University of Stavanger

Faculty of Science and Technology

MASTER'S THESIS

<table>
<tr><td>Study program/ Specialization:

Offshore Technology/Subsea and Marine technology</td><td>Spring semester, 2017

Open / Restricted access</td></tr>
<tr><td>Writer: Andrei Andreev</td><td>………………………………………………
(Writer's signature)</td></tr>
<tr><td colspan="2">Faculty supervisor:
Ove Tobias Gudmestad

External supervisor(s):
Anatoly Borisovich Zolotukhin</td></tr>
<tr><td colspan="2">Thesis title:

Optimization of the upper completion assembly by using redundant pump exemplified by the well in the Prirazlomnoye field, Pechora Sea</td></tr>
<tr><td colspan="2">Credits (ECTS): 30</td></tr>
<tr><td>Key words:
The Prirazlomnoye field, the Prirazlomnaya platform, upper completion, redundant pump, redundancy, ESP, upper completion optimization concept.</td><td>Pages: ……64………

+ enclosure: …………

Stavanger, …15.06.2017………..
Date/year</td></tr>
</table>

Abstract

Nowadays development of Russian offshore oil and gas fields is relevant and perspective. A lot of Russian and foreign oil and gas companies tend to get an experience in offshore field development by establishing pilot projects even in the Arctic. Although oil price is rather low, deal with offshore projects more attractive compare to an onshore, because of higher reservoir productivity of offshore oil fields. It allows us to open new horizons and gather required experience for the future projects. Sometimes, one oil platform derives more oil than subsidiary oil company may. Presence characterized by high leasehold price for an oil platform, marine vessels, and equipment. Therefore, oil companies aim at an operating cost reduction, ensuring the reliability and integrity of all platform systems, and their downtime reduction.

The problem, which will be considered in the thesis, is an artificial oil production system failure (namely upper completion and ESP). Sometimes oil platforms have one drilling rig and sometimes even do not have and in a case of failure of any main module of the upper completion, the oil production stops and it will be continued only after replacement of broken equipment and pulling a new one, But what we have in a case while drilling? We cannot replace the upper completion till drilling of the well is done or we have to stop drilling in order to renew our well with the broken upper completion. Anyway, in both cases company loses money and time.

In the thesis will be considered the upper completion assembly with two ESP in series, for ensuring work of one of them in case of another failure (pumps work alternately, for their guaranteed start). With the help of the special program required pumps and their operational characteristics will be chosen. This concept may reduce well downtime, but only in case of trouble-free operation of other modules of the upper completions, that also may stop production (circulation valve, X-tree, power cable, reservoir control valve and others). Therefore, this problem needs integrating approach.

Acknowledgements

This master thesis was supported by Professors Anatoly Zolotukhin and Ove Tobias Gudmestad. I thank my colleagues Ivan Kradinov, Ilya Efimkin and Thomas Ole Messelt Fadnes who provided insight and expertise that greatly assisted the thesis. I show my gratitude to the Milton Eduardo Angulo Cruz for improving my knowledge in the theory of pump selection. I thank Professors Lorents Reinås and Arnfinn Ivar Nergaard from UIS for knowledge in subsea production technology.

I thank Rinat Khabibulin for assistance with Nodal Analysis and software for the pump selection, and Marina Kravchenko for knowledge in lift hydrodynamics.

I would also like to show my gratitude to the Aydar Bilalov and Aleksandr Boiko for sharing their knowledge about oil fields in Pechora Sea.

Also, I would like to thank my family, who gratefully supported me while writing the thesis.

Table of content

Introduction

Offshore oil production is closely connected with high reliability requirements. It is characterized by high cost of the equipment, staff health importance, fragile environment and the value of time. Low reliability of systems or equipment can result in its unexpected failure. Failure may cause many negative effects such as wells shut down and reduction in oil production, losses of time and money, possible staff injuries or even death and environmental pollution. Therefore, the label «Reliability» is one of the main targets in the Design, Commissioning, Production and decommissioning stages.

It should be mentioned that nowadays time costs in offshore production platforms is much more significant compared to onshore production. It can be partially explained by the average production rates that are much higher offshore. According to the article [1], the average daily production rate of the onshore well in Russia is about 9,9 t/day, compare to e.g. offshore well in the Prirazlomnoye field that amounts to 1350-1450 t/day.

The purpose of this work is to increase the reliability of the upper completion assembly and decrease the amount of mean upper completion fails, namely in one of the most sensitive periods of the offshore field development – «drilling period». During this period the drilling rig is in operation.Therefore, upper completion failure causes stop of drilling in order to replace the equipment. That is why the concept of the upper completion with redundancy pump is proposed. The conceptual idea of the redundant equipment is already widely used in different industries.

In the thesis the concept of the upper completion with redundancy pump will be described.

Abbreviations

A/L – Artificial lift

BHP – Bottomhole pressure

BP – Business Plan

DMT – Downhole Measurement Tool

DLS – Dogleg severity

ESP – Electrical Submersible Pump

IPR – Inflow Performance Relationship

MD – Measured Depth

RCV – Reservoir Control Valve

SSD – Sliding Side Doors

TRSSV – Tubing Retrievable Subsurface Safety Valve

TVD – Total Vertical Depth

Chapter 1. General information

1.1 Geography and resources of the Pechora Sea

The Pechora Sea is located in the European part of Russia, the southeastern part of the Barents Sea. The western border of the sea is off Kolguyev Island, while the eastern border is the western coasts of Vaygach Island and the Yugorsky Peninsula and the northern border is the southern end of Novaya Zemlya.

The length of the Sea is about 300 km from West to East and 180 km from North to South. The surface area is approximately 81 000 km^2 and the overall water volume of 4380 km^3.

The Pechora Sea is quite shallow and its average depth is around 6 m. However, the deepest point reaches 210 m. The eastward – flowing Kolguev Current runs into the southern part of the sea. Pechora River is the main river entering the sea [2].

The Pechora Sea belongs to the Timan-Pechora Basin. There is quite a number of oil and gas fields, however most of them have not been developed yet because of big challenges associated with to harsh environmental conditions. Marine structures and their facilities could be affected by polar lows, waves, winds, and currents accompanied by the ice drift, ice ridges and icebergs. Oil and Gas resources of Pechora Sea are exhibited in figure 1.1 [3].

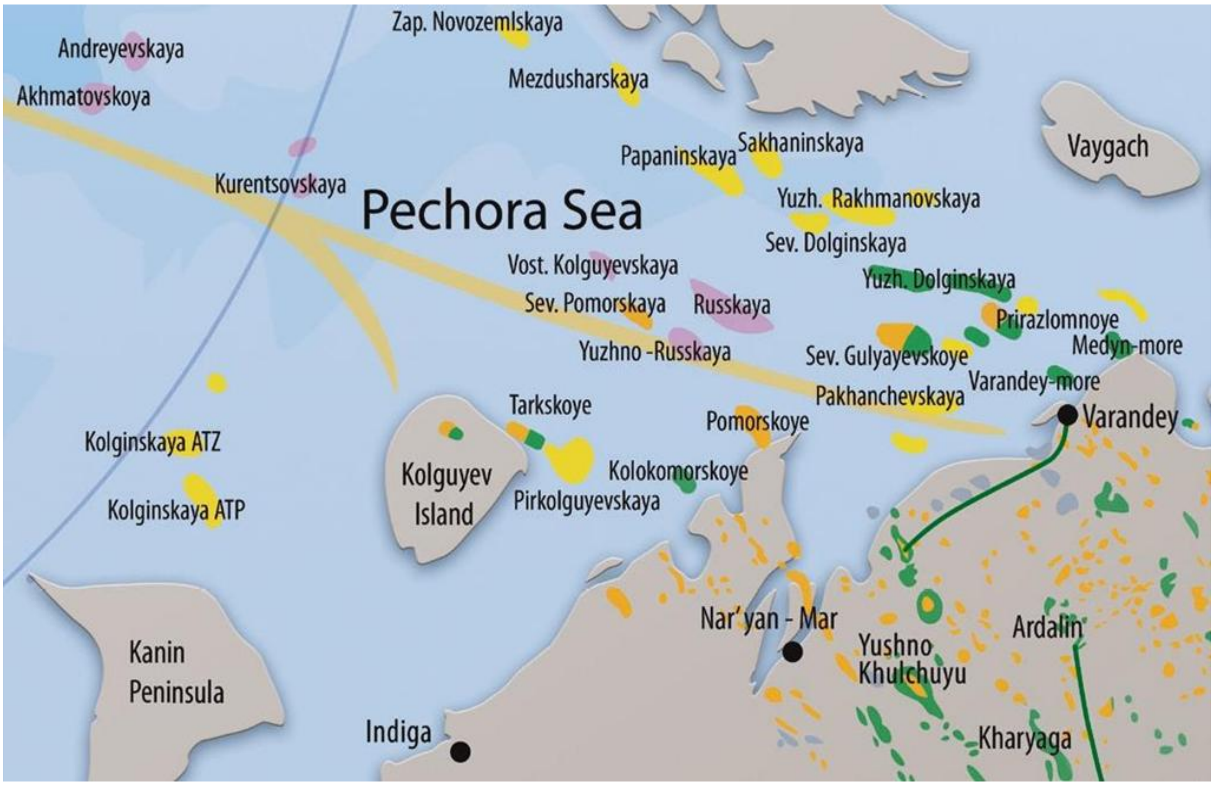


Fig. 1.1 – Oil and Gas resources of Pechora Sea

1.2 General information about the Prirazlomnoye oil field

Prirazlomnaya is an oil producing gravity based platform belonging to LLC Gazprom Neft Shelf, which is a subsidiary of Gazprom Neft. It was built by Sevmash Production Association and is located in Pechora Sea 60 km offshore (Varandey settlement) in the water depth of 19 to 20 meters.

This offshore fixed gravity platform is the first construction of its kind in Russia.

The topsides are based on the former UK North Sea Hutton tension leg platform, bought by Rosneft in 2002 and upgraded for its new work at the FSUE Sevmash military shipyard in Severodvinsk. The new platform, Prirazlomnaya, has a field life of 50 years. Platform cost is approximately $800m.

The topsides were dismantled near Murmansk and towed to Severodvinsk. Meanwhile, the caisson was constructed by Sevmash as a number of caisson superblocks. The yard was also responsible for the offloading complex, platform towing and the accommodation module. Nearby, in the Severodvinsk yard of Zvyozdochka, superblocks 1 and 4 were constructed. The technological module was built in the Vyborg shipyard and other parts of superblocks and piping were built at the Tsentrenergomontazh facilities.

The topsides weigh 39,000t. It has a single derrick and 40 well slots. There are two oil offloading systems with capacities of up to 10,000 m^3/h. The topsides sit on a 126 m^2, 97,000 t caisson. It includes 14 oil storage tanks with a capacity of 113,000 m^3 as well as two water storage tanks with a total capacity of 28,000 m^3. The facility has an oil production capacity of 22,000 t/d, a daily gas production capacity of one million cubic meters, and the water injection capacity of 32,000 m^3/d.

The superblocks were welded and installed in 2004 followed by the towing and installation the topsides and the concreting. After a period of settling down a safety berm was laid around the field.

The area is characterized by extremely low temperatures and strong ice loads. It is ice-free for about 150 days a year and the cold period lasts 215 days [4].

Maximum ice thickness is up to 1.8 m [4]. The temperature maximum is +29°C and the temperature minimum is -46°C [4]. Wind strengths reach up to 50 m/s and wave heights up to 10 m [4]. The main features are platform's resistance to strong ice loads, long self-sustainability and year-round operability.

The platform is designed for well drilling, oil production, storage and offloading. In total, the project will involve the commission of 36 slanted wells, comprising: 19 production wells, 16 injection wells and 1 disposal well. Production from the Prirazlomnaya Platform began in December 2013. Reservoir management plan is shown in Fig. 1.2.

Fig. 1.2 – Reservoir management plan [4]

1.3 Drilling and construction of the wells in the Prirazlomnaya field

Directional drilling is used for the well drilling in the Prirazlomnaya field. Layout of the Prirazlomnaya field development is shown in Fig. 1.3.

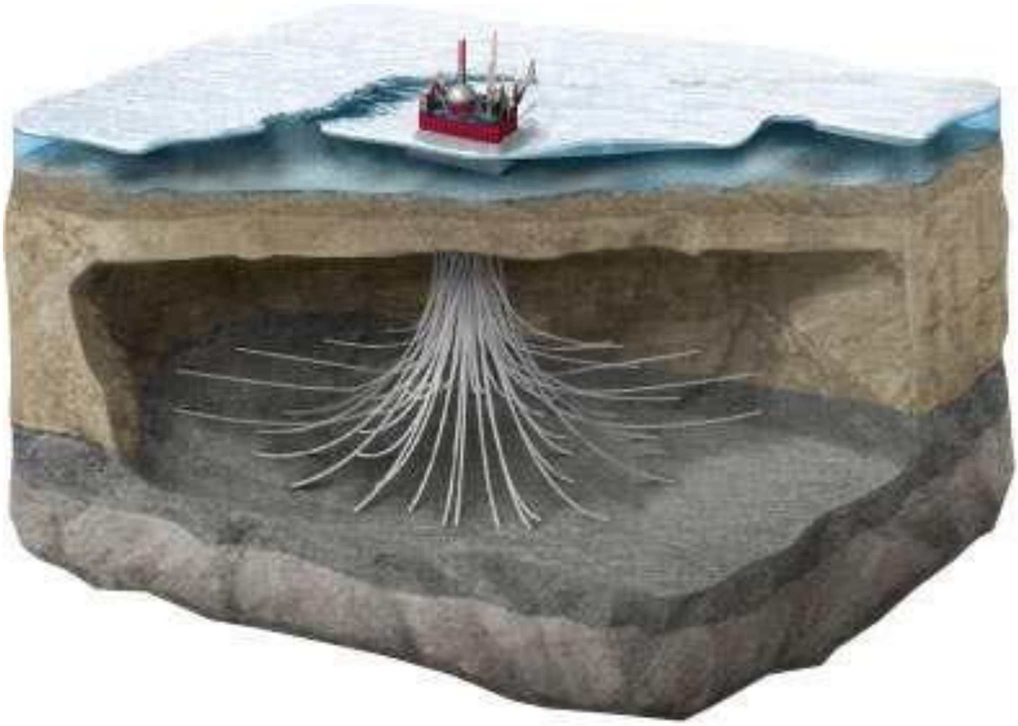


Fig. 1.3 – Layout of the Prirazlomnaya field development

In order to predict the challenges with the conductor casing installation driving method is used. The conductor has 660,4 mm diameter.

Surface casing with the diameter 473,1 mm is installed to the 650 m depth.

Intermediate casing with the diameter 339,7 mm is lowered and cemented at the 1500 m depth.

Production casing with the diameter 244,5 mm is lowered and cemented at the 2381/2479m depth (TVD/MD). And liner with diameter 177,8 mm is usually installed at the 2286/2383 – 2904/3002 m depth and being fixed over the production casing shoe. Casing strings are shown in Fig. 1.4.

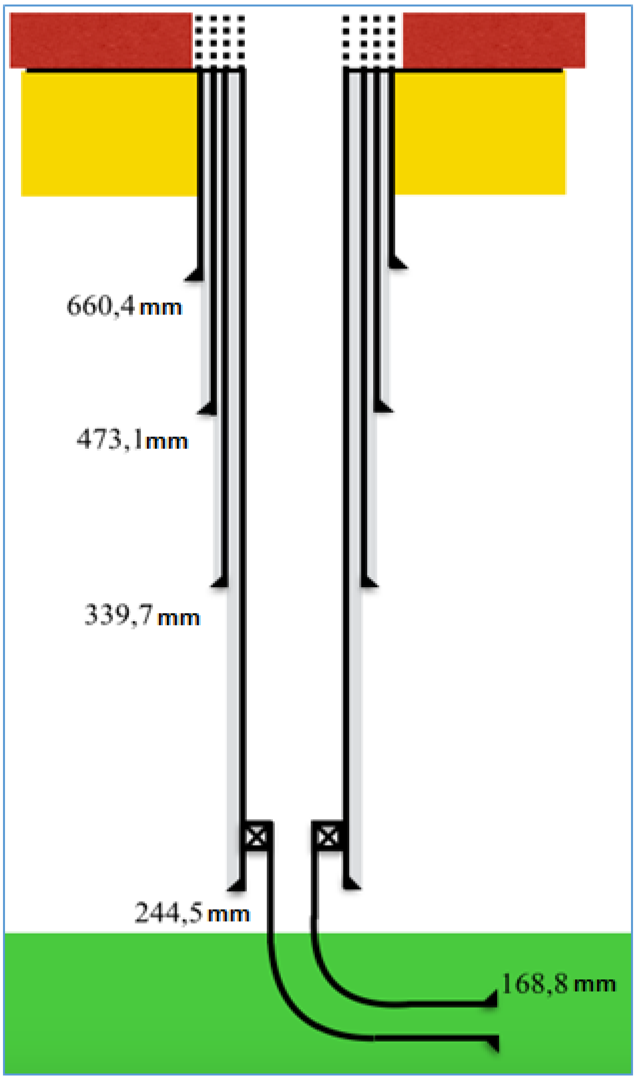
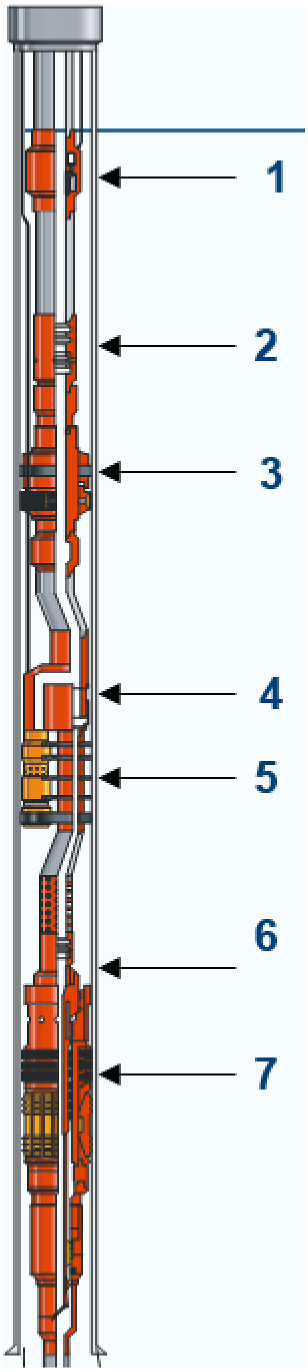


Fig. 1.4 – Prirazlomnoye field casing strings design

This approach of well construction allows isolating different layers and maintaining the pressure. The horizontal part of the well does not exceed 1000 m.

1.4 Description of the well upper completion example for offshore field

PH-7 well of the Prirazlomnaya field is taken as an example for the master thesis. Layout of the PH-7 upper completion is shown in figure 1.5.



1. Tubing Retrievable Subsurface Safety Valve (TRSSV)
2. Sliding Side Doors (SSD)
3. ESP Packer with penetrator
4. Y-tool and Bypass System
5. ESP, Protection and Motor
6. Reservoir Control Valve (RCV)
7. Permanent Packer

Fig. 1.5 – Layout of the PH-7 upper completion

Tubing Retrievable Subsurface Safety Valve (TRSSV) is designed for isolation of the lower tubing interval. It is controlled from the surface via a small diameter hydraulic Control Line connecting the safety valve to the surface Emergency Shutdown System. Since the valve is of the normally closed type, when applied.

Control Line pressure is removed, the valve automatically returns to the closed position, thus shutting in the well. TRSSV is shown in figure 1.6.

Fig. 1.6 – TRSSV

<u>Sliding Side Doors (SSD)</u> is a high-performance equalizing valve that allows the communication between the tubing string and the annulus for circulation and selective operation. The valve can be opened and closed by using cable technology. SSD is shown in figure 1.7.

Fig. 1.7 – SSD

Retrievable ESP Packer with penetrator is designed to isolate the annulus of the overlying well interval. ESP packer is hydraulically activated and set at pressure 24.0 MPa. It is a component of the artificial lift and it has a special sealing channel for passing the cable under the ESP (penetrator installation), as well as a channel for the passage of the hydraulic line. Retrievable ESP Packer is shown in figure 1.8.

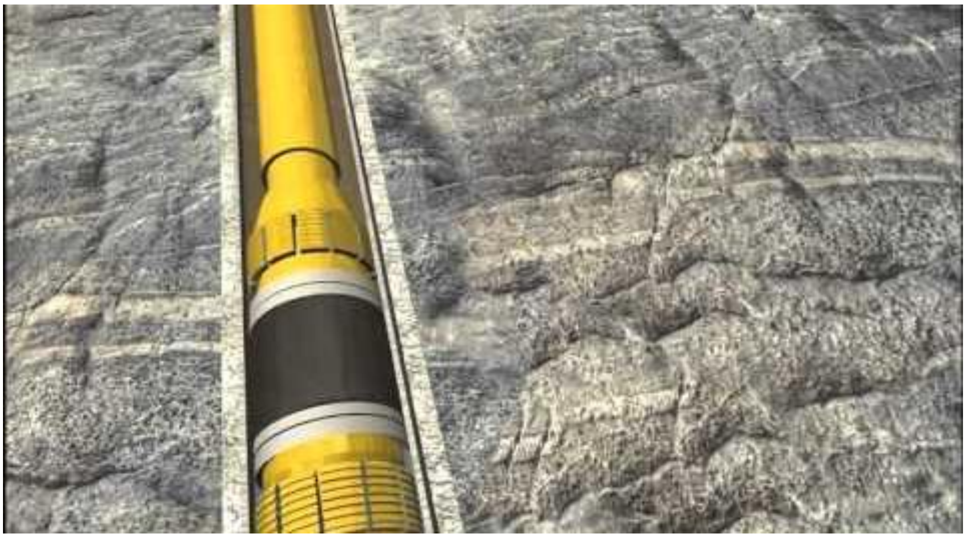


Fig. 1.8 – Retrievable ESP Packer

Y-tool and Bypass System provides access to the underlying interval and allows pumping and production while logging and wireline operations. Internal flow tube tolerances to suit either slick or electric line.

Positively locked in the bypass nipple to prevent recirculation of produced fluids during coiled tubing operations. Y-tool and Bypass System is shown in figure 1 (Appendix B).

The electrical submersible pump (ESP) is an efficient and reliable artificial-lift method for lifting moderate to high volumes of fluids from wellbores. The ESP's main components include:

– Multistaged centrifugal pump;
– Three-phase induction motor;
– Seal-chamber section (protection);
– Power cable;
– Surface controls.

Pumps used in ESPs are usually multistage and centrifugal ones. Every stage includes an impeller and a stationary diffuser. The pumping end of the ESP system is a multistage centrifugal pump with a specified flow range required to ensure high efficiency and proper thrust balance across the many pump stages. Operating the pump outside its specified range can cause either a serious down thrust or upthrust condition that results in premature wear of the pump stages [7]. A typical outline of the ESP is shown in Fig. 1.9.

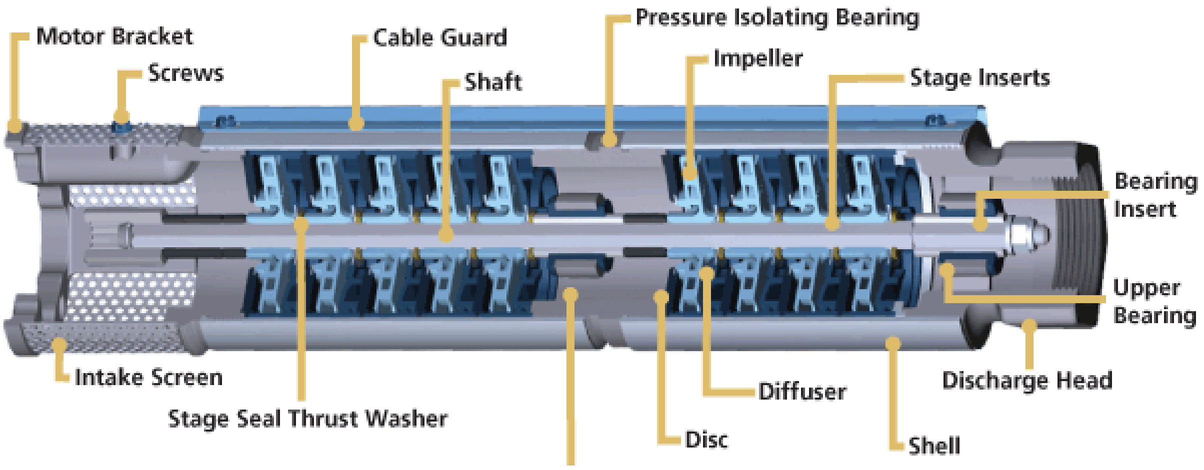


Fig. 1.9 – ESP

<u>Protector (seal section).</u> The protector or seal section is used to connect the pump housing to the motor housing and prevent well fluid from entering the motor. It also provides an oil reservoir that will be used to compensate for the loss of the motor oil due to heating or cooling when the ESP is working or shut off. Seal or protector for the motor for ESP is shown in Fig. 1.10.

Fig. 1.10 – Seal

The motor is the important force that drives the pump. One of the important factors in selecting the required voltage of the motor is the setting depth of the ESP. This is because motors set at a greater depth will lose more voltage of a certain amperage and cable. The motor for ESP is shown in Fig. 1.11.

Fig. 1.11 – The motor

Cables in ESPs are used to supply power to the motor. Cables are manufactured in either round or flat styles. The conductors of the flat cables are laid side by side and secured. The flat cable is usually used where there is limited clearance between the tubing (and ESP) and casing. However, the conductors of the round cable are multi-strand ones where each one is insulated. To avoid any physical damage, the exterior of these conductors is armor galvanized. Armored cables for ESP are shown in Fig. 1.12.

Fig. 1.12 – Armored cable for ESP

Reservoir Control Valve is a mechanical actuated isolation system that offers both a downhole barrier and positive reservoir control. The system may be installed during the initial completion or thereafter. The design provides fluid loss control and reservoir isolation during an ESP pump change out or a workover, reducing rig time and lowering fluid costs. The system is compatible with both lower completions designs and upper ESP installations.

The RCV is opened when the production stinger seal anchor is inserted into the RCV and the tubing has been landed. Consequentially the valve closes when the production stinger seal anchor is removed during ESP change out or workover. When closed, the RCV offers the operator reservoir isolation and a fluid loss barrier. RCV is shown in Fig. 1.13.

Fig. 1.13 – RCV

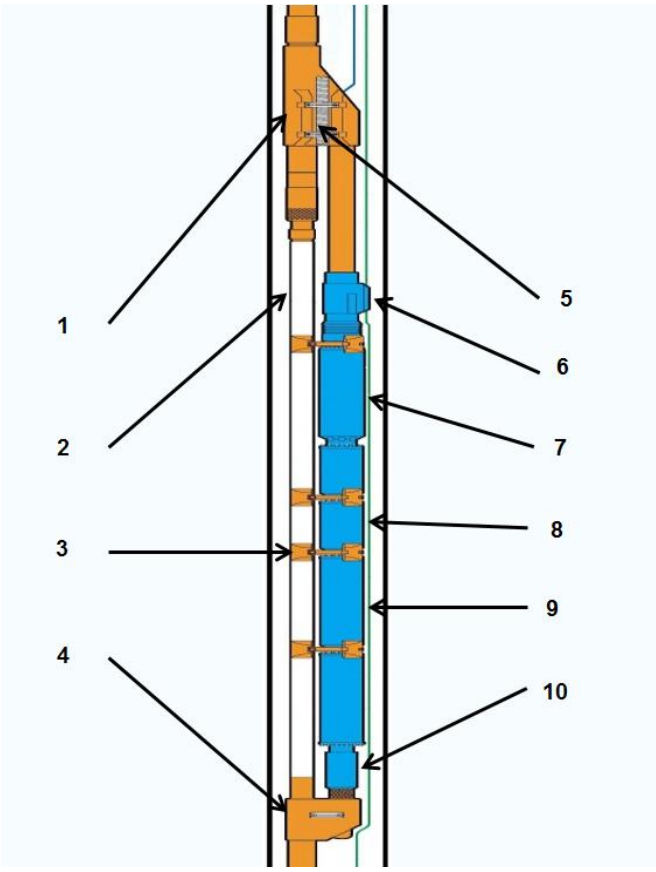
Permanent packer. The packer forms the basis of the cased-hole completion design. The packer is a sealing device that isolates and contains produced fluids and pressures within the wellbore to protect the casing and other formations above or below the producing zone. Permanent packers can be removed from the wellbore only by milling. Well isolation is accomplished by the fit of the elastomer seals in the polished packer bore.

Permanent packer is shown in Fig. 1.14

Fig. 1.14 – Permanent packer

Downhole measurement tool is a reservoir and data-acquisition system. Use of downhole sensors has rapidly expanded as an effective tool for improving ESP run-life performance. Sensors used in conjunction with surface monitoring and surveillance tools allow key ESP and well operating parameters to be acquired, stored, and evaluated continuously. This provides a powerful real-time tool for allowing operators continuously to keep up with the health of both the ESP and the well.

Y-tool and Bypass system, ESP completion with motor and protector are shown in Fig. 1.15



1 - Y-tool Sub
2 - Bypass Tube
3 - Bypass Clamps
4 - Y-tool Base
5 - Motor Lead Extension
6 - DMT Head
7 - Pump Section with Intake
8 - Protector
9 - Motor
10 - DMT

Fig. 1.15 – Y-Tool and Bypass system

Chapter 2. Background theory

2.1 Well trajectory surveillance

Dogleg severity (DLS) is a normalized estimation, normally described in degrees per 100 feet or degree per 30 meters, of the overall well bore curvature between two consecutive directional surveys. Regarding a planned well path, dogleg severity may be synonymous about building and/or tone. The following formula provides dogleg severity in degrees/30 m based on the Radius of Curvature Method [6].

$$DLS = \{\arccos\left[(\cos I_1 \cdot \cos I_2) + (\sin I_1 \cdot \sin I_2) \cdot \cos(Az_2 - Az_1)\right]\} \cdot \frac{30}{MD}, \tag{2.1}$$

Where:

DLS – dogleg severity, degrees/30 m;

MD – Measured Depth between survey points, m;

I_1 – Inclination (angle) at upper survey, degrees;

I_2 – Inclination (angle) at lower, degrees;

Az_1 – Azimuth direction at upper survey;

Az_2 – Azimuth direction at lower survey.

The trajectory surveillance description is shown in figure 2.1.

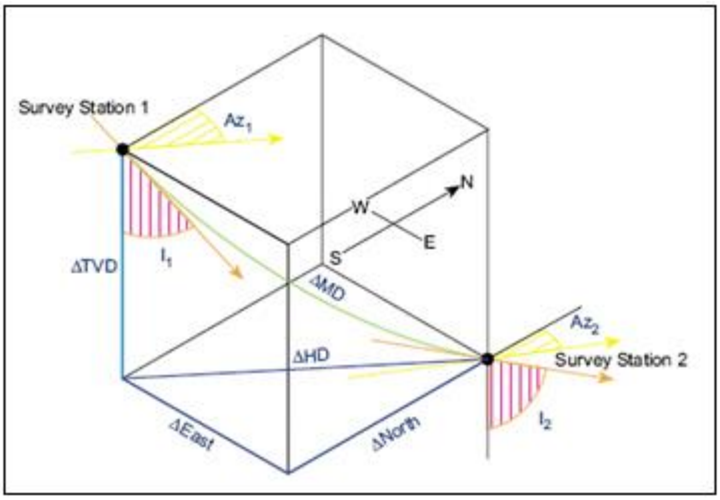


Fig. 2.1 – Description of survey

Based on the data about the upper completion from the Prirazlomnaya field maximum value of the DLS for the ESP installation is limited by 2°/30m. And maximum value of the DLS for ESP lowering is limited by 6°/30m. Therefore, the DLS at the depth of the installation must be accurately planned at the stage of good design. The inclinometry of the well interval for the depth of the ESP installation is shown in the table of Appendix C. According to the installed upper completion assembly at the PH-7 the length between the pump inlet and top of the Y-tool equal 14 m. And length between the pump inlet and bottom of the Y-tool equals 24 m. If to assume the same sizes if the ESP we can calculate the required length of the well part with limited DLS (2 °/30m).

According to that limitation and initial data, we can apply the depth of the upper ESP installation equal 2900 m (MD).

2.2 Nodal Analysis™

Systems analysis has been used for many years to analyze the performance of systems composed of multiple interacting components. The objective of systems analysis is to combine the various components of the production system for an individual well to estimate production rates and optimize the components of the production system [5].

The flow of reservoir fluids from the subsurface reservoir to the stock tank or sales line requires an understanding of the principles of fluid flow through porous media and well tubulars. As the fluid moves through the production system, there will be an associated pressure drop to accompany the fluid flow. This pressure drop will be the sum of the pressure drops through the various components in the production system. Because of the compressible nature of the fluids produced in oil and gas operations, the pressure drop is dependent on the interaction between the various components in the system. This occurs because the pressure drop in a particular component is not only dependent on the flow rate through the component, but also on the average pressure that exists in the component [5].

As a result, the final design of a production system requires an integrated approach, since the system cannot be separated into a reservoir component or a piping component and handled independently. The amount of oil and gas produced from the reservoir to the surface depends on the total pressure drop in the production system, and the pressure drop in the system depends on the amount of fluid flowing through the system. Consequently, the entire production system must be analyzed as a unit or system [5].

Nodal analysis scheme for the PH-7 well is exhibited in figure 2.2.

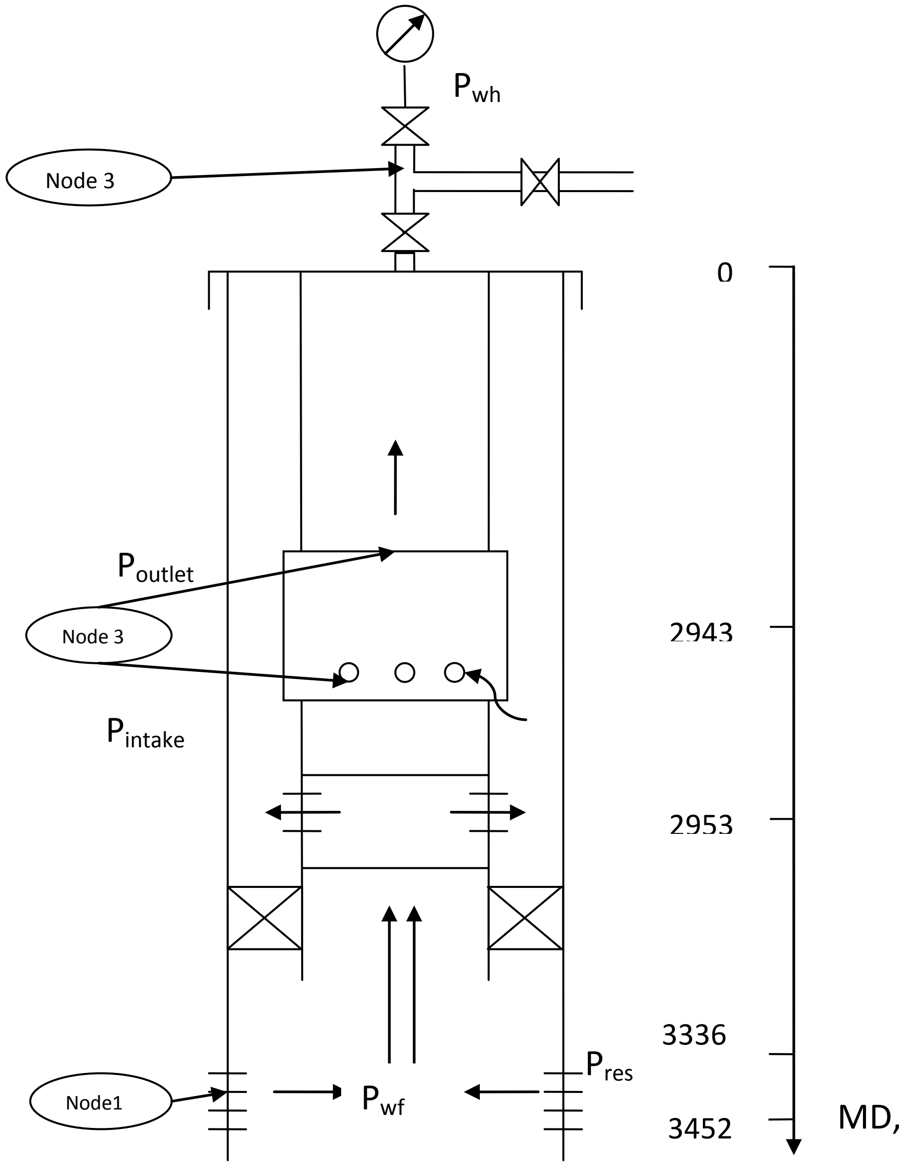


Fig. 2.2 – Nodal analysis scheme

For clearance, we divide the well into 3 nodes:

1) Perforated interval;

2) Pump (intake and outlet);

3) Wellhead.

Example of calculation

Main variables used in this section are described in the Table 2.1. Units are shown in table 2.2.

Table 2.1 – Variables with description

Variable	Description	Units	
		SI	Industry
C	productivity of the reservoir	$\frac{m^3}{sec \cdot Pa}$	$\frac{m^3}{day \cdot atm}$
P_{res}	reservoir pressure	Pa	atm
P_{wf}	bottom hole pressure	Pa	atm
Q	flow rate	$\frac{m^3}{sec}$	$\frac{m^3}{day}$
P_{fr}	pressure losses in distance between considered nodes	Pa	atm
$P_{gravity}$	hydrostatic pressure in the depth of the node	Pa	atm
P_{wh}	wellhead pressure	Pa	atm
f	friction loss rate	-	ft/1000 ft of tubing length (measured)
W	Hazen-Williams roughness constant	-	-

Table 2.2 – Units

Units	SI
1 ft	0,3048 m
1 inch	0,0254 m
1 barrel per day	1,84013*10^{-6} m^3/sec
1 atm	101325 Pa
1 psi	6894,76 Pa
1 bar	100000 Pa

Productivity of the reservoir is given by:

$$C = \frac{Q}{P_{res} - P_{wf}} = \frac{Q}{\Delta P} \tag{2.2}$$

This relationship can be graphically expressed and it calls Inflow Performance Relationship (IPR).

Therefore, the wellbore pressure is expressed by:

$$P_{wf} = P_{res} - \frac{Q}{C} \tag{2.3}$$

Pump intake pressure consists of:

$$P_{intake} = P_{wf} - P_{fr} - P_{Gravity} \tag{2.4}$$

Pump outlet pressure is given by:

$$P_{outlet} = P_{wh} + P_{fr} + P_{Gravity} \tag{2.5}$$

Pump pressure difference is expressed by:

$$\Delta P^{pump} = P_{outlet} - P_{intake} \tag{2.6}$$

In order to define pressure losses due to friction, different approaches such as Hazen-Williamson formula or Bernoulli equation and others can be implemented [8].

One of them is the empirical approximation suggested by Hazen-Williamson.

Hazen-Williamson formula is given by:

$$f = 2.083 \cdot \left(\frac{100 \cdot Q}{34.3 \cdot W}\right)^{1.85} \cdot D^{-4.8655} \tag{2.7}$$

Where:

W – Hazen-Williams roughness constant:

- Typically 120 for most steel tubing applications;
- Can be less for highly corroded tubing – 90 to 110.

Q – flow rate, barrels per day;

D – inside diameter of pipe, in.

To find the total friction Head (in distance), we multiply f by the total measured length of tubing:

$$H_{fr} = f \cdot \Delta MD \tag{2.8}$$

And to find the friction pressure, convert to the friction head to pressure using the average fluid gradient that is given by:

$$P_{fr} = H_{fr} \cdot G_{AVG} \tag{2.9}$$

To calculate P_{fr} we need G_{AVG}:

$$G_{AVG} = G_0 \cdot SG_{AVG}, \tag{2.10}$$

Where:

G_0 – conversion coefficient equal to 0,433, psi/ft;

SG_{AVG} – the specific gravity of the fluid, defined by:

$$SG_{AVG} = \frac{\rho_{fluid}}{\rho_{water}} \tag{2.11}$$

Now we can define $P_{gravity}$:

$$P_{Gravity} = \Delta T \cdot V \cdot D \cdot G_{AVG} \tag{2.12}$$

System curve

System curve is a characteristic of the lift or a graphical presentation of the Energy equation (Bernoulli equation):

$$\frac{v^2}{2} + gz + \frac{p}{\rho} = const, \tag{2.13}$$

Where:

v – fluid flow speed at a point on a streamline;

g – acceleration due to gravity;

z – elevation of the point above a reference plane, with the positive z-direction pointing upward – so in the direction opposite to the gravitational acceleration;

p – pressure at the chosen point;

ρ – density of the fluid at all points in the fluid.

System curve represents the head required for the artificial lift to provide the flow with flow rate Q or velocity v.

Chapter 3. Concept of the upper completion with redundancy pump

3.1 Selection of the artificial lift method for the Prirazlomnaya field well

3.1.1 Artificial lift methods

Artificial lift is a method used to lower the producing bottomhole pressure (BHP) on the formation to obtain a higher production rate from the well.

Major artificial lift systems used in oil and gas industry are enumerated below [9]:

- Sucker-rod pumping
- ESP
- Gas lift and intermittent gas lift
- Jet hydraulic pump systems
- Plunger lift
- Progressive cavity pumps

There are other methods, such as:

- Modifications of beam pump systems
- Various intermittent gas lift methods
- Various combination systems
- Continuous Belt Transportation

There are about 2 million oil wells in operation worldwide. More than 1 million wells do not use natural lift. More than 750,000 of the artificially lifted wells use sucker-rod pumps. In the United States, sucker-rod pumps lift approximately 350,000 wells. Approximately 80% of all United States oil wells are making less than 10 B/D with some water cut. The vast majority of these wells is lifted with sucker-rod pumps. Higher volume wells, 27% are rod pumped, 52% are gas lifted, and the remainder is lifted with ESPs, hydraulic pumps, and other methods of lift. These statistics indicate the dominance of rod pumping for onshore operations. For offshore and higher-rate wells around the world, the use of ESPs and gas lift is much higher.

3.1.2 Artificial lift selection

With wide range of artificial systems available, it is important to choose the most optimal methods of artificial lift for the well. Inclinometry, depth, estimated production, reservoir properties, and other factors must be taken into account while selecting an artificial lift method.

The common method for the artificial lift selection is use of charts that show the range of head and rate in which particular lift types can function. The charts are approximate for initial selection possibilities, as any simplified charts such as these would be. Particular well conditions, such as high viscosity or sand production, may lead to the selection of a lift method that is not initially indicated by the charts. The chart for the artificial lift system selecting is shown in figure 3.1.

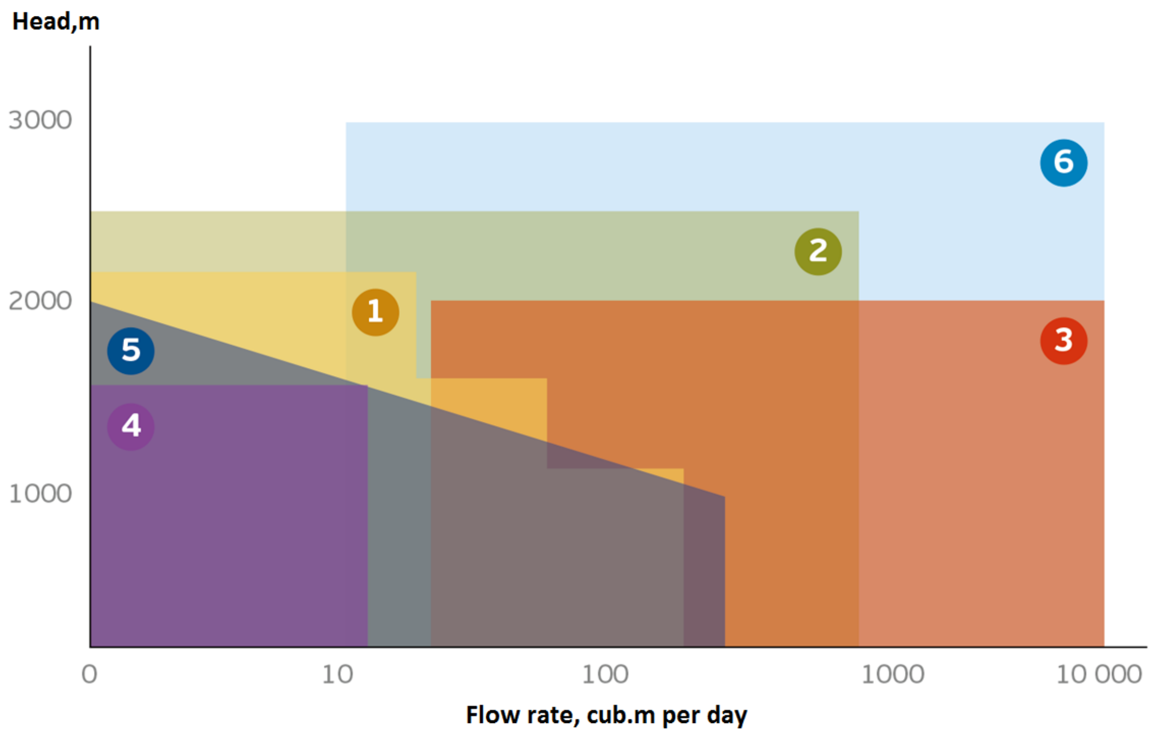


Fig. 3.1 – The chart for the artificial lift selection

Where:

1) Rod pumping;

2) Hydraulic jet pumping;

3) Gas lift;

4) Plunger lift;

5) Progressive cavity pumping;

6) ESP.

According to the Table from Appendix B the designed fluid rate is 2500 cubic meters per day. Therefore, only ESP and Gas lift system is applicable for such conditions. With work in limited conditions in Prirazlomnaya platform, we have to consider limited space. This factor significantly influences the size of the surface equipment supporting the fluid production. The gas lift system requires some free space for the compressors and supplementary equipment.In the case of the top side of the Prirazlomnaya platform this is physically not possible, due to lack of free space, fluid and rock properties, reservoir conditions contribute to ESP operation.

Summarizing all the reasons mentioned above, we can conclude that an ESP system is the most optimal for the well of the Prirazlomnaya field.

3.2 Description of the concept

According to internal data of Gazprom neft shelf the failure of the pump carries the following risk. A simplified bow-tie is shown in figure 3.2.

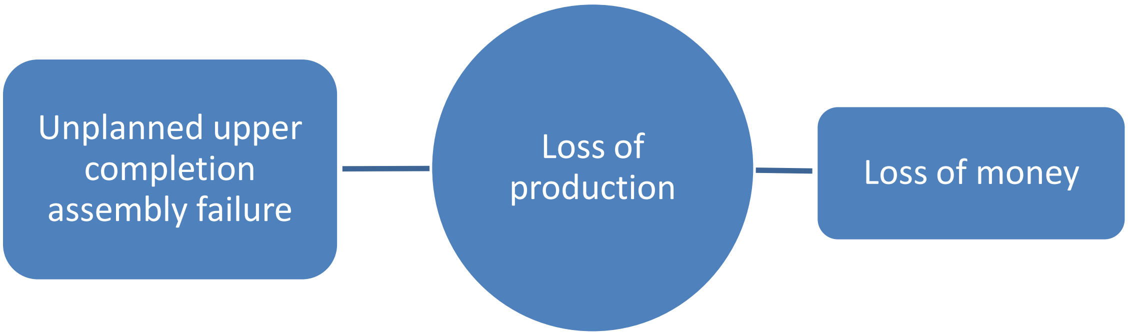


Fig. 3.2 – Bow-tie diagram

One of the barriers that can prevent/reduce losses of production (and unplanned repair) of the upper completion if it fails is the particular offshore approach for the upper completion integrity. This approach follows the same rules as the reliability approach for the platform equipment. In accordance with industry statistic most of the upper completion failures occur due to following module failures:

– pump;
– power cable;
– motor;
– tubing.

Along the upper completion assembly, we pay attention to equipment for artificial production, namely ESP and Y-Tool. The main concept of upper completion with redundancy pump is shown in Fig. 3 of Appendix A.

The principle of the ESPs operation is based on the pump alternating in the case of one failure. Main scheme of the fluid production for the lower ESP operation is exhibited in Fig. 2 of Appendix A. In a case of lower ESP failure, the power cable in variable speed drive is switched to the power cable for the upper pump and upper pump start production. The scheme of the upper pump in operation is shown in Fig. 1 of Appendix A.

The following upper completion modules should be doubled for the proposed technologybrealization:

– Y-tool Sub
– Bypass Tube
– Bypass Clamps
– Y-tool Base
– Motor Lead Extension
– DMT Head
– Pump Section with Intake
– Protector
– Motor
– DMT

In order to provide increased redundancy of the upper completion, all the modules must meet system redundancy needs. All modules mentioned in the beginning of this section are doubled, except for tubing. In order to fulfill redundancy requirements, tubing must be accurately selected. Based on internal “Gazprom neft shelf” data and offshore experience this criterion is quite feasible.

3.3 Offshore West African experience

West Africa's first dual Y-Tool, dual ESP wells installed for VAALCO Energy Inc, are addressing the risks of deferred production and unplanned intervention due to lack of rigs. Driven by the desire to maximize return on investment, the company is determined to reduce the commercial and technical risk to acceptable levels to complete and produce the wells.

Offshore West Africa rigs are in short supply with availability estimates ranging from 6-months to a year and day rates continuing to rise. This complicates the scheduling of workovers and drives up their cost along with deferred production. Consequently, the shutdown of a well due to equipment failure is economically disastrous.

The Etame block consists of the subsea Etame field, the Avouma platform, and the future Ebouri platform, all tied back to the FPSO Petroleo Nautipa. The scheme of the Etame block is shown in Fig. 3.3.

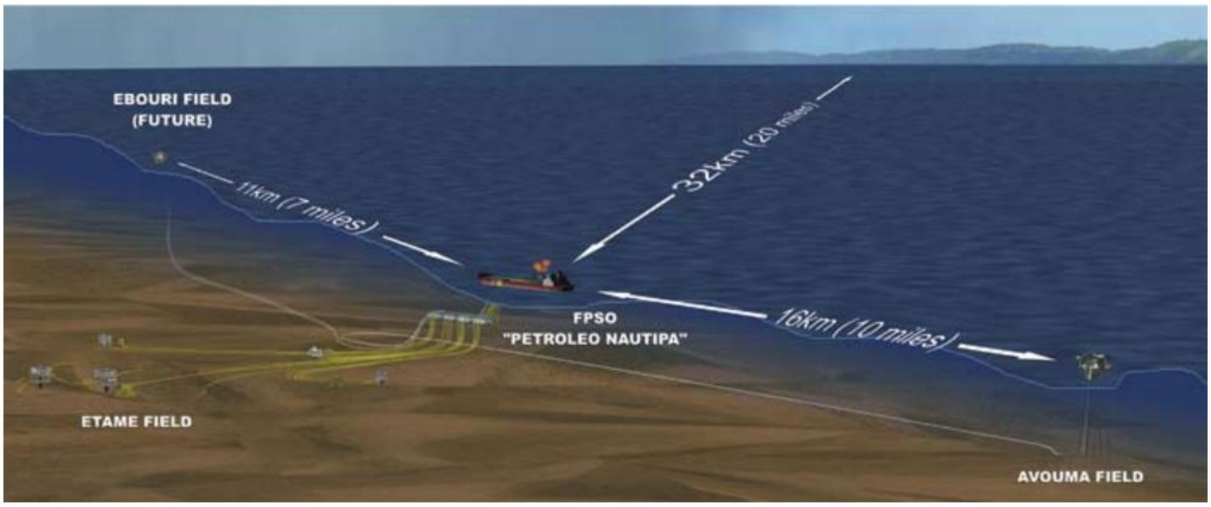


Fig. 3.3 – The Etame block

The key feature characterizing the dual-ESP technique is the ability to switch from one pump to the other in a matter of minutes, and with minimal intervention. With a fully-redundant operational spare pump installed in the well, the operator is protected from even a completely-unexpected failure. Should a failure occur, the company could easily switch to the back-up pump and continue production.

VAALCO was not satisfied with simply installing a back-up. It wanted to take steps to ensure maximum efficient life from the pumps it had. The company set three goals: minimize the risk of deferred production for prolonged time intervals, provide real-time downhole data for production optimization and reservoir monitoring and provide ESP surveillance to eliminate preventable failures and provide an early-warning system. Compared to unexpected loss of production from Avouma; the added cost of the dual-ESP solution was valuable insurance.

The chosen pump configuration was the dual ESP bypass system that features an Auto Y-Tool subsurface automatic diverter system with an integral flapper valve. The flapper valve is actuated by flow and requires no mechanical intervention to shift it from pump to bypass mode. The dual y-tool allows reservoir access through the bypass tubing for conducting sandface measurements or remedial completion services without the need for an intervention. Auto Y-tool head is shown in Fig. 3.4.

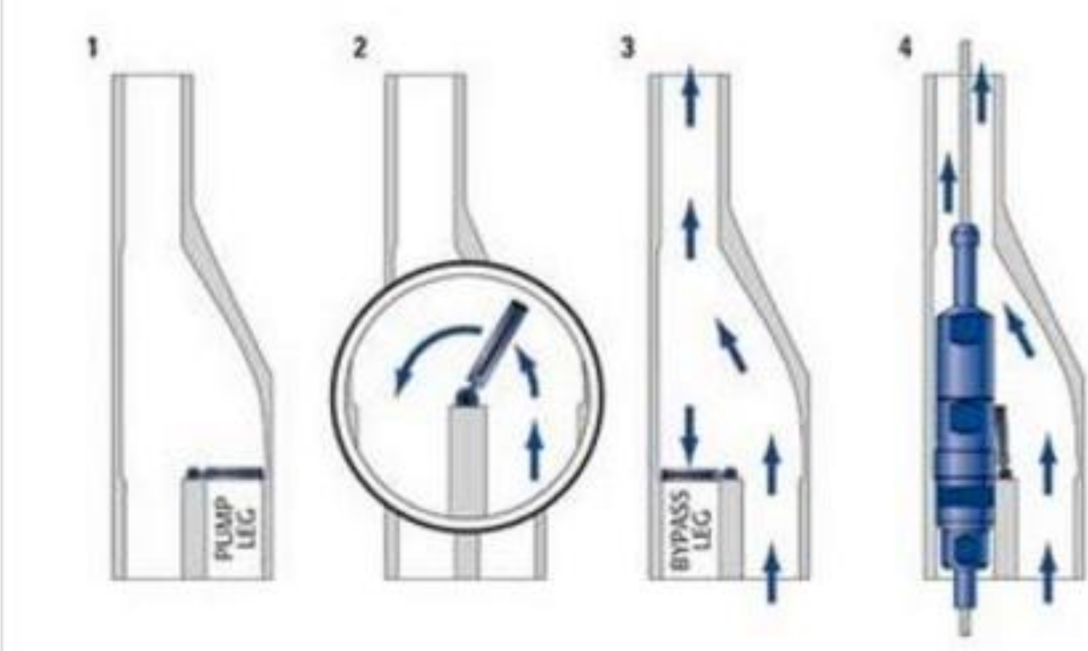


Fig. 3.4 – Auto Y-Tool

The dual ESP bypass system that features an Auto Y-Tool subsurface automatic diverter system with an integral flapper valve that allows for switching operating units without slick line intervention.

It should be noted that when dual ESPs are employed, it is traditional to run the lower ESP until it either fails or reaches incipient failure mode, then switch to the upper ESP. It is not considered good practice to alternate the pumps for any reason. The philosophy is that unnecessary ESP stops and starts could cause damaging electrical loading and shorten the motor's service life.

Throughout the design and commissioning phase, VAALCO engineers took the position that most ESP failures are preventable; therefore, they set out to anticipate and prevent them by a combination of good engineering practice, choosing proven reliable equipment, redundancy and thorough testing. They projected this work ethic through the operation phase by employing a continuous surveillance and monitoring system to ensure that the wells and the pumps would perform optimally with a long life.

To date, the dual ESP pumps with the dual Auto Y-Tools subsurface automatic diverter system have been successfully installed for 11 months.

3.4 Calculations with help of RosPump software

In order to simplify the calculations and make it more accurate RosPump (Software for the pump selection) is used. The nodal analysis is on the base of the RosPump software.

RosPump is a software for calculating the optimal process conditions for wells equipped with submersible electric centrifugal pumps (ESPs) and downhole rod pumps.

The program allows calculating bottom hole pressure, the pressure at the pump intake, outlet and all required parameters for the pump selection. Finally, it contains pumps catalog that allows selecting the pump with required operating parameters to meet our needs. All the calculations will be more accurate because the software considers multiphase flow.

Initial data for the calculations is presented in the table of Appendix B.

Calculation consists of two cases. The lower pump is considered in the 1st case.

Full nodal analysis for the case 1 is exhibited in figure 3.5.

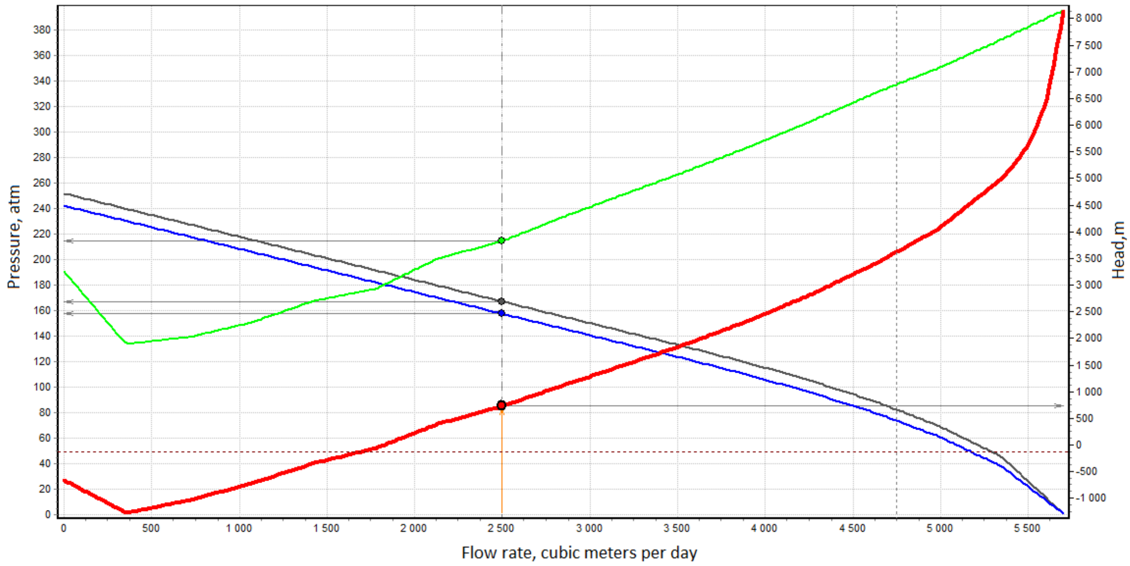


Fig. 3.5 – Nodal analysis for the 1st case

Legend

Bottom hole pressure (IPR), Pwf

Pressure at the pump intake, Pintake

Tubing characteristic-pressure at the pump outlet, Poutlet

Required head, H (m)

Description of the conditions for the lower pump is exhibited in the table 5.

Table 3.1 – Description of the conditions for the lower pump

Parameter	Value	Unit
The depth of the pump installation	2940	m
Water cut	0	%
Gas volume fraction at pump intake	8	%
Pressure at the pump intake	158	atm
Pressure at the pump outlet	215	atm
Pump pressure difference	57	atm

After that calculation we get the parameters for the lower pump:

$$\Delta P^{pump} = 57 \text{ atm}$$

$$Q = 2500 \frac{m^3}{day}$$

The upper pump is considered in the 2st case

Full nodal analysis of the case 2 is exhibited in figure 3.6.

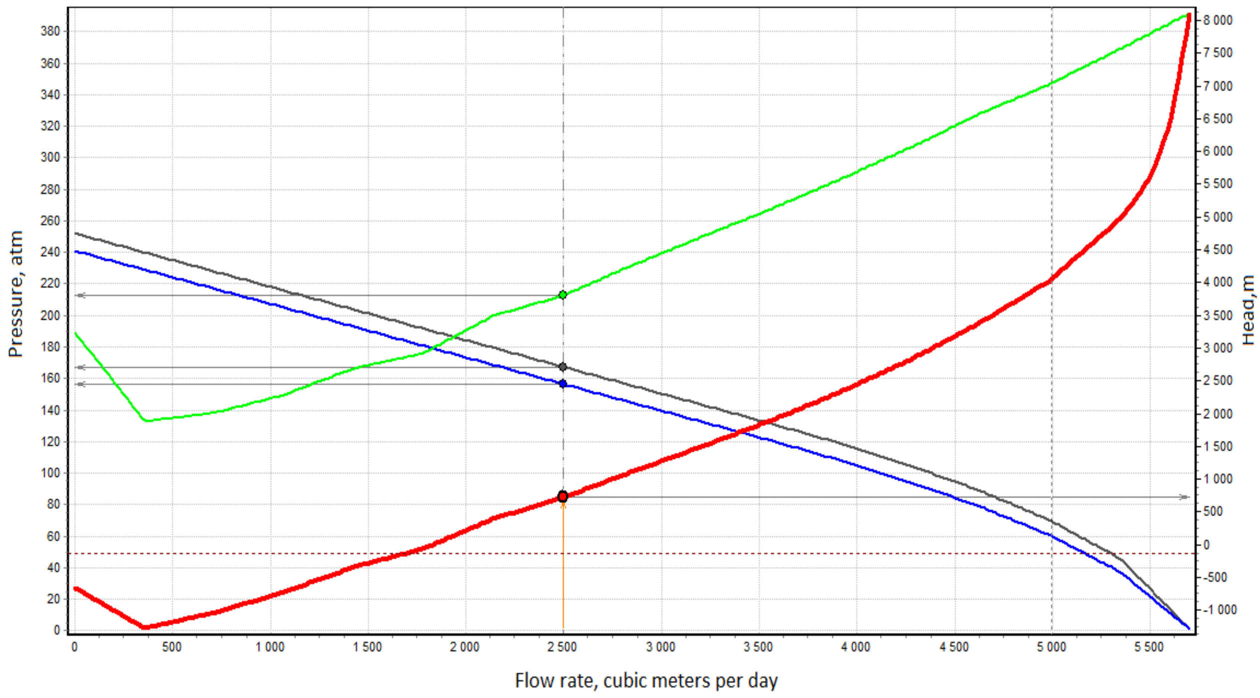


Fig. 3.6 – Nodal analysis for the 2nd case

Legend

Bottom hole pressure (IPR), P_{wf}

Pressure at the pump intake, P_{intake}

Tubing characteristic-pressure at the pump outlet, P_{outlet}

Required head, H (m)

Description of the conditions for the lower pump is shown in the table 3.2.

Table 3.2 – Description of the conditions for the lower pump

Parameter	Value	Unit
The depth of the pump installation	2900	m
Water cut	33	%
Gas volume fraction at pump intake	6	%
Pressure at the pump intake	156	atm
Pressure at the pump outlet	216	atm
Pump pressure difference	60	atm

After that calculation we get the parameters for the upper pump:

$$\Delta P^{pump} = 60 \text{ atm}$$

$$Q = 2500 \ \frac{m^3}{day}$$

Several pumps can fit such needs, as an example, ESP by Weatherford-19000

Proper equipment selection, however, goes beyond sizing. ESP users often may underestimate the potential well problems that may develop as well inflow increases and reservoir pressure declines due to use of ESP systems. To gain the ESP robustness and operating flexibility, one needs to anticipate harmful well conditions and select the appropriate metallurgies and equipment configurations to handle those conditions effectively.

It is well known that centrifugal pumps are efficient at moving liquid, but can quickly gas lock with small amounts of free gas. In many ESP applications, the reservoir pressure remains at or above the bubble point with no free gas present so that the operation has few problems. As the reservoir matures and pressures drop below bubble point, however, an increasing amount of gas comes out of solution, and some of this free gas must be produced by the ESP.

3.5 Limitations of the concept implementation

In the late stage of the field development this concept will not bring the profit, because of the high water cut, and free drilling rig, that is why the upper completion assembly can be replaced at any time. In order to understand the optimal time and amount of wells for the concept of the upper completion with the redundancy pump implementation, we make an analysis of the well production impact in the field development lifetime.

Theoretical well production profile is shown in figure 3.7.

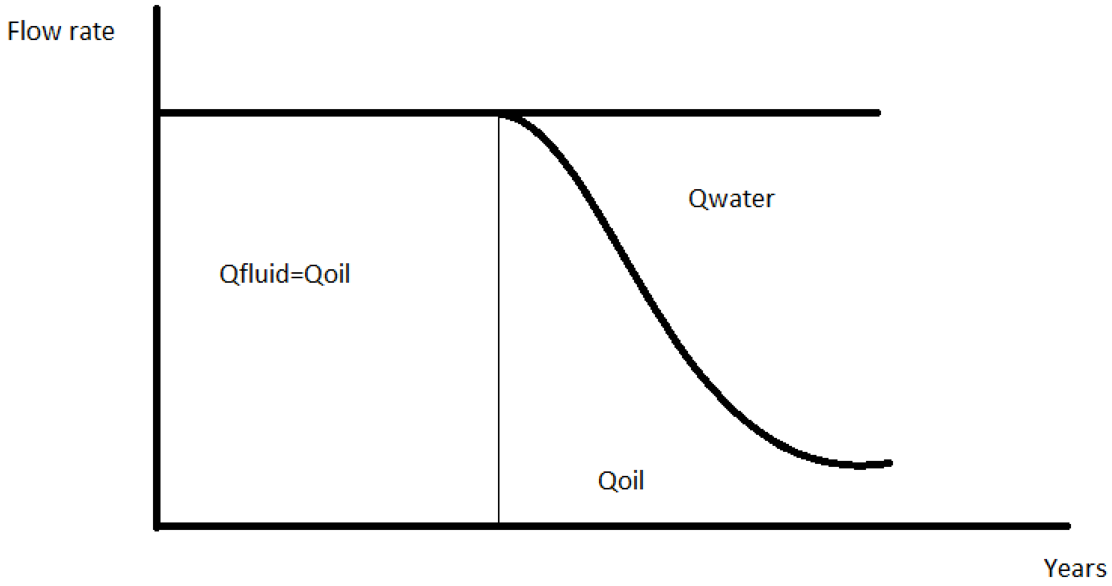


Fig. 3.7 – Theoretical well production profile

Where Q – flow rate.

In the left part of the graph, we can see that the flow rate of the fluid equal oil flow rate. However, when the water breakthrough appears, the water cut of the well will increase.

PH-7 is one of the first production wells in the Prirazlomnoye field. Real well production profile usually deviates from the theoretical. It happens due to platform stops or any operations or maintenance. In order to simplify calculations, the PH-7 well production profile is modified. This approach does not influence the correctness of the concept. The PH-7 well production profile is exhibited in Fig. 3.8.

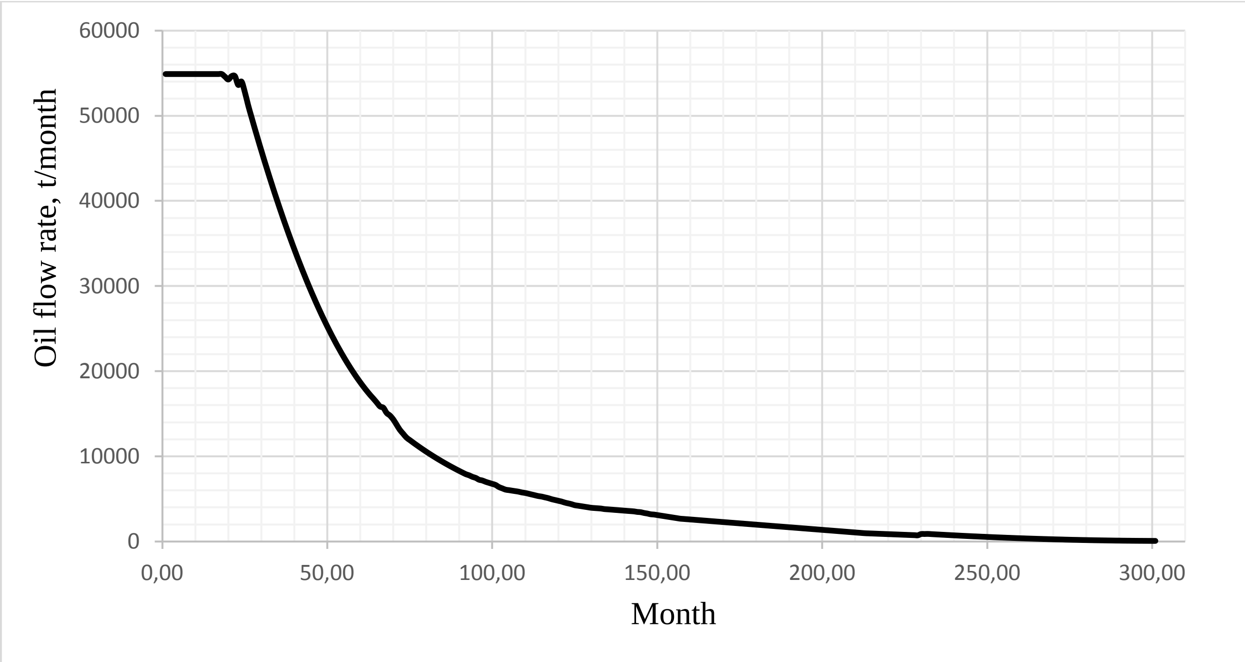


Fig. 3.8 – PH-7 Oil production profile

During the first several years we have small water production, but in the later stage of the well life, we can see that oil production decreases while water increases.

Let`s transfer this well production profile concept into the Field production profile that is exhibited in the next figure.

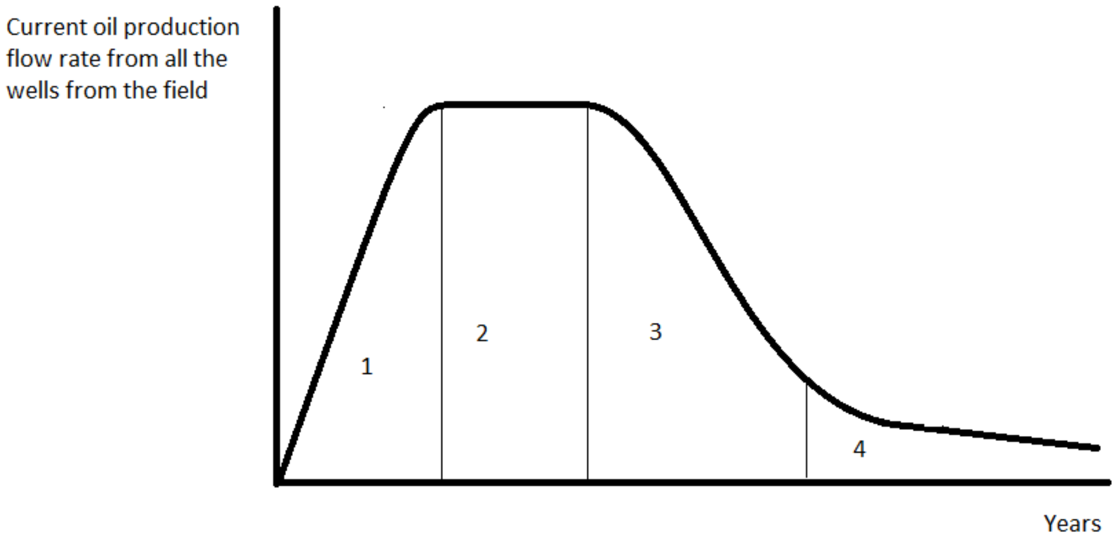


Fig. 3.9 – Theoretical oil production profile in the field

Zone 1 is characterized by increasing the well amount and we call it drilling period. This zone is the most interesting for the concept implementation. The drilling rig is involved in the drilling of wells and has no free time for the upper completion replacement at that period.

Zone 2 is characterized by the peak production.

Zone 3 is characterized by water that appears in the production fluid at that period.

Zone 4 is called as “late stage of the field development”.

Several assumptions have been made for the field production profile construction:

- all wells have similar well production profile (as PH-7);
- maintenance stops are not shown;
- the profile is constructed according to the applied drilling plan on the Prirazlomnoye field.

Field oil production profile is shown in Fig. 3.10.

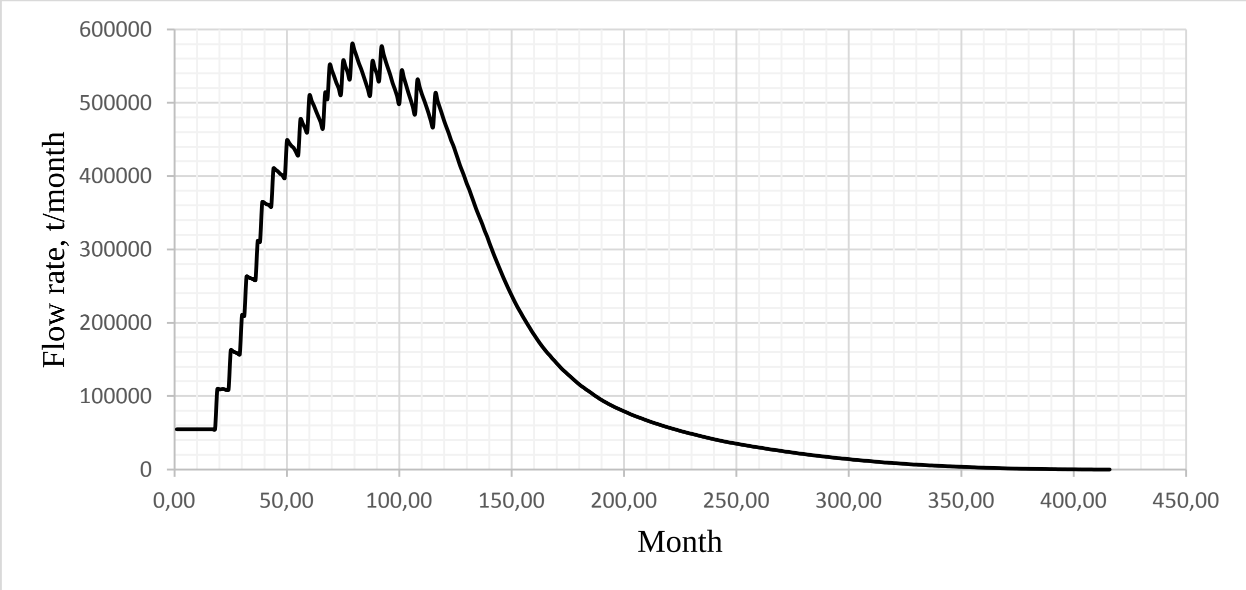


Fig. 3.10 – Field oil production profile

Such profiles can be constructed by exporting the data from the hydrodynamic model of the field. It is more important for us to consider the period while drilling rig is engaged in the drilling process. According to the drilling plan, the last 20th well is going to be commissioned in 116 months. Therefore, it is important to consider only 115 months.

For the annual business plan is applied the allowable deviation from the annular production. This deviation equal 3 mean daily production per year. This deviation for the profile before is exhibited in the next fugure.

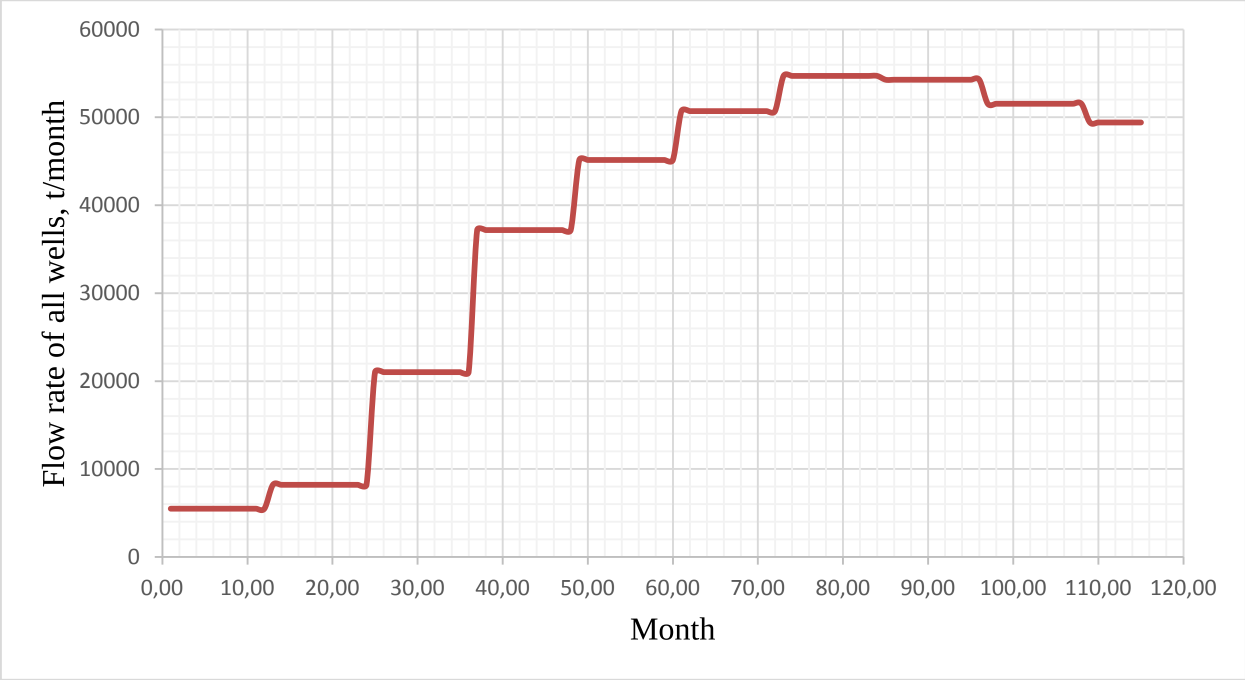


Fig. 3.11 – Allowable deviation

If to assume only one unexpected/unplanned upper completion failure per year we may construct the graph Allowable deviation vs. each well production profile.

Allowable deviation versus each well production profile is shown in Fig. 3.12.

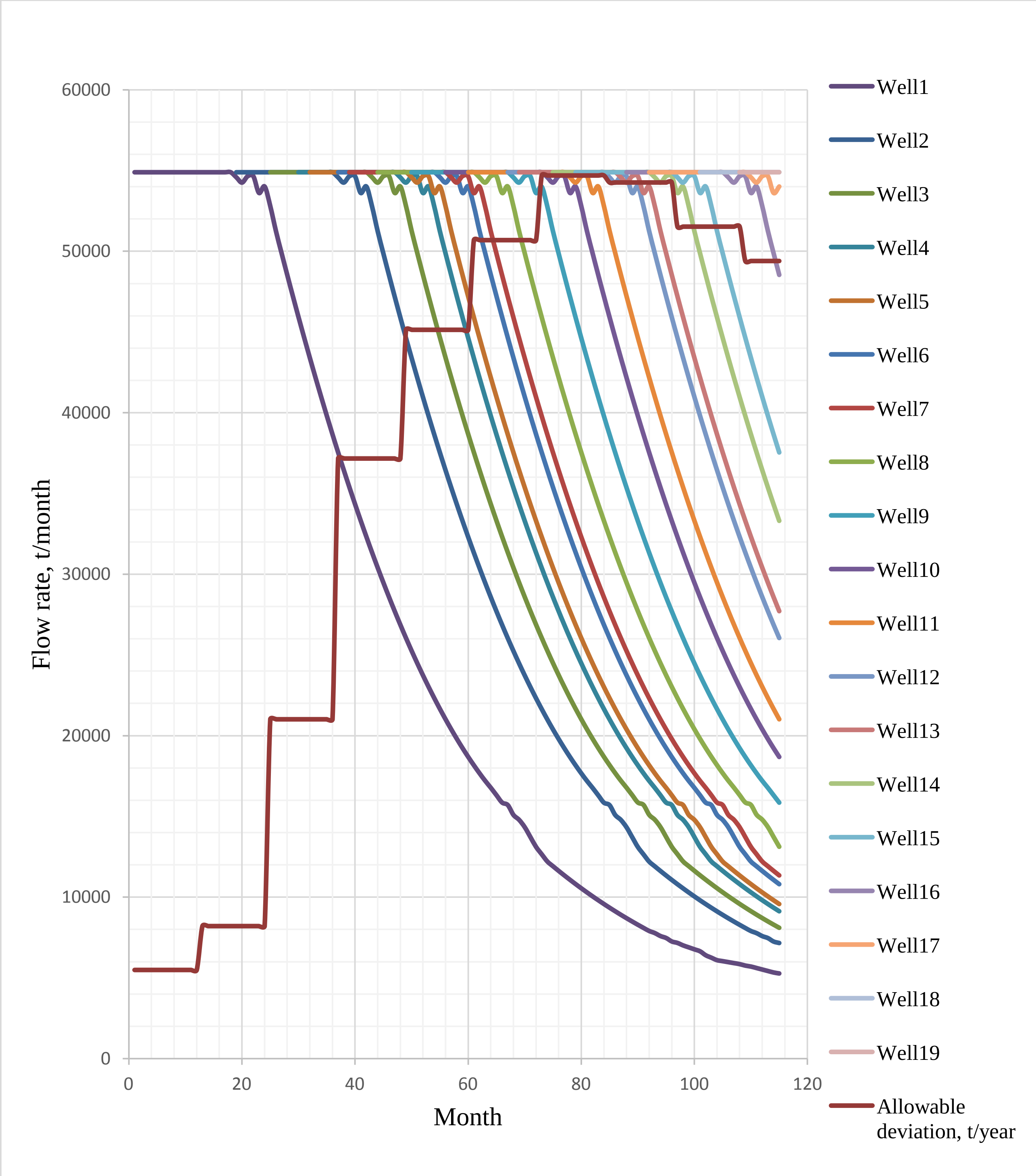


Fig. 3.12 – Allowable deviation vs. each well production profile

Parts of the production profile lower than allowable deviation do not need to be taken into consideration with mentioned assumption because they do not exceed allowable deviation.

Description of the graph is presented in the next figure.

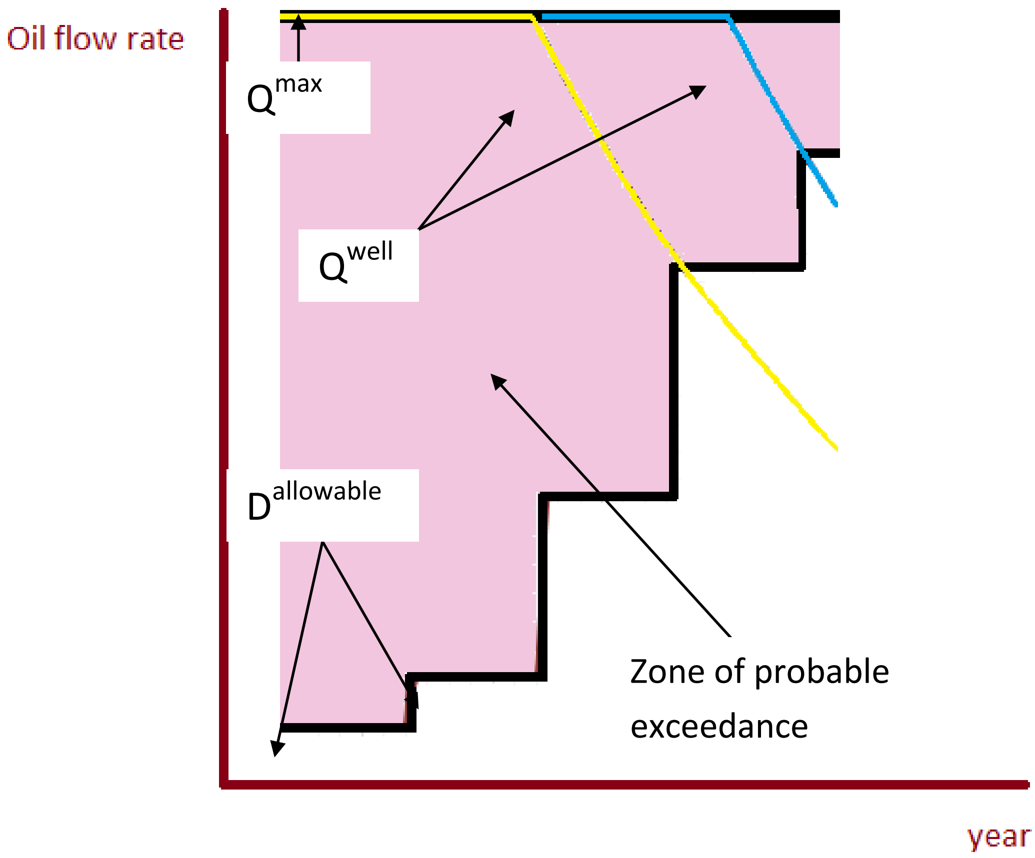


Fig. 3.13 – Description of the Fig. 3.12

Where:

- Q^{well} is a well production profile or possible deviation from field oil production profile;
- $D^{allowable}$ is allowable deviation;
- Q^{max} is a maximum possible annular deviation;

Probable exceedance is given by:

$$E^{probable} = Q^{max} – D^{allowable} \tag{3.1}$$

Maximum probable exceedance (in tons) from business plan in the case of one unplanned upper completion failure per year is shown in Fig. 3.14.

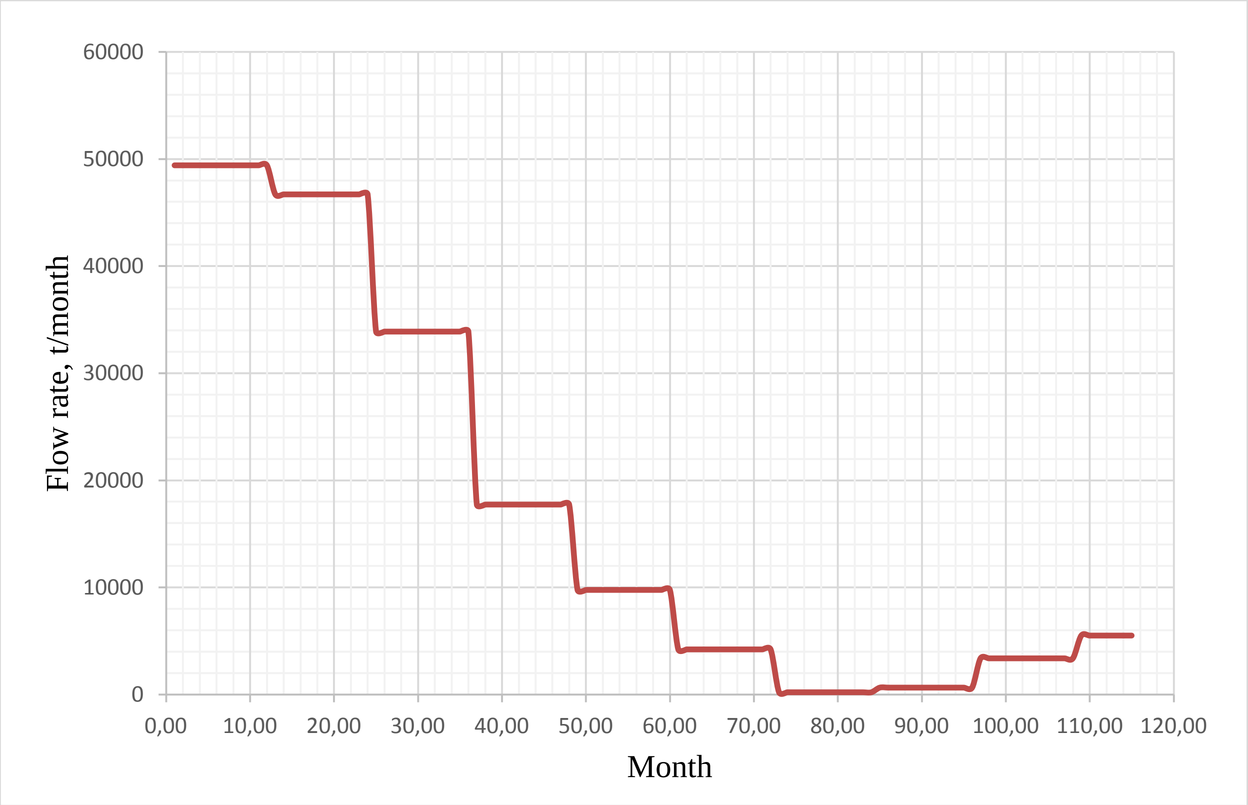


Fig. 3.14 – Maximum probable exceedance (in tons) from the BP

We can clearly see that maximum probable exceedance from the business plan is gradually decreasing, therefore effect or benefit of the redundancy pump implementation decreasing too.

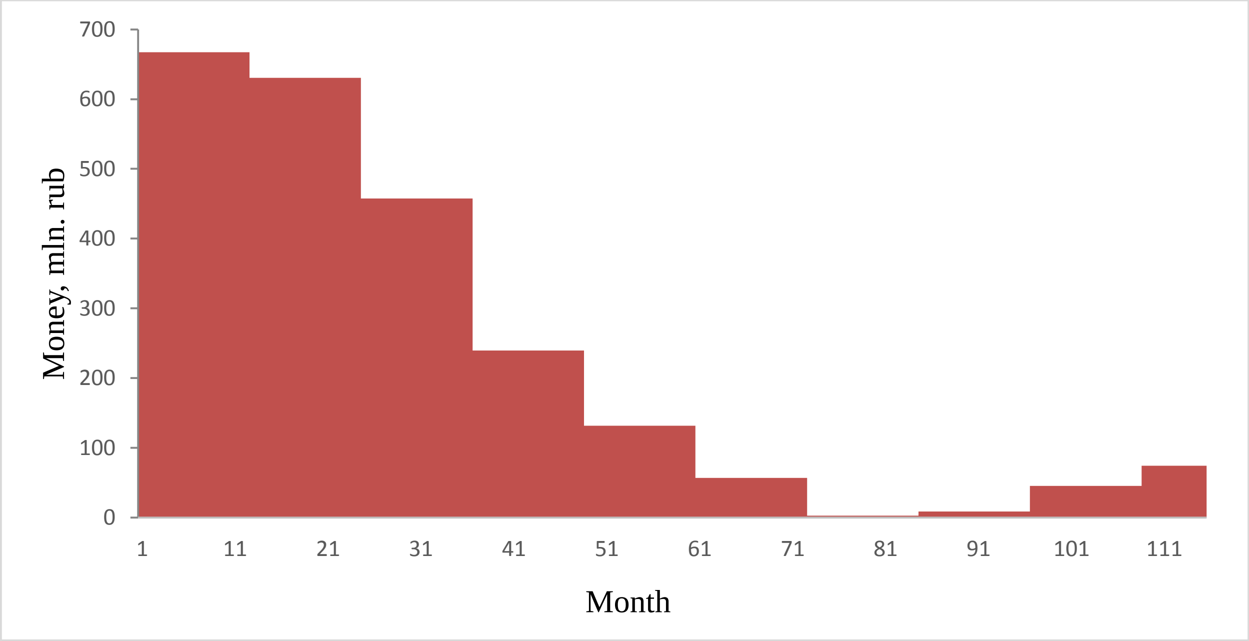


Fig. 3.15 – Maximum probable exceedance from the BP (in money)

If to assume that the cost of the upper completion with redundancy pump is about 80 million rubles (according to internal data) and cost of 1 ton of oil equal 13500 rubles then we can calculate the cost of the several upper completions installation vs probable exceedance. The extra cost of equipment versus probable exceedance of business plan (in million rubles) is shown in Fig. 3.16.

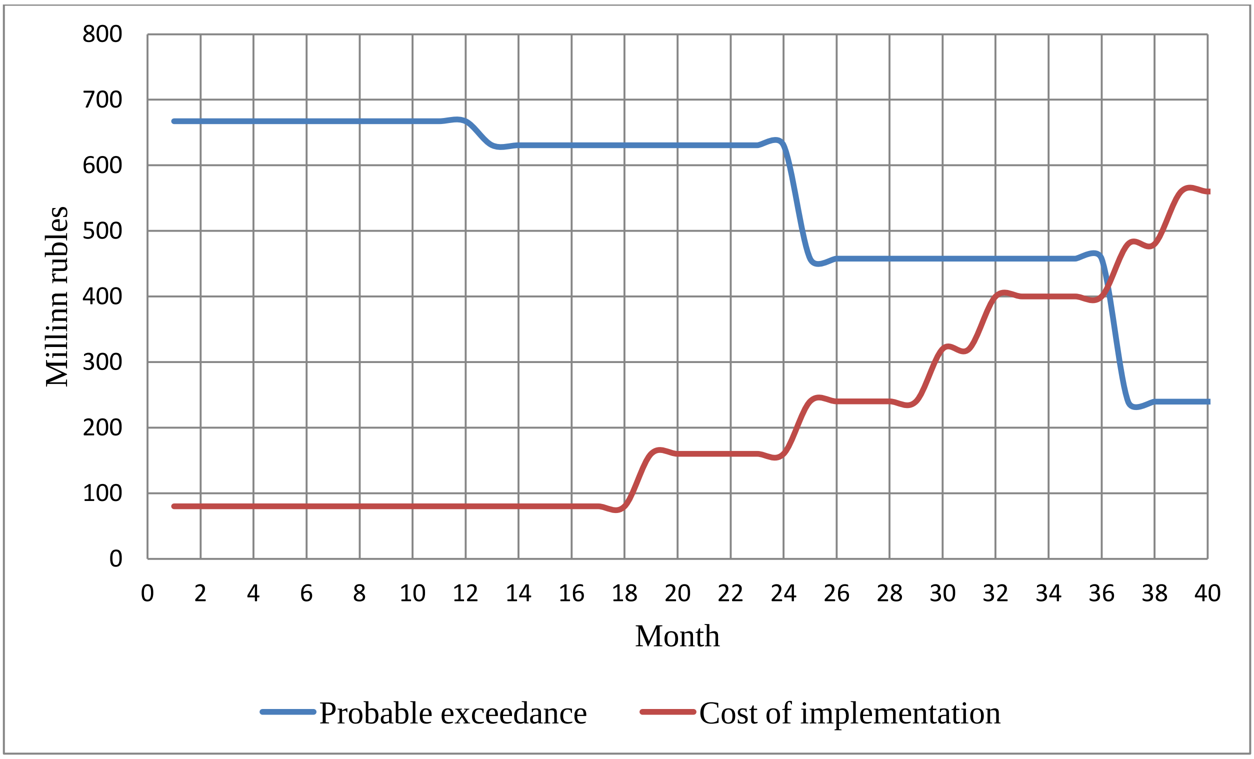


Fig. 3.16 – Extra cost of equipment vs Probable exceedance

According to the graph increasing amount of the upper completions implementation in the field after 36 months become higher than probable exceedance. Therefore, it is recommended to implement this concept for these particular data only as far as the cost of implementation of this concept become higher than "Probable exceedance".

The concept of the upper completion with redundancy pump should be implemented in the wells: 1,2,3,4,5 (commissioned while 36 months).

3.6 Supplementary

Consequences of unplanned upper completion failure:

– deviation of the planned production (business plan);

– displacement of the drilling plan;

– loss of production in the late stage due to drilling plan displacement;

– equipment repair;

– loss of time.

It should be mentioned that if to consider the field with the subsea production system, then well repair time can significantly increase due to the necessity of the drilling ship/Jack Up that can operate only in limited weather and ice conditions. It mostly influences fields located in the Arctic.

Additional risks should be mentioned:

Redundancy of the upper completion with an extra pump does not equal to double redundancy of the initial upper completion with one pump. It should be taken into account that both pumps are in subsurface conditions. Both of them have contact with reservoir fluid. So the redundancy pump that is not operating while first is producing can also be affected by wax deposits or other damaging factors that can somehow don't let the pump to be started or even broke it.

Key features should be considered:

1) Dogleg severity. Dogleg severity limits the concept implementation. The dogleg severity for the wells with the planned concept implementation should be accurately designed before we start drilling.
2) The composition of the fluid. The composition of the fluid affects the materials for the pump manufacturing and limit the concept implementation because in a case of high waxy oil it can plug the redundancy pump while it was on reserve.
3) *Mechanical properties of the rock* e.g. sand production could result in the necessity of the sand or gravel filter are in turn may have less reliability than upper completion with redundancy pump.

4) *Tubing*. Tubing must provide with required reliability equal redundancy of the system.
5) *X-tree*. The X-tree must be equipped with 2 power cable penetrators.
6) *Power cable*. The system must be equipped with two separate power cables. One power cable is for each pump.
7) *The inclination of the well*. Inclination must be accurately designed in order to fulfill the passport requirements of the equipment.
8) *Reliability analysis.* Reliability analysis should be completed for each particular field and type of equipment.

Conclusion

The purpose of this work is to increase the reliability of the upper completion assembly and decrease amount of mean upper completion fails, namely in one of the most sensitive periods of the offshore field development – a «drilling period». Results of the analysis show that it is quite achievable.

The proposed concept of the “Dual Life” upper completion assembly is cost-effective to apply for the first 5 wells, but we need to take into account all the assumptions mentioned in the thesis. However, the period of applicability can be prolonged by taking into account the cost of the pulling and running operations, depreciation of the drilling equipment and the cost of the equipment repair. Operation of subsea production system for the field development provides additional potential for the concept implementation.

The scientific base is directed, but engineering approach requires deeper analysis of all conditions. The technical realization and technology design must include:

1) The analysis of the well geometry for the accurate well trajectory design;

2) Fluid analysis;

3) Rock analysis;

4) Accurate well equipment selection;

5) Reliability analysis;

6) Economical analysis;

7) Analogues in world practice analysis;

8) Risk analysis;

All mentioned points should consider the specifics of the field development technology.

References

[1] Аналитическая служба «Нефтегазовой вертикали». Нефть современной России: +/- 20 лет // «Нефтегазовая Вертикаль».– 2015.– №21.– P. 12.

[2] Печорское море // inpath.ru: Моря мира. 2011. URL: http://inpath.ru/nature/sea/263.

[3] Arnfinn O. Arctic Europe Petroleum Resources and Infrastructure // SPE Offshore Europe. URL: https://www.offshore-europe.co.uk/__novadocuments/317692?v=636196362251900000

[4] ООО «Газпром нефть шельф». Технологический регламен технологического комплекса МЛСП «Приразломная». М., 2011. 278 p.

[5] Brown K.E. The Technology of Artificial Lift Methods. Oklahoma.,1984.

[6] Dogleg Severity Calculatiom based on Radius of Curvature Method // drillingformulas.com: Directional Drilling, Drilling Engineering Calculations. 2009. URL: http://www.drillingformulas.com/dogleg-severity-calculationbased-on-radius-of-curvature-method/.

[7] Sevin B. Design and Application of Submersible Pumps in Horizontal Wells in South Texas, Texas., 1991.

[8] Modahi M.H. The importance of ESPs in maximizing oil recovery. Nova Scotia., 2012.

[9] Brown K.E. Overview of Artificial Lift Systems. Tulsa., 1982.

[10] Clegg J.D., Bucaram S.M., Hein N.W.J. Recommendations and Comparisons for Selecting Artificial-Lift Methods. Texas., 1993.

[11] Lea J.F., Patterson J. Selection Considerations for Artificial Lift.. Dubai., 1997.

Appendix A

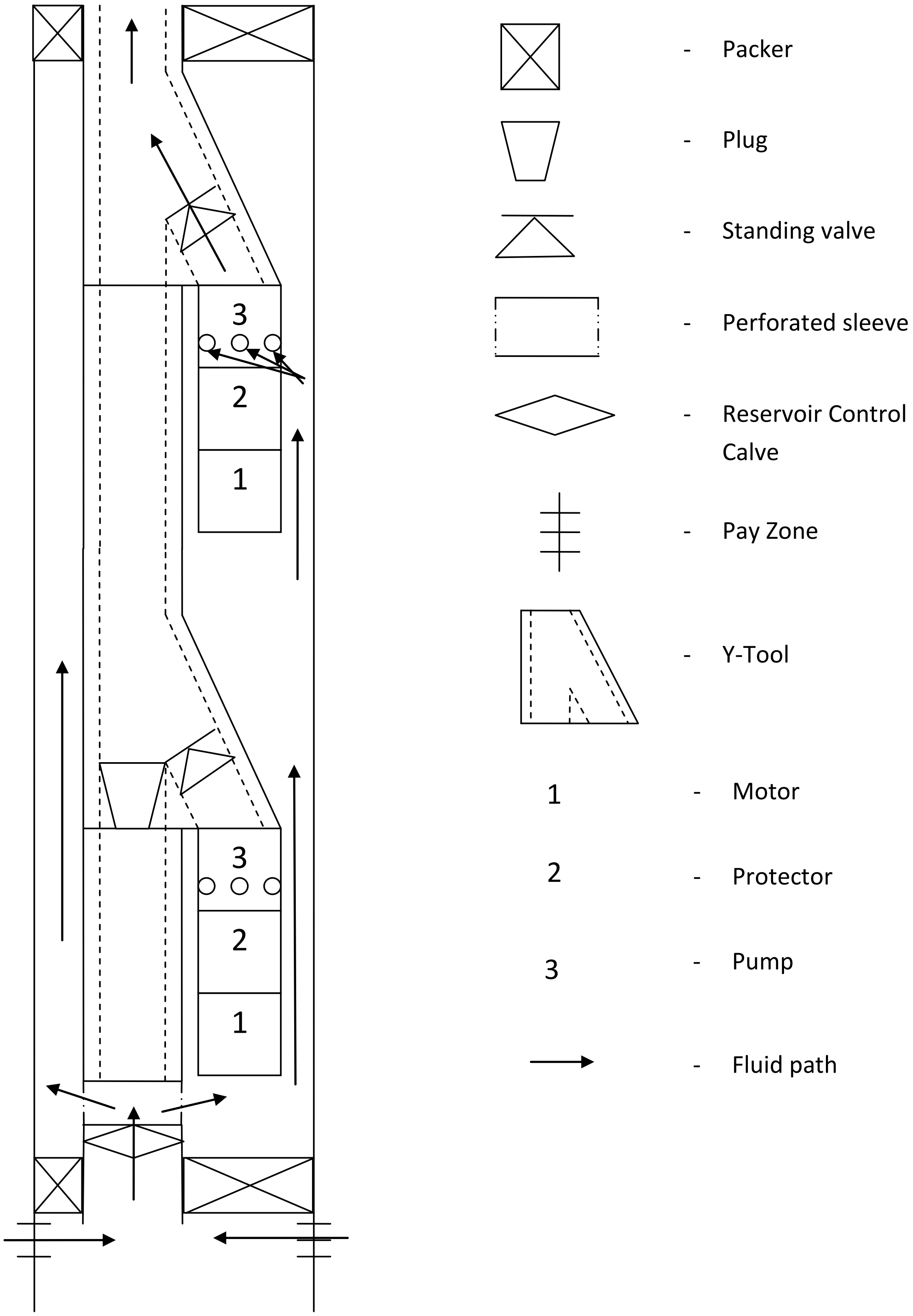


Fig. 1 – Concept description. Upper pump operation

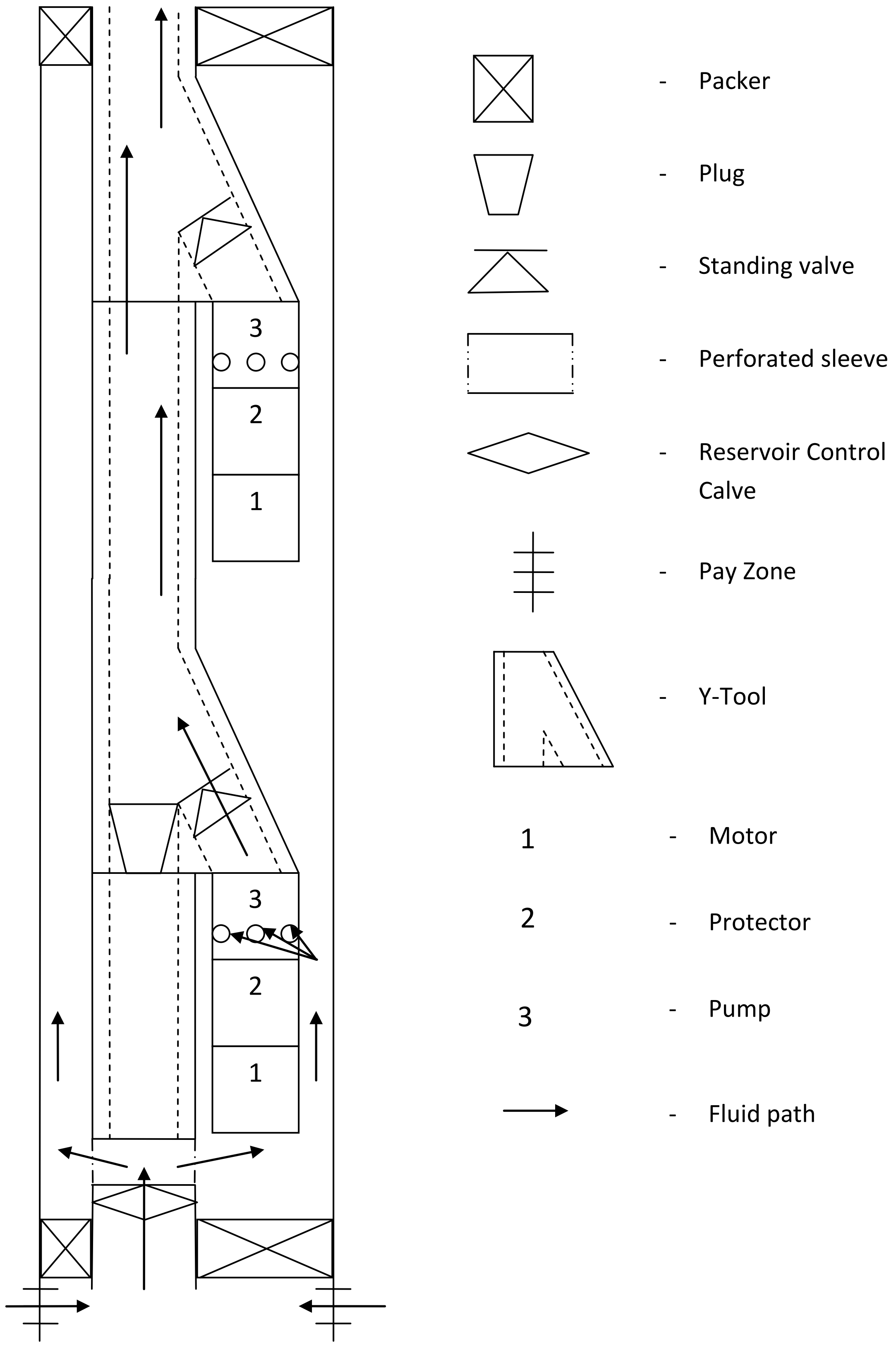


Fig. 2 – Concept description. Lower pump operation

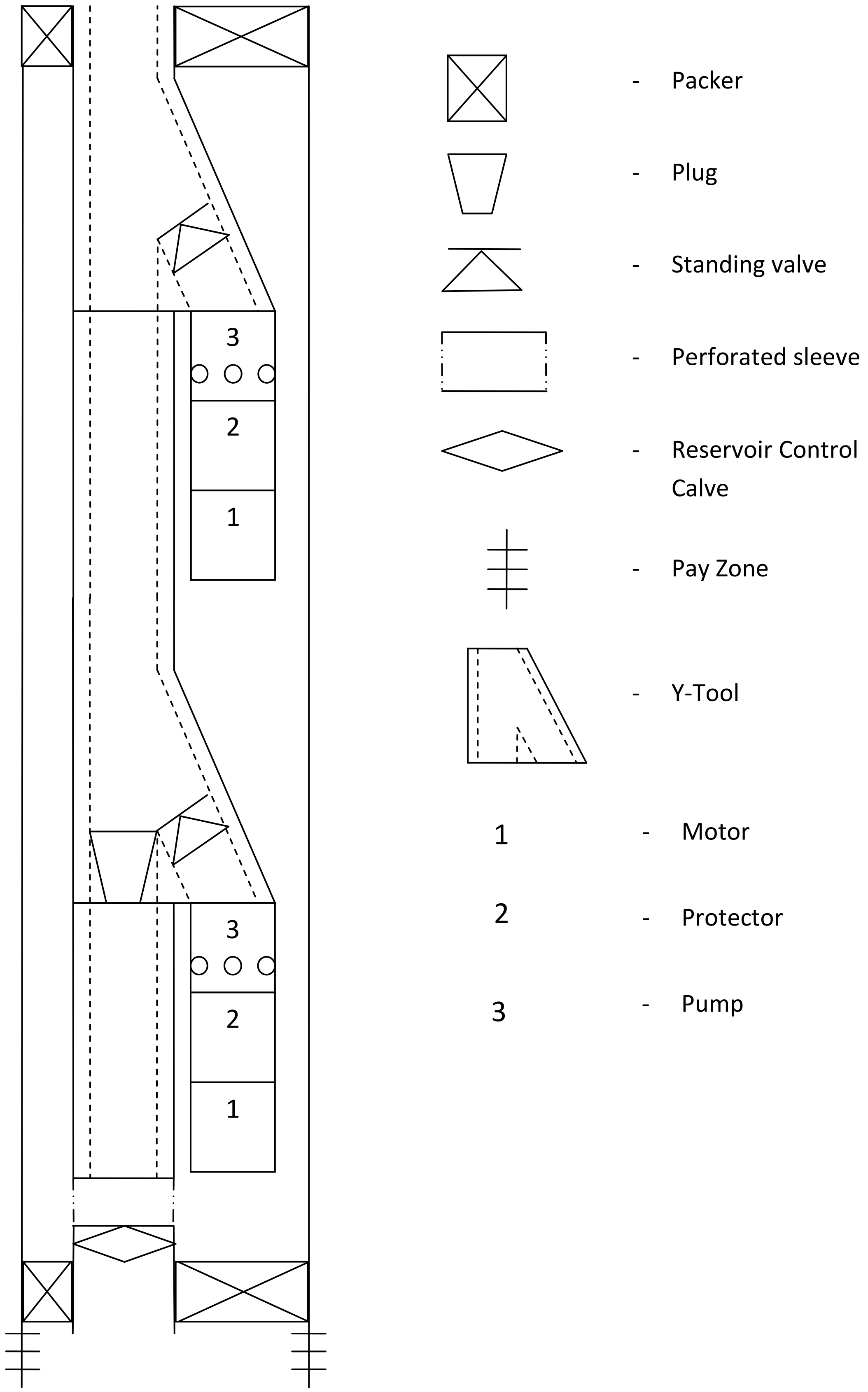


Fig. 3 – Concept description

Appendix B

Table 1. Initial data. Fluid properties

Parameter	Value	Units
Density of oil at st.cond.	906	kg/cm
Average density of the fluid in the well (WC=0%)	876	kg/cm
Average density of the fluid in the well (WC=45%)	946	kg/cm
Average density of the fluid in the well (WC=98%)	1037	kg/cm
Average density of the killing fluid in the well	1100	kg/cm
Density of oil at reservoir conditions	885	kg/cm
Water density	1040	kg/cm
Bubble point pressure	132	atm
Gas oil ratio	78.4	cm/cm
Oil viscosity at res. cond.	3.87	mPa*s
Specific gas gravity (to air)	0.676	-
Oil volume factor	1.12	cm/cm

Reservoir properties

Parameter	Value	Units
Reservoir pressure	25,2	MPa
Reservoir productivity	29.5	cm/day/atm

Well properties

Parameter	m	ft
MD of Top of the perforated interval	3452	11325.5
TVD of Top of the perforated interval	2366	7762.5
MD of bottom of the perforated interval	4126	13536.8
TVD of Top of the perforated interval	2415	7923.2
Internal casing diameter	0.2224	0.728
External casing diameter	0.2445	0.8
Internal tubing diameter	0.9962	0.325
External tubing diameter	0.1143	0.374

Design criteria

Parameter	m	ft
Lower pump installation depth	2943	m
Flow rate	2500	Cubic m/day
Minimum allowable shaft frequency	38	Hz
Maximum allowable shaft frequency	65	Hz

Appendix C

Table 1. Inclinometry of PH-7 well at the depth of ESP installation

MD (m)	I (°)	Az (°)	TVD (m)	DLS (°/30m)
2420,00	64,84	164,64	2025,03	1,15
2430,00	65,22	164,58	2029,25	1,15
2440,00	65,60	164,52	2033,41	1,15
2443,00	65,71	164,50	2034,65	1,15
2450,00	65,68	164,31	2037,53	0,77
2460,00	65,64	164,03	2041,65	0,77
2470,00	65,59	163,75	2045,78	0,77
2471,12	65,59	163,72	2046,24	0,77
2480,00	65,60	163,27	2049,91	1,39
2490,00	65,61	162,76	2054,04	1,39
2499,19	65,62	162,29	2057,84	1,39
2500,00	65,61	162,26	2058,17	1,01
2510,00	65,47	161,93	2062,31	1,01
2520,00	65,34	161,59	2066,47	1,01
2527,93	65,23	161,32	2069,79	1,01
2530,00	65,21	161,30	2070,66	0,47
2540,00	65,09	161,18	2074,86	0,47
2550,00	64,97	161,06	2079,08	0,47
2556,13	64,90	160,99	2081,68	0,47
2560,00	64,89	161,23	2083,32	1,72
2570,00	64,86	161,87	2087,57	1,72
2580,00	64,83	162,50	2091,82	1,72
2584,46	64,82	162,78	2093,71	1,72
2590,00	64,84	162,97	2096,07	0,92
2600,00	64,86	163,30	2100,32	0,92
2610,00	64,89	163,64	2104,56	0,92
2612,68	64,90	163,73	2105,70	0,92
2620,00	64,92	163,99	2108,81	0,97
2630,00	64,95	164,34	2113,04	0,97
2640,00	64,98	164,70	2117,27	0,97
2640,87	64,98	164,73	2117,64	0,97
2650,00	64,94	165,02	2121,51	0,86
2660,00	64,90	165,33	2125,74	0,86
2668,97	64,87	165,61	2129,55	0,86
2670,00	64,88	165,56	2129,99	1,27
2680,00	64,93	165,10	2134,23	1,27
2690,00	64,99	164,63	2138,46	1,27
2697,38	65,03	164,29	2141,58	1,27
2700,00	65,03	164,29	2142,69	0,06
2710,00	65,01	164,27	2146,91	0,06
2720,00	65,00	164,26	2151,14	0,06

MD (m)	I (°)	Az (°)	TVD (m)	DLS (°/30m)
2750,00	64,95	163,40	2163,83	0,96
2754,09	64,94	163,26	2165,56	0,96
2760,00	64,95	163,59	2168,06	1,52
2770,00	64,97	164,15	2172,29	1,52
2780,00	64,99	164,71	2176,53	1,52
2782,32	64,99	164,84	2177,51	1,52
2790,00	64,99	164,92	2180,75	0,28
2800,00	64,99	165,02	2184,98	0,28
2810,00	64,99	165,12	2189,21	0,28
2810,69	64,99	165,13	2189,50	0,28
2820,00	64,99	165,45	2193,44	0,92
2830,00	64,99	165,79	2197,66	0,92
2838,93	64,99	166,09	2201,44	0,92
2840,00	64,99	166,08	2201,89	0,21
2850,00	65,01	166,01	2206,12	0,21
2860,00	65,03	165,93	2210,34	0,21
2867,23	65,05	165,88	2213,39	0,21
2870,00	65,05	165,76	2214,56	1,15
2880,00	65,04	165,34	2218,78	1,15
2890,00	65,04	164,92	2223,00	1,15
2895,26	65,04	164,70	2225,22	1,15
2900,00	65,04	164,56	2227,22	0,78
2910,00	65,05	164,28	2231,44	0,78
2920,00	65,06	163,99	2235,65	0,78
2923,56	65,06	163,89	2237,15	0,78
2930,00	65,06	163,85	2239,87	0,15
2940,00	65,05	163,80	2244,09	0,15
2950,00	65,04	163,74	2248,31	0,15
2951,93	65,04	163,73	2249,12	0,15
2960,00	64,99	163,42	2252,53	1,07
2970,00	64,94	163,03	2256,76	1,07
2980,00	64,88	162,64	2261,00	1,07
2980,20	64,88	162,63	2261,09	1,07
2990,00	64,91	162,72	2265,25	0,25
3000,00	64,94	162,80	2269,48	0,25
3008,51	64,96	162,88	2273,09	0,25
3010,00	64,96	162,88	2273,72	0,11
3020,00	64,93	162,85	2277,95	0,11
3030,00	64,90	162,83	2282,19	0,11
3036,53	64,88	162,81	2284,97	0,11
3040,00	65,00	162,82	2286,44	1,00

Appendix D

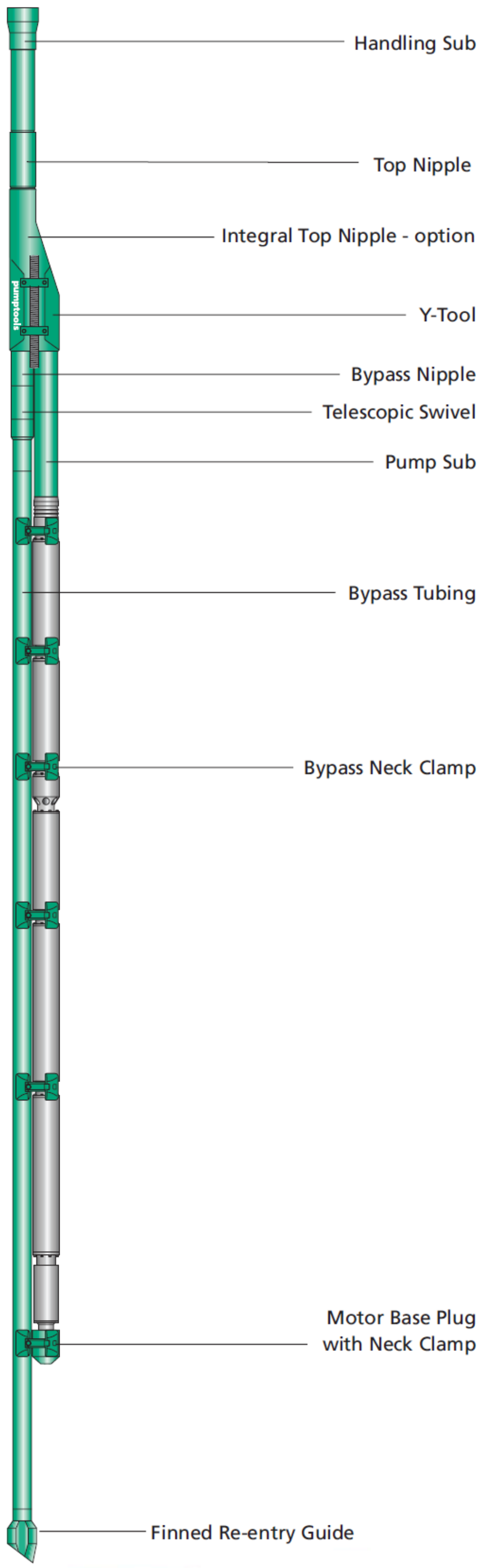


Fig. 1 – Y-Tool and Bypass system