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MASTER'S THESIS

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Abstract

Seadrill's constant strive to achieve their goal in setting the standard in drilling pursues the focus on operations excellence. The company's fleet is expanding with frequent new Mobile Offshore Drilling Units (MODU) and this might involve challenges with keeping up operations excellence from the first day. In this thesis the main object is to perform operation efficiency analyzes across three of Seadrill's semisubmersible rigs; West Venture, West Phoenix and West Eminence. The chosen operations for analyses are:

- Unrestricted tripping of drillpipe in cased hole
- Unrestricted running of casing into the well
- Running and pulling BOP

The analyses were based on Daily Operations Database Application (DODA) reports, which is Seadrill's daily operation reporting system. The reports contain specified amount of hours spent to perform the operation and the tripping distance, and tripping rates were determined and compared with the rigs. In the BOP operations the analyses emphasizes in addition on operation efficiency when placing BOP on wellhead and unlatch BOP from wellhead including the related operations. The well data are based on exploration wells, except from the first analysis which contain operations from other wells.

The outcome out the results indicates that West Venture overall attained highest rates. West Venture has been operating on the same field the last 10 years which indicates they are well prepared for challenges that might occur, and the crew is well incorporated with the procedures to perform the drilling operations in an efficient way. West Eminence attained overall lowest rates. West Eminence' first drilled well in history was included in the analyses, and the crew faced a relatively troublesome running-in stage regarding equipment on board the rig. The next analyzed well drilled by West Eminence was drilled approximately one year later and trouble with the equipment on board the rig were reported. Still, West Eminence indicates improved operation efficiency from the first drilled well to the next well drilled one year later.

The DODA-reports contained varying data quality for efficiency analysis. Some of the reports contained operations that should not be included in the operation efficiency analyses, but the report included accumulated several operations in the tripping report which made it difficult to be aware of the factual time spent on tripping operations. If better observation of operation efficiency in the DODA system is desirable, some suggestions for improvement are presented.

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Abbreviations

1	BHA	Bottom Hole Assembly
2	HPHT	High Pressure High Temperature
3	TD	True Depth
4	DP	Drill Pipe
5	MU	Make up
6	LD	Lay down
7	WOB	Weight on bit
8	RPM	Revolutions per minute
9	DC	Drill Collar
10	MWD	Measurement-while-drilling
11	LWD	Logging-while-drilling
12	NPD	Norwegian Petroleum Directorate
13	PSAN	Petroleum Safety Authority Norway
14	OLF	Oljeindustriens Landsforening
15	DDRS	Daily Drilling Report System
16	DDR	Daily Drilling Report
17	CET	Central European Time
18	RIH	Run In Hole
19	HRN	Horizontal Roughneck
20	DDM	Derrick Drilling Machine
21	SCR	Slow Circulation Rate
22	POOH	Pull out of hole
23	VPH	Vertical Pipehandler
24	OD	Outer Diameter
25	BJ	BJ Services Company
26	FMS	Flush Mounted Spider
27	BPM	Beats per minutes
28	KP	Kilo pound
29	CVP	Conduit Valve Package

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1 Introduction

This thesis studies operations efficiency and compare three semi-submersible drilling rigs, West Venture, West Phoenix and West Eminence, owned by Seadrill, and the reason for choosing these three rigs was that Seadrill experienced great variation in operations efficiency. The three rigs uses dual ramrig systems and they are all 5th and 6th generation semi-submersible rigs. The thesis will focus on operations like unrestricted tripping of drillpipe in production casing sections, running production casing into the well and running/pulling Blow out preventer (BOP). These operations are normally straight forward operations and they should be comparable with other similar rigs. The study is based on daily drilling reports from the concerned rigs and it will attempt to make a comparison of efficiency of the operations. A lot of the information in this thesis is based on internal Seadrill documents.

1.1 Background of the thesis

Seadrill experience great variations in drilling operations efficiency at some of the company's new rigs despite of state of the art drilling equipment. The company focus is on increasing the operation efficiency, and operations controlled solely by the drilling contractor can be defined as "Key steps" (ref Table 1) [1]. The "Key steps" includes for instance operations like unrestricted tripping of drillpipe, running and pulling riser, running casing and testing BOP and surface equipment. In other studies, the time spent on "Key steps" operations represented more than 30% of the total construction time of the wells [1].

1.2 Objectives

The aim at the thesis is:

- Analyze and compare activities in the daily drilling and operations reports from West Venture, West Eminence and West Phoenix. The focus will be on operations like tripping drillstring, tripping BHA[1], running casing in hole, run and land BOP with riser and pull BOP with riser.

1.3 Report structure

Chapter 2 presents a general literature study of the well construction, some equipment used in the drilling operation, the drilling crew's tasks and which operations during the well construction process that are controlled by the operator and which are controlled by the contractor. It is important to understand the difference of which operations Seadrill as a contractor can improve and the parameters that are given by the operator. Such parameters might be among other rate of penetration, mud weight and bit type. Seadrill have to make sure to oblige these instructions and has by limited extent chance to improve operations efficiency in these parameters.

Chapter 3 describes the different kind of mobile offshore drilling units that Seadrill holds.

Chapter 4 introduces the three semi-submersible rigs used for analysis in this thesis, and their track records the recent years.

Chapter 5 describes relevant operations and some consideration regarding the analyzed operations.

Chapter 6 elucidates some scientific publications that might be relevant for this work.

Chapter 7 describes the DODA-reports, which are the basis for the analysis, and the current wells the reports are collected from. It is also described how the analyses have been performed.

Chapter 8 presents and gives a discussion of the results.

Chapter 9 gives some conclusions and some suggestions for improvements.

2 Well construction process, equipment and main operations

In this chapter some general theory of the construction of the well will be presented. In addition, equipment used in the operations, the crew working on with the drilling operations and the daily operations reporting systems used by Seadrill will be described.

2.1 Construction of a well

There are different types of well that is drilled by a rig, exploration wells, production wells, HPHT[2] wells and horizontal wells [2]. Seadrill possess various MODUs, which mean that the well entrance and the wellhead are located on the seabed, in contrast to fixed installations where the wellhead might be located above sea level on the platform.

2.1.1 Drilling sequence

The sequences of drilling operation are often similar, especially the drilling part. The main general sequences of drilling a production well are:

1. Drill 36” hole
2. Run in 30” conductor casing
3. Cement casing
4. Nipple up diverter
5. Drill 26” hole
6. Run 20” surface casing
7. Cement casing
8. Drill 17 ½” hole
9. Run 13 3/8” casing

10. Cement casing
11. Drill 12 ¼" hole
12. Run 9 5/8" casing
13. Cement casing
14. Drill 8 ½" hole
15. TD[3] logging
16. Well testing
17. Run 7" liner
18. Completion
19. Production startup

2.1.2 Hole sizes

- 36" hole is normally the first drilled hole [2]. Normally it is desirable to avoid washing out the entrance of the hole, and the drilling is performed with a low flow rate. Depending on field solution, there might be a template or temporary guide base located on the seabed to help the drill bit to enter the ground.
- After the 30" conductor casing is set, the 26" hole is drilled.
- After the 26" hole is drilled, the 20" casing is set and the riser and BOP are mounted.
- 17 ½" hole is often a rather long section which might be 1000 meters or more [3].
- 12 ¼" hole might also be a long section and it often ends near the predicted reservoir [3].
- 8 ½" hole is often the last drilled hole section and it is normally penetrating the reservoir-seal and progress into the pay-zone [3].

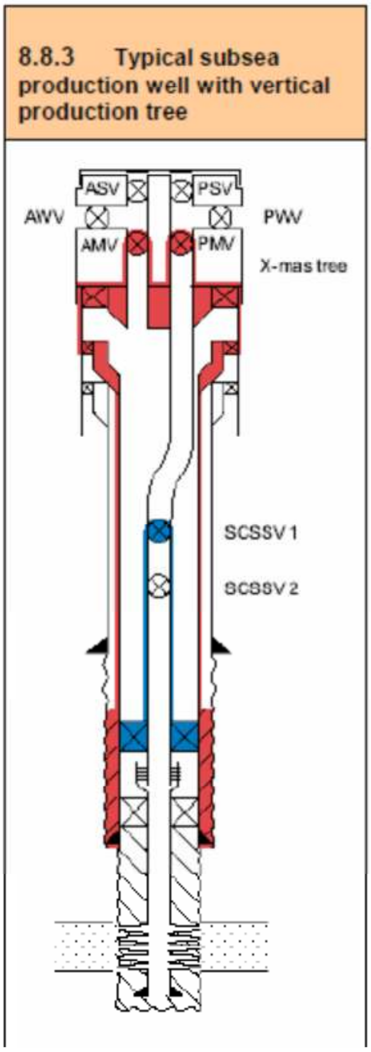
2.1.3 Casings

- When the 36" hole has been drilled, the 30" conductor casing is to be set [2]. There are basically three techniques of setting the conductor pipe: jetting, piledriving or drilling. When the conductor is set, it is cemented to surface. The most common in Seadrill is drilling, run casing in hole and then cement the casing to surface. The casing prevents the seabed from caving and allows returns to enter the sea. It may also work as foundation for the wellhead, casing and completion loads.
- The 20" casing, often called surface casing offer quite few functions [2]. It allows a BOP to be installed. The surface casing is always cemented to surface (seabed), and it is often set deep.

The 20” casing protects the wellbore from unconsolidated sand, sloughing shales, shallow gas, and potential of lost circulation.

- 13 3/8” intermediate casing should isolate all formations up to the surface casing shoe, so that the next section can be drilled safely and efficiently [3].

- 9 5/8” production casing should isolate the productive zones so that fluid cannot migrate along the wellbore [3]. This is illustrated in Figure 1 where casing is considered as a secondary well barrier. In the thesis some of the wells used 10 ¾” casing and not 9 5/8” casing, but the analyses do not take this into account. Both the sizes are considered as production casing.



Well barrier elements	See Table	Comments
Primary well barrier		
Production packer	7	
Completion string	25	Production tubing between SCSSV and production packer.
SCSSV	8	SCSSV 1 or SCSSV 2.
Secondary well barrier		
Casing cement	22	
Casing	2	
Wellhead	5	W/ casing hanger and seals.
Tubing hanger	10	
Subsea production tree	33	Annulus bore w/master valve, production bore w/master valve.

Note
None

Figure 1 - NORSOK standard barriers [4]

- 7” production liner is set across the reservoir and is normally tied back in the previous casing and not to the surface [3].

2.2 Responsibility & Main Operations

In this section the roles of operator, contractor and service vendors are presented. In addition some of the relevant drilling operations reported in the daily drilling operations reports are described.

2.2.1 Companies role in the oil industry

In the oil industry, one normally distinguishes between operator, contractor and service vendors:

Operator

The oil companies serves as the operator and normally is the head of the drilling project and makes the important decisions [5]. Typically oil companies in the Norwegian continental shelf are Statoil, ConocoPhillips and Shell. Often the operator has the major stake in the project, and also gains the profit.

Contractor

The contractor is the company that owns and operates the drilling rig, like for example Seadrill [6]. Normally the drilling contractor receives payment for services rendered. The operator normally pays the contractor a daily rate for the rig and the crew. This may not include fuel, casing, wellheads, logging-services or cementing. Often the day rate represents approximately half of the cost of a well. From the contractor's view, the total daily cost to drill a well is roughly twice the rig's day rate.

Other contracting methods are footage rates (dollars/meter drilled) or turnkey operations, where the contractor receives a lump sum payment for drilling a well.

Service companies

Service companies deliver equipment, services and solutions to the oil and gas companies to improve performance in all related drilling operations [7]. The service companies often hold key competence within their domain or niche. Halliburton delivers for example downhole equipment like completion tools, drilling mud, drilling bits etc. Aker Solutions for example delivers surface equipment like dual ramrig system, iron roughnecks etc.

The operator's and contractor's responsibility

When analyzing the performance of the operations in this task, it is important to distinguish between the operator's and the contractor's responsibilities [1]. From Seadrill's point of view, they have to deal with instructions and responsibilities given by the operator and try to optimize their internal procedures and operations that are not governed by the operator. Such operations might be unrestricted tripping of drill pipe, running casing etc. These operations are described in Table 1, which shows a typical distribution of responsibility between operator and contractor.

Drilling contractor's responsibility	Shared responsibility	Operator's responsibility

• Tripping DP[4] (in casing)
• Run casing
• Run riser
• Pull riser
• M/U[5]& L/D[6]BHA
• Positioning
• Pre-spud activity
• BOP subsea test
• Surface equipment test
• HSE proactive duties
• Rig maintenance
• Rig crew training
• Housekeeping
	• Drilling
	• Circulating
	• Horizontal displacement
	• Observe and control drilling parameters
	  o WOB[7]
	  o RPM[8]
	  o Pump rate
		• Well path
		• Mud
		• Hole diameter
		• Bit type
		• BHA's
		• Casing strings
		• Casing complexity
		• Shallow water or gas
		• Hydrates
		• H2S/CO2
		• Salt drilled

Table 1 - Typical distribution of responsibility between operator and contractor [1]

2.2.2 Main operations

In this section the most relevant operations reported in the daily drilling operations reports will be described.

Tripping pipe

This operation implies running in or pulling the drillstring out of the hole [8]. Tripping operation is normally done because the drill bit is worn or for some reason needs to be replaced. If running in hole, the pipe threads ends are connected by the iron roughneck on the drillfloor and lowered down to correct depth for connecting the next drillpipe. When pulling out of hole, the operation is performed in the opposite manner.

Flow check

The flow check is usually performed to among other things to make sure of stable well conditions [9]. In most cases this operation comprises observing stable fluid levels for a predetermined amount of time. According to procedures this operation normally takes at least 15 minutes.

Change slips

Slips are located in the rotary table and holds the drillpipe [10]. The drillstring is then in tension below rotary table and the crew can screw or unscrew the upper part of the drillstring. When the spin operation is done, the driller raises the drillstring so that the crew can remove the slips from the rotary table and continue the operation.

Break circulation

The break of circulation is often performed to for example to take a survey, or a round trip (pulling the entire string out of the wellbore and back) [11]. This is necessary to be done in certain operations like for example logging.

Fill pipe

When running drillpipe in hole, it has to be filled with mud inside the string during the tripping to equalize potential pressure differences between inside and outside the drillstring.

Pump slug

When pulling drillpipe out of hole, the volume the drillstring makes in the wellbore has to be replenished with mud as the drillstring is moving out of the hole. This is done to maintain well control and not expose the well to potential harm.

2.3 Downhole and surface equipment

To perform operations one a rig, a lot of equipment are used. In this thesis the most relevant equipment are presented. It is mostly pipe handling equipment and other tools related to the drilling operations.

2.3.1 Surface equipment

In this section relevant equipment for the operations performed on the drillfloor are presented.

Iron Roughneck

The iron roughneck is used to connect and disconnect drill pipes, drill collars and other equipment [12]. The introduction of iron roughneck eased the work load for the roughnecks as well as reducing the risk of personnel injury.

Figure 2 - Iron roughneck [12]

Manipulator arm

This device supports the drillcrew by ease and secure safe handsfree operations on the drill floor area [12]. Common functions are:

- Guiding the lower pipe end or casing from V-door to center of well
- Guiding riser in hoisting operations
- Lifting bottom hole assembly components

Figure 3 - Manipulator arm [12]

Mud bucket

This device transports drill string mud smooth and safe to the mud tank [12].

Figure 4 - Mud bucket [12]

Gantry crane

The gantry crane transfers the drillpipes from storage area to the catwalk machine and conversely [13].

Figure 5 - Gantry crane [14]

Fingerboard

In draw works derrick systems the fingerboard is used to store the pipe vertically in the derrick [7]. In dual ramrig systems the fingerboard might be placed horizontal at the drillfloor, which gives less over-head operations [15]. The pipes are stored in slots where steel fingers keep them in place.

Slips

Slips are used to grip the drillstring and hold it fixed in the rotary table [16]. The equipment consists of steel wedges that are hinged together, formed to entwine the drillpipe. After the slips are placed around the drillpipe and into the rotary table, the drillstring can be lowered. The gravity force of the string provides a compressive force that wedges the drillpipe to the slips and locks the string so that the upper part of the drillstring can be managed. After the connection or disconnection of drillpipe is done, the driller can raise the drillstring and the crew removes the slips from the rotary. Slips can me set manually or automatically by using power-slips.

Figure 6 - Manual slips (left) and Power-Slips (right) [17]

Safety clamps

Figure 7 - Safety clamp [18]

Safety clamps are used to secure various tubular products during installation [18]. The safety clamp prevents the drillstring from being dropped downhole accidentally if the slips or elevators securing the string lose their grip. In combination with manual slips, the clamp will land on top of the slips, adding extra slip-force to the slips which will contribute to more effective jamming of the tubular in the slips.

Bushing

Bushings are inserted into the rotary table to ensure alignment of drillstring with the center of the well [19]

Figure 8 - Casing bushing [19]

Casing Running Tool

A casing running tool may consist of several equipment tools in one casing-running assembly [20]. The combination and features gives several operational efficiencies by automating the casing running operations, reducing the amount of manpower and reducing the amount of equipment to rig up. The casing running tool is directly connected to the topdrive, and is able to hoist single joints of casing, make up the casing connections, pick up and run the casing string in hole.

Hoisting systems

There are mainly two categories of hoisting systems on a rig, ramrig and drawworks[21].

Dual Ramrig

Figure 9 - A typical dual Ramrig concept [22]

The ramrig design uses most of the same equipment as a conventional single derrick system, but the tower/derrick design is different [20]. Depending on capacity requirements, the hoisting system can consist of two or more cylinders. The hoisting wires are anchored in the drillfloor and to the topdrive, and has a travelling yoke (two wheels) connected to the wires. This connection gives the speed and travelling distance of the top drive which is twice the stroking distance of the cylinders. The Ram Guides are used for guiding the rams to keep them in track. In ramrig, the center of gravity of the rig is lower than to a conventional rig. One reason is that the pipes are stored on a lower deck (not vertically on the derrick). The lifting force is generated by the cylinders (Rams) and not by the draw works, which lead to drilling with constant speed instead of constant weight [20]. This might be of great advantage when drilling in deep and ultra-deep water. There are two topside drilling packages, the main and the auxiliary derrick. A Dual ramrig can either drill two separate holes or use both the ramrigs on a single hole. The operations are performed in parallel, and not in sequence. The advantage with this design is that some operations can be moved out of the critical path.

Draw works

The draw work is basically wires winched over the travelling block and the crown block that forms the lower and hoisting function [16]. The structure used to support the crown blocks and the drillstring is called derrick[23]. They are usually in pyramidal shape and offer good foundation for heavy lift operations. This type of draw works is very common on rigs, but the rigs analyzed in this thesis use the dual ramrig system. A crown block is a fixed set of sheaves located at the top of the derrick, where the drilling line is threaded[24]. The traveling blocks are positioned below the crown block and the sheaves are lashed around the two blocks to provide the hoisting and lowering function. By use of several pulleys, one can use relatively small lines to hoist loads much heavier than a single line can handle.

Figure 10 - West Aquarius, a semi-submersible with derrick tower [25]

Top Drive

A topdrive is used to rotate the drillstring [26], and it consists of one of more. The topdrive is suspended from the hook, and can travel up and down inside derrick. Topdrive is different from the rotary table and Kelly method because it can perform drilling operations with three joint stands instead of single joints of pipe. The driller can also quickly engage the pumps or the rotary while tripping pipe, which is not that handy with the Kelly system. Modern topdrives are a major improvement to drilling rig technology and has made it possible to drill more extended horizontal-reach wells and has also contributed with reducing the risk for stuck pipe.

Figure 11 - Topdrive [27]

Pipe handling equipment

All the three rigs uses two AKMH-1899 hydraulic roughnecks, one on the main rig and one on the aux rig [28]. Iron roughnecks have replaced several operations the roughnecks had to perform earlier like spin in/make up/break out and spin out drill pipe, drill collar and other various tools. They are more effective than man power and reduce the risk for accidents on the rig since the hydraulic machines are normally operated remotely from the control room.

RUNNING AND HANDLING OF TUBULARS	West Phoenix / West Eminence	West Venture
Iron roughneck	Hydraulic Auto Roughneck AKMH-1899 (2 ea. one in Main and one in aux rig)	Hydraulic Auto Roughneck AKMH-1899 (2 ea. one in Main and one in aux rig)
Drill floor manipulator arm	AKMH type BC-072 (2 ea. one in main rig and one in aux rig)	AKMH
Remote casing tong	No	No
Pipe handling system from fingerboard to drill floor level	AKMH pipehandling system 2 ea. bridge cranes, 2 ea. lower guiding arms.	AKMH pipehandling system 2 ea. bridge cranes, 2 ea. lower guiding arms.
Cat head (EZY torque)	AKMH hydraulic Cat Head (2 ea. one in main rig and one in aux rig)	AKMH hydraulic Cat Head (2 ea. one in main rig and one in aux rig)
Block retraction system	No	No
Remote control systems for transport of DP, DC[9] Casing. etc. from pipedeck to the drillfloor	AKMH, 1 ea. gantry crane, 2 ea. tubular feeding machines and 2 ea. pipe shutes.	AKMH, 1 ea. gantry crane, 2 ea. tubular feeding machines and 2 ea. pipe shutes.

Table 2 - List of running and handling of tubulars equipment on the rigs [28]

2.3.2 Downhole equipment

In this section the equipment used in the well are presented.

Casing

Casing is a large-diameter pipe lowered into an openhole, isolates the well from the formation. It must withstand various loads like collapse, burst and tensile force [7]. The casing is run into the hole to protect the wellbore from adjacent formation. The main purpose of casing in the well is:

- To protect fresh-water aquifer
- Provide foundation for installation of wellhead equipment
- Provide pressure integrity
- Seal off weak or fractured formations to avoid fluid loss
- Seal off weak formation so that stronger formation can be penetrated safely
- Seal off high-pressure formation so that lower pressure formation can be drilled with lower fluid densities

Drill string

The drill string is typically made up of the following sections:

- Bottom hole assembly (BHA)
  BHA is the lower portion of the drillstring and consists of the bit, bit sub, a mud motor (in certain cases), stabilizers, drill collar, heavy-weight drillpipe, jarring devices (jars) and crossovers[7]. The main purpose of the BHA is to provide weight on bit and provide directional control when drilling. Often the BHA includes useful measuring equipment like MWD [10]-tools, LWD [11]-tools and other devices.

- Drill Collars
  Drill collars are used to deliver WOB (weight on bit) for drilling, and they are thick-walled tubular [7]. Multiple collars can be screwed together along with other tools to make bottomhole assembly.

- Transition pipe, Heavy Weight Drill Pipe (HWDP)
  A HWDP provides a gradual transition from heavy drill collars to lightweight drill pipe [29]. This design prevents stress concentration at the top of the drill collars. HWDP is well-suited for directional drilling, because it bends easily, in addition it allows drilling at higher Rotations per Minute (RPM) and reduces torque in the well.

- Drillpipe
  The pipes are normally made of steel with threaded ends [7]. One stand is normally made up of three drillpipes. The drillpipe connects the rig surface equipment with the BHA and the bit and is used for pumping drilling fluid to the bit and to lower/hoist and rotate the bit.

- Subs
  Subs are a short threaded piece of pipe used to adapt improper drillstring parts to fit into the string. Subs may also perform a special function, for example lifting subs which might be used with drill collars to provide a shoulder to fit the drill pipe elevators.

- Drill bit
  The drill bit is the bottom of the drillstring and is the unit that penetrates the formation [7]. The bit is making new hole either by scraping or crushing. The bit will perform the operation by help of rotational motion and the weight-force.

BOP

BOP is a large valve at the top of the well that can be closed off if the driller loses control of the formation fluids. The BOP is considered as a part of the well barrier elements during well operations [4].

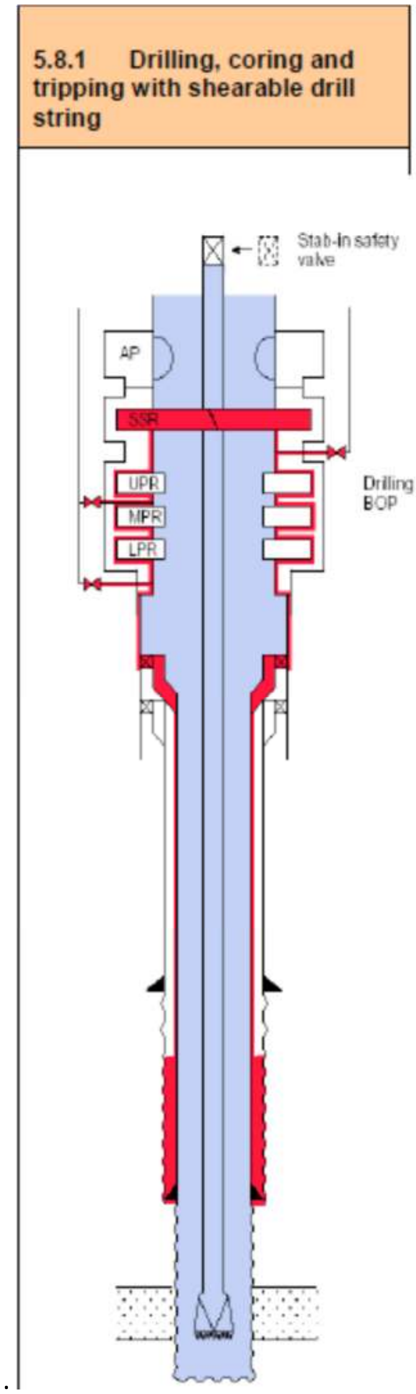


Figure 12- BOP [4]

The valves are usually remotely hydraulically operated, and certain procedures can be started to regain control of the reservoir pressure if a kick occur. If control is not gained by circulating kill mud, the rams can be activated by closing off the wellbore. The BOPs come in different designs and normally contains pipe ram, blind ram and shear ram.

- Pipe ram seals around the pipe in the wellbore
- Blind ram seal off the whole wellbore when the drillstring is out
- Shear ram seal off the whole wellbore even if the drillstring is in hole. The ram then cuts the drillstring and is normally used in extreme situations when severe kick occur and there is not enough time to trip out the drillstring.

The blowout preventer is very important to the safety of the drill crew and it is very important that it is always working to keep the well under control.

Slip joint

The slip joint is connected to the riser below and it is a telescopic joint that allows vessel heave without expose the riser to comprehensive tension force [30].

Riser

The riser is a large diameter pipe that connects the subsea BOP stack to the floating surface rig [7]. Cuttings and drilling mud are transported back to the surface through the riser. The riser pipe diameter is large enough to allow passage of drillpipe, logging tools and multiple casing strings.

Christmas tree

The Christmas tree is an assembly of spools, pressure gauges, chokes and valves fitted to the wellhead [7]. It can be used to control production, or to direct and control the flow of formation fluid from the well.

2.4 Roles and responsibilities

In this section the drilling crew will be presented.

2.4.1 Drilling crew

The personnel who operates the drilling rig typically consist of roustabouts, roughnecks, derrickmen, assistant drillers, driller, toolpusher and rig leader [7]. The drilling rigs operate 24 hours every day, and normally there are two crews working 12 hours each.

Toolpusher

The toolpusher is the contractor's drilling supervisor located on the rig, and he normally carries out administrative tasks like verify that the rig has sufficient materials, spare parts and crew to maintain efficient operations [7].

Rig leader

The rig leader is the operator's drilling supervisor located on the rig, and he normally verifies that the drilling operation goes on according to the planned instructions compiled by the operator.

Driller

The driller is the supervisor of the drilling crew, and he is responsible for the drilling operations and safety of the crew [7]. The driller`s role is to supervise the operations and control the major rig systems like pumps, drawworks and rotary table from the control room.

Derrickmen

The derrickman works on a platform (called monkeyboard) attached to the derrick which is located about 26 meters above rig floor [31]. During tripping operations, the derrickman wears a special harness that helps him to lean out from the fingerboard to throw a line around the drillpipe in the center of the derrick and pull it back to its storage location (fingerboard). This operation can be quite challenging, but in modern drilling rigs the derrickman has been replaced by automated pipe-handling equipment. Now the derrickman controls the pipe-handling machinery.

Machinists

The machinists are responsible for maintenance of the engines. While all members of the rig crew help with major repairs, the machinists perform routine preventive maintenance and minor repairs.

Roughnecks

Traditionally, typical tasks for a roughneck were to make up or break connections of drillpipes that is tripped in or out of the hole. That task is now replaced by iron roughnecks, so now roughnecks assists in operations like maintenance and repairing equipment on the drill floor and derrick.

Roustabouts

Roustabouts are the general name for an unskilled worker on the rig [32]. Their jobs are normally to ease the skilled personnel's jobs so they can focus on the important tasks. Typical jobs for a roustabout are cleaning up location, scraping and painting rig components etc.

2.5 Reporting

Daily Drilling Reports

The daily drilling reports are an important tool to get an overview of the activity performed on the rig every24-hour periods, and the reports are distributed to the contractor, the operator and the authorities [33].

Standards

The Norwegian authorities (NPD[12]and PSA[13]) have since 1984 required daily drilling reports from the operators that perform drilling activity in the Norwegian continental shelf. From 18.2.2008, a new standard (ISO 15926) were implemented. The standard are based on a collaboration including Norwegian and foreign oil companies, Energistics, NPD and PSA. OLF[14] has been the coordinator for implementing the new standard in Norway. This standard will also be used for internal communication between companies. From 01.10.2009, some changes in the reporting format were performed. The most important was that the daily reports could be sent through LicenceWeb. LicenceWeb is the official communication tool for all licenses on the Norwegian Continental Shelf [34].

Reporting routines and content

The Authorities requires that all drilling and well activities should be reported daily to their DDRS[15] system [33]. This reporting should be done each working day. During holidays and weekends, the reports can be delivered the following working day. Each report should be delivered before 08.00 in the morning, and the ordinary DDR[16] should be reported at 24.00. For exploration wells, a final report should be issued within six months after the well is completed [35].

2.5.1 DODA

DODA is Seadrill's daily operations reporting software [36]. Key data from well, marine and drilling operations are registered daily in this database. The database provides the generation of the daily operations reports and special reports which can for example be used for comparing operational parameters across the different rigs. The database is operated through a web interface.

Data registration

Each rig shall register relevant key data for marine and drilling and well operations daily in accordance with DODA instructions. Data registration should preferably be completed by 07:30 CET[17] the following day, so that the onshore organisation can be updated before any morning meetings. At 07:50 the reports are automatically generated, and on Monday the weekly report is also generated at this time.

Input for data registration

The database consists of many tables, and the data registration module gives the users access and possibility to modify several tables.

The following tables can be used in data registration:

Rig and Well	Operator and well identification
Budget	The well`s time budget
Section	The well`s sections (depth etc.)
Daily Drill	Daily operational information
Daily Marine	Daily operational information
Operations 24h	Daily operational information
Bit	Information about the current drill bit
Drill Parameters	Daily operational information
Weekly	Weekly information

Table 3 - Modules in data registration [20]

Rig and Well

The information about operator and well identification are registered once per well and contain key information about the operation like:

- Installation, the name of the rig performing the operation
- Operator
- In which field the well is located
- Well, name of the well
- Well type
- Country
- Water depth
- Planned Well TD
- Planned days for drilling
- Planned days for completion
- Well start
- Spud date
- Total days drilling
- Total days for completion
- Multi-lateral well

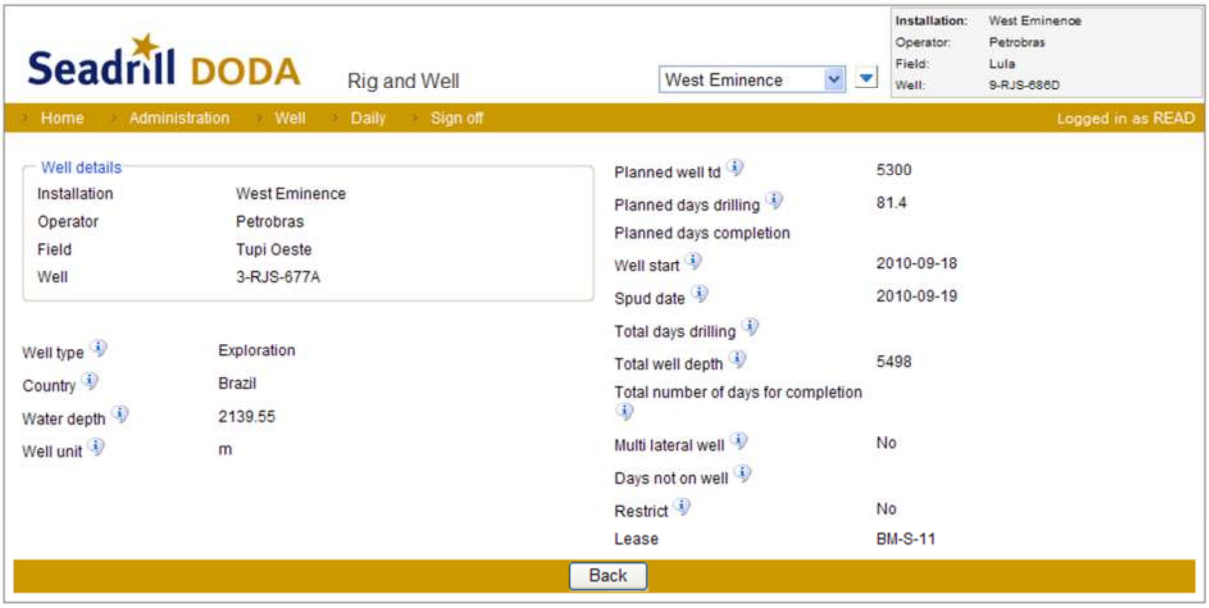


Figure 13 - DODA rig and well screenshot [20]

Budget

This section shows information about the predicted time budget. For registration of time budget, the well has to be divided into activities. Every section should be divided into drilling activity other activity. As the well is progressed the result is shown in Figure 14. Every operation should contain the following data:

- Activity number
- Hours planned
- Well depth (the current depth of well when activity is done)

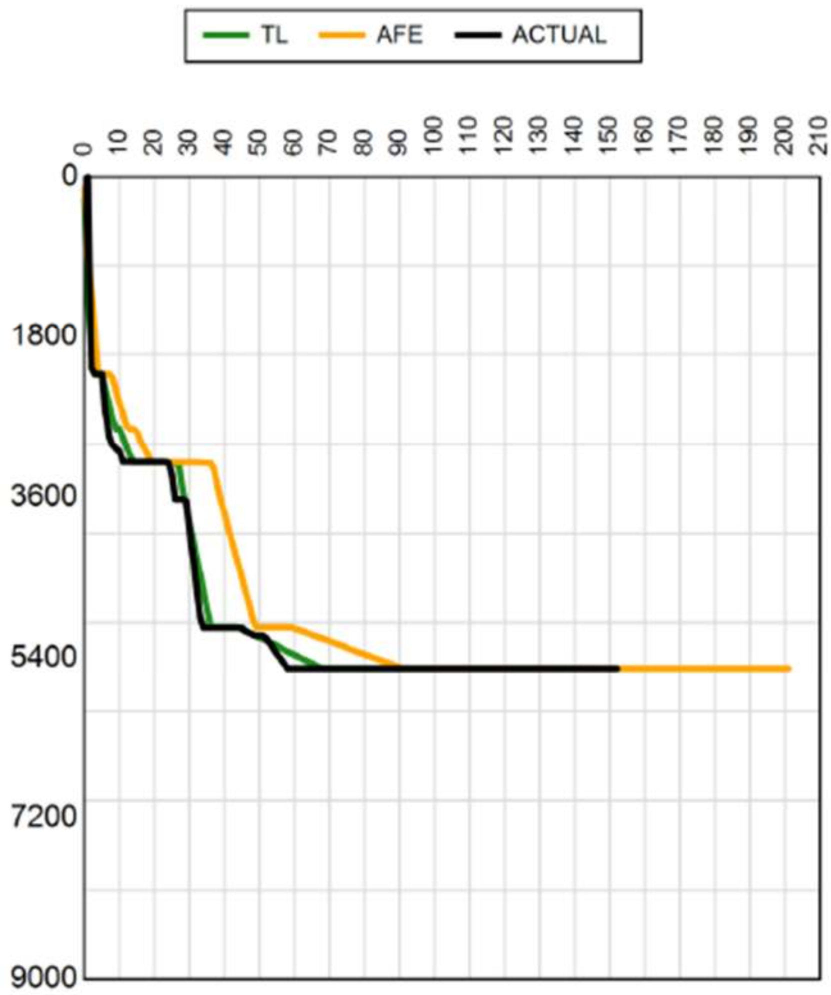


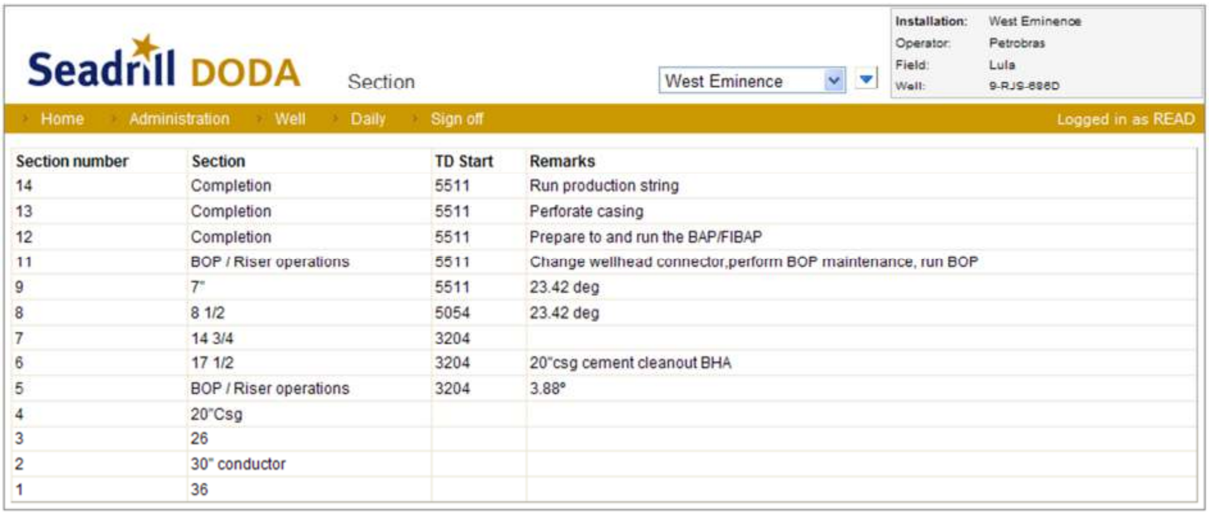
Figure 14 - DODA time budget overview screenshot [20]

In the reports a diagram compares the technical limit (TL), approval for expenditure (AFE) and the actual performance of the well. The X-axis shows the time spent in days, and Y-axis shows the current drilled depth in meters.

Section

This section provides information about the well sections (depth etc.). In order to register true time consumption, well depth and inclination for each hole section, the well have to be divided into sections. Every section should be registered with the following data:

- Section number
- Section
- True depth start
- Inclination at start of section
- Remarks



Section number	Section	TD Start	Remarks
14	Completion	5511	Run production string
13	Completion	5511	Perforate casing
12	Completion	5511	Prepare to and run the BAP/FIBAP
11	BOP / Riser operations	5511	Change wellhead connector,perform BOP maintenance, run BOP
9	7"	5511	23.42 deg
8	8 1/2	5054	23.42 deg
7	14 3/4	3204	
6	17 1/2	3204	20"csg cement cleanout BHA
5	BOP / Riser operations	3204	3.88°
4	20"Csg		
3	26		
2	30" conductor		
1	36		

Figure 15 - DODA section screenshot [20]

Daily Drill

Daily input of drilling operations and well operations from the rig is registered in this section. Some important Health Safety Environment Quality (HSEQ) input data registered are:

- Days since last personnel injury
- Date last lost time accident (LTA)
- Number of synergy reports (software where all HESQ issues like personnel injury, dropped objects and spilled fluid are reported)

Some important drilling operations input data are:

- Days ahead or behind plan
- Current well depth
- Last 6 hours operation of auxiliary ramrig
- Comments from the drilling crew

Some important well operations input data are:

- Total pipe tripping length (sum total tripping distance in/out) code 6A
- Total casing tripping length (sum total tripping distance in/out) code 12A
- Total riser tripping length (sum total tripping distance in/out) code 14A
- Last casing size
- Shoe depth last casing
- Information about BHA equipment

Some important stock, consume and weight input data:

- Mud weight at 24:00 hours
- Current mud in use
- Stock of brine, mud, etc.

See Appendix B for an example of how the information looks like in a report.

Daily Marine

This is the daily input of operational information from the weather and sea conditions. Some important marine operations input are:

- Wind speed and direction
- Sea waves and amplitude (max)
- Vessel movement

See Appendix B for an example of how the information looks like in a report.

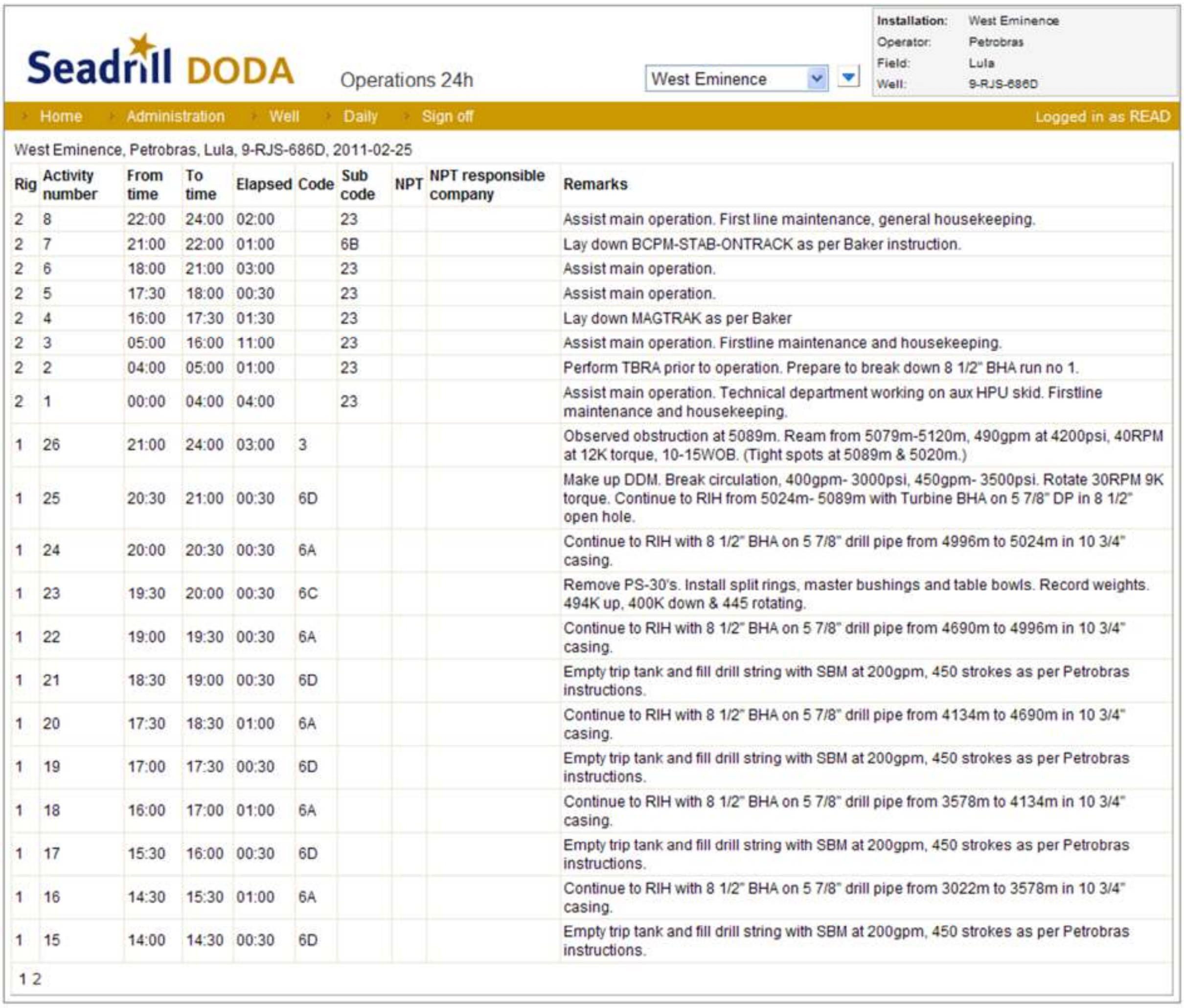
Operations 24h

This is the basis to the analyses performed in this thesis. In operations 24h, the rig leader describes the activities performed in a 24-hour period. The following information should be registered for every activity period:

Rig	Main/Aux: if the rig possess dual ramrig
Actual section	Last inserted section will automatically be chosen.
Activity number	Automatically generated
To time	Chosen from calendar
Code	Chosen from a predefined assortment
Down	Downtime should be marked by "Down"
Downtime responsible company	Chosen from a predefined assortment
Remarks	Any comments to the operational activity.

Table 4 - Operations 24h [20]

Figure 16 shows an example of the operations 24h section. More in depth will be described in chapter 7. The purpose is to give a view of what actually happens on the different rigs. The remarks section give comments to what has been done, and must be as short and concise as possible without omit essential information.



Rig	Activity number	From time	To time	Elapsed	Code	Sub code	NPT	NPT responsible company	Remarks
2	8	22:00	24:00	02:00		23			Assist main operation. First line maintenance, general housekeeping.
2	7	21:00	22:00	01:00		6B			Lay down BCPM-STAB-ONTRACK as per Baker instruction.
2	6	18:00	21:00	03:00		23			Assist main operation.
2	5	17:30	18:00	00:30		23			Assist main operation.
2	4	16:00	17:30	01:30		23			Lay down MAGTRAK as per Baker
2	3	05:00	16:00	11:00		23			Assist main operation. Firstline maintenance and housekeeping.
2	2	04:00	05:00	01:00		23			Perform TBRA prior to operation. Prepare to break down 8 1/2" BHA run no 1.
2	1	00:00	04:00	04:00		23			Assist main operation. Technical department working on aux HPU skid. Firstline maintenance and housekeeping.
1	26	21:00	24:00	03:00	3				Observed obstruction at 5089m. Ream from 5079m-5120m, 490gpm at 4200psi, 40RPM at 12K torque, 10-15WOB. (Tight spots at 5089m & 5020m.)
1	25	20:30	21:00	00:30	6D				Make up DDM. Break circulation, 400gpm- 3000psi, 450gpm- 3500psi. Rotate 30RPM 9K torque. Continue to RIH from 5024m- 5089m with Turbine BHA on 5 7/8" DP in 8 1/2" open hole.
1	24	20:00	20:30	00:30	6A				Continue to RIH with 8 1/2" BHA on 5 7/8" drill pipe from 4996m to 5024m in 10 3/4" casing.
1	23	19:30	20:00	00:30	6C				Remove PS-30's. Install split rings, master bushings and table bowls. Record weights. 494K up, 400K down & 445 rotating.
1	22	19:00	19:30	00:30	6A				Continue to RIH with 8 1/2" BHA on 5 7/8" drill pipe from 4690m to 4996m in 10 3/4" casing.
1	21	18:30	19:00	00:30	6D				Empty trip tank and fill drill string with SBM at 200gpm, 450 strokes as per Petrobras instructions.
1	20	17:30	18:30	01:00	6A				Continue to RIH with 8 1/2" BHA on 5 7/8" drill pipe from 4134m to 4690m in 10 3/4" casing.
1	19	17:00	17:30	00:30	6D				Empty trip tank and fill drill string with SBM at 200gpm, 450 strokes as per Petrobras instructions.
1	18	16:00	17:00	01:00	6A				Continue to RIH with 8 1/2" BHA on 5 7/8" drill pipe from 3578m to 4134m in 10 3/4" casing.
1	17	15:30	16:00	00:30	6D				Empty trip tank and fill drill string with SBM at 200gpm, 450 strokes as per Petrobras instructions.
1	16	14:30	15:30	01:00	6A				Continue to RIH with 8 1/2" BHA on 5 7/8" drill pipe from 3022m to 3578m in 10 3/4" casing.
1	15	14:00	14:30	00:30	6D				Empty trip tank and fill drill string with SBM at 200gpm, 450 strokes as per Petrobras instructions.

1 2

Figure 16 - DODA Operations 24h screenshot [20]

The system separates between main rig and auxiliary rig (Rig 1 and Rig 2). Only 24 hours per day (out of maximum 48 hours) should be classified as primary operations. It is possible to perform primary operations in an alternating manner between main and auxiliary rig. The system possesses the possibility to report activities every 15 minutes, but normally every 30 minutes is acceptable for the customer (operator).

Bit

This section gives information about the drill bits. One input for each drill bit used. Some important inputs are:

- Bit size
- Bit number
- Manufacturer
- Bit type
- Hours run
- Footage drilled

Drill Parameters

This section gives information about the daily drilling parameters, and some important inputs are:

- Current depth
- Current well deviation
- WOB
- RPM
- Torque
- Pump pressure
- Strokes per Minutes (SPM)

Weekly

The weekly report is a summary of the last week's operations on the rig. Some input parameters for the weekly report:

- Drilling activity this week and plan for next week
- Marine and dynamic positioning activity this week and plan for next week
- Technical and maintenance activity this week and plan for next week

Reporting

The reporting routines are separated into two sections:

Daily report

The reports are automatically generated from key information presented in this section. It is a total overview of the status on the different rigs on a short term and includes the 24-hour activities, bit information, rig information, mud storage and much more. See Appendix B for an example of a daily report.

Weekly report

This report contains a short summary of the daily reports from the last week, month, quarter and year. This is a general operational overview of the different rigs in a longer term. Key information regarding for example downtime, sick leave and tripping speed are presented. The rig leader also comments events and activities last week, and plans for the following week. See Appendix B for an example of a weekly report.

3 Rig units

Seadrill holds several types of Mobile Offshore Drilling Units [25]. In this chapter the most common rig units are presented.

The rigs are classified for which water depth they can operate. Deeper water depths require larger rigs with more storage capacity. The different kind of rigs holds various characteristics, which makes some of them more suited in for example harsh ultra deepwater environment. In this thesis it has been carried out analyses of three of Seadrill's rigs, which are 5th and 6th generation semi-submersibles.

Class name	Depth [m]
Shallow water	<150
Deepwater	150-1000
Ultra deepwater	>1000

Table 5 - Water depth classification [37]

Figure 17 shows the different kind of rig units Seadrill holds.

Figure 17 - Different kind of rig units [25]

3.1 Jack-up

Figure 18 - Offshore Intrepid, a jack-up rig [25]

A jack-up rig is a mobile self-elevating drilling unit with normally three structure legs which is lowered down to the seafloor and the body is hoisted above sealevel [25]. When the rig is in transit, the structure legs are raised and the hull is riding the sea while a tugboat is moving the rig.

3.2 Tender rig

Figure 19 - T3, a tender rig [25]

With tender rig one can drill from a wellhead platform installation without install a rig permanent drilling package [25]. The rig is moored next to the platform and the module-based drilling packages are lifted onto the platform. When drilling, much of the equipment is stored on the rig, and it also offers quarters and helicopter deck.

3.3 Semi-submersible

A semi-submersible is composed a deck which is supported by columns down to the pontoons [38]. When the rig is in transfer, the vessel floats on the pontoons. This makes it easy to enter ports where there normally is shallow water. The pontoons are submerged into the water with ballast at the field. Historically the first generation semi-submersibles were built in the early 1960s[39]. A short overview of the semi-submersible rig generations:

Generation	Water Depth	Dates
First	200 m	Early 1960s
Second	300 m	1969–1974
Third	500 m	Early 1980s
Fourth	1000 m	1990's
Fifth	2500 m	1998–2004
Sixth	3000 m	2005–2010

Table 6 - The semi-submersible generation overview [40]

Figure 20 - West Phoenix, a semi-submersible rig [20]

The fifth generation Semi Submersibles has the possibility of incorporated early production capability. This requires crude oil storage capacity, additional topsides, and offloading systems [41]. The crude oil storage option boosts the dimensions of the rig, higher initial investment, operational costs and profit margin might be reduced. The fifth generation includes new ideas of how to make up and run drillstring components, riser pipe, casing and tubing [42]. Up to Quadruples of pipe are being made up at “Mouse-hole stations” including their own mechanized handling and make up equipment. As a result of this, prefabrications of stands of risers, drill pipe and casing stands can be carried out offline without interrupting drilling operations. Compared to the fourth generation semi submersibles, these rigs can operate in deeper water depths where one faces new challenges. This requires new concepts to reduce the well cost to an economically defensible level. The cost is mainly related to the rate of penetration and due to activities like tripping, logging, running casing etc. where no drilling depth is made.

Approximately one third of the total rig time is spent on drill string tripping and other running operations [42]. Increased efficiency on pipe handling and make up time will significantly reduce the total time required to drill a well. By replacing people involved in the pipe handling with mechanized technology, the job is done more efficient and with less risk exposed to the crew.

The sixth generation MODUs are a further development of the fifth generation vessels by growing even into larger units [41]. These units may operate in harsh weather conditions where other earlier generations of MODUs are forced to give up [22]. This contributes to cost-efficiency. The vessels are capable of operating in water depth down to approximately 3 000 meters, and drilling exploration and development well down to more than 9 000 meters [43]. Larger vessels come at higher initial investment and operational cost, but also at a higher cost in terms of sustainability and environmental impact [41]. Semi-submersibles keeps in position above the well by using computer controlled thruster system (dynamic positioning) [25].

3.4 Drillship

Drillships are equipped for drilling, and keeps stationary above the well by using a computer-controlled thruster system (dynamic positioning) [25]. Drillships can work in deep and ultra-deep environments.

Figure 21 - West Navigator, a drillship [20]

4 Presentation of the rigs used in the analysis

The three selected rigs for this thesis are semi-submersibles capable of double ramrig operations [43]. Double ramrig operations are capable of working in harsh environment and in areas of ultra-deep water [15].If needed, it can be fit for arctic environments. The double ramrig solution provides dual rig functions at a lower operational cost compared to conventional dual rig solutions.

Rig name	Rig type	Derrick type	Current location	Max water depth	Rig generation	Production year
West Venture	Semi-submersible	Double ramrig	Troll 31/2, Norway	2 600 feet	Fifth	2000
West Phoenix	Semi-submersible	Double ramrig	Devenick field, UK	10 000 feet	Sixth	2008
West Eminence	Semi-submersible	Double ramrig	Lula field, Brazil	10 000 feet	Sixth	2009

Table 7 - Key information of the rigs [20]

4.1 West Venture

Figure 22 - West Venture [20]

West Venture is a fifth generation semi-submersible rig[28]. The unit was built in 2000 [43] and is equipped with dual derricks for simultaneous operations. The dual derricks will share a common vertical setback for drill string and marine riser. The rig is particularly well suited for drilling in deeper waters and harsh environments.

Key features include high deck loads and storage capacities, which will render the rig less dependent on logistic support.

In Table 8 West Venture's operation record the last year is presented.

Country	Operator	Field	Well	Well Type	Well Start
Norway	Statoil	Troll 31/2	E-4 P&A	Development Sub-Sea completions; horizontal, single and multilateral wells. West Venture has operated on Troll field in water depth between 314 m to 382 m. All operation of West Venture at the Troll field is on DP station keeping.	February 2011
Norway	Statoil	Troll 31/2	O-23 Completion		January 2011
Norway	Statoil	Troll 31/2	K-12 P&A		December 2010
Norway	Statoil	Troll 31/2	D-1 Completion		December 2010
Norway	Statoil	Troll 31/2	Z-1 Completion		November 2010
Norway	Statoil	Troll 31/2	Z-2 Drilling 17 ½"-8 ½" Completion		November 2010
Norway	Statoil	Troll 31/2	Z-1 Drilling 36"- 8 ½"		October 2010
Norway	Statoil	Troll 31/2	Z-2 Drill 36"/26" hole		September 2010
Norway	Statoil	Troll 31/2	P-13 completion		September 2010
Norway	Statoil	Troll 31/2	S-14 Re-entry		August 2010
Norway	Statoil	Troll 31/2	Y-23 Top completion		July 2010
Norway	Statoil	Troll 31/2	O-21 Install X-Tree		July 2010
Norway	Statoil	Troll 31/2	O-26 Install X-Tree		July 2010
Norway	Statoil	Troll 31/2	G-3 Re-entry P&A		July 2010
Norway	Statoil	Troll 31/2	P-13 Re-entry P&A. Drill 17 ½"&12 ¼"		March 2010

Table 8 - West Venture track record [20]

4.2 West Phoenix

West Phoenix is a sixth generation semi-submersible rig [28]. The rig was built in 2008 and uses dual ramrig delivered from Aker Maritime Hydraulics [43]. It started operating for Seadrill in January 2009.

Figure 23 - West Phoenix [20]

The rig has been operating in the Northern Sea in water depths below 1100 meters. In Table 9 West Phoenix' operation record since startup is presented.

Country	Operator	Field	Well Type	Water Depth	Well Start
UK	BP UK	Devenick 9/29a-S2	Development subsea completion / HPHT	154	December 2010
Faroe Island	ENI Denmark	Anne Marie 6004/8a-A	Exploration	1145	July 2010
Norway	TEPN Norway	Hild 30/4-D-1 AH	Development subsea completion / HPHT / well test	120	September 2009
Norway	TEPN Norway	Victoria 6506/9-1	Exploration / HPHT / well test	455	January 2009

Table 9 - West Phoenix track record [20]

4.3 West Eminence

West Eminence is West Phoenix`s sister rig and is currently located in Brazil. The rig was built in 2009 and the equipment is similar to West Phoenix [43]. West Eminence started operating for Seadrill in July 2009.

Figure 24 - West Eminence [20]

In Table 10 West Eminence's operation record since startup is presented.

Country	Operator	Field	Well Type	Water Depth	Well Start
Brazil	Petrobras	Lula 9-RJS-686D	Exploration	2170	January 2011
Brazil	Petrobras	TupiOeste 3-RJS-677A	Exploration	2139	September 2010
Brazil	Petrobras	Tupi Oeste 3-RJS-677	Exploration	2139	August 2010
Brazil	Petrobras	Tupi9-RJS-660	Development subsea completion	2149	May 2010
Brazil	Petrobras	Tupi 3-RJS-662A	Exploration	2115	July 2009
Brazil	Petrobras	Tupi 3-RJS-662	Exploration	2115	July 2009

Table 10 - West Eminence track record [20]

5 More in depth on the Tripping operation

In this section it will be presented some considerations regarding tripping operations.

5.1 Kick & swabbing

Swabbing may occur when the drill string is pulled towards the surface [44]. This may result in pressure decrease, depending on the tripping speed of the string, and the annular space between the string and the well bore. If pressure is reduced below pore pressure, reservoir fluid can enter wellbore. Swabbing is one of the greatest well control hazards of drilling operations. In case a kick is taken, the BOP has to be closed, the pipe stripped back to bottom and a well kill procedure must be initiated. Swab calculations are performed to give the optimal tripping speed of drill string without losing pressure control in the well.

5.2 Lost circulation & surge

If lost circulation occurs, the chance of losing the hydrostatic overbalance may occur [44]. Lost circulation can happen by natural or induced losses. Natural loss might result from fractured, cavernous, subnormal-pressured, or pressure-depleted formations. Induced loss might be a result of mechanical fracturing like:

- Too high drilling density
- Too high annular circulating pressure
- Surge pressures caused by running string or BHA fast into the well
- Breaking circulation
- Riser or casing leaks
- Downhole plug failures

It is very important to perform calculations regarding optimal tripping speed of drillstring without risking lost circulation.

5.3 Running in the hole

When running a pipe in the well, the amount of mud volume in the hole replaced by the pipe should not exceed the predicted pipe volume displacement [44]. Some holes adsorb considerably volumes of drilling fluid during trips due to seepage loss. Some formations are sensible to fluid loss or fracture if pipe of tools are run too fast in the hole due to generation of pressure surges. In salt and other plastic formations, these losses can later flow into the wellbore.

5.4 Operation procedures

Seadrill uses software a called Total Management System (TMS) for distributing corporate directives and rig procedures across the organization. The system is relatively new and gradually started implementation of rigs into the Seadrill organization in March 2010. TMS is still under development and the whole MODU fleet is expected to be implemented in the beginning of 2012 throughout organization. With this interface it will be possible to gain access to all rig procedures through the whole organization. The procedures are prone to continuous development, and new versions occur now and then. It is possible to gain access to all versions of the procedures posted in TMS.

West Phoenix and West Eminence are based on the same operational procedures [28]. Appendix D presents an example of the detail seen in procedures for tripping drillpipe, running casing and running/pulling BOP.

6 A general literature review on analysis of cost and time efficiency in drilling operations

A lot of technical work has been performed to enhance the drilling operation efficiency. In this section the purpose is to point out some publications that address these issues and which may have some relevance for the analysis carried out in this thesis.

6.1 The perfect well ratio: defining and using the theoretically minimum well duration to improve drilling performance

This paper describes the difficulties of evaluating drilling performance of wells in different situations and presents a “Perfect Well Ratio” concept that can compare drilling performance in different units and conditions[45]. The “Perfect Well Time” is defined as the minimum time a well can possibly be drilled based on clearly defined physical factors that confine the drilling time. It is not based on benchmarking like “Best in Class”, “Technical Limit” or “Best of Best”, which points out the best performances based on empirical data. The Perfect Well Ratio (PWR) is a dimensionless parameter that can be calculated as a ratio of the actual time to the perfect time. The paper describes a technique that allows consistently calculation of the physical limit for a particular drilling operation using a technique that converts standard operational times to calculate the minimum time to drill an interval to a “perfect well time”. Some perfect tripping ratings were determined in the publication and some relevant rates are presented in In Table 11.

Operation	Perfect time
Tripping time in casing	1645 m/hour
Casing running time	820 m/hour

Table 11 - Operational time for the "Perfect Well" [45]

6.2 Benchmarking drilling performance: Achieving excellence in MODU's operating practices for deepwater drilling

This publication focuses on improving operational efficiency and reduction of well costs by benchmarking techniques to monitor, analyze and detect best practices in drilling operations [1].

The authors defined the activities controlled exclusively by the drilling contractor as "Key steps", which included operations like unrestricted tripping of drillpipe, running and pulling riser, casing running, and testing surface equipment. The key step activities represented more than 30% of the construction time of wells studied.

The model for benchmarking

- *Collect Performance Data.* Daily operational data from company`s reporting system.
- *Identify Best-In-Class Performance*
- *Analyze Processes*
- *Identify Best Practices*
- *Adopt Best Practices*
- *Monitor*

Three rigs with the same pipe handling equipment and working under similar operational conditions were benchmarked. A benchmarking team consisting of a team leader from one of the rigs, a member of the sister rig, a toolpusher, an expert from the engineering support group and one facilitator carried out three case studies; non-restricted drillpipe tripping, tripping drillpipe improvements on rigs and process improvements.

In the non-restricted drillpipe tripping task they identified the best-in-class rig and improvements to the two other rigs were adopted. This resulted in a tripping time improvement of 25 – 30%.

In case study no 2 they improved drawworks speed by 0.95 – 1.35 m/sec on the two other rigs.

Some relevant data from the paper for tripping of tubulars are presented in Table 12. The P90 column describes that 90% of all analyzed empirical data is below this value.

Tripping operation	Low [m/hour]	High [m/hour]	P90 Benchmark [m/hour]
POOH drillpipe non-restricted	487	853	731
RIH[18] drillpipe non-restricted	426	762	640
Run intermediate casing	167	542	423
Run riser and BOP (include test)	70	91	85
Pull riser and BOP	79	128	112

Table 12 - Benchmarked tripping speed of tubulars [1]

6.3 More Ultra-deepwater Drilling Problems

The paper discusses issues regarding ultra-deepwater drilling like weather conditions, mechanical failures on subsea equipment and wellbore, BOP, subsea wellheads etc. [46]. The high cost of deepwater operations is a challenge and has driven an increased level of complexity in the operations which can lead to costly non-productive time events. Moving operations out of the critical path, like make up BHA in offline mode should be done, but problems might occur when operations are done differently offline compared to operation performed in the critical path. An example might be applying different torque. The paper emphasizes detailed contingency plans as a success-factor to minimize rig downtime.

7 Data collection and analysis

Optimizing operation efficiency and reducing well cost is always of interest, and studies have indicated improvements by adopting best practice to poor efficiency rigs [1]. To determine operation efficiency for the three rigs, some chosen drilling operations were proposed by Seadrill:

- Tripping drillpipe non-restricted – the drillpipe is tripped in any casing size and it is not restricted by for example surge and swabbing.
- Tripping drillpipe non-restricted in production casing section – the drillpipe is tripped only in this section and some the time spent on mandatory procedures like flow check and compensate through casing shoe have been subtracted from the reported time spent on tripping drillpipe in an attempt to find an effective tripping rate.
- Tripping BHA – includes tripping the bottom hole assemblies, picking up/laying down BHA and other work with BHA.
- Run production casing – running from BOP to the desired destination. It also includes setting the casing hanger in wellhead.
- Run riser with BOP and land on wellhead – includes all the work from when starting to lower the BOP into the sea until BOP is landed on wellhead.
- Unlatch BOP and pull with riser – includes all the work from when starting to pull diverter until the riser handling equipment is rigged down on the rig.

The drilling operations mentioned above can mainly be categorized as tripping operations, and the results will be presented as a tripping rate (m/hour) in the analysis and comparison tripping rate m/h will be used as a measure on efficiency. The tripping rate will give a general hint of the operational efficiency as this represent the total time spent on the operation versus the tripping distance.

In the analysis of BOP operations, some other relevant works were analyzed in addition to the tripping rate.

Interviews of the rig managers on the three rigs have been performed in order to get a better understanding of the operations efficiency on their rig.

7.1 Well reports

As a basis of the analysis, well reports from three rigs were used. The data were taken from West Venture, West Phoenix and West Eminence, see Table 15. Eminence was operated in Brazil, while Venture and Phoenix were operated in the Norwegian Continental shelf. The reports were exported from DODA into Excel-sheets with relevant header. Each line is a set of information containing information from all the headers. A glimpse of a DODA-report is presented in Appendix A.

If an operation is performed, like tripping BHA from A to B, it should be reported into the DODA system before starting a new operation like for example changing slips. When the next operation is performed like for example tripping drillpipe from B to C, it should be reported into the DODA system separately. These three operations shall not be reported as one, but as three separate operations with their own predefined code (6A, 6B and 6C). When exporting these reports into excel, these three operations shall represent three rows successively, and all operations for the entire period will chronologically be listed. Each reported row contains information related to the headers presented in Table 13.

Header	Header description
INSTALLATION	This section describes which drilling unit that has been used.
RIG	This describes which rig that has been used in the operation. Many of the rigs contain double ram rig, which can perform two operations at the same time [43]. In the excel-sheet, the rigs are normally marked 1 (main) or 2 (auxiliary).
OPERATOR	The operator company is the responsible manager of the field, and this section provides the name of the operator
FIELD	This section describes which field the drilling unit is performing the operations.
WELL	This section describes which well in the field the drilling unit is performing the operation.
DAY	The day the operation was performed.
ACTIVITY NUMBER	The activity number represents the succession of the current operation performed during 24 hours. For example activity number 1 always represents the first operation occurring after midnight. Notice that rig 1 and 2 are marked separately.
ACTUAL SECTION	This describes in which section of the well the operation was performed. An operation could have for example been performed in the 36" section. The concept also deals with main task categories like workover, plugging/abandoning well and completion.
FROM TIME, TO TIME AND ELAPSED	The time the operation started. The time used on a specific operation was rounded to nearest half hour.
TO TIME	The time the operation stopped.
ELAPSED	The time used for performing the operation. If an operation were performed in 22 minutes it was written as 30 minutes in the report.
CODE	The code is used to classify different types of operation. The complete table of codes is presented in Appendix A.[43]
SUB_CODE	This section uses the same codes as described in Table, and it should only be used when operations are performed by secondary rig. This means operations that are not affecting the **"critical line".**
DOWN	If the drilling unit does not operate, it will be marked with a D in this section. Otherwise it would be marked NULL which represent productive time.
DOWN TIME RESPONSIBLE COMPANY	If there was down time on the drilling unit, it was specified in this section if the responsible company is Seadrill or a collaborator company.
REMARKS	In this section, the details of the job performed are registered. This could include information, like which equipment used, depth-interval, connections performed etc.

Table 13 - DODA codes [20]

7.2 Analyze method & process

In this thesis, Daily operation data from DODA is the basis for the analysis performed analyzing operational data. To analyze effective tripping rating m/h is a measure of efficiency. The quantitative method has been used to evaluate the analyzed data. The quantitative method is to systematically analyze empirical data and try to employ mathematical models, theories or hypothesis to pertain to a phenomenon. The tripping distance is specified in the "remarks" section, and to compare tripping distance versus time for the different operations, it has to be manually collected from DODA-reports and put into an excel sheet to calculate the speed rate. This operation was performed through all analyses. A lot of categorization and filtration of lines have been done to sort at the relevant data.

7.2.1 Processing of operational data based on DODA-codes

This analysis is focusing on DODA-code 6A, 6B, 12A and 14A, which mainly is running or pulling drillpipes, BHA, running casing and running/pulling BOP. Ideally, these codes should solely contain tripping operations and no other operations related to the tripping operations. Through analysis of tripping rates based on codes, the amount of operation lines from the three rig's DODA reports are presented in Table 14. These lines are the basis for the processed data in this analysis.

Country	Field	Well	Well type	Water Depth [m]	Rig	Well start
Brazil	TupiOeste	677A	Exploration	2139	West Eminence	September 2010
Brazil	Tupi	662A	Exploration	2115	West Eminence	July 2009
Faroe Island	Anne Marie	8a-A	Exploration	1145	West Phoenix	July 2010
Norway	Troll 31/2	Z-1	Drilling 36"-8 ½"	321	West Venture	October 2010
Norway	Troll 31/2	Z-2	Drilling 36" & 26"	317	West Venture	September 2010
Norway	Troll 31/2	P-13	Completion	337	West Venture	September 2010
Norway	Troll 31/2	S-14	Re-entry	376	West Venture	August 2010

Table 14 - Wells analyzed

To get an overview of the well data, categorization and separation of data were performed. All operations from HPHT-wells were excluded. The first separation criterion is the code section in the well report. All activities should contain a code, so that it should be possible to classify. The code refers to Table 22, which describes the kind of operation performed.

The second separation criterion is the section where the operation is performed. Refer to "ACTUAL SECTION", this section covers drilling of different sections, but also activities like workover, completion and plugging/abandoning well are included.

After sorting the codes into separate worksheets in excel, one started to analyze the lines and sorting the different kind of operations within the current code-segment into new sheets. For example code 6A contains pulling pipe out of hole and running pipe in hole. These two operations were separated into two excel-sheets, before further processing. As specified in the code description, the depth should always be registered. 6A and some other codes required depth registration, which were specified in the "remarks" section. The depth interval were manually collected and registered. The registration made it possible to calculate tripping rate of the operation since the time parameter already were included in the report.

7.2.2 Tripping of drillpipe in production casing

In this analysis, the data from DODA-reports were collected from operations performed when working with the 8 ½" section of the well. The wells used in the analysis are presented in Table 15.

Country	Field	Well	Well type	Water Depth [m]	Rig	Well start
Brazil	TupiOeste	677A	Exploration	2139	West Eminence	September 2010
Brazil	Tupi	662A	Exploration	2115	West Eminence	July 2009
Faroe Island	Anne Marie	8a-A	Exploration	1145	West Phoenix	July 2010
Norway	Troll 31/2	X-14-H	Exploration	370	West Venture	January 2001
Norway	Troll 31/2	H-3	Exploration	350	West Venture	August 2009

Table 15 - Wells analyzed

In this analysis, the attempt to estimate effective tripping rate of drillpipe were performed. Since the rigs operate in different water environments, the intention of choosing these wells was to make the premises of the rig`s operations as equal as possible. The estimate of the effective tripping rate was based on the following assumptions:

- HPHT wells do not take part in the analyses due to the complexity of operations.
- The rigs operate in different water environments, only tripping operations between BOP and casing shoe were considered
- Estimated time on sub-operations (ref Table 16) were defined and deducted from the tripping operation. Sub-operations will be discussed below.
- Downtime caused by other vendors were not included
- Harsh weather conditions causing downtime were not included

When performing a tripping of drillpipe operation the crew carries out several sub-operations that is considered as mandatory procedures (ref Table 16) are covered by the DODA-code 6A and are considered as a part of the tripping operation. The intention of removing mandatory procedures during tripping operations is to achieve effective tripping rate. If a rig reports a specified amount of minutes spent on for example flow check, this number has been subtracted in the effective tripping rate calculations. If a rig reports that a flow check is performed without specifying amount of minutes spent, estimates from Table 16 has been used as basis for subtraction in the effective tripping rate calculations. The tripping rate will indicate the efficiency of the rig based on how many hours the crew uses to trip the string a particular distance.

Estimated operation time running string in production casing	
Operation	**Estimated time [minutes]**
Fill/empty trip tank	15
Fill pipe every 20 stand	15
Compensate through BOP	10
Compensate through casing shoe	10
Change slips	5
Estimated operation time pulling string in production casing	
Operation	**Estimated time [minutes]**
Fill/empty trip tank	10
Compensate through casing shoe	10
Flow check @ casing shoe	15
Change slips	10
Pump slug	15
Flow check before enter BOP	10
Compensate through BOP	10

Table 16 - Estimates for tripping operations

7.2.3 Running production casing in hole

In this analysis, the data from DODA-reports were collected from operations performed when working with the 12 ¼" section of the well. The wells used in the analysis are presented in Table 15. The estimate of the effective tripping rate was based on the following assumptions:

- Only running operations between BOP and casing shoe
- Downtime caused by other vendors were not included
- Planned procedures like rig maintenance were not included
- Harsh weather conditions causing downtime were not included

7.2.4 Running and pulling BOP

The wells used in this analysis are the same as for the previous. The wells are located at different water depth, so the analyses were divided into tripping phase and landing/unlatching BOP phase. The tripping phase focus on the time spent from running BOP from sealevel down to seafloor, and landing/unlatching BOP phase focus on the time spent on operations related to the landing/unlatching BOP. Time consumption on some specific operations like install diverter, test lines, install slip joint etc. were also analyzed. The definition of estimating running and pulling BOP is limited by:

- Downtime caused by other vendors were not included
- Planned procedures like rig maintenance were not included
- Harsh weather conditions causing downtime were not included

8 Results and discussions

Some of the data used in the analysis contains reported downtime, which cause halt in the operation. Downtime that Seadrill is not responsible for caused by other vendor's equipment will not affect tripping ratings.

What kind operations that is included in the code may correlate to how the offshore installation manager (OIM) has reported into the DODA system. The analysis rejected some data based on the following criterion:

- Codes that originate from HPHT-wells.
- Operations that have to obey restrictions from operator`s directives that force the operation to be performed with lower pace like reduced tripping speed etc.

8.1 Tripping rates based on codes

In this analysis, average tripping rates for West Venture, West Phoenix and West Eminence were determined. The results from the analysis are presented in Figure 25 and Table 23 (see Appendix C). The total trip-time and total trip-distance sections are included in Table 23 to show the amount of data these analyses are based on.

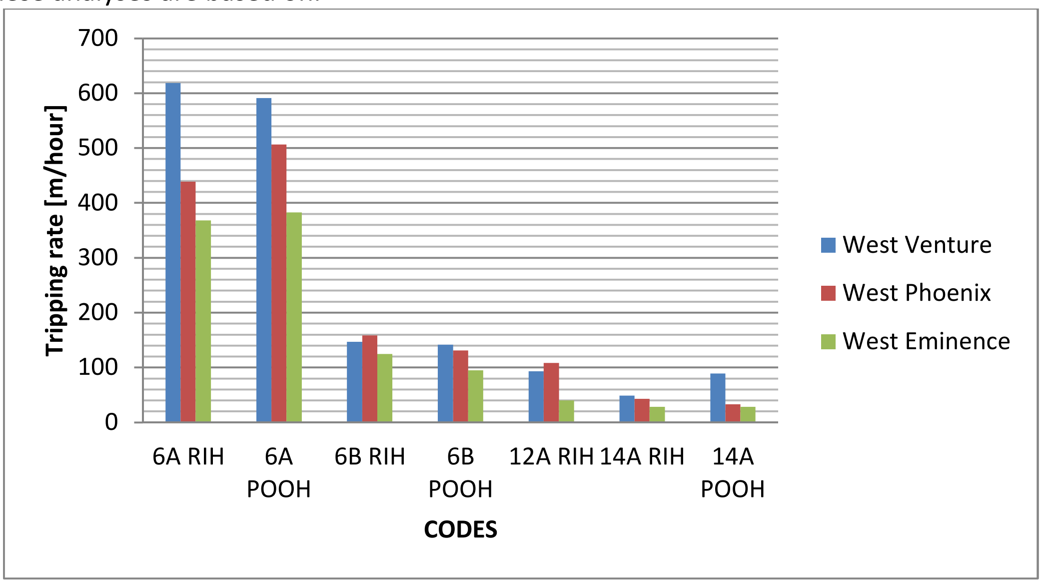


Figure 25 - Average tripping rates

8.1.1 Code 6A and 6B

Referring to Table 22 in Appendix A, these codes should be used when tripping drillstring and bottom hole assemblies in casing in and out of hole. The code has been divided into two subsections in the analysis; pulling out of hole (POOH) and running in hole (RIH). The key parameter focused on was the time spent on tripping compared to the tripping distance. Some data were rejected in accordance with the criterions listed in section Processing of operational data based on DODA-codes.

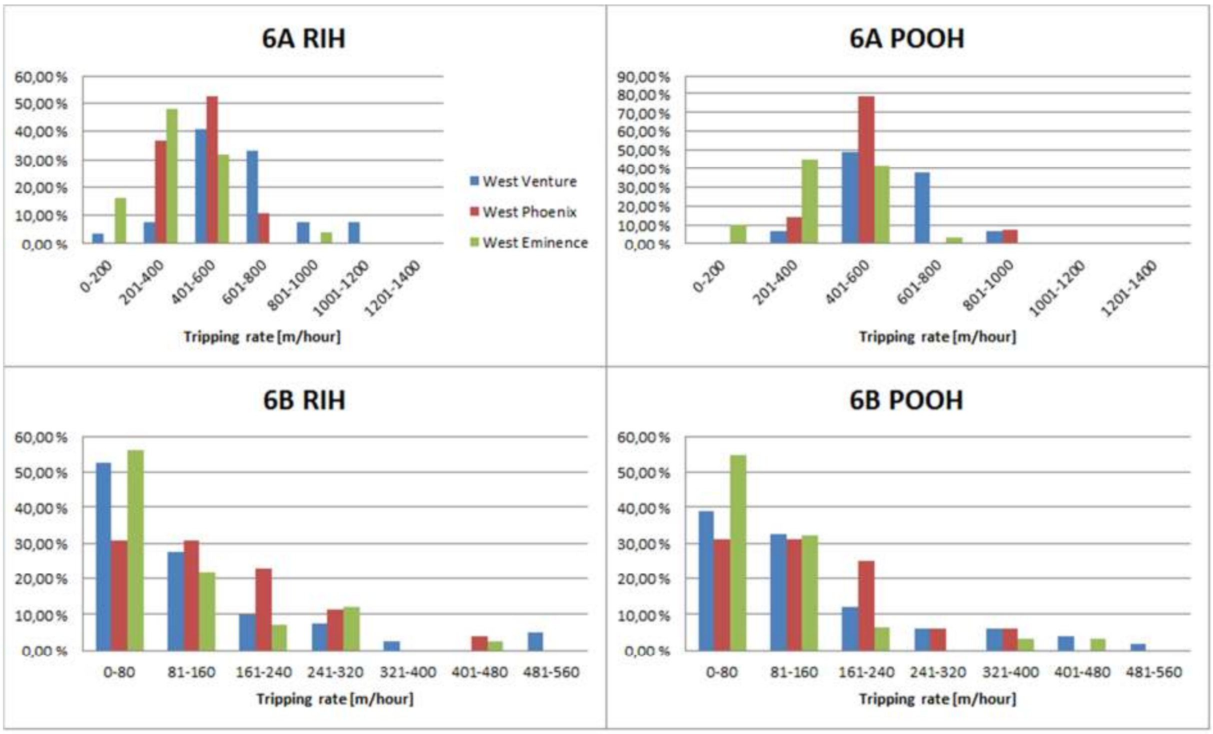


Figure 26 - Tripping distribution of drillpipe and BHA

The results presented in Figure 25 shows that West Venture achieved highest average tripping rating in this analysis, and this is also reflected the tripping distribution presented in Figure 26. The spread of data is wider compared to West Phoenix and West Eminence showing large variation in performance. The graph shows that West Venture performed rates of tripping of drillpipe in hole higher than 1000 m/hour, but also rates lower than 400 m/hour. West Phoenix' average tripping rate is lower compared to West Venture and the tripping speed distribution is more narrowed with rates in the interval between 300 through 650 m/hour.

8.1.2 Code 12A

Code 12A should be used for time registration when running casing, liner, tubing or screens into the well (see Table 22 in Appendix A). The code should not include other work like rigging up/down, landing string etc. The focus has been on the casing running, so all activities related to liner, tubing or screen running have been removed from the analysis. The 30" conductor running operations have been neglected from the analysis, since this is a more complicated operation compared to running other casings. The key parameter was the time spent on tripping compared to the tripping distance. The results are presented in Figure 25 and Table 23 in Appendix C.

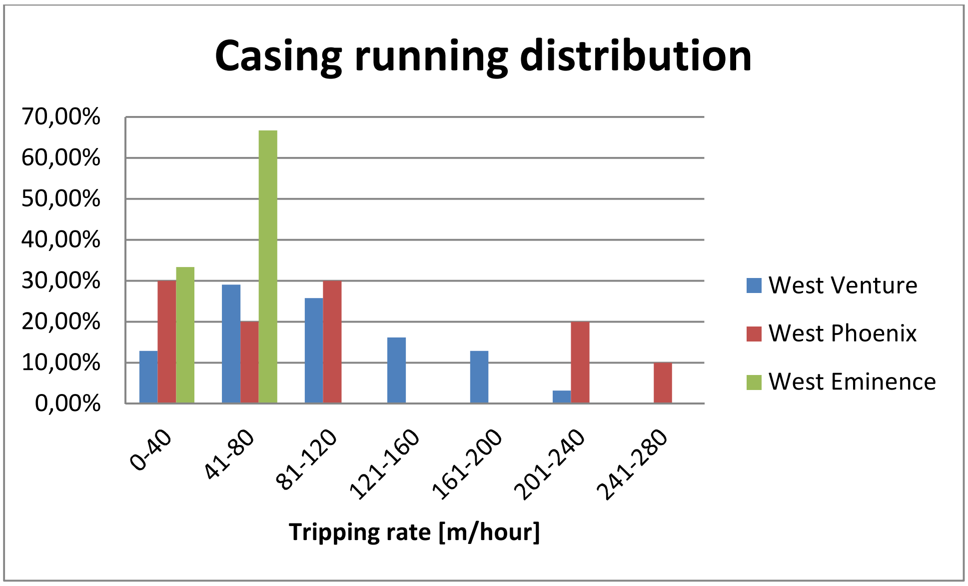


Figure 27 - Casing running distribution

The results show that West Phoenix slightly attained the highest average tripping speed. As seen in Table 23 there was little operational data available for West Eminence compared to particularly West Venture. The casing running speed distribution presented in Figure 27 shows that the variation is quite wide for West Venture and West Phoenix. The main reason for this is that some of the data contains some preparation work that ideally should not be included on this code (some of the work should probably been reported on code 12B), and it is hard to estimate the actual time spent on the tripping operation. This may reduce the tripping rate considerably. When it comes to West Eminence, the running operation data is collected from a complete casing running operation. The reports shows that the average tripping rate increased as the operation continued, which might indicate some initial difficulties and a more experienced drillcrew.

8.1.3 Code 14A

Referring to Table 22 in Appendix B, this code should be used when running/pulling riser. It does not include other work like preparing for running, BOP work, handling joints or rigging down after job etc. The code was divided into two sections; pull operations and run operations. The key parameter focused on this code was the time spent on tripping compared to the tripping distance.

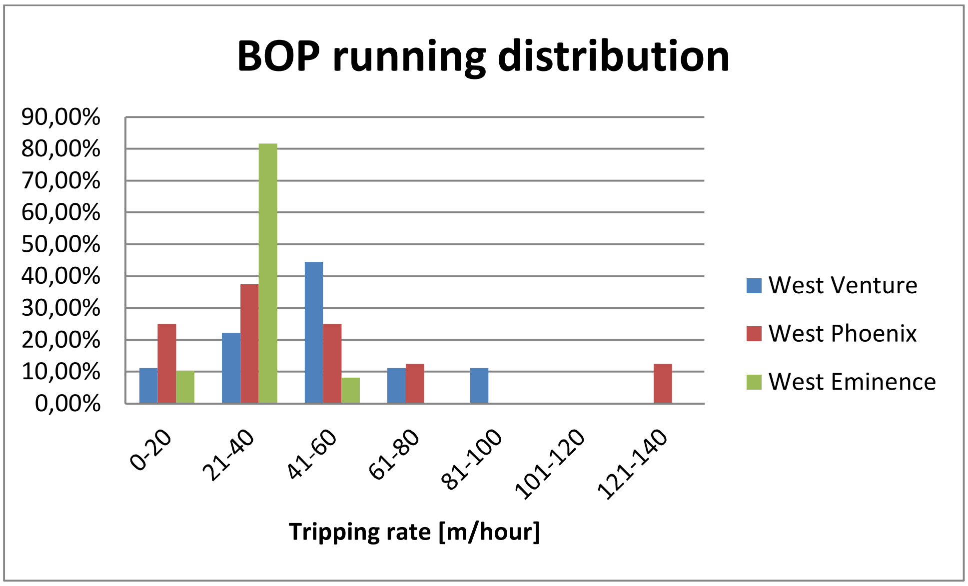


Figure 28 - BOP running distribution

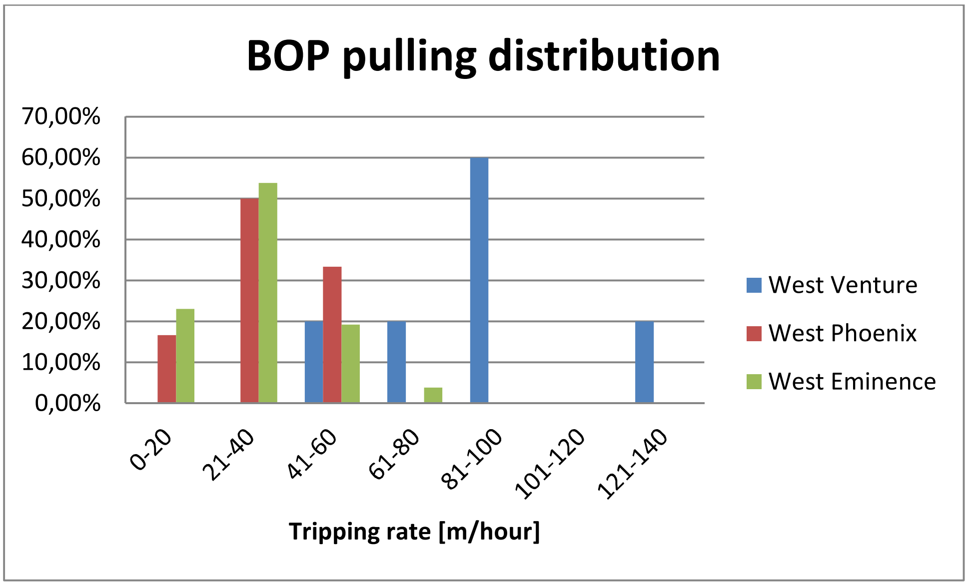


Figure 29 - BOP pulling distribution

Figure 25 e and Table 23 present the average tripping speed for the three rigs where West Venture and West Phoenix achieved equal average running speed. It is interesting to notice that the average pulling rate for West Venture is more than twice the rate of both West Eminence and West Phoenix. If we correlate the result with the pulling speed distribution in Figure 29 the distinct tripping speed seem to have the same form.

8.1.4 Summary

The overall results indicate that West Eminence in general is a little behind, and West Venture is considerably more effective in some operations. West Phoenix and West Eminence seems to have smaller variation while West Venture sometimes attains considerably higher rates. It is probably many factors that influence the tripping rates. The crew on West Venture is familiar with the procedures and equipment and has operated on the same field for more than ten years. The crews on West Phoenix and West Eminence were not so familiar with the rig and faced initial difficulties with equipment. Another factor that might influence the tripping rates is how the OIM reports the operations in the DODA system.

As mentioned earlier in section Tripping rates based on codes, this analysis gave an average tripping rating based on random tripping operations. This analysis pointed out some trends, and it was an interesting basis for further analysis. The next step in the analysis focuses more on specific operations to make it easier to compare. It was of interest to find as similar wells as possible, and the exploration wells chosen for further analyses are presented in Table 15 in section 7.2.2.

A comparison of the tripping rate results in this section has been carried out with the results in the technical publication discussed in chapter 6.2. It is important to emphasize that the method for determination of tripping rate in the technical publication is unknown, but probably different from the method in this analysis. The benchmarking in the technical publication was performed on three semi-submersible rigs using drawworks derrick system and not ramrigs. The result from the benchmark presents the best and most efficient rig. The results are presented as P90 (the 90 percentile), which means that 90% of the analyzed trips are below the presented rate in Figure 30.

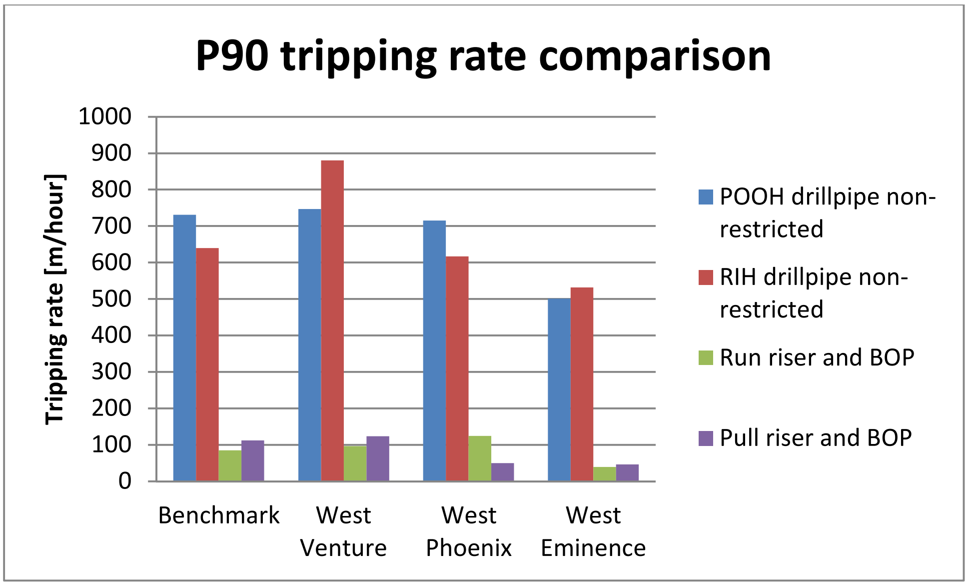


Figure 30 - P90 tripping rate comparison

The figure might indicate that West Venture matches the best rig from the benchmark. By adopting best practices from West Venture to West Eminence and West Phoenix, one might achieve uplifting results like the results in the technical publication.

8.2 Tripping operations in production casing

In this analysis the intention was to find the string tripping work efficiency of the three drilling rigs by estimate average tripping rates. The analysis are based on data from drilling the 8 ½"-section, and the analyzed operation is tripping the drillstring through 9 5/8" or 10 3/4" casing (depending on which well) between the casing shoe to BOP. The estimated time spent on additional tripping related the procedures are presented in Table 16.

8.2.1 Running drillstring in production casing

The entire tripping operation goes from BOP to casing shoe and includes all the operations it takes to transport the string. It includes all work that is reported except planned rig maintenance, harsh weather conditions and downtime related to other vendors. The results presented in Figure 31 shows that West Phoenix' well 8a-A has the highest running rate.

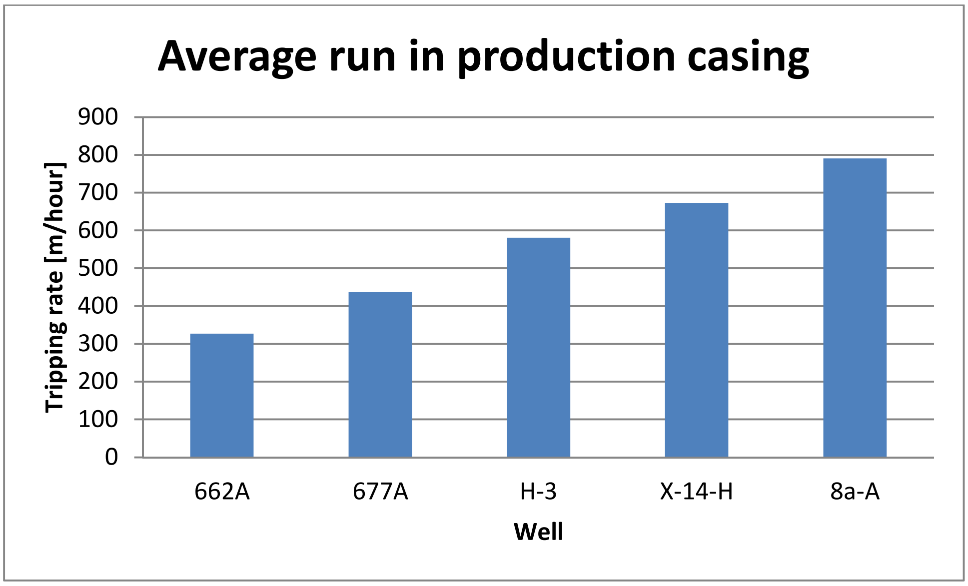


Figure 31 - Average run in production casing

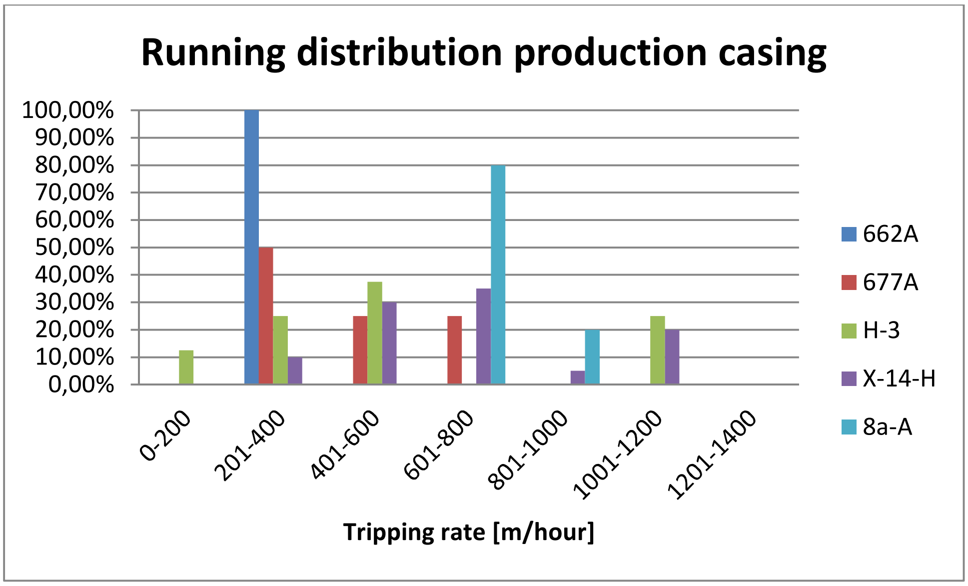


Figure 32 - Running distribution production casing

West Phoenix' well 8a-A achieved highest average running rate. Both West Venture's well, H-3 and X-14-H had occurrences of maximum running rates higher than West Phoenix (ref Figure 32) but the results indicates that West Phoenix reported fairly narrow spread around running rate 800 m/h. West Venture scored as mentioned higher maximum running rates compared to West Phoenix, but the results indicated occurrences of relatively low minimum running rates as well. West Eminence showed improvement from the first drilled well to the second drilled well.

8.2.2 Pulling drillstring in production casing

The analysis focuses on the entire tripping operation from casing shoe to BOP and follows same criteria as in section 8.2.1. The results presented in Figure 33 shows that West Venture's wells achieved the highest tripping rates.

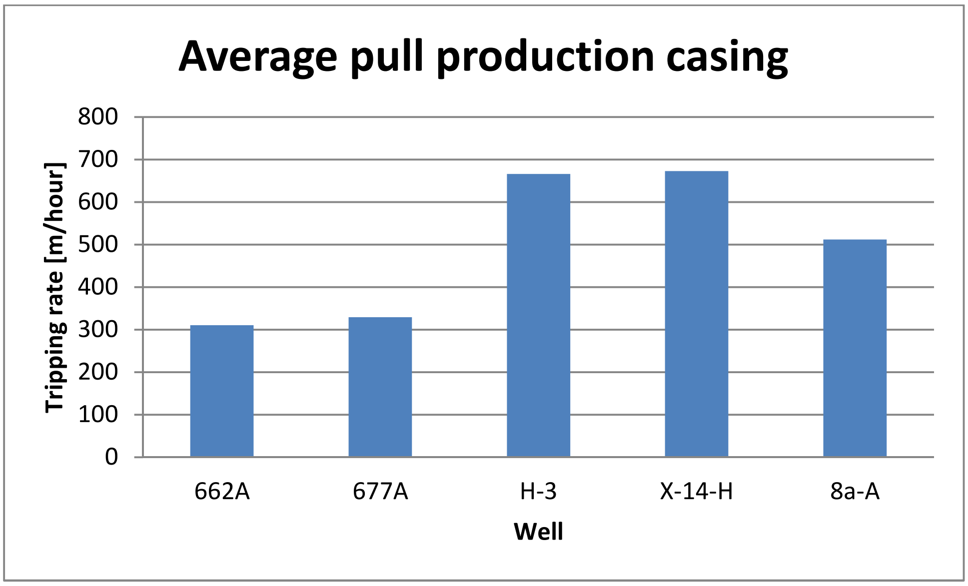


Figure 33 – Average pull production casing

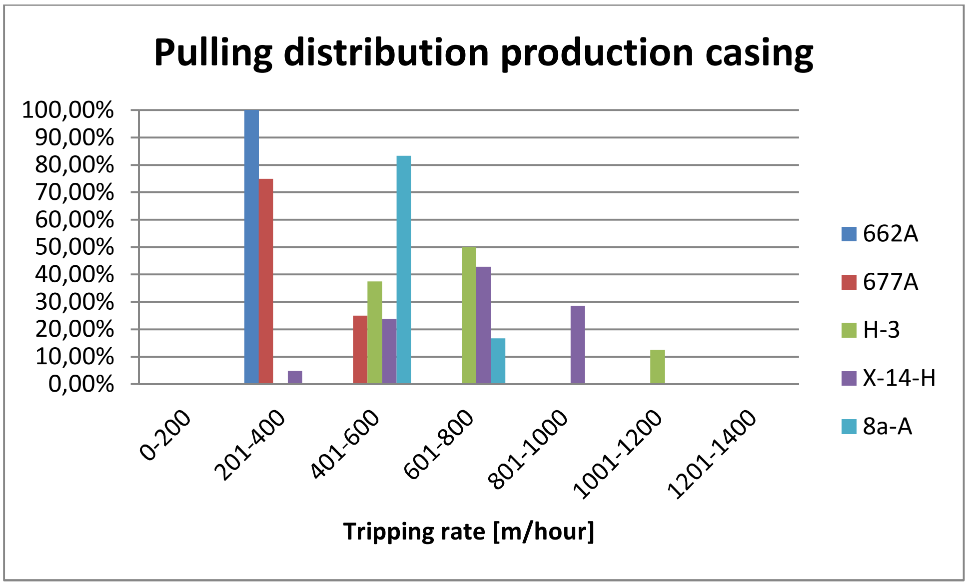


Figure 34 - Pulling distribution production casing

8.2.3 Summary

West Eminence show better average tripping rate in well 677A, which was started drilling approximately one year after the rig's first dilled exploration well, 662A. This might indicate correlation with the crew's enhanced experience with the rig and Figure 32 shows that 677A achieved higher maximum rates compared to 662A. If we compare tripping speed from this section with the results in Figure 25 from section 8.1.1 one can find some correlations between the results. The results from West Phoenix' running rates shows aberration in the running rate. In the first analysis, West Phoenix scored considerably lower average running rate compared to the second analysis. The reason for this is not known, but the analyses performed in this section subtracted the time spent on sub-operations while the first analysis did not. Intuitively the second analysis should give higher rates compared to the first since several defined sub-operations are subtracted from the time spent on the running operation. It is also worth mention that some OIM reports in a more detailed level compared to other, which means that some sub-operations in this analysis are based on estimates while other are based on the actual reported amount of time.

8.3 Running the production casing

The casing running analysis is based on all operations that are reported from when the casing passing through the BOP to the desired depth of casing position including setting the casing hanger in the wellhead. The results are presented in Figure 35 and shows that well H-3 and 8a-A attained the highest running rates. X-14-H is not included in this analysis since data from this operation was not available.

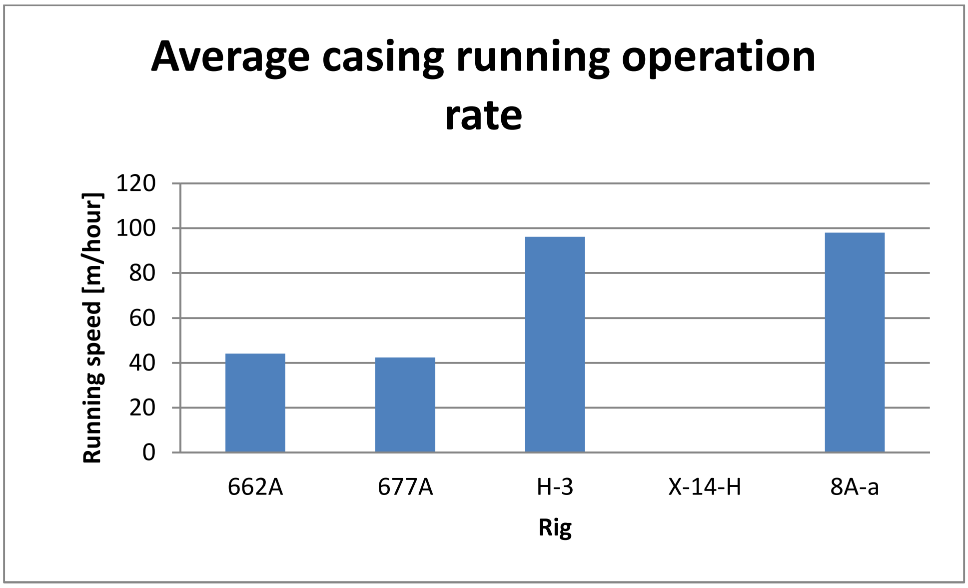


Figure 35 - Average casing running operation rate

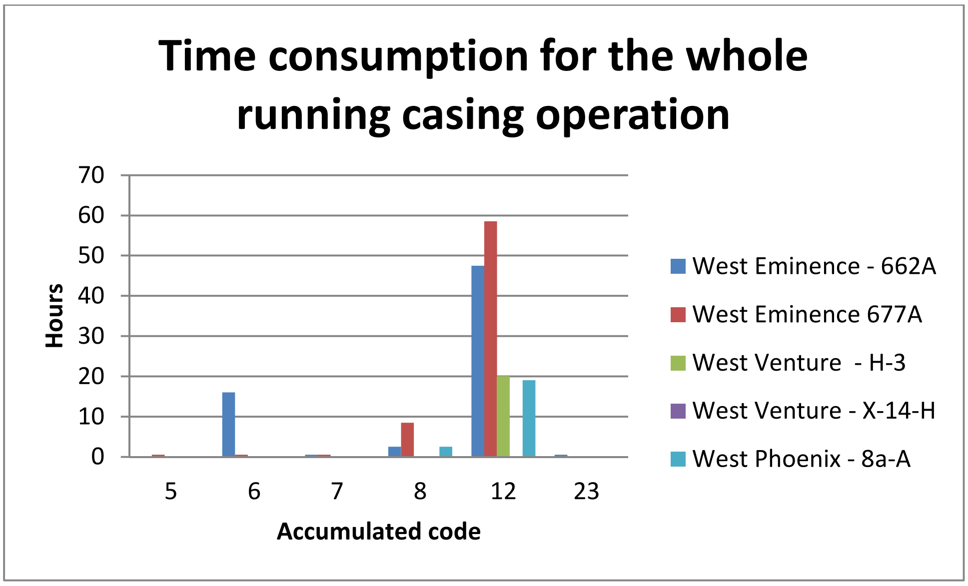


Figure 36 - Time consumption for the whole running casing operation

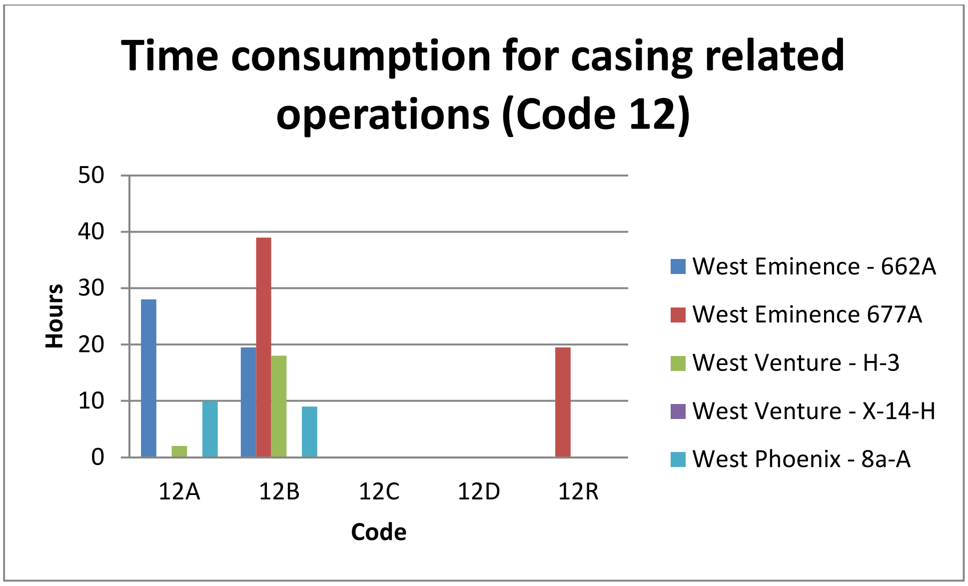


Figure 37 - Time consumption for casing related operations (Code 12)

In Figure 36 the total time consumption on the casing running operation are presented. The figure presents all the reported operations from the BOP until the casing hanger is set in wellhead. The major reported operations are code 12. Code 12 is the sum of all code 12A through 12R, and is contains casing-related activities. In the same way the other codes are the sum of all its sub-letters. Code 8 is for example the sum off all downtime regardless of vendors or who is responsible (code 8 through 8EWI). There has been reported some downtime on West Eminence and West Phoenix (ref Figure 36), but it was not included in the calculations. Figure 36 show that West Venture and West Phoenix spent approximately the same amount of time performing the casing running job. It also shows that West Eminence spent more time on well 677A, which was drilled after one year of operation, compared to well 662A, which was the first drilled exploration well. Other results in the analyses shows that West Eminence performed improvements during this year, but in this analysis the first drilled well spent the least amount of hours. When looking into Figure 37 one explanation might be that the running casing operation in well 677A were performed with restrictions (Code 12R)

8.4 BOP tripping operations

The analysis is based on the operational time spent on lowering and pulling the BOP between the rig and the seafloor. The analysis is divided into running operation, which is the operational time spent from lowering the BOP into the sea until landing the BOP on the seafloor, and pulling operation, which is the operational time spent from unlatching BOP and pulling to sealevel. It was focused on tripping rate and on comparing some defined reported operations. The code 14 sub codes are more specified compared to other codes (ref Table 22), so ideally in this analysis it should be possible to compare how many hours some specified operations require.

8.4.1 BOP running operation

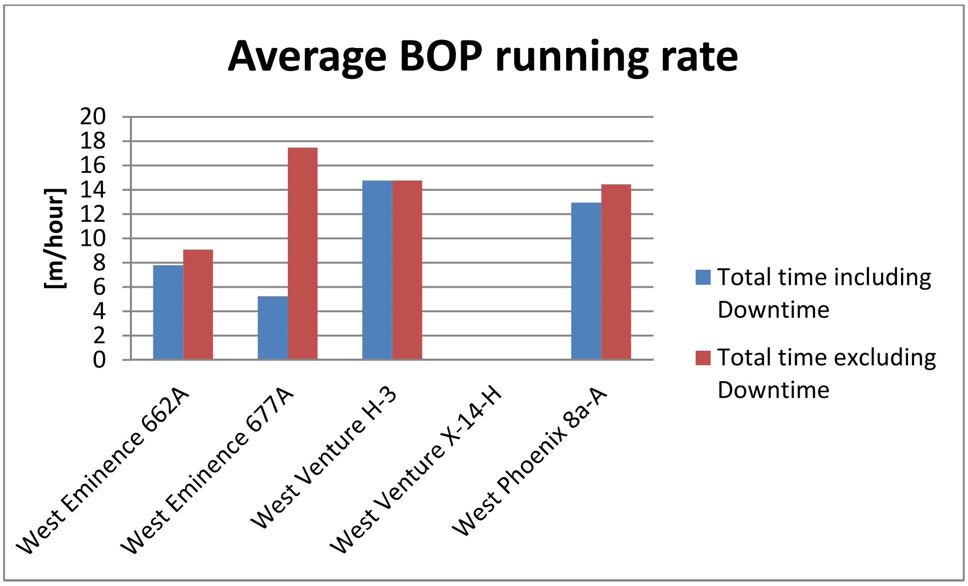


Figure 38 - Average BOP running rate

Operational data from well X-14-H were not available in this analysis. The average running rate of BOP is presented in Figure 38 where the presented result are defined as the total time spent from the preparation work until BOP handling equipment are rigged down compared to the total tripping depth. This includes all reported work spent on this operation. The water depths vary from approximately 350 meters through 2150, as presented in chapter 4.

Since all operations are included in the running rate, the ultra deepwater wells intuitively should have achieved higher score compared to deepwater wells since the time spent on for example preparing operation, preparing equipment and landing BOP are procedures that are performed independently of the water depth. For more shallow water depths, the time spent on preparation/landing BOP operations represent a larger portion of the total time used. By studying Figure 40 one notice that West Venture's well H-3 spends less time on all related BOP work (code 14A tripping not included) compared to the other wells, which spends up to more than four times more hours. H-3 obviously spends less time on running BOP (ref Table 18) because of the water depth, but the effective BOP running rate (ref Figure 39) shows that West Venture runs the BOP fastest.

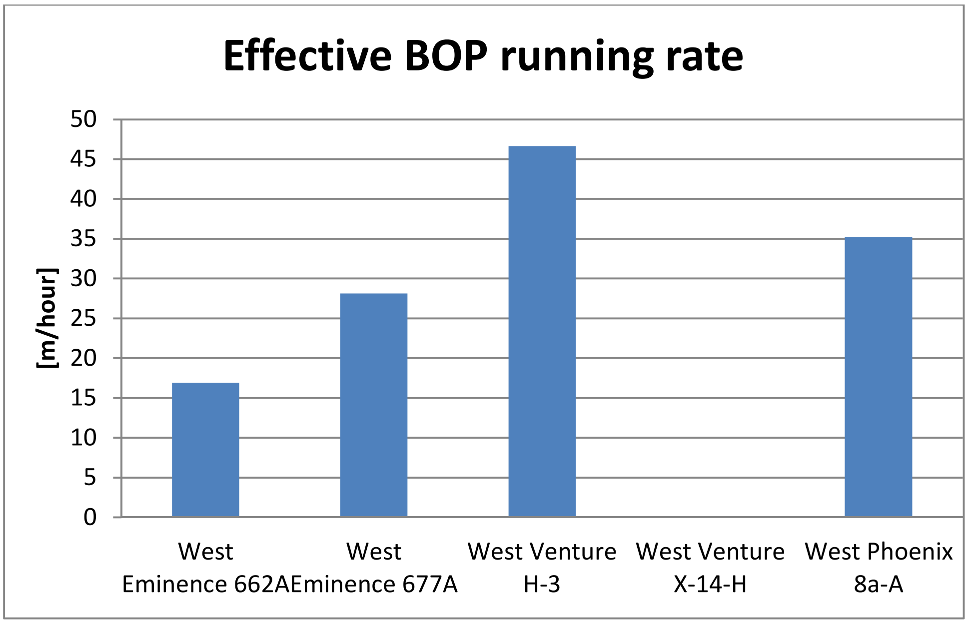


Figure 39 - Effective BOP running rate including only tripping operations

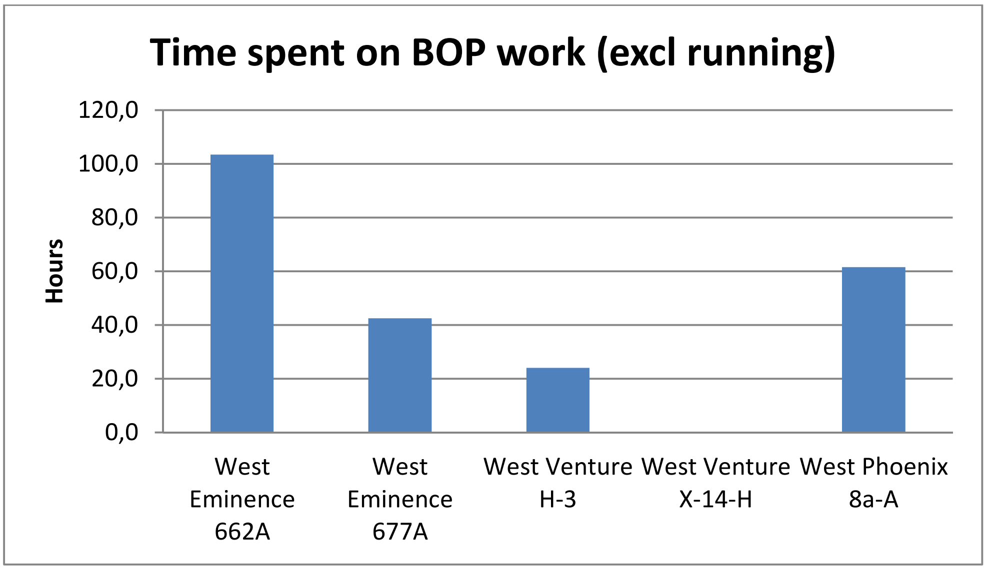


Figure 40 - Time spent on BOP work (excl tripping)

The effective tripping rates are only based on the amount of time spent on tripping divided by the tripping depth. No preparation work, installation, landing or rig down equipment is included in the parameter.

Based on the DODA-reports, the total time spent on the running BOP operation is presented in Table 17. This includes all the reported operations from entering the sea until landed the BOP.

RUNNING BOP			HOURS		
OPERATION	662A	677A	H-3	X-14-H	8a-A
RIG MOVE	0	0	0		0,5
PLANNED MAINTENANCE	2	0	0		0
DOWNTIME	39	293,5	0		11
BOP OPERATION	228,5	132,5	31,5		121,5
TEST BOP	1,5	1,5	0		1
OTHER WORK	0,5	4,5	0,5		0,5
SUM	271,5	432	32		134,5

Table 17 - Total time spent running BOP

Table 18 presents the time consumption on the different BOP operations during the same period as the results in Table 17. . The analysis was performed to reveal potential variations in how long time the crew spends on the specified operations. The operation section in Table 18 is partially adapted to the operations specified in the DODA-reports, for full description see Table 22.

				HOURS		
CODE	OPERATION	662A	677A	H-3	X-14-H	8a-A
14A	RUNNING BOP	125,0	76,0	7,5		32,5
14AA	TEST LINES	26,5	10,0	3,5		7,5
14B	PREPARATION WORK	17,0	5,0	0,0		1,0
14BA	PREPARE DRILLFLOOR	19,0	2,0	0,0		0,0
14BB	SKID BOP TO WELLCENTER	7,0	0,0	3,5		8,5
14BC	INSTALL SLIP JOINT	13,5	1,0	1,0		4,5
14BD	INSTALL FLEX JOINT, SUPPORT RING	1,5	18,0	3,0		3,0
14BE	INSTALL TERMINATION RING	4,0	4,0	2,5		20,5
14BF	LAND BOP	6,5	7,5	2,0		7,0
14BG	INSTALL DIVERTER	4,0	3,5	4,0		6,5
14BH	RIG DOWN BOP HANDLING EQUIPMENT	4,5	5,5	4,5		3,0
14CA	INSTALL SPACER SPOOL ON WELLHEAD	0,0	0,0	0,0		0,0
14CB	REMOVE BOP FROM STUMP	0,0	0,0	0,0		0,0
14CC	NIPPLE DOWN AND PUT BOP BACK ON STUMP	0,0	0,0	0,0		0,0
SUM		228,5	132,5	31,5		121,5
SUM EX TRIPPING		103,5	56,5	24,0		89,0
EFF RATE		17	28	47		35
TRIP PERCENT		55%	57%	24%		27%

Table 18 - Total time spent on BOP work (running)

Well 662A (West Eminence)

West Eminence experienced some amount of downtime hours during the operation (ref Table 17). An essential cause of the downtime was a leak in one of the Ram hoisting system, but the rig also faced some oil leak in the hydraulic system and some dropped objects (which also result in downtime) several times during the operation. This was the first well drilled by West Eminence in, which might imply that the crew has to work through an initial phase to get used to the rig.

Well 677A (West Eminence)

In this operation, West Eminence experienced vast amount of downtime hours during the operation (ref Table 17). They experienced problems with the BOP, which resulted in the first run had to be cancelled at approximately 380 meter water depth and a lot of troubleshooting were carried out. The second run were also cancelled at 380 meter water depth and pulled out for troubleshooting. On the third attempt they were able to continue running the riser. The crew also faced trouble with Riser chute and other equipment on the drillfloor. A damaged joint of slick riser were ran into the hole and had to be returned. In addition to the planned Task Based Risk Assessment-meeting (TBRA), several meetings during the period took place to instruct the crew to use Francis torque tools. These additional instruction lessons were reported as downtime. Due to all the trouble experienced with the running operation the average running speed, presented in Figure 38, shows this well has the lowest running rate. But if subtracting downtime, the same figure shows that this well attained high tripping rate and looking into Figure 40 and Figure 39 shows that they do correlate with Figure 38. The reason for this might be, as mentioned in the start of this section, the water depth versus time gives advantageous results for West Eminence because the rig operates in water depth at approximately 2150 meter.

The construction of this well started approximately one year after startup of the rig (well 662A), and it is interesting to note that the amount of hours spent on BOP-work (code 14 in Table 17)) were considerably improved compared to well 662A. This reflects the effective running rate, presented in Figure 39, and many of the operations presented in Table 18 like running the BOP with riser (code 14A), testing lines (14AA) and preliminary work (14B, 14BA) related to running BOP. Some work related to skidding the BOP to well center (14BB) were performed while downtime and is therefore not reported under this code. Based on the reports, some work related to a gooseneck has been reported on code 14BC in well 662A but on code 14BD in well 677A. This might possibly explain the disagreement in the amount of time spent on the operations. The remaining codes (14BE-14BH) seem to contain acceptable conformities.

Well H-3 (West Venture)

In this well the seabed is located at 350 meters below sea level, which is the shallowest well in this benchmark. There were no downtime reported in this BOP running operation and, according to Table 17, most of the running operation are related to the BOP running operation (code 14). The amount of hours spent on tripping is obviously less compared to the two wells drilled by West Eminence since the water is much deeper in these operations. But according to results in Figure 39 the effective running rate is higher compared to the two wells drilled by West Eminence. The time spent on testing lines, install slip joints, flex joints, termination ring and landing BOP were performed faster compared to 662A and 677A, while the time spent on installing diverter and rig down handling equipment were approximately the same.

Well X-14-H (West Venture)

No data were available for this operation

Well 8a-A (West Phoenix)

West Phoenix experienced some downtime in the BOP running operation mainly caused by hydraulic leak and removal of rust from inner barrel. The wellhead is located approximately 1150 meter water depth. According to Figure 39, the effective BOP running rate is slower compared to H-3, but faster than both the West Eminence's wells. Still, 677A were performed with an effective BOP running rate closer to 8a-A, and these two wells have better comparability than 8a-A versus 662A since the both the rig crews have roughly one year experience with their rigs. It was reported problem with installing termination ring due to a bent line on slip joint, and that caused the relatively huge amount of time spent on the operation (code 14BE in Table 18). West Venture performed the testing of lines in the shortest period of time compared to West Phoenix and West Eminence, but West Phoenix performed the testing of lines faster than West Eminence. 2.5 hour BOP dummy run was performed in well 677A and 8a-A while 662A and H-3 did not reported to commence this operation (code 14BF). Still both West Eminence and West Phoenix reported more than twice the time compared to West Venture.

8.4.2 BOP pulling operation

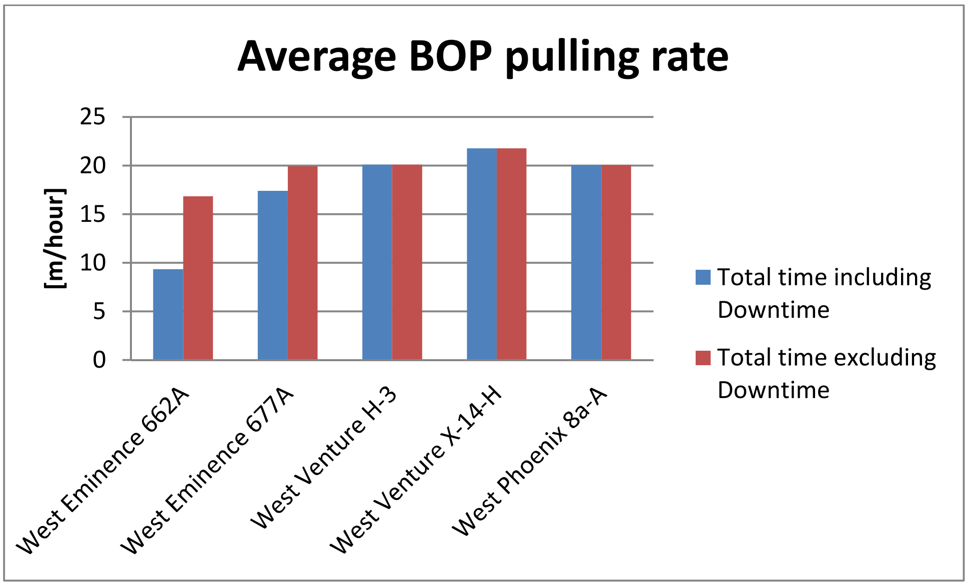


Figure 41 - Average BOP pulling rate

The average pulling rate of BOP is presented in Figure 41 and is defined in the same way as average running rate of BOP (ref Figure 38). Here West Eminence showed improvements in efficiency, but looking into Figure 42 and Figure 43 shows same pulling rate and some improvements on time spent on BOP. The error was caused by that most of the pulling operation were performed in harsh weather conditions and by that it was reported on code 21 (wait on weather). An exception in the calculation had to be done, and the code 21 was merged into code 14A. The outcome disfavors West Eminence since the pulling operation probably was affected by the harsh weather conditions. West Venture appears to perform the operation most effective with highest pulling rates and less hours spent on BOP work. It is interesting though that well X-14-H, which was drilled in 2001, shows higher rates compared to H-3.

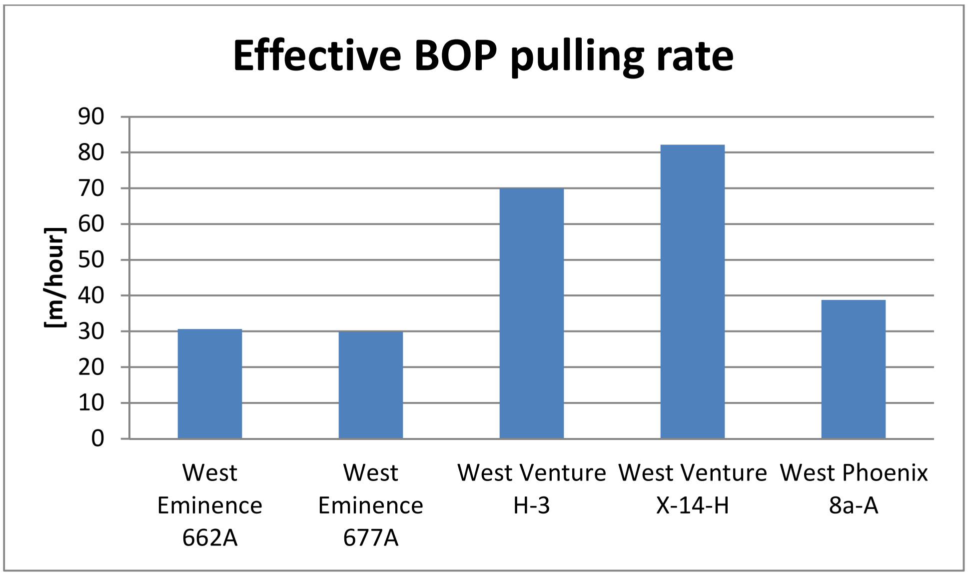


Figure 42 - Effective BOP pulling rate including only tripping operations

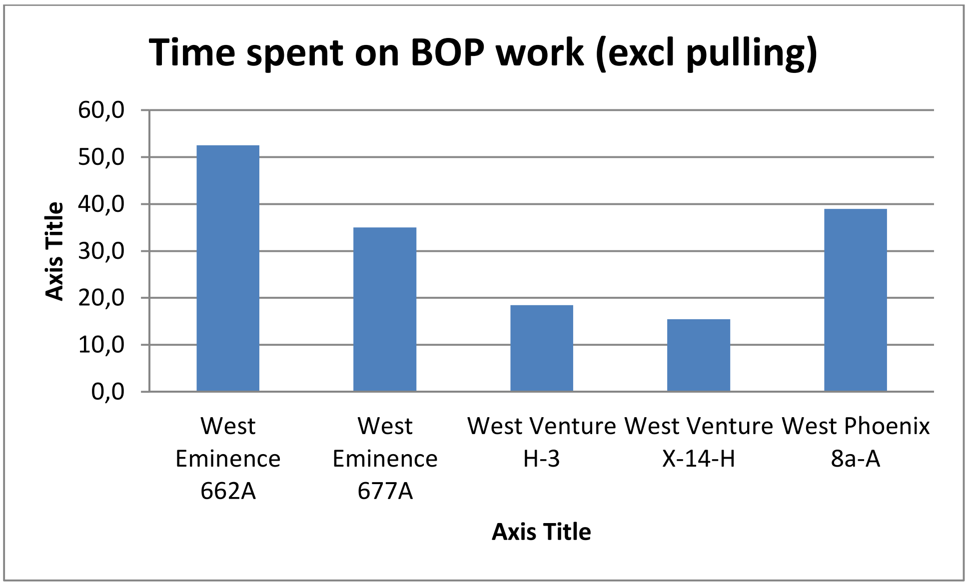


Figure 43 - Time spent on BOP work (excl pulling)

PULLING BOP	HOURS				
CODE	662A	677A	H-3	X-14-H	8a-A
RIG MOVE	0	23,5	0	0,5	0
CIRCULATING MUD	0,5	0	0	0	0
PLANNED MAINTENANCE	0	0,5	0	0	0
DOWNTIME	100,5	16	0	0	0
BOP WORK	121,5	41	23,5	20	58,5
TEST BOP	0,5	0	0	0	0
WAITING ON WEATHER	0	42	0	0	17,5
OTHER WORK	3	3,5	0	0	0
SUM	226	126,5	23,5	20,5	86

Table 19 – Total time spent pulling BOP

		HOURS				
CODE	OPERATION	662A	677A	H-3	X-14-H	8a-A
14A	PULL BOP	69,0	71,5	5,0	4,5	29,5
14AA	-	0,0	0,0	0,0	0,0	0,0
14B	RIG DOWN AFTER JOB	17,0	3,0	5,5	15,5	6,0
14BA	PREPARE DRILLFLOOR FOR BOP WORK	4,5	7,5	1,0	0,0	0,0
14BB	PICK UP RISER JOINTS	1,5	0,0	3,0	0,0	0,0
14BC	REMOVE SLIP JOINT	2,5	3,0	0,0	0,0	8,0
14BD	REMOVE FLEX JOINT, SUPPORT RING	5,0	16,5	5,0	0,0	4,5
14BE	TERMINATION RING	8,0	0,0	1,5	0,0	5,5
14BF	LAY DOWN LANDING STAND	1,0	2,0	0,0	0,0	0,5
14BG	REMOVE DIVERTER	8,0	3,0	2,5	0,0	2,0
14BH	RIG DOWN BOP HANDLING EQUIPMENT	4,0	0,0	0,0	0,0	9,0
14CA	-	0,0	0,0	0,0	0,0	0,0
14CB	-	0,0	0,0	0,0	0,0	0,0
14CC	NIPPLE DOWN BOP AND PUT BOP ON BACK ON STUMP	1,0	0,0	0,0	0,0	3,5
SUM		121,5	106,5	23,5	20,0	68,5
SUM EX TRIPPING		52,5	35,0	18,5	15,5	39,0
EFF RATE		31	30	70	82	39
TRIP PERCENT		57 %	67 %	21 %	23 %	43 %

Table 20 - Total time spent on BOP work (pulling)

The operation section in Table 20 is partially adapted to the operations specified in the DODA-reports, for full description see Table 22.

Well 662A (West Eminence)

During this operation, the crew reported a lot of downtime (ref Table 19) where the major part were caused by jacking up the rig and remove old stop collar and install new spacer and stop collar (80 hours). In addition the crew reported various leak and some various equipment repair.

The average pulling rate presented in Figure 41 show that well 662A achieved the lowest running rate, and the result correlates with the considerable fraction of downtime reported (ref Table 19). Figure 42 shows that the effective running rate for well 662A is approximately equal to well 677A.

Well 677A (West Eminence)

The crew reported downtimes mainly related to equipment failure. It was also reported rough weather conditions during this pulling operation. Despite the weather they continued the pulling operation, but reported it in code 21 (wait on weather). The pulling speed was reported as restricted.

The average pulling rate presented in Figure 41 show that well achieved better result compared to well 662A, but also slightly better than West Phoenix' 8a-A. The total amount of time spent on BOP work, except tripping, shows (ref Table 20) that well 677A have improved compared to 662A, and is roughly equivalent to well 8a-A. If downtime is not included, well has 677A the best running rate, which was intuitively expected as discussed in BOP running operation. When looking into Figure 42, well 677A achieved a lower rate compared to 8a-A.

Well H-3 (West Venture)

The DODA-reports from well H-3 shows no downtime during this pulling operation. The average pulling rate for H-3 (ref Figure 41) is higher compared to West Eminence, and approximately equal to West Phoenix. Both Table 20 and Figure 42 shows that well H-3 spent less amount of hours on BOP work (except tripping) and achieved higher effective pulling rate compared to West Eminence and West Phoenix.

Well X-14-H (West Venture)

The DODA-reports from well X-14-H shows no downtime during this pulling operation. The average pulling rate for X-14-H (ref Figure 41) was the highest rate achieved in the analysis. The time spent on BOP work (except tripping, ref Table 20) and the effective pulling rate represents the best case. The DODA-reports contained only code 14A and 14B, and it is not known if these two codes were the only reporting options at that time or if they have not been used. The report shows operations that should have been reported on other codes starting with 14.

Well 8a-A (West Phoenix)

The DODA-reports from well 8a-A shows no downtime during this pulling operation. There were reported some harsh weather conditions that affected the operations (code 21, Table 19). The time associated with this was subtracted from the calculations, but some work was simultaneous performed on the drillfloor during the weather downtime (daily rig maintenance, clean drillfloor etc.) which is advantageous for West Phoenix in this analysis. Still it does not influence the results considerable much. It is interesting to notice that the average pulling rate in Figure 41 is at the same level as West Venture's wells, while the effective pulling rate in Figure 42 is considerably lower compared to the same wells. One explanation might be the tripping percent (ref Table 20) comprise a dominating part of the operation in the well 8a-A, while in West Venture's wells it is only a minor part of the operation. This could to a great extent be explained by the water depth, but the effective pulling rate (ref Figure 42) and the total time spent on BOP work (ref Table 20) shows that West Venture is performing the operations in a shorter period of time.

8.5 DODA Data & report quality

In order to perform analysis from DODA-reports, the data have to be of a certain quality and fulfill certain requirements. The DODA system provides a lot of information and gives a great outline of the daily operations across all the MODUs. When performing this analysis, it can be considered as good data quality if the following requirements are fulfilled:

1. Specified which kind of well operation performed (drilling, completion, workover, plugging and abandoning, etc.) and if it is HPHT or not.
2. Specified in which section the operation is performed (when drilling)
3. Information about operations had to be reported in such way that it could be easily understood and the exact time spent on the different operations must be given.
4. For the running and pulling operations the tripping distance must be specified in the "Remarks"-category (ref Table 13).
5. If downtime occurs in the operation, it must be specified who is responsible for the failure.
6. The operation reported must be classified in the correct DODA-code and other operations that are not related should not be putted in the same operation.
7. The different codes should cover the key operations in such way that different operations do not merge into the same code.

An analysis would then provide some performance indicators and it would be possible to point out operations that are carried out more effectively on one rig compared to another. Still some considerations regarding resources needed, the crew's competence and ability to handle the machines, the rigs are not entirely identical (West Venture versus West Eminence/West Phoenix) and other effects that might affect the performance are not taken into account.

In this analysis several requirements are considered sufficiently fulfilled:

1. Specified which kind of well operation performed (drilling, completion, workover, plugging and abandoning, etc.) and if it is HPHT or not.
2. Specified in which section the operation is performed (when drilling)
4. For the running and pulling operations the tripping distance must be specified in the "Remarks"-category (ref Table 13).
5. If downtime occurs in the operation, it must be specified who is responsible for the failure.

The data provided from these requirements are considered as sufficient for the analyses. The other requirements will be discussed.

3. Information about operations had to be reported in such way that it could be easily understood and the exact time spent on the different operations must be given.

The DODA-reports as of today require comprehensive knowledge and experience from drilling activities to fully understand the reports. In some part of the reports the comments in the "Remarks"-field can be descriptive, while other parts can be sparsely reported. A lot of information has to be read between the lines since this field should provide all the additional information related to the activity including for example what has been done, what went wrong, what was attempted to be done to fix the problem etc.

As described in Operations24h in section 2.5.1, the DODA reporting system is capable of reporting activities every 15 minutes. In practice, it has been reported activities every 30 minutes or longer periods. The reporting interval is mostly determined separately by each rig leader, but the rig leader should report a new operation when a new operation starts and not combining several operations into one code if several codes describe the operations in a better way. It is understandable that the rig leader cannot report every 15 minutes since they have many other important tasks on the rig during their shifts. Internal surveys indicated 2 hours reporting into DODA per shift, which means approximately 17% spent on DODA-reporting. This is quite extensive compared to various other reporting which indicates approximately 30 minutes. As mentioned, mostly of the activities are reported

6. The operation reported must be classified in the correct DODA-code and other operations that are not related should not be putted in the same operation.

Through the analysis, some vagueness reporting indicated ambiguous indications that the activity should be reported to one code or another. This issue is presented in Table 18 and Table 20 which is related to BOP work.

7. The different codes should cover the key operations in such way that different operations do not merge into the same code.

In the analysis it often occurred that several operations that should be reported to different codes were merged into an activity-code that describes the operation in the best way. This often occurred in drillpipe tripping operations (code 6A) where typically change of slips (code 6C) were performed and included in code 6A. Now and then the time spent on changing slips was specified in the remarks-field so it was possible to separate the two operations.

There exists a user manual that gives guidelines how to report into DODA. The manual states some requirements for reporting quality and some recommendations how to report in the "Remarks"-field. This guideline gives sufficient information about how to report, but the analysis indicates that there are some challenges to make a more uniformed understanding of some of the codes to increase the reporting quality across the MODUs. It was also registered that some activities included some sub activities where the time spent were specified in the remarks section (for example flow check during tripping of drillpipe). Often it was not specified at all, even if procedures indicate that it should have occurred. This brought uncertainties to the analysis, since it is not reported to be done.

8.6 Summary

This section presents a general discussion regarding results and issues in the analyses.

It is interesting to see that West Phoenix's tripping rates are regularly higher than West Eminence's even though the rigs are identical. West Eminence works in a harsher deepwater environment compared to West Phoenix, which might require even more focus on operational procedures and contingency plans. This is discussed in chapter 6.3. An interview with the rig manager at West Eminence indicates that most of the failures and downtime on the rig are caused by the drillcrew by wrong use, lack of knowledge and lack of operational understanding. He reports considerably improvements since startup until this date, which correlates with the results in the analysis (well 662A versus 677A).

It is interesting to notice that West Venture, the 5th generation semi-submersible rig in general performs the operations more efficiently compared to West Phoenix and West Eminence. Both West Phoenix and West Eminence are 6th generation semi-submersible rigs and should have better premises to perform operations more efficiently than West Venture. As already mentioned, West Venture has been operating on the same field for more than 10 years and the crew is familiar with procedures and equipment, which of course is advantageous. Still it is important that the drilling rigs are able to face new challenges regarding water depths and harsh weather conditions.

In chapter 6.2 it is discussed the importance of improving operational efficiency by monitor, analyze and detect best practice in drilling operations. The model for benchmarking was:

- Collect performance data
- Identify Best-In-Class performance
- Analyze processes
- Identify Best Practices
- Adopt Best Practices
- Monitor

This model resulted in considerable improved operational drilling efficiency for the two rigs adopting the best practices. It seems like procedures and the drillcrew's operational knowledge and skill might be more important than possessing the last generation semi-submersible drilling rig.

To collect performance data from DODA daily operations reports, one has, as of today, to manually analyze the Operations 24h reports to determine operational performance data. The report quality might not be of satisfactory quality to present reliable performance data. By introducing some extra features to the registering of operational records, one might be able to produce acceptable operational performance data. In addition, DODA should be able to automatically perform these analyses performed in this thesis and present statistics of the drilling operations. The features are presented in chapter 9.1.

9 Conclusions

Daily drilling operational data from wells drilled by West Venture, West Eminence and West Phoenix were analyzed. The operational data were imported from the DODA reporting software and the first analysis carried out average tripping rates of tripping drillpipe, tripping BHA, running production casing and running/pulling BOP with riser were determined. The analyses were divided into two parts, running in hole and pulling out of hole. The intent was to determine tripping rates (m/h) as a measurement of operational efficiency.

It is important to remember that the tripping rates are based on data reported from the rigs leaders of the rigs. The rig leaders' approach when reporting is to describe the operations that has been carried out in a short and concise way, and not necessary taking into account to report as time specific as possible. This may affect the analyzed data results to contain more uncertainties since it was hard to determine the accurate time spent on the operations.

Based on the first analysis results:

- West Venture attained highest rates when tripping drillpipe

The last three analyses were performed in order to determine operations efficiency in a specific section of the well or a specific phase of the well construction. Based on the second analyses results:

- West Venture attained highest rates when tripping BOP and spent least amount of hours on work related to landing and unlatching BOP.
- West Eminence attained overall lowest tripping rates and spent most amount of hours on work related to landing and unlatching BOP.
- The analysis indicates that West Eminence showed improvement in operations efficiency from the first well drilled to the next well drilled one year later.

9.1 Suggested improvements

With some improvements, the report quality of DODA-reports regarding operations efficiency might be more reliable. It should then also be possible to automatically carry out more statistics from each rig regarding operations efficiency. Suggested improvements regarding DODA Operations24h:

- When specifying tripping distances in the remarks section, it should also be registered as a separate post when registering an operational record in the Operations 24h. Figure 46 in Appendix B shows a screenshot of registering an operational record. The yellow area is not part of the original screenshot, but the suggested feature. By doing this the depth intervals are stored in the database and DODA can calculate tripping rates.
- When registering an operational record in the Operations 24h, the choice of a particular code should emerge a list of possible sub-operations related to the code. It should then be possible to check off all the performed sub-operations and specify amount of minutes spent on each separate sub-operation. By doing that, all the information will be stored in the DODA database and it should be possible to determine effective tripping rates by subtracting the amount of minutes spent on sub-operations, and also achieve automatically generated statistics of the time spent the different sub-operations across the rigs.

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Appendix A

INSTALLATIC	RIG	OPERAT	FIELD	WELL	DAY_	ACTI	ACTUAL_S	FROM_TIM	TO_TIME	ELAPSED	CODE	DOWN	DOWN_	REMARKS	SUB_CC
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-08	1	8 1/2	00:00	02:00	02:00	23	NULL	NULL	Cont circulate B/U due to possible core point. Work string while circulate w/2050litres/230 bar/15 rpm. Boost riser	NULL
West Phoeni	2	Eni Denr	Anne-M	6004/8a-A	2010-10-08	1	8 1/2	00:00	24:00:00	24:00:00	NULL	NULL	NULL	Held meeting with crew according l/d old BHA and prepared new BHA. Brake bit and flush through stand, rack sa	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-08	2	8 1/2	02:00	03:00	01:00	22	NULL	NULL	Flow check well on TT. Bit dept 3396 metres.	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-08	3	8 1/2	03:00	04:30	01:30	6D	NULL	NULL	Pump out of hole w/ 81/2" BHA on 5 7/8" Dp from 3396 meters to 3213 meters w/1500 litres/135 bar	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-08	4	8 1/2	04:30	05:00	00:30	8EMA	D	NULL	Problems with brake out std from DDM, torque wrench will not brake.	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-08	5	8 1/2	05:00	05:30	00:30	6D	NULL	NULL	Cont Pump out of hole w/ 81/2" BHA on 5 7/8" Dp from 3213 meters to 3130 meters w/1500 litres/135 bar	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-08	6	8 1/2	05:30	07:30	02:00	5	NULL	NULL	Sirc bottoms up w/2000 litres/227 bar/15 rpm @ 2340 stk. Boost riser w/1200 litres/12 bar. Total pumped 14100 st	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-08	7	8 1/2	07:30	08:00	00:30	22	NULL	NULL	POOH from 3130m to 3074m and flow check well. Meanwhile perform yellow DROPS	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-08	8	8 1/2	08:00	08:30	00:30	6D	NULL	NULL	POOH 5 std wet from 3074m to 2932m	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-08	9	8 1/2	08:30	09:00	00:30	6D	NULL	NULL	POOH from 2932m to 2903m while pump 5,5m³ 1,55 sg slug, chase slug with 1,7m³ 1,30 sg mud. Stand by for sta	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-08	10	8 1/2	09:00	12:30	03:30	6A	NULL	NULL	Continue POOH from 2903m to 1511m	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-08	11	8 1/2	12:30	13:00	00:30	22	NULL	NULL	Flow check well prior to pull 8 3/8" BHA trough BOP	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-08	12	8 1/2	13:00	15:30	02:30	6A	NULL	NULL	Continue POOH BHA from 1511m to 344m.	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-08	13	8 1/2	15:30	18:30	03:00	6B	NULL	NULL	Pull out 8 3/8" BHA from 344m to surface, inspect an gauge 8 3/8" bit. Rack in chute Aux for download data.	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-08	14	8 1/2	18:30	19:00	00:30	6B	NULL	NULL	Pick up core stand and make up bit. RIH @ 18:40hrs w/ outer barrel from surface to 221 meters.	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-08	15	8 1/2	19:00	19:30	00:30	6B	NULL	NULL	Held pr job meeting with crew according to make up inner barrel and manual handling of drilling equipment.	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-08	16	8 1/2	19:30	20:00	00:30	6B	NULL	NULL	Make up inner barrel in outer barrel.	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-08	17	8 1/2	20:00	21:00	01:00	6B	NULL	NULL	Space out inner barrel in outer barrel.	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-08	18	8 1/2	21:00	21:30	00:30	6B	NULL	NULL	RIH w/8 ½" core on 6 ¾" DC from 21 m to 89 m	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-08	19	8 1/2	21:30	22:30	01:00	6B	NULL	NULL	RIH w/8 ½" core on 5 7/8" HWDP f/89 m to 288 m	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-08	20	8 1/2	22:30	24:00:00	01:30	6A	NULL	NULL	RIH w/8 ½" core on 5 7/8" Dp f/ 288 m t/ 1012 m. Fill pipe every 500 meters.	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-09	1	8 1/2	00:00	00:30	00:30	6A	NULL	NULL	RIH w/8 ½" core on 5 7/8" Dp f/ 1012 m inside riser and throug BOP t/ 1141 m.	NULL
West Phoeni	2	Eni Denr	Anne-M	6004/8a-A	2010-10-09	1	8 1/2	00:00	24:00:00	24:00:00	NULL	NULL	NULL	Download MWD. Break out CLSS, and change out with new. Rack back same in setback.	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-09	2	8 1/2	00:30	04:00	03:30	6A	NULL	NULL	RIH w/8 ½" core on 5 7/8" Dp in 9 7/8" csg f/ 1141 m t/ 3074 m. Fill pipe every 500 meters@03:40 hrs held pr-job r	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-09	3	8 1/2	04:00	08:30	04:30	7	D	NULL	Take planed maintenance stop: Change oil and hyd filters. Change solenoid valves on DDM tilt and torque wrench f	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-09	4	8 1/2	08:30	09:00	00:30	5	NULL	NULL	Break circulation in steps, maximum pump rate 1200 lpm/ 40 bar.	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-09	5	8 1/2	09:00	15:30	06:30	8EMA	D	NULL	Attempt to break connection with torque wrench. Make/break function not operating. Datatechs and hydraulic eng.	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-09	6	8 1/2	15:30	17:30	02:00	3	NULL	NULL	Continue RIH with 8 ½" core head from 3074 m to 3101meter. Take 20 ton weight. Pull back up to 3098 meter. Go	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-09	7	8 1/2	17:30	18:30	01:00	3	NULL	NULL	Continue RIH with 8 ½" core head from 3130 m to 3174m. Restrictions at 3130m. Work area from 3174m to 3184m	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-09	8	8 1/2	18:30	21:30	03:00	3	NULL	NULL	Wash down with 1200 litres/40 bar from 3184m to 3380 meters. Ream tide spot @ 3305 m and 3364 m.	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-09	9	8 1/2	21:30	22:00	00:30	3	NULL	NULL	Ream down last std f 3364 m to 3412. Tag bottom @ 3412 m midte tide. With 1200 litres/20 rpm/ 40 bar	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-09	10	8 1/2	22:00	24:00:00	02:00	5	NULL	NULL	Sirc B/U with 1200 litres/40 bar/20 rpm @ 2250 stk boost riser with MP`s 1 & 2.	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-10	1	8 1/2	00:00	01:00	01:00	4	NULL	NULL	Drop 1.2" ball and make up drilling std. Chaise ball w/570 litres/21 bar @ 00:40 hrs ball at seat and get 25 bar on s	NULL
West Phoeni	2	Eni Denr	Anne-M	6004/8a-A	2010-10-10	1	8 1/2	00:00	24:00:00	24:00:00	NULL	NULL	NULL	Prepare for changing out pad eye in top of derrick for manrider snatch block. Perform TBRA. Pick up BHA and ma	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-10	2	8 1/2	01:00	05:30	04:30	4	NULL	NULL	Tag bottom and start core w/ 830 litres/ 44 spm/40-44 bar/50-80 rpm/1-5 t WOB from 3412 meters to 3423 meters	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-10	3	8 1/2	05:30	06:00	00:30	4	NULL	NULL	Perform pull test. to 2 ton overpull. Go back to bottom and attempt to core. no go.	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-10	4	8 1/2	06:00	08:00	02:00	4	NULL	NULL	Pull of bottom and sirc bottoms up w/ 1200 litres/60 bar, start boost riser with 1800 lpm/20 bar when bottoms up ar	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-10	5	8 1/2	08:00	09:00	01:00	6D	NULL	NULL	Flow check well static for 10 min straight line. Rack back drilling stand.	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-10	6	8 1/2	09:00	10:30	01:30	6D	NULL	NULL	POOH with core from 3408m to 3073m weat.	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-10	7	8 1/2	10:30	11:00	00:30	6D	NULL	NULL	Flow check well at shoe. POOH from 3073m to 3060m while pump 5m³ 1,55 sg slug, chase with 1,7m³ 1,30 sg m	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-10	8	8 1/2	11:00	13:30	02:30	6A	NULL	NULL	Continue POOH from 3060m to 1625m.	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-10	9	8 1/2	13:30	14:00	00:30	6D	NULL	NULL	Flow check well for 10 min prior to pull BHA to BOP	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-10	10	8 1/2	14:00	17:30	03:30	6D	NULL	NULL	Continue POOH with core from 1625m to 288m. Reduce pulling speed to 1 min/stand at 915m, 3 min/stand at 610	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-10	11	8 1/2	17:30	19:00	01:30	6B	NULL	NULL	POOH with BHA from 288m to surface. Lay down one single 5 7/8" HWDP. At 122m reduce pulling speed to 9 min	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-10	12	8 1/2	19:00	19:30	00:30	6B	NULL	NULL	POOH with BHA on 6 ¾" DC f/ 90 meters to32 meters w/ reduce pulling speed to 9 min/stand, sniff for H2S on eve	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-10	13	8 1/2	19:30	20:00	00:30	4	NULL	NULL	Held pr-job meeting with crew according to handle core barrel	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-10	14	8 1/2	20:00	22:00	02:00	4	NULL	NULL	Set outer barrel in table and brake out and L/d inner barrel to deck. Recover 10,75m -97,7% with core. Parallell acti	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-10	15	8 1/2	22:00	22:30	00:30	4	NULL	NULL	POOH w/ outer barrel and brake of bit, set same in set back.	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-10	16	8 1/2	22:30	23:00	00:30	4	NULL	NULL	Clean and tidy rig floor. Parallell activity: Function test shear ram on yellow pod, Sem B.	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-10	17	8 1/2	23:00	23:30	00:30	6B	NULL	NULL	P/u 8 ½" BHA from set back, check bit and RIH from surface to 59 meters.	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-10	18	8 1/2	23:30	24:00:00	00:30	6D	NULL	NULL	Make up DDM to string and test MWD with 1500 litres/100 bar/79 stk	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-11	1	8 1/2	00:00	00:30	00:30	6B	NULL	NULL	RIH w/8 1/2" BHA on 6 ¾" DC from 59 meters to 153 m	NULL
West Phoeni	2	Eni Denr	Anne-M	6004/8a-A	2010-10-11	1	8 1/2	00:00	24:00:00	24:00:00	NULL	NULL	NULL	Axess change out pad-eyes in Ram Guide. Bring down equipment for Axess from Ram Guide. Pre job meeting	NULL
West Phoeni	1	Eni Denr	Anne-M	6004/8a-A	2010-10-11	2	8 1/2	00:30	01:30	01:00	6B	NULL	NULL	RIH w/8 1/2" BHA on 5 7/8" HWDP from 153m to 343 meters.	NULL

Table 21 - Glimpse of a DODA-report used in the analysis [20]

CODE	DESCRIPTION
1A	Rig move between locations. Not positioning, anchor handling or other operations on the location in order to position the rig (1B)
1B	Rig preparations (positioning/anchor handling at location, rig skidding, opening hatches and all other operations to start working on the well)
2	Drilling (drilling formation and making new hole)
3	Reaming previously drilled hole (incl. back reaming and drilling cement)
4	Coring (Dropping ball, circulating, coring new hole and recovering core samples at surface. Not making up BHA or tripping)
5	Circulating and conditioning mud (not including circulating for geological samples)
6A	Effective tripping of drillpipe at normal speed in casing, not tripping BHA, not changing handling equipment, not cleaning drillfloor after trips or other activities (6B-C-D). Always register depth (from xx to xx and total length of trip: xx)
6B	Tripping bottom hole assemblies (BHA) including picking up/laying down and other work with BHA.
6C	Tripping, working on handling equipment (elevators, slips, tongs etc.). Time spent for changing elevators, slips, slips inserts etc. Specify activity and type of handling equipment
6D	Tripping others. Tripping activities not covered by 6A, 6B or 6C (example: Tripping of drillpipe in open hole, testing MWD tool, breaking ciculation, etc.).
7	Lubricate rig (stop in operation due to planned maintenance)
8	Repair rig. All stop in operation (downtime), Seadrill is responsible for according to in force contract with client. This code to be used when no other code 8 can be used.
8A	Rig repair. Stop in operation (downtime) caused by the dynamic positioning system that Seadrill is responsible for according to in force contract with client
8EAB	Repair rig (ABB equipment). All stop in operation (downtime), Seadrill is responsible for according to in force contract with client.
8ECA	Repair rig (Cameron equipment). All stop in operation (downtime), Seadrill is responsible for according to in force contract with client.
8ECO	Repair rig (Continental Emsco equipment). All stop in operation (downtime), Seadrill is responsible for according to in force contract with client.
8EDR	Repair rig (Drillquip equipment). All stop in operation (downtime), Seadrill is responsible for according to in force contract with client.
8EHY	Repair rig (Hydril equipment). All stop in operation (downtime), Seadrill is responsible for according to in force contract with client.
8EMA	Repair rig (Maritime Hydraulics equipment). All stop in operation (downtime), Seadrill is responsible for according to in force contract with client.
8ENA	Repair rig (National Oilwell equipment). All stop in operation (downtime), Seadrill is responsible for according to in force contract with client.
8ESH	Repair rig (Shaffer equipment). All stop in operation (downtime), Seadrill is responsible for according to in force contract with client.
8ESW	Repair rig (Swaco equipment). All stop in operation (downtime), Seadrill is responsible for according to in force contract with client.
8EVA	Repair rig (Varco equipment). All stop in operation (downtime), Seadrill is responsible for according to in force contract with client.
8EVE	Repair rig (Vetco equipment). All stop in operation (downtime), Seadrill is responsible for according to in force contract with client.
8EWI	Repair rig (Wirth equipment). All stop in operation (downtime), Seadrill is responsible for according to in force contract with client.
9	Slip & cut drilling line
10	Survey
11	Wireline logs. Rigging up, tearing down, and running logging equipment.
11A	TLC. Logging on wire and pipe
11B	Logging others including MWD logging.
12A	Running casing, liner, tubing, screens etc. (not: rigging up/down, landing string, cementing) Always register from xx ¿ to xx and length of trip
12B	Rigging up for running casing, liner, tubing, screens etc., running landing string, circulating prior to cementing, cementing casing and rigging down after job

12C	Cut and pull casing (not plugging back -code 17)
12D	Milling casing
12R	Casing activities done under restrictions. Always register from xx to xx and length of trip
13	Wait on cement
14A	Running/pulling riser (not preparing for running, not BOP work, not handling slip joint, not diverter or rigging down after job etc.). Always register number of riser joints and depth (from xx to xx and total length of trip: xx)
14AA	While running riser, testing lines (kill/choke/booster etc.)
14B	Preparing for running riser, BOP work, handling slip joint, diverter and rigging down after job etc.
14BA	Prepare drillfloor for BOP/Riser work
14BB	Pick up riser joint(s), skid BOP to well center, m/u riser to BOP, install guidelines
14BC	Install/remove slip joint
14BD	Install/remove Flex joint, support ring, Pod/Mux cables
14BE	Install/remove Termination ring
14BF	Land BOP/over pull test/lay down landing stand
14BG	Install/remove Diverter
14BH	Rig down BOP/Riser handling equipment
14CA	Install spacer Spool on Wellhead
14CB	Remove BOP from Stump and install on well head / spacer spool
14CC	Nipple down and put BOP on back on Stump
15	Test BOP including running/pulling test plugs etc.
15A	Testing of other BOP equipment (manifolds, inside BOPs etc.)
16	DST
17	Plug back. Setting plugs in open hole or casing for plugging back
18	Squeeze cement. Making up squeeze tools, conducting squeeze jobs, laying down squeeze tools
19	Fishing. To include actual hours from time fishing job occurs until normal operation is resumed.
20	Directional work
21	Waiting on weather
22	Well control (all operations involved with handling well control situations)
23	Others, This code to be used when no other code describes the activity
A	Completion, Perforating
B	Completion, Tubing trips
C	Completion, Treating
D	Completion, Swabbing
E	Completion, Testing
F	Completion, Additional

Table 22 - DODA code description [20]

Appendix B

Seadrill

Daily Operations Report

Rig

Installation	West Eminence
Report no.	6
Field	Lula
Date	2011/1/11
Operator	Petrobras
Waterdepth	2152

HESQ

Date last recordable injury	2010/10/8
Days since last rec. inj.	95
Date last LTI	2010/10/8
Days since last LTI	95
Number of OBS	40
Number of synergi reports	2
No red and yellow UF	0

Descr. recordable injury, red and yellow UF

DRILLING OPERATIONS

Well	9-RJS-686D
Spud date	2011/1/8
Days since spud	3
Planned well TD	5510
(-)ahead or (+)behind AFE	0
(-)ahead or (+)behind TL	0
Estimated well finished	2011/5/5
Well depth at 24 hrs.	2623
Footage last 24 hrs.	405
Uptime last 24 hrs.	20:30
NPT last 24 hrs.	3:30
Downtime code 8	3:30

Operations at 06:00 hrs.

Aux rotary drilling ahead with 26" bit 06:00 depth 2750m

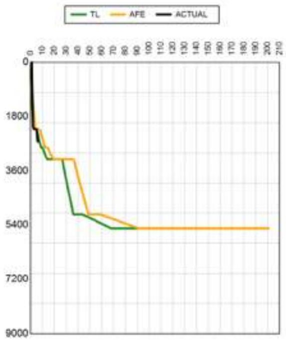
Main rotary making up 2nd 26" BHA 06:00 depth 27m

Comments drilling department

Drilling:
Main DDM - 1219 / Saver Sub - 20
Aux DDM - 185 / Saver Sub - 185
Equipment Lubricated
Main - TIA
Aux - BRC
Subsea:
-DNV approved

Comments technical department

Reset power failure on auxiliary rig drillview system.
Completed saveall extensions on port bunker manifold.
Continue internal fitting of rigging lo



MARINE OPERATIONS

	24:00 hrs.	max
Wind m/sec.	3	6.5
Wind dir.	234	
Sea H max	2	2
Sea dir.	0	
Sea per.	8	9
Sea sig. P		
Sea H 3		
Pitch S/A	1	1.2
Heave D/A	0.4	0.4
Roll S/A	0.8	0.8
Heading	10	
Air temp. C0	24	25

Comments DP system	
04:00	DP OK
08:00	DP System ok.
12:00	DP System OK.
16:00	DP System all ok.
20:00	DP ok.
24:00	DP OK

Platform Manager	Philip Noon
Operators Rep.	Antonio Luckmann
Drilling Sec. Leader	John Payne
Tech. Sec. Leader	Gareth Morgan

Seadrill

Well Operations

West Eminence, FIELD: Lula, WELL: 9-RJS-686D, REP.NO.: 6, 2011/1/11

Total pipe tripping length (6A)	0
Total casing tripping length (12A)	0
Total riser tripping lenght (14A)	0
Last casing size	30"
Shoe depth last casing	2213
F.I.T	
Mud weight at 24:00 hours	8.6

Type of mud in use	SW
Days since last BOP pressure test	0
Days since last BOP function test	0
Days since last pit drill	0
Days since last kick drill	0
Washpipe hours main/aux rig	1/126
Highlights	Bit hours 15.4

B.H.A.	Bit-Roller, MOTOR, X/O, STAB, NM MWD sub, On trak-MWD, BCPM, MWD sub,4 x 9 1/2" DC, STAB, 2 x 9 1/2" DC, X/O, NM Sub Filter, 9 x 8" DC, JAR, 2 x 8" DC, X/O, 9 x 5 7/8HWDP
BOP rams	BSR. CSR. UPR. [3½" x 7⅝"].VBR's. MPR. [5½" Fixed]. LPR. [3½" x 7⅝"].VBR's.
Rig remarks	-PR 23500073 shaker screens stock replenishment. -PO 146714 HRN Dies 144. -PR 23500083 SS Drag chain for VPH. -PO 143077 replacement of number 3 insert bushings. -PO 133291 for jockey pump A -PO 137269 Service Loop for critical spares -PO 143627 Valves and Spares for Cement manifold -PO 135876 Lug Jaw for HT200 manual tong. -PO 134331 Stab in valve repair parts. -PO 140714 additional lighting for pipedeck. -PO 148248 tubular chute chain and guide rollers. -PO 149103 AC Compressor repairs. -PR 23500443 Harddrives required for MH server backups.

Bit	Size	Manufacturer	Type	Jets	HRS run	Footage	Dull condition
2	26	Smith	Roller Cone Mill	2x22 / 22 / 24	12	405	

Drill parameters

Depth	Deviation	WOB	RPM	Torque	Pressure	SPM	Volume	Remarks
2623	1.1	25	235	4-7	2710	201	0	Seawater

Helicopter traffic

Flight No.	Arrival	Pax on	Departure	Pax off	Fuel	POB
PR-CHU	03:00 PM	8	03:09 PM	7		138

POB at 24:00 hours

Seadrill	Seadrill ext.	Operator	Op. Extra	Op. Service	Catering	Other	Total
90	6	7		19	16		138

Misc. Stock, consum & weights onboard at 24:00 hours

Item		Start	Used	Received	In stock
Fuel	m3	2708	50	0	2658
Lub. Oil	Ltrs.	7500	0	7400	14900
Helifuel	Ltrs.	3876	0	0	3876
Potwater	m3	305	55	430	680
Drillwater	m3	329	184	353	498
Slop	m3	92	-6		98
Brine	m3	618	16	0	602
Mud	m3	0	0	0	0
PreMix	m3	109	0	0	109
Oil based mud	m3	484	484	0	0
Bentonite total	MT	84	3	0	81
Barite total	MT	161	57	64	168
Cement total	MT	208	0	0	208

Comments marine departement

DP OK
Thruster 2p down , awaiting - Deckcrews: attending helicopter and 4 boats; trash segregation and food waste disposal; washdown main deck and upper deck (portside); 2 men cleaning the Brine Pumps area (stbd pontoon). Working on Lodic, IFS, TBRA, on manrider at moonpool.

Stability Summary

Figure 44 - DODA Daily Operations Report [20]

Seadrill

Weekly Operations Report

Rig

Installation	West Eminence
Week no.	2
Week ending date	2011/1/16
Year	2011
Operator	Petrobras
Field	Lula
Well	9-RJS-686D

	Week: 2	Month: 1	Quarter: 2011 - 1	Year: 2011	Current well: 9-RJS-686D	Last well: 3-RJS-677A
LTI	0	0	0	0	0	1
Medical	0	0	0	0	0	0
Disposal to environment	0	0	0	0	0	0
Sickleave %						
Sickleave cost						
Sickleave budget						
Number of OBS	198	456	456	456	295	3684
Number of synergi rep.	9	22	22	22	13	189
Red and yellow UF	0	0	0	0	0	7
Tidiness & cleaning	4	3.3	3.3	3.3		
Operational progress	4	3.5	3.5	3.5		
Maint. code 7 hrs.	1.5	2	2	2	1.5	11.5
W.O.W code 21 hrs.		69.5	69.5	69.5	27.5	42
Downtime code 8 hrs.	5.5	25.5	25.5	25.5	9	482
Uptime hrs.	160	348.5	348.5	348.5	229	1853.5
NPT hrs.	8	32.5	32.5	32.5	16	773
Drilling speed m/day	140.9	213.6	213.6	213.6	320.4	50
Drilling speed d/10k ft	21.6	14.3	14.3	14.3	9.5	61
Pipe tripping std/hrs						13.7
Casing running jnt/hrs						7.2
Riser running m/hrs		21.3	21.3	21.3	34	31.2

Comments recordable injuries

1/11/2011 None

1/12/2011 None

1/13/2011 None

1/14/2011 None

1/15/2011 None

Comments red and yellow UF

Main activity this week and plan for next week (page 1)

Last week: Run in hole and drill 26inch section.
Next week: Continue to drill 26inch section on main.
Run 20inch casing on auxiliary and cement.

Figure 45 - DODA Weekly Operations Report [20]

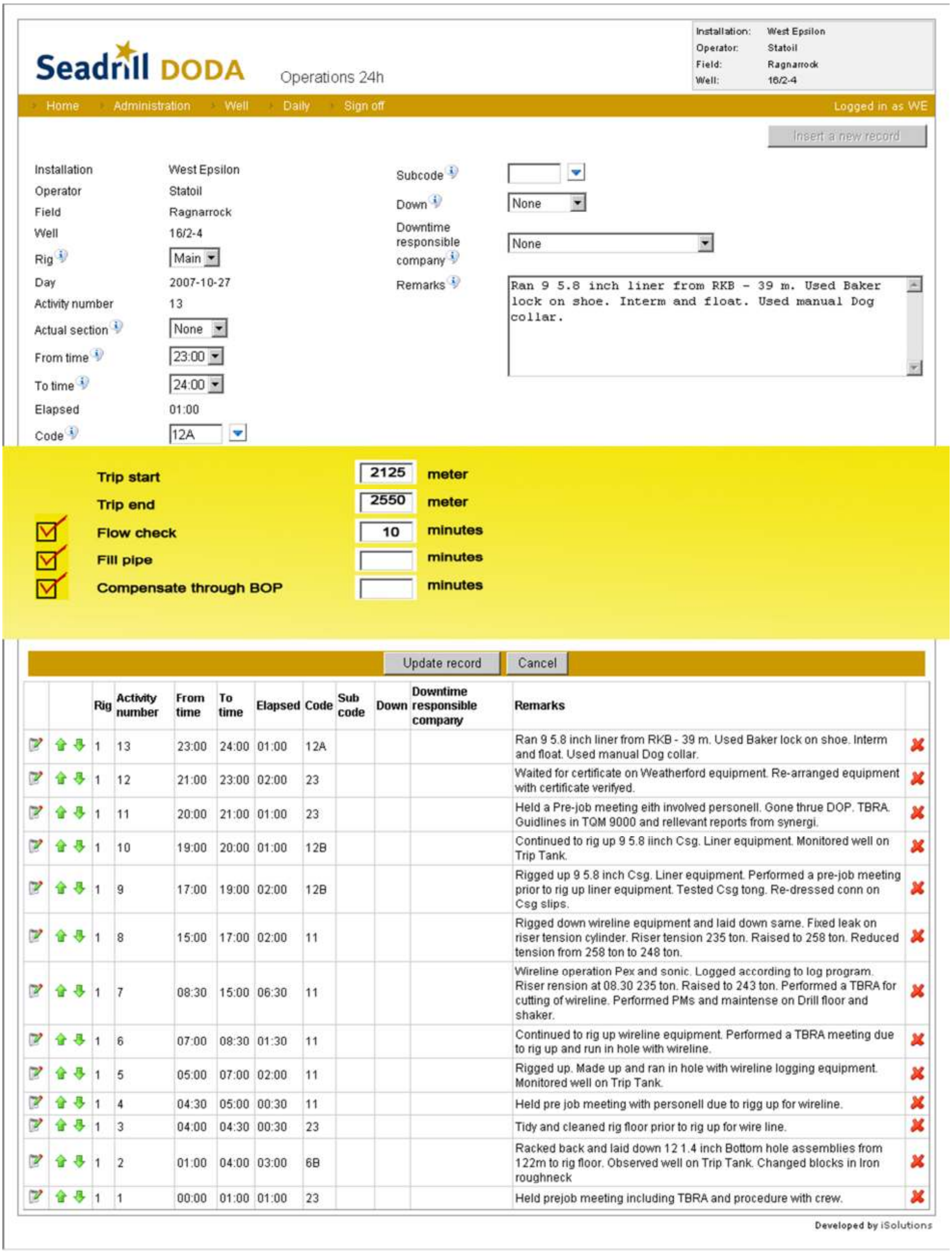


Figure 46 - DODA Operations 24h registration (edited) [20]

Appendix C

Results based on tripping codes

CODE	TOTAL TRIP-TIME [HOURS]			TOTAL TRIP-DISTANCE [M]			AVG SPEED RATE [M/HOUR]		
	VENTURE	PHOENIX	EMINENCE	VENTURE	PHOENIX	EMINENCE	VENTURE	PHOENIX	EMINENCE
6A RIH	38	48,5	59,5	21590	21181	22398	535	437	376
6A POOH	55	52,5	55,5	32908	25971	21443	598	487	386
6B RIH	55,5	33,5	59,5	6494	3819	5805	121	114	107
6B POOH	68	32,3	46,5	8094	3029	4581	119	94	99
12A RIH	106	46,25	8,5	10875	4209	364	103	91	43
14A RIH	27	16	151,5	1125	637	4213	42	40	28
14A POOH	16	27	72,5	1257	719	2234	79	39	31

Table 23 - Results of tripping rates based on codes

Appendix D

Tripping drillstring

Procedures for running drillstring with BHA in hole

1. Pick up the DC to the position where the tube instructor arm (TIA) can be installed on the DC stand, Bring back the Elevators with the link arms and follow in with the TIA to Well Centre.
2. Position the DC over the Bit sub and lower the DC into the Bit sub.
3. Install chain tong on Bit sub and make up to the DC.
4. Pick up the DC with Bit sub and position the DC / Bit sub over the Bit
5. Lower the DC slowly over the Bit and Rotate slowly with the Rotary counter clockwise.
6. Once the bit threads are closed and the Rotary has stopped, the AD can bring in the HRN[19] and with the correct torque make up the Bit sub to the DC.
7. Remove the TIA
8. Install the Rig make up tong on the DC and lock the Rotary table.
9. Lift the securing arm on the DC stand and the Bit out of the Bit breaker with the DDM[20] and move to one side. Stab the Bit down on the Rig floor.
10. With the Bushings removed run the first stand down past the bit and stabilizers. Re-install the bushings and continue down to the slip area and set the slips.
11. Remove the Elevators.
12. Raise the DDM and bring in the HRN to break out the Lift nubbin.
13. Pick up the next stand of DC's as in the last process until the Stand is up to the stabbing height. Clean and dry the threads if required. Dope the thread.
14. Bring in the HRN and spin in the DC.
15. Once BHA is in the hole we will need to change the torque for the DP
16. Change inserts of required
17. When running in the hole we will open the compensator to pass the BOP, Well Head and any liners or hangers.
18. Flush choke and kill lines, take the SCR[21] before entering open hole

Procedures for pulling out of hole

1. Fill Trip Tank to POOH[22]
2. Prepare Trip Sheet to POOH
3. Flow check for 15min.
4. Pull stand to sufficient connection height set the slips Break out the DDM.
5. Lift stand out of box end and guide lower end of stand by using the TIA
6. Lower stand down chute.
7. Open elevator.
8. Move stand to setback by Bridge crane and VPH[23].
9. If the well is stable start to pull out of the hole with DDM connected. If there are any hole problems pump and back ream as Required
10. If there are no hole problems and we can pull without the DDM connected pull the first 5 stands slowly recording the volume of the Trip sheet for each stand pulled.
11. After the first 5 stands are pulled the pipe stripper can be installed.
12. Pull at a slow rate checking for swabbing. The Trip sheet should now be filled in each 5 stands of DP pulled and each stand of DC's
13. Flow check at the casing shoe
14. If all is correct on the trip sheet after the flow check continue to POOH until the BHA gets to the BOP and flow check
15. Continue to POOH until the BHA is at surface and Remove the stripper and the PS30's

16. Continue to POOH with the BHA
17. Install Lift nubbin in DC stand with Tugger and make up with the HRN Check the Torque required for each joint. Driller and assistant driller confirm torque with the audible alarm. Check the Guide is correctly set for each OD[24] of tubular to be made up or broken out
18. Once the Bit is at Surface drain any fluids left in the string in to the Hole before pulling all the way out.
19. Install the Bit Breaker plate and Bit breaker
20. Lift the stand with the Bit and place in to the Bit Breaker.
21. Lock the Rotary Table Remove the TIA and install the Break out tong and pull on the Hyd Cat Head line

Production Casing running

Procedures for rig up casing handling equipment

1. Remove PS 30's & master bushings
2. Install BJ[25] split ring & FMS[26]
3. Rig up power tong
4. Rig down DP elevators & bails if needed
5. Rig up spider elevators & single joint pick ups
6. Rig up fill up tool

Pick up and run casing

1. Place joint casing.
2. Install lift sub into box. Tighten with chain tong & paint mark on lift sub & joint
3. Latch single joint elevators onto joint. Latch elevators.
4. Install TIA and move to well center
5. Lower assembly through rotary table set slips and install safety clamp
6. Fill and check float and shoe for flow
7. Pick up next joint as per steps 1-4
8. Stab pin end into box of stump in rotary table
9. Close Spider elevators when dies are past upset of box
10. Take weight of string
11. Close slips
12. BJ open spider
13. Remove lift sub with single joint pick ups
14. Continue pick up & RIH as per tally. Fill pipe
15. Compensate through BOP
16. After running last stand of casing rig down spider elevators and rig up DP elevators
17. Pick up and make up casing hanger assembly
18. Remove FMS
19. Run the landing string and fill every 5 stands
20. At 20" shoe connect top drive and circulate & 8 bpm[27] (15 min)
21. Compensate through shoe
22. Run last stand DP. Pick up cement stand
23. Open compensator and set casing hanger in well head. Circulate @ 5 bpm

Running and pulling BOP with riser

Pick up and run riser

1. Skid the BOP into well center
2. Stab riser running tool into first joint of riser
3. Pick up & lower first riser joint through rotary

4. Pick up the BOP stack
5. Lower BOP carefully through BOP skid
6. Land in Spider
7. Pick up and run riser joints according to running tally
8. Picking up and run pup joints from deck
9. Perform a pressure test of all auxiliary lines on Riser prior to pick up telescopic joint
10. Check telescopic joint on deck before lifting
11. Pick up and make up slip-joint
12. Pick up and make up Space/ flex-joint & land in spider
13. Pick up and make up landing joint
14. Install goosenecks
15. Skid BOP-skid out of moonpool and into BOP garage

Pressure test

1. BOP in test mode
2. Test Choke & Kill and Mud Boost
3. Test conduit lines
4. Test Choke & Kill and Mud Boost
5. Test conduit lines
6. Install storm loops
7. Lower landing joint & install tension ring
8. Prepare for landing BOP

Landing BOP

1. Land BOP with bleeding off pressure on compensator
2. Set down 40 Kips[28]. Close connector and verify volume of BOP fluid used
3. Use ROV to observe indicator pin
4. Take over pull 50 Kips. Use compensator for over pull test of connector
5. Slack back off to neutral weight & lock open compensator
6. Scope out slip joint & lay out landing joint

Install Diverter

1. Rig down riser running tool
2. Check that the tilt cylinder pin is in and then skid diverter to the pick up position
3. Install 5 7/8 inserts in the DDM elevator
4. Make up Diverter to Upper flex-joint
5. Check / verify for correct latch of Diverter Running-tool in Diverter
6. Clean seal area in Diverter-housing with high-pressure gun
7. "Extend" Diverter Landing Dogs and visually verify in diverter housing.
8. Verify "Retract" of Diverter Lockdown Dogs
9. Verify "Retract" of Diverter Hydraulic Stabs
10. Land the diverter in the housing
11. "Extend" Diverter Hydraulic Stabs
12. "Energize" Diverter Flowline seals with regulated pressure according to operations manual
13. Release and Lay down the diverter running tool
14. Remove Riser Spider/gimbal and prepare for next operation
15. Pressure up the Telescopic-joint Upper packer according to operation manual
16. Fill up the riser and check the flow line seals
17. Diverter Function test
18. Prepare BOP space out sheet

Procedures for pull BOP

Pull Diverter

1. Install Spider skidding beams and skid spider to rotary table.
2. Lift out master bushing and outer adapter ring from rotary
3. Lower the spider and land in the rotary table
4. Rotate spider to correct position
5. Clean the inside of the diverter
6. Pick up Diverter running tool and remove hole cover
7. Lower and stab running tool into the diverter
8. Pick up Diverter and set in spider
9. Clean Diverter on OUTSIDE
10. Lift the diverter and land in diverter bucket
11. Release elevators from Diverter running tool
12. Skid Diverter to parking position
13. Rig up riser running tool

Pull BOP

1. Lower down landing-joint and start collapsing the slip-joint
2. Verify status on CVP[29] at BOP
3. Unlatch BOP
4. Remove tension ring and goosenecks
5. Lay down Flex joint and slip joint
6. Pull Riser and BOP
