1.3
Savings/loss	**-4.9**	**1.6**	**1.5**	**1.4**	**1.3**	**1.2**	**1.1**	**1.0**	**0.9**	**0.8**	**0.7**
Accumulated savings/loss	**-4.9**	**-3.3**	**-1.7**	**-0.3**	**1.0**	**2.3**	**3.4**	**4.4**	**5.4**	**6.2**	**7.0**

Chart 16 shows the cash-flow for table above. It clearly shows that the proactive approach has potential for saving money. From the graph, the approach seems to start saving money in 2019.

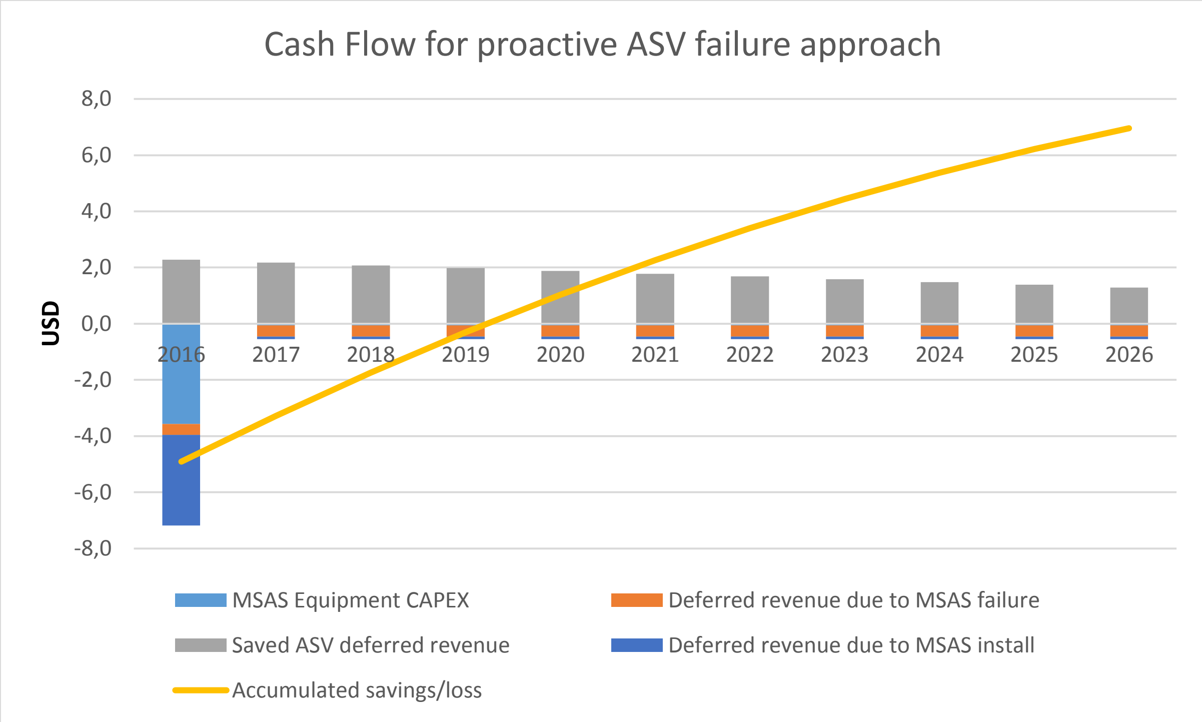


Chart 16 – Proactive barrier replacement costs

5.4.4 Benefits of installing redundant systems to the TR-ASV

From the results presented above, the benefit with the reactive approach is that it does not require a large capital investment at the beginning. But, by 2026 the approach is set to cost the company 22 million USD in lost revenues and equipment related expenditures.

The reactive approach has a considerably larger initial capital investment of nearly 5 million USD, with saved and added production deferrals considered. But, by 2026, the project is set to have potentially saved the company 7 million USD in lost revenues.

Comparing a lost, negative, revenue of 22 million USD to a saved, positive, revenue of 7 million USD, the difference is 29 million USD. Thus, the difference between the two options is large. The possible financial upside of implementing redundant systems to the TR-ASV should make Company consider the alternatives to reduce the downtime related to TR-ASV failures.

Taken into considerations that the production deferred in the examples above were reduced from nearly 800 BOE per day per well to 500 BOE per day per well. Also, the average observed deferral duration was five months, and it was reduced to three months. The actual savings may be considerably larger.

5.5 General discussion about thesis

The purpose of this section is to provide input from the author on the work performed and how it can improve.

5.5.1 Method used

The method developed for this thesis is thought to generate fair and accurate results of the actual performance of the Company. It is thought to be an accurate depiction of the actual performance of the Company. However, since all of the calculations are based on coding and manual handling of the data, there is always the possibility of error.

The method changed as the thesis progressed. At the beginning the outcome of the thesis was not clearly known, simply because the potential findings were unknown. As findings were developed, additional theories were added to the thesis to relate the findings to real-life applications. In hindsight, the potential thesis outcome could possibly have been known, but at the time of starting the thesis it was difficult to predict that. However, the author is satisfied with the developed methodology and is of the opinion that it provides good results.

Overall, this method can be adapted in an automated system to generate the same results. This is thought to be achievable as most of the information is already in the system. If company makes some alterations to the PPIT software, this data can be auto generated for review.

5.5.2 Future work and recommendations to Company

Company should consider making these calculations automated in the PPIT system. The PPIT contains the data necessary to make the calculations of reliability and repair time. Making these available will help Company with increasing their availability and production output on the assets.

Company should also consider implementing the *Equipment Level* and failure codes into the PPIT data set. As discussed in previous sections of this thesis, the current data set does not provide enough information to assign failure mode of *Equipment Level B* groups to the deferrals after the fact. By implementing these at the time of deferral, Company can generate trends and better identify areas of improvement.

Company should also consider the implication as described in the Case A and Case B examples. For systems were the well production is less than the plant, clearly focus and effort would be directed at the wells. For the systems were well production is greater then the plant, what then. It is felt in this case a bench mark on “minimum spare” well system capacity should be considered.

6 Conclusion

With decreasing oil prices, optimizing existing production is essential to generate as much revenue as possible. When the product sold decreases in value, more volume is required to maintain the revenue levels. Therefore, when oil prices are low, well availability is an important contributor to reaching revenue targets. A major international oil and gas company, with assets in NCS and UKCS, had a goal to better understand which failures impact their asset's well production availability. The goal of this thesis was to determine Company's assets' availability though practical system reliability and maintainability.

With data collected from the company's performance database, PPIT. Based on the data, 1,854 production deferrals were issued during a period of nearly ten years for three separate assets. A total of 102 wells were included in the survey. A total of 822 service years were included in the review. *Well equipment failure* accounted for 40% of the production volume deferred, *platform priorities* accounted for 28% and *reservoir and well service* accounts for 32%.

Planned deferrals accounts for 17% of all production volume deferred. The total planned production volume deferred is 7 million BOE. Thus, 83% of the total production volume deferred is unplanned, which accounts for 35 million BOE. The total deferral duration was over 29,000 days, deferring 42 million BOE.

The total MTBF, which includes planned and unplanned deferrals, for all assets is 0.45 years. This means that at any given time, any of the company's wells are, on average, expected to have deferrals twice a year. The MTBF for equipment failure is 2.09 years. The main contributor to the low MTBF is the "Surface tree" equipment group. Additional equipment groups which causes low MTBF are the "DHSV" and "HPU/Logic" groups. "Intermediate completion" groups did not have any registered failures, this the MTBF is equal to the total service time.

The average MTTR for any deferrals for all assets is 16 days. The equipment average MTTR is 26 days. This is also expected, as the equipment MTTR is only unplanned deferrals.

The overall asset reliability is 61%. The industry average, compared to reliability data from WellMaster RMS, is 60%. This, on average, the Company's assets are according to the expected average. Asset 1 are below the expected performance average, whilst Asset 3 is above. Asset 2 has very low reliability and measures should implemented to increase the overall reliability.

As the components has a generally high reliability performance, altering component reliability will be less effective as the values are already high. Channing high values to higher values will not dramatically increase the availability of the system. Therefore, the focus should be on reducing the time it takes to repair the systems. If a component has high reliability, but is difficult to fix, the availability of the component may be relatively low. The following is highlighted;

- Efforts should be made reducing repair time for Cluster 2 equipment. If the repair time cannot be reduced, better maintainability of the equipment should be developed.
- To increase availability of the system, the initial focus should be on reducing the repair time of the components.
- A significant amount of the equipment has a reliability above 95%.
- Repair time has a big impact on the availability of a product.

Company has an overall good performance on the wells system availability. All the assets range between 84% and 93%. This is considerably higher than what was though prior to the commencement of this thesis. Even though Asset 2 is very low on reliability, it still manages to maintain a good availability of the wells. Thus, the maintainability of the wells systems is a very contributing factor in achieving the desired uptime of a well system.

Based on the information found in this thesis, the major contributor in reducing deferred production, and increasing the availability of a well system, is the maintainability of the wells. If the equipment has low reliability but has a relatively low MTTR, the equipment will remain available most of the time. Therefore, the equipment the company should focus on to improve well system availability is the equipment with high MTTR. A high MTTR will cause more production deferrals than a low MTBF. Therefore, measures should be made by Company to gather information related to how effective the company is at fixing failed equipment. This may be the most effective method to increase well availability.

For example, a possible way to increase availability is to install redundant systems on the TR-ASV to ensure continuous production. From this thesis, it was disclosed that the TR-ASV single failures caused large amounts of deferred production. By installing redundant system, deferred production can be lowered by tens of millions of dollars over a period of ten years.

Further, it was discovered that the managing of asset performance may be affected by discussions which are not directly related to the well itself. Asset 3 received a platform upgrade in 2012-2013, which has caused the production capacity on the platform to increase. Thus, all well failures cause a full system deferral. This yields less time to fix problems when they occur as the asset needs the production to perform as required. This causes a sub-optimum and “firefighting” environment.

However, overall, the Company has roughly industry average reliability for most assets. Company is relatively efficient at mending their failures. Thus, the availability of all the assets are reliability high. The high availability of the wells are thought to be due to the efficient maintainability skills of the organization. This thesis has proved that if the reliability of an item is poor, but easy to fix, the availability of the well system may still be high. Thus, Company should focus their time on reducing the maintainability of the system first.

Company has an overall good performance on the wells system availability. All the assets range between 84% and 93%. This is considerably higher than what was though prior to the commencement of this thesis. To manage well availability, the Company should review how it is reacting to failed equipment. A possible way to increase availability is to install redundant systems on the TR-ASV to ensure continuous production. From this thesis, it was disclosed that the TR-ASV single failures caused large amounts of deferred production.

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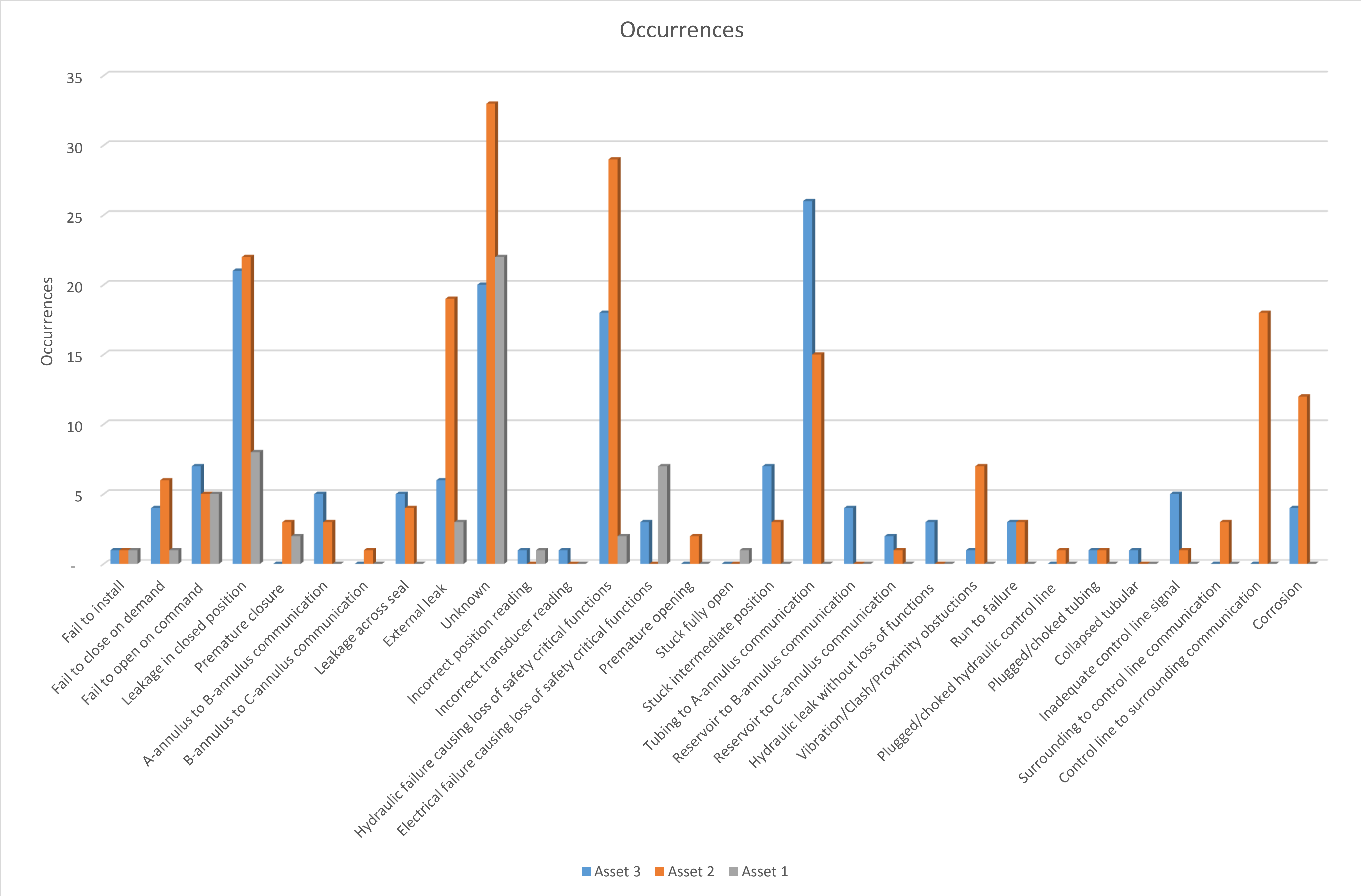
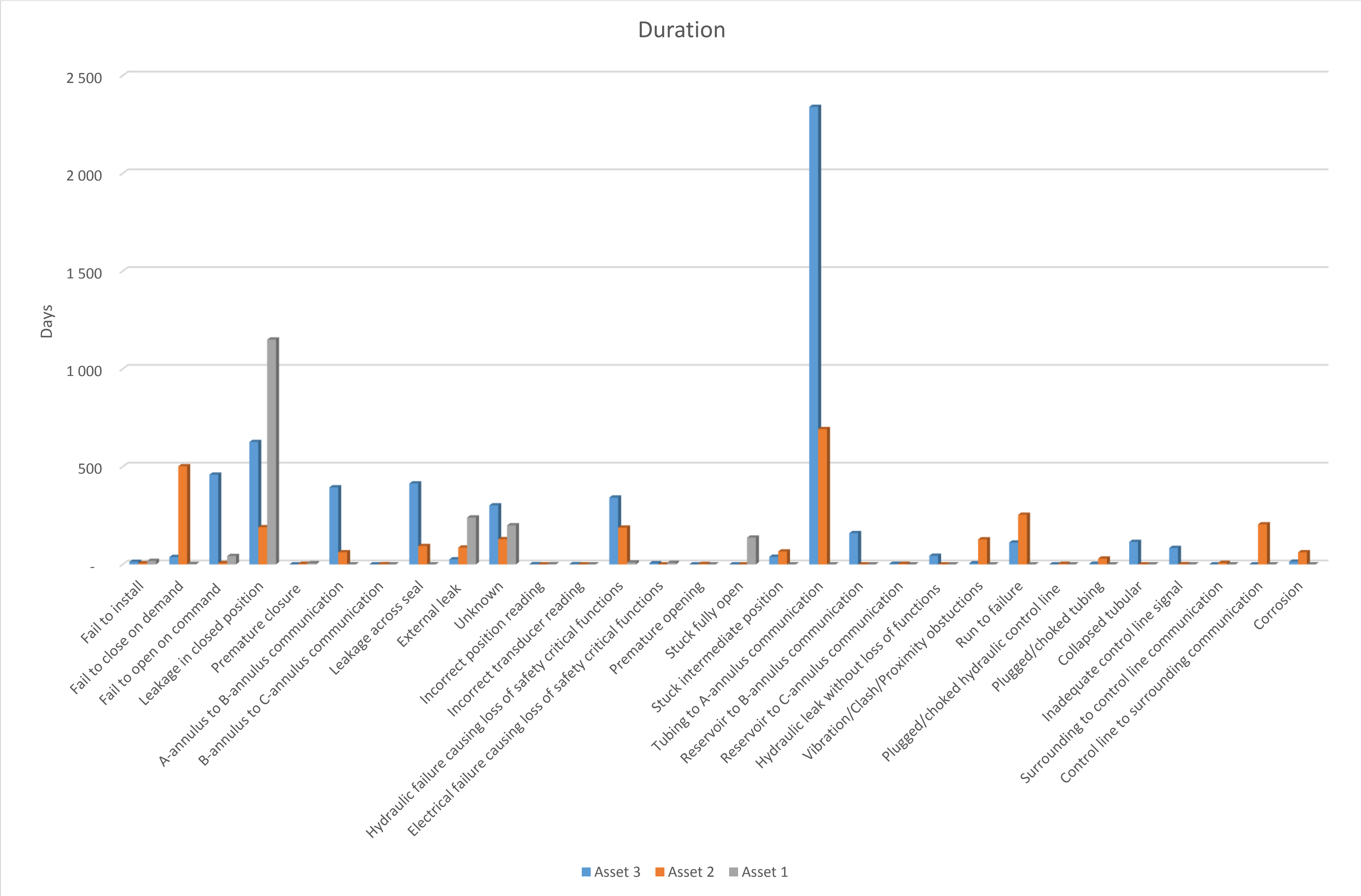
Appendix A

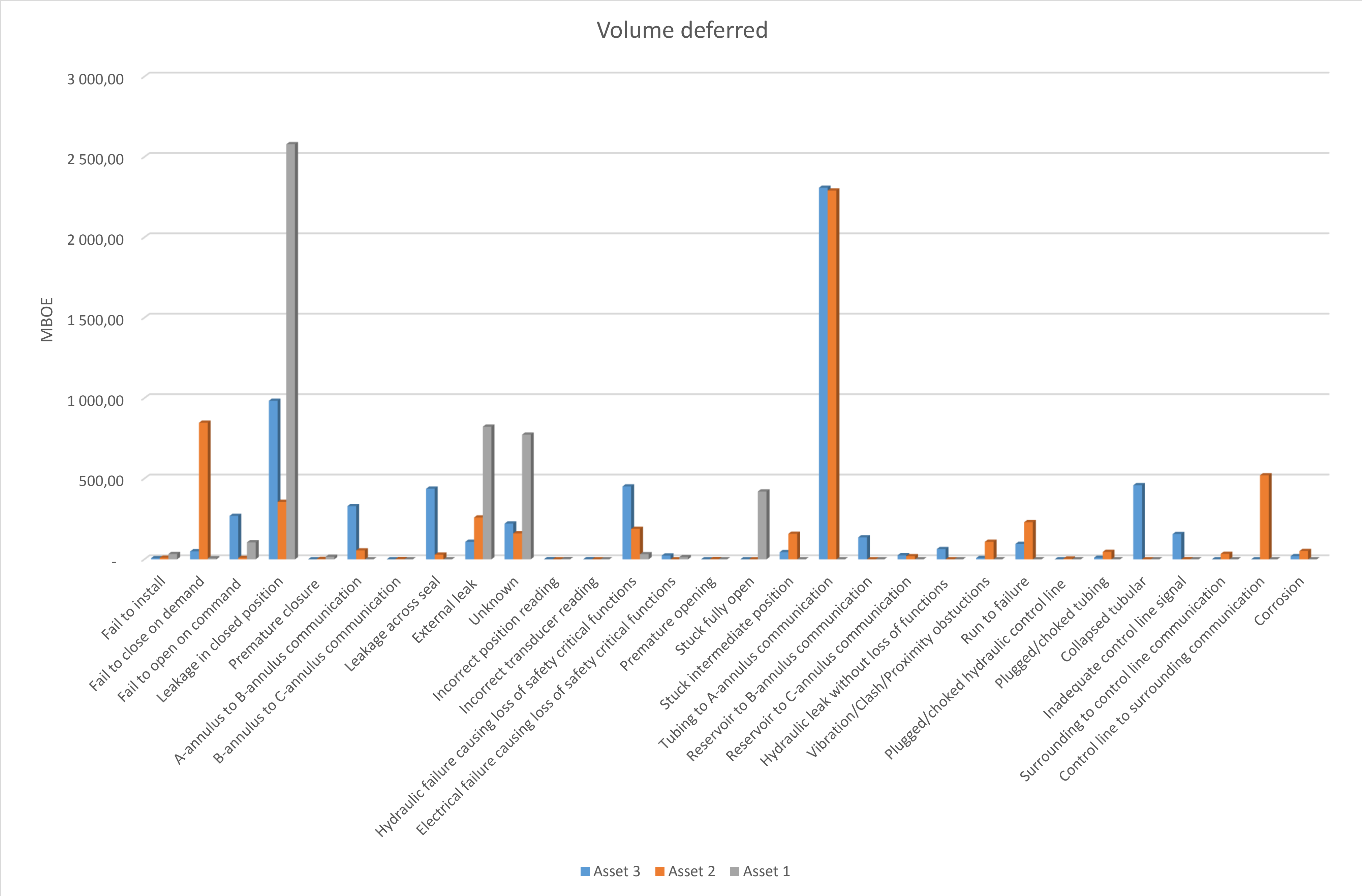
			Asset 3						Asset 2						Asset 1						Summay		
			# of deferrals		Deferred production		# of days of deferral		# of deferrals		Deferred production		# of days of deferral		# of deferrals		Deferred production		# of days of deferral				
ID	Failure modes (complete list)	Code	QTY - VAL	%	Deffered production (MBOE) - VAL	%	Duration - VAL	%	QTY - ULA	%	Deffered production (MBOE) - ULA	%	Duration - ULA	%	QTY - CLA	%	Deffered production (MBOE) - CLA	%	Duration - CLA	%	# of deferrals	Deffered production (MBOE)	# of days
1	Fail to install	FTI	1	0.13%	6.40	0.04%	13	0.09%	1	0.13%	9.79	0.07%	6	0.06%	1	0.33%	33.02	0.32%	18	0.37%	3	49.21	37
3	Fail to close on demand	FTC	4	0.53%	49.40	0.29%	38	0.25%	6	0.76%	846.56	5.75%	502	5.28%	1	0.33%	5.83	0.06%	2	0.04%	11	901.78	542
4	Fail to open on command	FTO	7	0.92%	268.67	1.58%	459	3.07%	5	0.63%	8.83	0.06%	7	0.07%	5	1.66%	105.05	1.02%	43	0.88%	17	382.56	509
5	Leakage in closed position	LCP	21	2.76%	982.94	5.78%	626	4.19%	22	2.78%	355.48	2.41%	190	2.00%	8	2.65%	2,578.78	24.97%	1,150	23.58%	51	3,917.19	1,966
6	Premature closure	PCL	-	0.00%	-	0.00%	-	0.00%	3	0.38%	2.03	0.01%	3	0.03%	2	0.66%	15.16	0.15%	6	0.12%	5	17.19	9
9	A-annulus to B-annulus communication	ABC	5	0.66%	329.31	1.94%	394	2.63%	3	0.38%	55.05	0.37%	62	0.65%	-	0.00%	-	0.00%	-	0.00%	8	384.36	456
10	B-annulus to C-annulus communication	BCC	-	0.00%	-	0.00%	-	0.00%	1	0.13%	0.84	0.01%	1	0.01%	-	0.00%	-	0.00%	-	0.00%	1	0.84	1
12	Leakage across seal	LAS	5	0.66%	436.68	2.57%	414	2.77%	4	0.51%	28.50	0.19%	94	0.99%	-	0.00%	-	0.00%	-	0.00%	9	465.18	508
16	External leak	EXL	6	0.79%	107.80	0.63%	26	0.17%	19	2.40%	258.45	1.76%	86	0.90%	3	0.99%	821.84	7.96%	240	4.92%	28	1,188.08	352
19	Unknown	UNK	20	2.63%	220.99	1.30%	302	2.02%	33	4.17%	160.52	1.09%	129	1.36%	22	7.28%	772.91	7.48%	200	4.10%	75	1,154.41	631
20	Incorrect position reading	IPR	1	0.13%	0.10	0.00%	1	0.01%	-	0.00%	-	0.00%	-	0.00%	1	0.33%	1.00	0.01%	1	0.02%	2	1.10	2
21	Incorrect transducer reading	ITR	1	0.13%	0.20	0.00%	1	0.01%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	1	0.20	1
23	Hydraulic failure causing loss of safety critical functions	HFS	18	2.37%	450.82	2.65%	342	2.29%	29	3.66%	187.89	1.28%	188	1.98%	2	0.66%	31.43	0.30%	10	0.21%	49	670.14	540
24	Electrical failure causing loss of safety critical functions	EFS	3	0.39%	23.43	0.14%	6	0.04%	-	0.00%	-	0.00%	-	0.00%	7	2.32%	13.24	0.13%	8	0.16%	10	36.67	14
27	Premature opening	POP	-	0.00%	-	0.00%	-	0.00%	2	0.25%	0.64	0.00%	2	0.02%	-	0.00%	-	0.00%	-	0.00%	2	0.64	2
30	Stuck fully open	SFO	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	1	0.33%	419.68	4.06%	137	2.81%	1	419.68	137
31	Stuck intermediate position	SIP	7	0.92%	44.20	0.26%	39	0.26%	3	0.38%	158.05	1.07%	66	0.69%	-	0.00%	-	0.00%	-	0.00%	10	202.25	105
33	Tubing to A-annulus communication	TAC	26	3.42%	2,308.31	13.57%	2,340	15.65%	15	1.89%	2,290.56	15.56%	692	7.28%	-	0.00%	-	0.00%	-	0.00%	41	4,598.87	3,032
34	Reservoir to B-annulus communication	RBC	4	0.53%	135.97	0.80%	160	1.07%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	4	135.97	160
35	Reservoir to C-annulus communication	RCC	2	0.26%	24.59	0.14%	3	0.02%	1	0.13%	19.02	0.13%	3	0.03%	-	0.00%	-	0.00%	-	0.00%	3	43.61	6
36	Hydraulic leak without loss of functions	HFN	3	0.39%	63.10	0.37%	44	0.29%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	3	63.10	44
42	Vibration/Clash/Proximity obstuctions	VCO	1	0.13%	7.60	0.04%	6	0.04%	7	0.88%	108.18	0.73%	128	1.35%	-	0.00%	-	0.00%	-	0.00%	8	115.78	134
45	Run to failure	RTF	3	0.39%	94.95	0.56%	112	0.75%	3	0.38%	229.69	1.56%	254	2.67%	-	0.00%	-	0.00%	-	0.00%	6	324.64	366
46	Plugged/choked hydraulic control line	PHC	-	0.00%	-	0.00%	-	0.00%	1	0.13%	3.89	0.03%	3	0.03%	-	0.00%	-	0.00%	-	0.00%	1	3.89	3
48	Plugged/choked tubing	PTG	1	0.13%	9.50	0.06%	3	0.02%	1	0.13%	45.69	0.31%	30	0.32%	-	0.00%	-	0.00%	-	0.00%	2	55.19	33
49	Collapsed tubular	CTG	1	0.13%	458.59	2.70%	115	0.77%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	1	458.59	115
50	Inadequate control line signal	ICS	5	0.66%	156.30	0.92%	84	0.56%	1	0.13%	0.07	0.00%	1	0.01%	-	0.00%	-	0.00%	-	0.00%	6	156.37	85
52	Surrounding to control line communication	SCL	-	0.00%	-	0.00%	-	0.00%	3	0.38%	33.72	0.23%	8	0.08%	-	0.00%	-	0.00%	-	0.00%	3	33.72	8
53	Control line to surrounding communication	CLS	-	0.00%	-	0.00%	-	0.00%	18	2.27%	520.11	3.53%	205	2.16%	-	0.00%	-	0.00%	-	0.00%	18	520.11	205
54	Corrosion	COR	4	0.53%	19.33	0.11%	14	0.09%	12	1.52%	50.72	0.34%	62	0.65%	-	0.00%	-	0.00%	-	0.00%	16	70.05	76
55	Reservoir failure	RES	107	14.08%	6,744.55	39.66%	6,978	46.67%	218	27.53%	4,339.07	29.47%	4,188	44.04%	84	27.81%	2,380.38	23.04%	1,584	32.47%	409	13,464.00	12,750
56	Non-well specific equipment failure	NEF	504	66.32%	4,063.15	23.89%	2,433	16.27%	378	47.73%	4,509.41	30.63%	2,463	25.90%	165	54.64%	3,151.23	30.51%	1,479	30.32%	1,047	11,723.80	6,375
Sum	Well equipment failure		149	19.61%	6,199.16	36.45%	5,542	37.06%	196	24.75%	5,874.14	39.90%	2,858	30.06%	53	17.55%	4,797.94	46.45%	1,815	37.21%	398	16,871.24	10,215



Occurrences
35
30
25
20
15
10
5
-
Occurrences
Fail to install
Fail to close on demand
Fail to open on command
Leakage in closed position
Premature closure
A-annulus to B-annulus communication
B-annulus to C-annulus communication
Leakage across seal
External leak
Unknown
Incorrect position reading
Incorrect transducer reading
Hydraulic failure causing loss of safety critical functions
Electrical failure causing loss of safety critical functions
Premature opening
Stuck fully open
Stuck intermediate position
Tubing to A-annulus communication
Reservoir to B-annulus communication
Reservoir to C-annulus communication
Hydraulic leak without loss of functions
Vibration/Clash/Proximity obstuctions
Run to failure
Plugged/choked hydraulic control line
Plugged/choked tubing
Collapsed tubular
Inadequate control line signal
Surrounding to control line communication
Control line to surrounding communication
Corrosion
Asset 3
Asset 2
Asset 1



Duration
Days
2 500
2 000
1 500
1 000
500
-
Fail to install
Fail to close on demand
Fail to open on command
Leakage in closed position
Premature closure
A-annulus to B-annulus communication
B-annulus to C-annulus communication
Leakage across seal
External leak
Unknown
Incorrect position reading
Incorrect transducer reading
Hydraulic failure causing loss of safety critical functions
Electrical failure causing loss of safety critical functions
Premature opening
Stuck fully open
Stuck intermediate position
Tubing to A-annulus communication
Reservoir to B-annulus communication
Reservoir to C-annulus communication
Hydraulic leak without loss of functions
Vibration/Clash/Proximity obstuctions
Run to failure
Plugged/choked hydraulic control line
Plugged/choked tubing
Collapsed tubular
Inadequate control line signal
Surrounding to control line communication
Control line to surrounding communication
Corrosion
Asset 3
Asset 2
Asset 1


Volume deferred
MBOE
3 000,00
2 500,00
2 000,00
1 500,00
1 000,00
500,00
-
Fail to install
Fail to close on demand
Fail to open on command
Leakage in closed position
Premature closure
A-annulus to B-annulus communication
B-annulus to C-annulus communication
Leakage across seal
External leak
Unknown
Incorrect position reading
Incorrect transducer reading
Hydraulic failure causing loss of safety critical functions
Electrical failure causing loss of safety critical functions
Premature opening
Stuck fully open
Stuck intermediate position
Tubing to A-annulus communication
Reservoir to B-annulus communication
Reservoir to C-annulus communication
Hydraulic leak without loss of functions
Vibration/Clash/Proximity obstuctions
Run to failure
Plugged/choked hydraulic control line
Plugged/choked tubing
Collapsed tubular
Inadequate control line signal
Surrounding to control line communication
Control line to surrounding communication
Corrosion
Asset 3
Asset 2
Asset 1

Appendix B

Level A *Equipment* Source (All)			Level B *Equipment* Source (All)	Asset 3 # of deferrals	Asset 3 Duration (years)	Asset 3 Deferred Production (MBOE)	Asset 2 # of deferrals	Asset 2 Duration (years)	Asset 2 Deferred Production (MBOE)	Asset 1 # of deferrals	Asset 1 Duration (years)	Asset 1 Deferred Production (MBOE)	Summary # of deferrals	Summary Duration (years)	Summary Deferred Production (MBOE)
			Total:	**771**	**45.68**	**27,494.7**	**779**	**26.03**	**14,222.8**	**302**	**13.36**	**10,329.5**	**1,852**	**85.07**	**52,047.0**
			Equipment failure	**149**	**15.17**	**6,199.2**	**194**	**7.82**	**5,485.9**	**53**	**4.97**	**10,027.5**	**396**	**27.97**	**21,712.6**
1	**Well Deferrals not related to specific well equipment**	**A**	**Well barrier element test , Heavy lift , injection limitation, etc**	622	30.51	21,295.6	585	18.21	8,736.8	249	8.39	302.0	1,456	57.11	30,334.4
2	Surface Tree (Dry)	A	Production Pressure/Temperature Sensor/Transmitter	-	-	-	-	-	-	-	-	-	-	-	-
		B	Choke	6	0.05	24.0	37	0.37	158.2	2	0.01	2.0	45	0.42	184.2
		C	Choke Actuator	5	0.04	23.5	4	0.02	8.3	10	0.11	10.0	19	0.18	41.8
		D	Production Wing / Kill Wing Valve	3	0.02	6.2	8	0.06	32.4	-	-	-	11	0.09	38.6
		E	Chemical Injection Valve	1	0.05	54.3	-	-	-	-	-	-	1	0.05	54.3
		F	Valve Actuator	9	0.39	123.3	3	0.01	1.8	1	0.02	1.0	13	0.42	126.1
		G	Upper Master Valve	6	0.41	141.1	4	0.02	26.0	1	0.05	1.0	11	0.48	168.0
		H	Lower Master Valve	2	0.08	87.6	1	0.00	0.3	-	-	-	3	0.08	87.9
		I	Swab Valve	1	0.00	0.1	1	0.00	3.0	-	-	-	2	0.01	3.1
		J	Tree Cap	-	-	-	-	-	-	-	-	-	-	-	-
		K	Penetrators (control line/ESP)	-	-	-	-	-	-	-	-	-	-	-	-
		L	Bottom Connector	-	-	-	-	-	-	-	-	-	-	-	-
		M	Pressure Containment Connection Seal	-	-	-	1	0.00	1.9	-	-	-	1	0.00	1.9
		N	Hydraulic Control Plumbing	3	0.06	55.0	-	-	-	-	-	-	3	0.06	55.0
		O	Tree Connection Flange	-	-	-	1	0.01	0.9	-	-	-	1	0.01	0.9
		P	Flowline	1	0.02	7.6	8	0.36	121.1	2	0.02	2.0	11	0.39	130.7
		Q	Ports and Fittings	3	0.26	160.3	1	0.01	1.9	-	-	-	4	0.26	162.2
3	Surface Wellhead (Dry)	A	Primary A to B packoff	-	-	-	-	-	-	-	-	-	-	-	-
		B	Secondary A to B packoff	-	-	-	-	-	-	-	-	-	-	-	-
		C	Lock down A to B packoff	-	-	-	-	-	-	-	-	-	-	-	-
		D	Control Line connection/device	-	-	-	-	-	-	-	-	-	-	-	-
		E	*Back Pressure Valve*	-	-	-	-	-	-	-	-	-	-	-	-
		F	*Connectors*	-	-	-	-	-	-	-	-	-	-	-	-
		G	*Gas Lift Valve*	-	-	-	-	-	-	-	-	-	-	-	-
		H	Ports and Fittings	5	0.02	24.5	2	0.15	202.8	-	-	-	7	0.17	227.3
		I	Upper Speed Head Connector - Pressure Containment Connection Seal	-	-	-	5	0.02	3.2	-	-	-	5	0.02	3.2
		J	Lower Speed Head Connector - Pressure Containment Connection Seal	-	-	-	-	-	-	-	-	-	-	-	-
		K	Annulus bleed-off systems	1	0.01	9.5	1	0.01	3.9	-	-	-	2	0.02	13.4
		L	Cannot define	1	0.55	114.5	1	0.00	0.0	1	0.00	1.0		0.55	
4	Tubing Hanger (Dry)	A	Neck Seal	1	0.01	114.5	1	0.05	0.0	-	-	-	2	0.06	114.5
		B		1	-	1.6	1	-	10.7	-	-	-	2	-	12.3
		C	Hanger Body Seal	-	0.89	-	-	-	-	1	0.04	1.0	1	0.93	1.0
		D	Body Lock Down	4	-	280.6	-	-	-	-	-	-	4	-	280.6
		E	Control Line connection	-	-	-	-	-	-	-	-	-	-	-	-
		F		-	-	-	-	-	-	-	-	-	-	-	-
		G	Other	-	-	-	-	-	-	-	-	-	-	-	-
5		A	DHSV Flapper	-	0.46	-	-	1.39	-	6	1.81	6.0	6	3.66	6.0

	DHSV System	B	Tubing Isolation Valve	6	-	450.9	9	-	848.1	-	-	-	15	-	1,299.0
		C	Insert Safety Valve	-	-	-	-	-	-	-	-	-	-	-	-
		D	Flow tube	-	0.25	-	-	0.54	-	2	0.38	2.0	2	1.17	2.0
		E	Cannot define	5	-	75.2	5	-	635.6	1	0.01	1.0	11	0.01	711.8
		F	Seals	-	0.88	-	-	0.56	-	-	-	-	-	1.44	-
		G	Control Line	4	0.61	97.4	11	0.59	643.0	1	0.01	1.0	16	1.20	741.4
		H	VOID	5	-	303.8	25	-	125.8	-	-	-	30	-	429.6
		I	Exit block	-	-	-	-	0.00	-	-	-	-	-	0.00	-
6	Gas Lift System	A	ESD Valve	-	0.01	-	1	0.03	0.5	4	1.91	4.0	5	1.95	4.5
		B	ASV/H-SAS	2	0.89	0.9	3	0.05	7.1	-	-	-	5	0.94	7.9
		C	Control Line	6	0.01	369.9	3	0.01	13.2	-	-	-	9	0.02	383.0
		D	Exit block for the control line	1	-	9.7	2	-	3.9	-	-	-	3	-	13.7
		E	Cannot define	-	-	-	-	0.01	-	1	0.02	1.0	1	0.02	1.0
		F	Envelope piping	-	-	-	3	0.01	12.5	3	0.16	3.0	6	0.18	15.5
		G	Gas Lift Valve	-	0.48	-	3	0.38	17.2	2	0.07	2.0	5	0.93	19.2
7	Upper Completion	A	Chemical Injection Valve/Mandrel	10	0.00	256.8	10	-	303.0	-	-	-	20	0.00	559.8
		B	P/T Gauge	1	0.14	0.7	-	-	-	1	0.01	1.0	2	0.15	1.7
		C	PBR / Floating Seals	1	-	64.1	-	-	-	-	-	-	1	-	64.1
		D	Production Packer	-	-	-	-	0.94	-	-	-	-	-	0.94	-
		E	Production/Injection Tubing	-	6.72	-	4	2.06	253.9	-	-	-	4	8.78	253.9
		F	Downhole Flow Control (e.g. Valves)	27	-	2,766.9	11	-	2,282.7	1	0.01	1.0	39	0.01	5,050.6
		G	Dynamic Seal Assembly	-	-	-	-	-	-	-	-	-	-	-	-
		H	Injection Check Valve	-	-	-	-	-	-	-	-	-	-	-	-
8	Intermediate Completion Eqt	A	Intermediate Completion Packer	-	-	-	-	-	-	-	-	-	-	-	-
		B	Upper Zone Isolation device	-	-	-	-	-	-	-	-	-	-	-	-
		C	Lower Zone Isolation device	-	-	-	-	-	-	-	-	-	-	-	-
9	Lower Completion Eqt.	A	Liner Hanger	-	-	-	-	-	-	-	-	-	-	-	-
		B	Lower Completion Packer	-	-	-	-	-	-	-	-	-	-	-	-
		C	Formation Isolation Valve	-	-	-	-	-	-	-	-	-	-	-	-
		D	Sliding Sleeves (e.g. Flow Isolation)	-	-	-	-	-	-	-	-	-	-	-	-
		E	Float Equipment (Flow Check)	-	-	-	-	-	-	-	-	-	-	-	-
		F	Gravel Pack Sleeve	-	-	-	-	-	-	-	-	-	-	-	-
		G	Isolation Plug of Lower Zone	-	-	-	-	-	-	-	-	-	-	-	-
		H	Open Hole Zonal Isolation Packer	-	-	-	-	-	-	2	0.19	2.0	2	0.19	2.0
		I	Distributed Sandface Sensors (e.g. Temp/Press.)	-	-	-	-	-	-	-	-	-	-	-	-
		J	Distributed Sensor Fiber (Optical)	-	-	-	-	-	-	-	-	-	-	-	-
10	Sand Control System	A	Gravel Pack (Open Hole)	-	0.07	-	-	-	-	1	0.03	1.0	1	0.10	1.0
		B	Gravel Pack (Cased Hole)	1	-	25.0	-	-	-	-	-	-	1	-	25.0
		C	Cased and Perforated	-	-	-	-	-	-	-	-	-	-	-	-
		D	Frac Pack	-	-	-	-	-	-	-	-	-	-	-	-
		E	Stand Alone Screens	-	-	-	-	-	-	-	-	-	-	-	-
		F	Expandable Screens	-	-	-	-	-	-	-	-	-	-	-	-
		G	Openhole/Pre-drilled Liner	-	-	-	-	-	-	-	-	-	-	-	-
		H	Chemical sand consolidation treatment Eqt.	-	-	-	-	-	-	-	-	-	-	-	-
		I	Other	-	-	-	-	-	-	1	0.05	1.0	1	0.05	1.0
11	Casing	A	Surface Casing	-	-	-	-	-	-	-	-	-	-	-	-
		B	Intermediate Casing	-	-	-	-	-	-	-	-	-	-	-	-
		C	Production Casing / tubing	-	1.08	-	-	-	-	-	-	-	-	1.08	-
		D	Liner	5	-	329.3	-	-	-	-	-	-	5	-	329.3
		E	zonal isolation cement	-	0.45	-	-	-	-	-	-	-	-	0.45	-
		F	Sustained casing pressure	6	0.13	160.6	-	0.10	-	-	-	-	6	0.23	160.6
12	Automation, Logic, HPU	A	HPU	3	0.00	55.0	11	0.06	129.4	-	-	-	14	0.06	184.4
		B	HPU lines / solenoids	1	0.04	0.4	7	0.01	14.8	-	-	-	8	0.05	15.2
		C	Automation / logic	1	0.08	25.0	3	0.00	0.8	9	0.06	9.0	13	0.15	34.8
		D	Insufficient hydraulic oil	12	-	94.1	1	0.01	0.4	-	-	-	13	0.01	94.5

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Appendix C

The purpose of this section is to disclose some of the formulas used in Microsoft Excel to obtain the data from PPIT.

Data management in Microsoft Excel

In order to verify and count the number of deferrals remained the same after data duplicate removal, sorting and filtering, the WellMaster RMS failure modes were added the original data for comparison. Since the raw data obtained from the PPIT database is not unique for each event, and that some data entries has happened with the same event index number, the criteria for selection from the filtered data back to the raw data has to be performed based on more than one criteria. Thus, the MATCH function is implemented into the INDEX function to allow for intersection of multiple columns with one row.

This was done by coding the following array;

$$\{=\text{INDEX}\underbrace{(\text{[Ref table]},\underbrace{\text{MATCH(1,([Cri \_range1]=Cri1)*(Cri\_range2]=Cri2),0)}}_{\text{MATCH function}})}_{\text{INDEX function}}\ \}$$

Equation 21 – Formula for quality checking raw date from PPIT (Roberts, u.d.)

The array function is made up by combining two function within MS Excel, INDEX and MATCH. The INDEX function works as either an array or a reference form. For this coding, the array form is utilized. In the array form, the function returns a value from the defined array parameters (Microsoft, 2016). The syntax for an INDEX function is;

=**INDEX**(*array*, *row_num*, *[col_num]*)

The first defined value within the INDEX function is the array. The array is the table of data that consists of the data desired to obtain. The row_num is the relative row number of the cell desired. And the col_num is the relative column number of the cell desired (Roberts, u.d.).

The MATCH function searches for a specified item within the range of the defined parameters and returns a value relative to the position of it in the range (Microsoft, 2016). The syntax for the MATCH function is;

=**MATCH**(lookup_value, lookup_array, [match_type])

The first defined value within the MATCH function is the lookup_value. The lookup_value is what the function is searching for. The lookup_array is the array of values the function is trying to find the lookup_value in. The match_type defines if the match of the lookup_value has to be exact (1) or not (0) (Roberts, u.d.).

The MATCH function in its most basic ways search for one value and returns a result. By making the MATCH function an array function, allows the function to utilize an array of values to be checked against the cells defined before returning a result.

By defining the lookup_value in the MATCH function to be 1, the function must build an array from scratch. The new array will check for values in the first criteria range which matches the first criteria, as well the second criteria range which matches the second criteria. When both criteria match, the array will be given a true value – “1”. Where the criteria do not match, the value will be false – “0”. Therefore, the lookup_value is “1”. The match_type is set to exact match “0”, as the function will only return a value when both criteria’s are met (Roberts, u.d.).

In order to manually review the data to ensure no duplicates were in the lists, the start and end date of each deferral has to determine. Due to the magnitude of raw data points provided from the PPIT system, and to ensure correct dates where matched with correct deferrals, a coding to complete the dates were made. The following syntax coding was utilized;

{=MIN(IF(Criteria_range1=Criteria1,IF(Criteria_range2=Criteria2,DateRange)))}

$$\{=\underbrace{\text{MAX}(\underbrace{\text{IF(Criteria\_range1=Criteria1,IF(Criteria\_range2=Criteria2,DateRange))}}_{\text{IF function}})}_{\text{MAX/MIN function}}\}$$

Equation 22 – Formula for determining start and end date for deferrals (Cheusheva, 2016)

The MIN function finds the lowest value, whilst the MAX function finds the largest value, hence start and end date respectively. The following two functions are the IF function. The syntax for the IF function is;

=IF(logical_test, [value_if_true], [value_if_false])

The IF function checks the logical comparison between values provided compared to that is expected from the function. The logical_test is either true or false. If the value is true, then the [value_if_true] logic is perform. If the value is false, then the [value_if_false] is performed (Cheusheva, 2016).

The syntax equation for either the start or end date of the deferral work by first checking the array of logical_test of Criteria_range1=Criteria1. When the first criteria is met, the second IF function checks the second logrical_test for Crieria_range2=Crieria2. Only when results from both arrays are true, the corresponding position returns a value in the dedicated DateRange. If the MIN function was utilized the earliest date in the array is returned, and if the MAX function is utilized, the most recent date in the array is returned.

Furthermore, the one of the most utilized functions for this thesis isthe SUMIFS function. The SUMIFS function is utilized to sum the various occurrences, durations and deferred production. The syntax for the SUMIFS function is;

=**SUMIFS**(sum_range, criteria_range1, criteria1, .., criteria_rangeN, criteriaN)

The sum_range is range of cells of which its vale is to be summed. The criteria_range is the range of cells in which the criteria is to be applied. The criteria is the defined requirements required for the cells to be summed (Microsoft, 2016).

Appendix D

Reliability data from WellMaster Phase VI

		Production Critical Components	WellMaster nomenclature	MTTF (years)		λ	Reliability for time duration (years) 1 pi	1 qi	5 pi	5 qi	10 pi	10 qi	15 pi	15 qi	20 pi	20 qi
WellMaster Reliability Data	Production	HPU / logic	HPU (subsea)	5.45		0.1835	83.24%	16.76%	39.95%	60.05%	15.96%	84.04%	6.38%	93.62%	2.55%	97.45%
		XMT cap	Tree connection	306.38		0.0033	99.67%	0.33%	98.38%	1.62%	96.79%	3.21%	95.22%	4.78%	93.68%	6.32%
		Choke	XMT - Choke valve	142.13		0.0070	99.30%	0.70%	96.54%	3.46%	93.21%	6.79%	89.98%	10.02%	86.87%	13.13%
		Swab valve	PSV	0			100.00%	0.00%	100.00%	0.00%	100.00%	0.00%	100.00%	0.00%	100.00%	0.00%
		Production wing valve	PWV	91.45		0.0109	98.91%	1.09%	94.68%	5.32%	89.64%	10.36%	84.87%	15.13%	80.36%	19.64%
		Kill valve	KV	0			100.00%	0.00%	100.00%	0.00%	100.00%	0.00%	100.00%	0.00%	100.00%	0.00%
		Upper Master Valve	PMV	54.97		0.0182	98.20%	1.80%	91.31%	8.69%	83.37%	16.63%	76.12%	23.88%	69.50%	30.50%
		Tree flange connection	Wellhead connector	306.38		0.0033	99.67%	0.33%	98.38%	1.62%	96.79%	3.21%	95.22%	4.78%	93.68%	6.32%
		Wellhead	Wellhead	0			100.00%	0.00%	100.00%	0.00%	100.00%	0.00%	100.00%	0.00%	100.00%	0.00%
		Tubing hanger system	Tubing hanger vertical	210.5		0.0048	99.53%	0.47%	97.65%	2.35%	95.36%	4.64%	93.12%	6.88%	90.94%	9.06%
		DHSV	TRSCSSV	15.1		0.0662	93.59%	6.41%	71.81%	28.19%	51.57%	48.43%	37.03%	62.97%	26.59%	73.41%
		Unloading IPO	Unloading GLV	116.71		0.0086	99.15%	0.85%	95.81%	4.19%	91.79%	8.21%	87.94%	12.06%	84.25%	15.75%
		GLV	Operational GLV	7.06		0.1416	86.79%	13.21%	49.25%	50.75%	24.26%	75.74%	11.95%	88.05%	5.88%	94.12%
		DMY GLV	Dummy GLV	358.94		0.0028	99.72%	0.28%	98.62%	1.38%	97.25%	2.75%	95.91%	4.09%	94.58%	5.42%
		Tubing string	Tubing	358.71		0.0028	99.72%	0.28%	98.62%	1.38%	97.25%	2.75%	95.90%	4.10%	94.58%	5.42%
		Production packer	Production Packer	676.61		0.0015	99.85%	0.15%	99.26%	0.74%	98.53%	1.47%	97.81%	2.19%	97.09%	2.91%
		Surface casing	Surface Casing	0			100.00%	0.00%	100.00%	0.00%	100.00%	0.00%	100.00%	0.00%	100.00%	0.00%
	Annulus	ESD Valve	AMW	297.26		0.0034	99.66%	0.34%	98.33%	1.67%	96.69%	3.31%	95.08%	4.92%	93.49%	6.51%
		Tubing hanger system	Tubing hanger vertical	0			100.00%	0.00%	100.00%	0.00%	100.00%	0.00%	100.00%	0.00%	100.00%	0.00%
		Casing hanger	Not in Wellmaster	0			100.00%	0.00%	100.00%	0.00%	100.00%	0.00%	100.00%	0.00%	100.00%	0.00%
		Surface casing	Surface Casing	0			100.00%	0.00%	100.00%	0.00%	100.00%	0.00%	100.00%	0.00%	100.00%	0.00%
		Tubing	Tubing	0			100.00%	0.00%	100.00%	0.00%	100.00%	0.00%	100.00%	0.00%	100.00%	0.00%
		TR-SCASSV assembly	TRSCASSV assembly	18.07		0.0553	94.62%	5.38%	75.83%	24.17%	57.50%	42.50%	43.60%	56.40%	33.06%	66.94%
		Production packer	Production Packer	0			100.00%	0.00%	100.00%	0.00%	100.00%	0.00%	100.00%	0.00%	100.00%	0.00%
		System reliability (h_WM) =		**1.9488628**		**0.5131**	**59.86%**		**7.69%**		**0.59%**		**0.05%**		**0.00%**	

Reliability data from PEIT

	Description	MTTF		λ	Reliability for time duration (years) 1 pi	1 qi	5 pi	5 qi	10 pi	10 qi	15 pi	15 qi	20 pi	20 qi
Asset 1	Surface tree	5.9	0.013	0.169	84.43%	15.57%	42.91%	57.09%	18.41%	81.59%	7.90%	92.10%	3.39%	96.61%
	Wellhead	94.5	0.003	0.011	98.95%	1.05%	94.85%	5.15%	89.96%	10.04%	85.33%	14.67%	80.93%	19.07%
	Tubing hanger	94.5	0.036	0.011	98.95%	1.05%	94.85%	5.15%	89.96%	10.04%	85.33%	14.67%	80.93%	19.07%
	DHSV	9.5	0.221	0.106	89.96%	10.04%	58.93%	41.07%	34.73%	65.27%	20.46%	79.54%	12.06%	87.94%
	Gas lift system	9.4	0.216	0.107	89.89%	10.11%	58.70%	41.30%	34.46%	65.54%	20.23%	79.77%	11.88%	88.12%
	Upper completion	47.3	0.010	0.021	97.91%	2.09%	89.96%	10.04%	80.93%	19.07%	72.81%	27.19%	65.50%	34.50%
	Intermediate completion	94.5	-	0.011	98.95%	1.05%	94.85%	5.15%	89.96%	10.04%	85.33%	14.67%	80.93%	19.07%
	Lower completion	47.3	0.096	0.021	97.91%	2.09%	89.96%	10.04%	80.93%	19.07%	72.81%	27.19%	65.50%	34.50%
	Sand control	47.3	0.040	0.021	97.91%	2.09%	89.96%	10.04%	80.93%	19.07%	72.81%	27.19%	65.50%	34.50%
	Casing	94.5	-	0.011	98.95%	1.05%	94.85%	5.15%	89.96%	10.04%	85.33%	14.67%	80.93%	19.07%
	HPU / logic	10.5	0.006	0.095	90.92%	9.08%	62.13%	37.87%	38.60%	61.40%	23.98%	76.02%	14.90%	85.10%
	System reliability (h_Asset 1) =	**1.7**		**0.582**	**55.85%**		**5.43%**		**0.30%**		**0.02%**		**0.00%**	

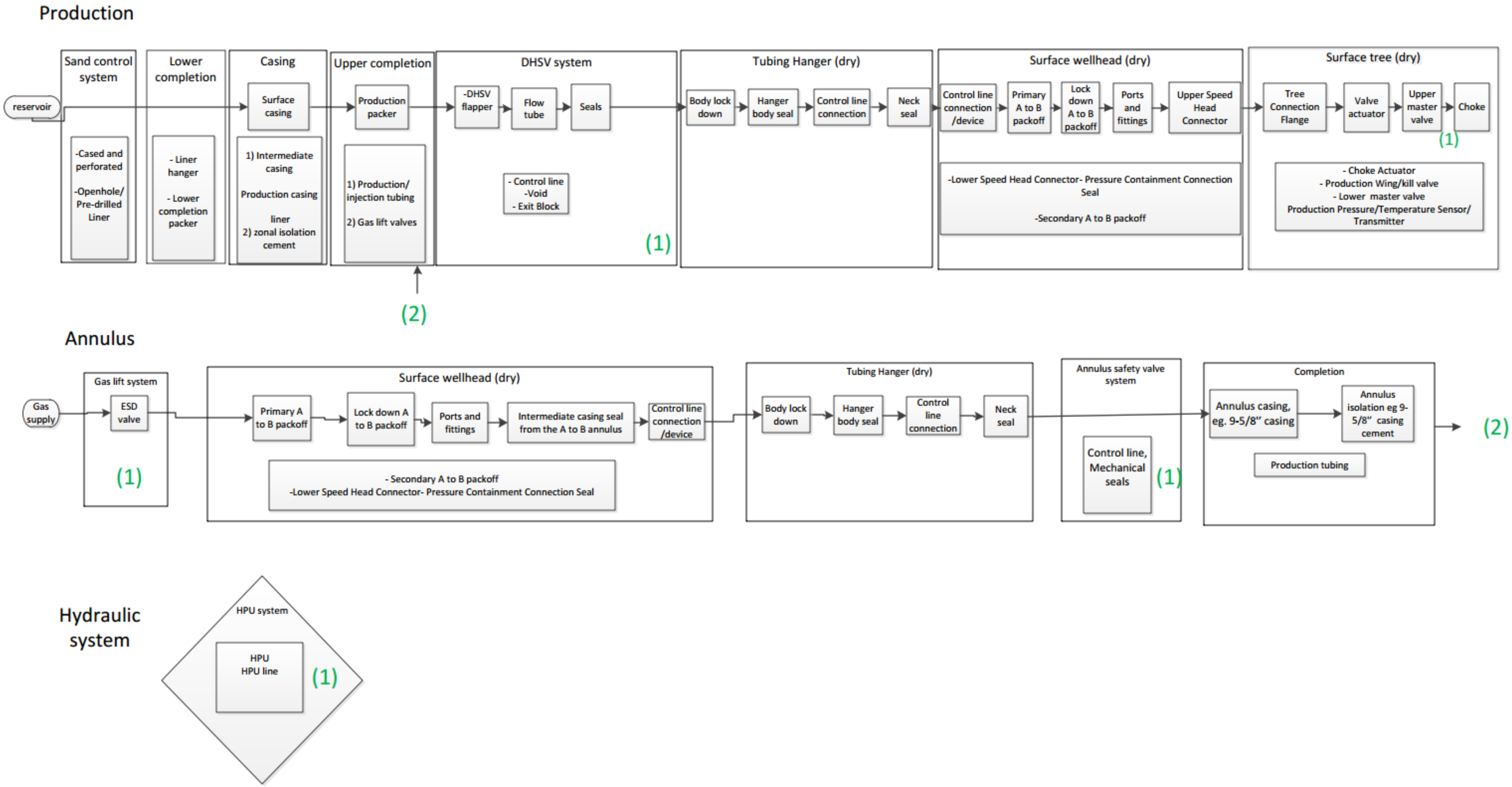
	Description	MTTF		λ	1 pi	1 qi	5 pi	5 qi	10 pi	10 qi	15 pi	15 qi	20 pi	20 qi
Asset 2	Surface tree	1.9	0.012	0.521	59.37%	40.63%	7.38%	92.62%	0.54%	99.46%	0.04%	99.96%	0.00%	100.00%
	Wellhead	15.1	0.019	0.066	93.61%	6.39%	71.86%	28.14%	51.64%	48.36%	37.11%	62.89%	26.67%	73.33%
	Tubing hanger	136.2	0.052	0.007	99.27%	0.73%	96.40%	3.60%	92.92%	7.08%	89.57%	10.43%	86.34%	13.66%
	DHSV	2.7	0.060	0.374	68.76%	31.24%	15.37%	84.63%	2.36%	97.64%	0.36%	99.64%	0.06%	99.94%
	Gas Lift System	1.2	0.020	0.822	43.94%	56.06%	1.64%	98.36%	0.03%	99.97%	0.00%	100.00%	0.00%	100.00%
	Upper completion	9.1	0.200	0.110	89.57%	10.43%	57.65%	42.35%	33.24%	66.76%	19.16%	80.84%	11.05%	88.95%
	Intermediate completion	136.2	-	0.007	99.27%	0.73%	96.40%	3.60%	92.92%	7.08%	89.57%	10.43%	86.34%	13.66%
	Lower completion	136.2	-	0.007	99.27%	0.73%	96.40%	3.60%	92.92%	7.08%	89.57%	10.43%	86.34%	13.66%
	Sand control	136.2	-	0.007	99.27%	0.73%	96.40%	3.60%	92.92%	7.08%	89.57%	10.43%	86.34%	13.66%
	Casing	12.4	0.009	0.081	92.24%	7.76%	66.77%	33.23%	44.59%	55.41%	29.77%	70.23%	19.88%	80.12%
	HPU / logic	9.7	0.006	0.103	90.23%	9.77%	59.81%	40.19%	35.77%	64.23%	21.40%	78.60%	12.80%	87.20%
	System reliability (h_Asset 2) =	**0.5**		**2.107**	**12.16%**		**0.00%**		**0.00%**		**0.00%**		**0.00%**	
Asset 3	Surface tree	14.8	0.035	0.068	93.46%	6.54%	71.29%	28.71%	50.83%	49.17%	36.23%	63.77%	25.83%	74.17%
	Wellhead	84.4	0.083	0.012	98.82%	1.18%	94.25%	5.75%	88.83%	11.17%	83.72%	16.28%	78.91%	21.09%
	Tubing hanger	118.2	0.181	0.008	99.16%	0.84%	95.86%	4.14%	91.89%	8.11%	88.08%	11.92%	84.43%	15.57%
	DHSV	29.6	0.110	0.034	96.67%	3.33%	84.43%	15.57%	71.29%	28.71%	60.20%	39.80%	50.83%	49.17%
	Gas lift system	6.5	0.073	0.154	85.76%	14.24%	46.40%	53.60%	21.53%	78.47%	9.99%	90.01%	4.63%	95.37%
	Upper completion	20.4	0.237	0.049	95.21%	4.79%	78.24%	21.76%	61.22%	38.78%	47.90%	52.10%	37.48%	62.52%
	Intermediate completion	591.0	-	0.002	99.83%	0.17%	99.16%	0.84%	98.32%	1.68%	97.49%	2.51%	96.67%	3.33%
	Lower completion	591.0	-	0.002	99.83%	0.17%	99.16%	0.84%	98.32%	1.68%	97.49%	2.51%	96.67%	3.33%
	Sand control	591.0	0.068	0.002	99.83%	0.17%	99.16%	0.84%	98.32%	1.68%	97.49%	2.51%	96.67%	3.33%
	Casing	42.2	0.118	0.024	97.66%	2.34%	88.83%	11.17%	78.91%	21.09%	70.10%	29.90%	62.27%	37.73%
	HPU / logic	42.2	0.009	0.024	97.66%	2.34%	88.83%	11.17%	78.91%	21.09%	70.10%	29.90%	62.27%	37.73%
	System reliability (h_Asset 3) =	**2.7**		**0.377**	**68.60%**		**15.19%**		**2.31%**		**0.35%**		**0.05%**	

					Reliability for time duration (years)									
					1		**5**		**10**		**15**		**20**	
	Description	**MTTF**		**λ**	**pi**	**qi**	**pi**	**qi**	**pi**	**qi**	**pi**	**qi**	**pi**	**qi**
Company Summary	Surface tree	6.5		0.2	85.68%	14.32%	46.18%	53.82%	21.32%	78.68%	9.85%	90.15%	4.55%	95.45%
	Wellhead	48.3		0.021	97.95%	2.05%	90.17%	9.83%	81.31%	18.69%	73.32%	26.68%	66.12%	33.88%
	Tubing hanger	91.3		0.011	98.91%	1.09%	94.67%	5.33%	89.63%	10.37%	84.85%	15.15%	80.33%	19.67%
	DHSV	10.3		0.097	90.72%	9.28%	61.46%	38.54%	37.78%	62.22%	23.22%	76.78%	14.27%	85.73%
	Gas lift system	24.2		0.041	95.95%	4.05%	81.31%	18.69%	66.12%	33.88%	53.76%	46.24%	43.72%	56.28%
	Upper completion	12.5		0.080	92.28%	7.72%	66.93%	33.07%	44.79%	55.21%	29.98%	70.02%	20.06%	79.94%
	Intermediate completion	821.8		0.001	99.88%	0.12%	99.39%	0.61%	98.79%	1.21%	98.19%	1.81%	97.60%	2.40%
	Lower completion	410.9		0.002	99.76%	0.24%	98.79%	1.21%	97.60%	2.40%	96.42%	3.58%	95.25%	4.75%
	Sand control	273.9		0.004	99.64%	0.36%	98.19%	1.81%	96.42%	3.58%	94.67%	5.33%	92.96%	7.04%
	Casing	74.7		0.013	98.67%	1.33%	93.53%	6.47%	87.47%	12.53%	81.81%	18.19%	76.51%	23.49%
	HPU / logic	17.1		0.058	94.33%	5.67%	74.67%	25.33%	55.76%	44.24%	41.64%	58.36%	31.09%	68.91%
	System reliability (h_Company Summary) =	**2.1**		**0.5**	**61.61%**		**8.88%**		**0.79%**		**0.07%**		**0.01%**	

Summary

Reliability of well equipment	**t=1 year**	**t=5 years**	**t=10 years**	**t=15 years**	**t=20 years**
WellMaster	59.86%	7.69%	0.59%	0.05%	0.00%
Clair	55.85%	5.43%	0.30%	0.02%	0.00%
Ula	12.16%	0.00%	0.00%	0.00%	0.00%
Valhall	68.60%	15.19%	2.31%	0.35%	0.05%

Appendix E



Production
reservoir
Sand control system
-Cased and perforated
-Openhole/ Pre-drilled Liner
Lower completion
- Liner hanger
- Lower completion packer
Casing
Surface casing
1) Intermediate casing
Production casing
liner
2) zonal isolation cement
Upper completion
Production packer
1) Production/ injection tubing
2) Gas lift valves
DHSV system
-DHSV flapper
Flow tube
Seals
- Control line
-Void
- Exit Block
(1)
(2)
Tubing Hanger (dry)
Body lock down
Hanger body seal
Control line connection
Neck seal
Surface wellhead (dry)
Control line connection /device
Primary A to B packoff
Lock down A to B packoff
Ports and fittings
Upper Speed Head Connector
-Lower Speed Head Connector- Pressure Containment Connection Seal
-Secondary A to B packoff
Surface tree (dry)
Tree Connection Flange
Valve actuator
Upper master valve
Choke
(1)
- Choke Actuator
- Production Wing/kill valve
- Lower master valve
Production Pressure/Temperature Sensor/ Transmitter
Annulus
Gas supply
Gas lift system
ESD valve
(1)
Surface wellhead (dry)
Primary A to B packoff
Lock down A to B packoff
Ports and fittings
Intermediate casing seal from the A to B annulus
Control line connection /device
- Secondary A to B packoff
-Lower Speed Head Connector- Pressure Containment Connection Seal
Tubing Hanger (dry)
Body lock down
Hanger body seal
Control line connection
Neck seal
Annulus safety valve system
Control line, Mechanical seals
(1)
Completion
Annulus casing, eg. 9-5/8" casing
Annulus isolation eg 9-5/8" casing cement
Production tubing
(2)
Hydraulic system
HPU system
HPU
HPU line
(1)