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FACULTY OF ENGINEERING AND INFORMATION TECHNOLOGY
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ENHANCE ESP RUNLIFE FOR NABRAGAH FIELD – BLOCK 43

A PROJECT SUBMITTED IN PARTIAL FULFILLMENT
OF THE REQUIREMENTS FOR THE DEGREE
OF BACHELOR OF SCIENCE
IN OIL AND GAS ENGINEERING

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DECLARATION

We hereby declare that this Bachelor's Project is the result of our own work , except for quotations and summaries which have been duly acknowledged

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APPROVAL

This is to certify that the project titled **ENHANCE ESP RUNLIFE FOR NABRAGAH FIELD** – **BLOCK 43** has been read and approved for meeting part of the requirements and regulations governing the award of the Bachelor of Engineering (Oil and Gas) degree of Emirates International University, Sana'a, Yemen.

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ABSTRACT

ENHANCED ESP RUN LIFE. The heart of the ESP unit is the submersible pump. The submersible pump used in ESP installations are multistage centrifugal pumps operating in a vertical position. Identify ESP performance at nabrajah field using relative software. Identify causes of ESP problems at nabrajah field. Determine the best ESP environment to reduce the occurs of the problem. The most important problems facing us in the oil sector are electrical problem mechanical problem. We relied on the subject of our study on the analysis of data taken from 43 of the oil field ,Nebraja, and we started studying and analyzing data and came up with convincing solutions

ACKNOWLEDGMENTS

First of all, we owe our most sincere gratitude to Allah the almighty and the most powerful for offering us such a strength, endurance, willingness, and capability to accomplish this project.

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Special thanks to Yemen Oil Investments Company and Data Bank Development Project for providing us with necessary Data for the project and their goodness.

Our special gratitude is due to all those who have helped in carrying out the research and contributed in any way for the success of this Project.

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LIST OF SYMBOLS

API	American Petroleum Institute
BHA	Bottom Hole Assembly
GOC	Gas Oil Contact
GR	Gamma Ray
GWC	Gas Water Contact
ID	Inner Diameter
M	Mobility
MD	Measured Depth
NW-SE	North West-South East
$Ø_{eff}$	Effective Porosity
$Ø_{total}$	Total Porosity
OWC	Oil Water Contact
PC	Capillary Pressure
PPM	Part Per Million
PVT	Pressure/Volume/Temperature
S_W*	Water Saturation
TD	Total Depth
TVD	True Vertical Depth
PF	Fluid Density
PG	Gas Density
PM	Matrix Density

CHAPTER ONE

1. INTRODUCTION

1.1. Overview

Petroleum is the inflammable mixture of hydrocarbons, comprising of gaseous, liquid and solid materials. It has become the main source of energy and mainstay of moder n civilization. Multiple usability of Petroleum in different fields of machine civilization made it indispensable for the growth of economic life of mankind. Every aspect of d ay-to-day life of man is somehow influenced by the use of petroleum. Transportation , defense, technology, industry, commerce, research and development and many oth er facets of human lifestyle was greatly modified after the use of petroleum. The wor ld consumed almost 70 million barrels a day.

Petroleum located under the ground in reservoirs depth can reach to thousands of m eters so in order to lift it up to the surface there are many kinds of artificial lift meth ods, one of them if ESP electrical submersible pump which will be the subject of the project study.

1.2. The Problem Statement

Electrical submersible pumping is the most inflexible of any artificial lift system beca use a specific ESP pump can only be used in a definite, quite restricted range of pum ping rates.

The major problem in Nabrajah field is ESP failures. This field is using ESP as an artific ial lift method in 15 production wells, since 2005 until 2015, usually most of the wells faced ESP failure problem. This is mainly due to highly sand production. Other cause s of failures are high GOR, cable failure and shaft broke. A special focus will be on the encountered sand production that results in ESP failure using available data related to reservoir data, geological data, workover report and production data.

1.3. Objectives

To achieve the aim of this study, the following objectives have been defined:

1. Review the fundamental and principles of design probable ESP.
2. Determine the type of fluids produced, and flow rate from the reservoir.
3. Identify ESP performance at Nabrajah field using relative software.

4. Identify causes of ESP problems at Nabrajah field.
5. Determine the best ESP environment to reduce the occurs of the problems.

1.4. Production Activities in Yemen and History:

Yemen has entered the area of oil in the summer of 1984 upon the Hunt Oil Company announced the first commercial discovery of oil in Yemen (Alif Field). The well Alif # 1 produced an average of 8000 Barrel Per Day (BOPD). Oil was found in Block 18, Marib. Following that, oil explorations successive in the other fields. They reached more than 14 fields of oil and gas. Then the development of the block was done through building surface plants and constructing a pipeline to the Red Sea.

In September 1986, the production and export of the first oil shipment was executed from block 18 under the guidance and reign of President Ali Abdullah Saleh, the maker of Yemen's new renaissance and oil revolution. another oil and gas explorations continued in other blocks.

In 1987, it was announced that oil was discovered in three fields of Shabwah governorate by a (former) Russian company, Techno-Export. These were West Ayad, East Ayad and Amel fields (block 4). Developing of the block was done through building its plants and construction of pipelines to Belhaf Port on the Arab Sea.

In 1991, significant oil discoveries were made on Sunnah field Masila block (block 14) by Canadian Occidental Petroleum (now Canadian Nexen Petroleum). Such discoveries were followed by more findings. Then, the block was developed by building its plants and construction of the oil pipeline to Al-Dhabah (Ash Shihr) area, Hadhramaut governorate, on the Arab Sea.

In September 1996, oil was discovered in Halewah field Jannah block 5. (It was discovered by a consortium of companies operating in the block). Then plants were built and the produced oil was carried by the pipeline of Hunt Yemen Company, the (former) operator of block 18, Marib. Hunt pipeline delivered oil the port on the Red Sea.

In 1998, Total E&P Yemen (Total Fina Alf) made a number of oil discoveries in the following.

fields: Kharir, Atouf, and Wadi Taribah, (East Shabwah block 10). Production was link ed with Al-Masila block 14.

On December 18, 1999, DNO, a Norwegian company as operator of Hwarim block 32, announced the discovery of oil. It started production and exporting oil through Al-M asila pipeline in November 2001.

On December 20, 2001, announce the oil commercial discovery in E.Saar (Block 53) D ove Energy -British, It started production and exporting oil through Al-Masila pipeline in 2002.

On October 14, 2003, Vintage, an American company and operator of Damis block S1 , announce the oil commercial discovery, it started production and exporting oil thro ugh Jannah pipeline in March 29, 2005.

On December 17, 2003, Nexen Petroleum Yemen Ltd., a Canadian company as opera tor of E.

Al-Hajr block 51, announce the oil commercial discovery, it started production and ex porting oil through Masila pipeline in November 9, 2005.

In July 2005, oil production initiated from Block 43, which operator by DNO a Norwe gian Company.

On October 1, 2005, Calvally a Canadian company as operator of Malik block 9, anno unce the oil commercial discovery, it started production December 29, 2005.

In addition, in January, 2006, OMV, a Austrian company as operator of Al-Uqlah bloc k S2, announce the oil commercial discovery, It started production and exporting oil i n December, 2006.

On March 2011, DNO, ANorw company as operator of south Hood Block 47, announc ed the discovery of Oil.

This is Yemen with very humble potentials to serve the people and the homeland

1.5. Geology of Yemen

Geological surveying and petroleum exploration in Yemen date back to the early decades of the 20th century from the 1930s–60s, the Iraq Petroleum Company conducted exploration in the Hadramout and Mahrah areas in north-east Yemen, during which period Ziad Rafiq Beydoun (1924–1998) pioneered geological studies of the country.

Between 1962 and 1967, Pan American Oil continued exploration in Hadramout (in South Yemen) and drilled a number of wells, with the non-commercial discovery of several barrels of oil from the fractured carbonates of the Cretaceous Qishn Formation in Tarfayt-1.

During the 1970s and 80s both North and South Yemen began offering concession blocks to a number of foreign oil companies. The first commercial discovery came in 1984 when the American company Hunt Oil drilled Alif-1 in the Marib sector of the onshore Sabatayn Basin in North Yemen, penetrating a total depth at 4,182m and hitting oil (40.4^o API) in the Alif Member of the Sabatayn Formation (Middle–Upper Tithonian age) with an initial flow of 7,800 bopd .

In 1986, the Russian company Techno-Export, which was operating in South Yemen, drilled West Ayad-1 in the Shabwa sector of the Sabatayn Basin, encountering 35^o API oil in the Jurassic. Petroleum exploration by Canadian company Nexen in the Sya'un-Masilah Basin, led to an oil discovery in 1991: Sunah-1 drilled to the total depth at 2,917m and discovered oil (36^o API) in sandstones of the Lower Cretaceous Qishn Formation.

Twelve onshore and offshore sedimentary basins have been identified in Yemen, categorized into three groups as shown in **Fig. 1-1** based on the geological era in which they originated: (1) Rub' Al-Khali; (2) Sana'a; (3) Suqatra; (4) Siham-Ad-Dali'; (5) Sabatayn; (6) Sya'un-Masilah; (7) Balhaf; (8) Jiza'-Qamar; (9) Mukalla-Sayhut; (10) Hawrah-Ahwar; (11) Aden-Abyan; (12) Tihamah.

Of these, only two onshore sedimentary basins, Sabatayn and Sya'un-Masilah, where oil was discovered in 1984 and 1991 respectively, are currently the only petroleum-producing basins in Yemen, while the   other basins, including the onshore Paleozoic and offshore Cenozoic basins, remain little-explored.

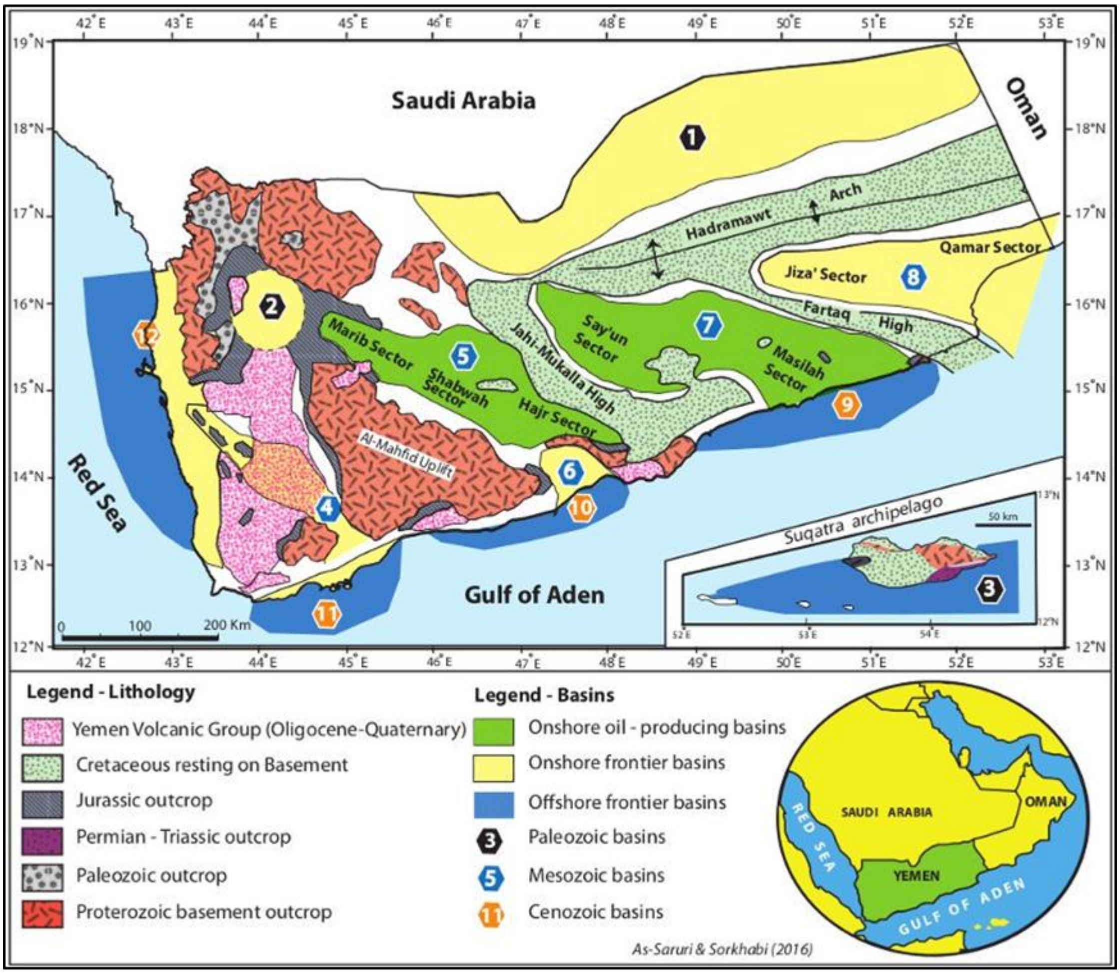


Figure 11 Sedimentary basins of Yemen and their classification according to the geologic era in which they formed . (Source: As-Saruri & Sorkhabi (2016))

1.5.1. Sabatayn and Sya'un-Masilah Basins:

These two basins are parallel rift basins separated by the Jahi-Mukalla High. They de veloped in Late Jurassic to Early Cretaceous times during the fragmentation of Gond wana. The basins share many similarities including source and reservoir rocks (bitumi nous shale members) of Late Jurassic-Early Cretaceous age, as shown in **Fig. 1-2**. Bot h basins also contain fractured Precambrian granite reservoirs with 41°API oil, charg ed by downthrown Upper Jurassic shale. (Saruri & Sorkhabi (2016)).

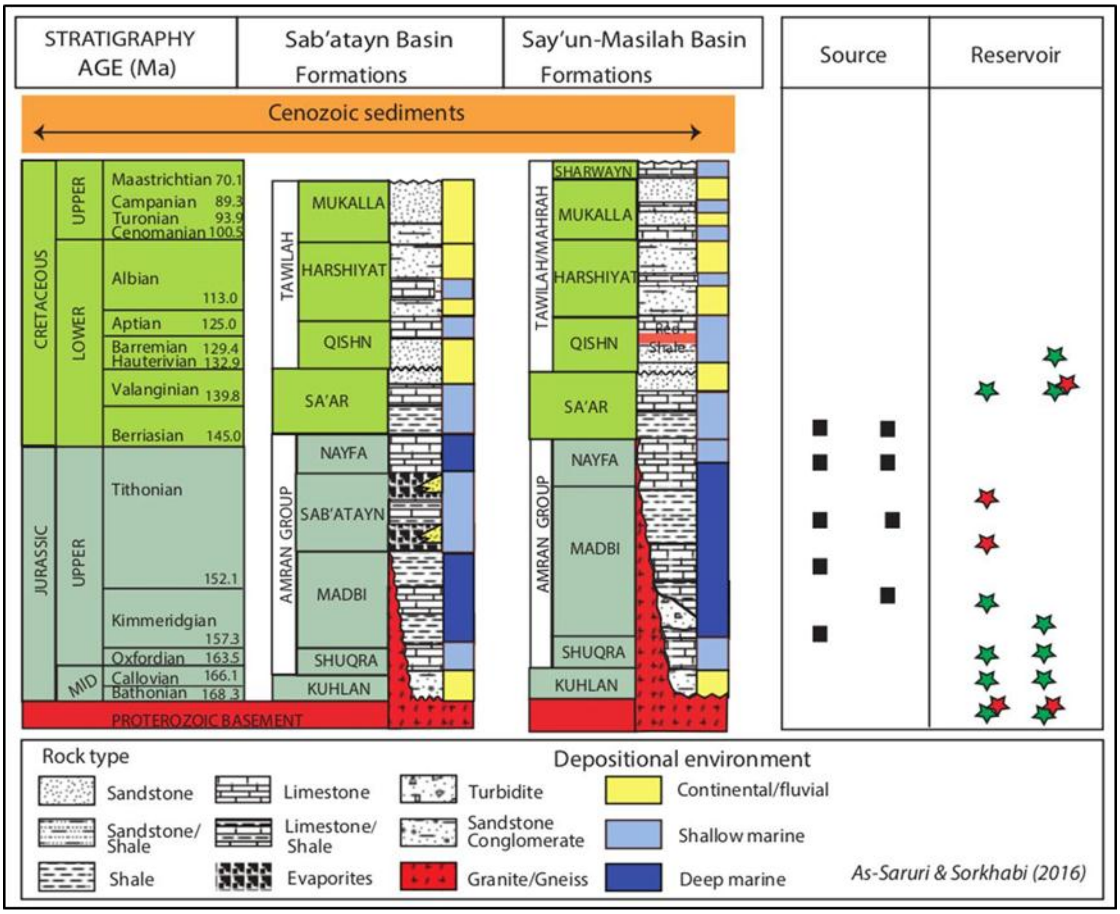


Figure 12 Stratigraphy and petroleum systems of Sabatayn and Sya'un-Masilah Basins. (Source: As-Saruri & Sorkh abi (2016)).

One significant difference between these two basins is that Tithonian-age evaporite beds are absent in the Sya'un-Masilah Basin while the intra-salt sandstones and sub-salt turbidites offer significant oil accumulations in the Sabatayn Basin. Another diffe rence is that the Lower Cretaceous sandstone of the Qishn Formation is an importan t reservoir in Sya'un- Masilah, but not in Sabatayn. The initial reservoir pressures in t he latter are gas-driven, while those in the Sya'un-Masilah Basin are water driven.

1.5.1.1. The Sabatayn Basin

Is a major hydrocarbon province in western Yemen. It is located within the southwes tern portion of the Arabian Peninsula. The stratigraphy of the basin is similar to othe r Yemen basins with one major exception; the presence of Late Jurassic Sabatayn salt , which provides a regional seal for the deeper petroleum systems. Most production i n the Sabatayn Basin originates from the reservoirs in the Alif Member of the Sabata yn Formation. Alif sands have produced in concession block 18, 5, 20, S1 and 19, as s hown in **Fig. 1-4**.

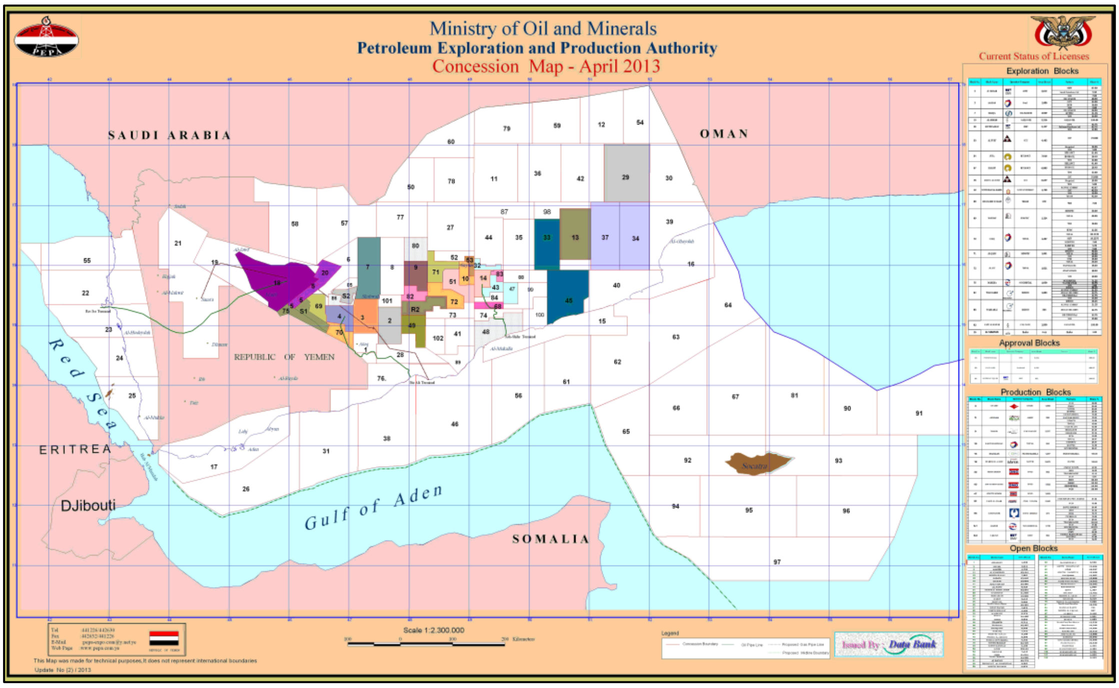


Figure 13 Simplified location map of the blocks in the Sabatayn Basin and study area, (YICOM).

Most of the crude oils produced in Yemen are between 28-32 degrees API, with Alif c rudes often being light and sweet with an API of 41 degrees. The Sabatayn Basin is kn own by a variety of names (Marib-Al Jawf, Marib-Shabwa, or Marib-Shabwa-Hajar Ba sin).

1.5.1.2. Sya'un-Masilah Basin

As with most other oil-bearing basins in eastern and western Yemen, the Masilah Bas in initiated as a rift basin during Upper Jurassic-Early Cretaceous post-Pangea breaku p. Rifting caused a series of northwest southeast and west-east trending major basin -bounding faults evolving, adjacent to which are three main Jurassic-Cretaceous rift g raven basins of Yemen: The Marib-Shabwah, the Masilah, and the Jiza'-Qamar Basins (**Fig. 1-5**). The tectonic evolution of the Masilah Basin can be divided into three stag es: pre-rift, syn-rift and post-rift (**Fig. 1-6**). Pre-rift megasequence ranges in age from Proterozoic to early Late Jurassic. The Pre-rift has been penetrated by wells drilled in the Masilah Basin.

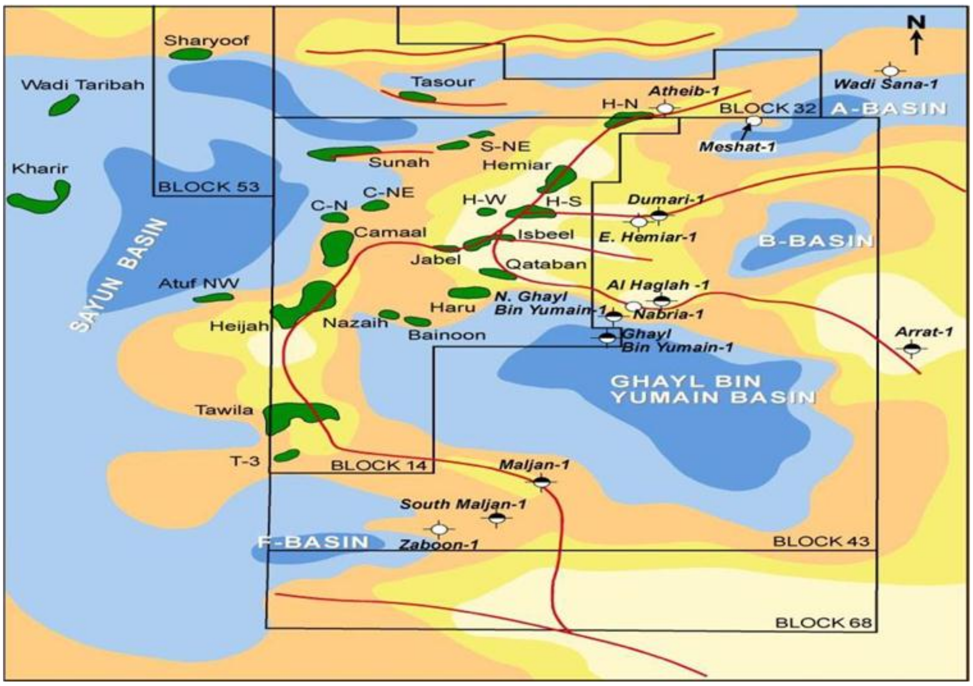


Figure 14 Main sedimentary basins in Republic of Yemen showing location map of the oilfields in the Masilah Basin

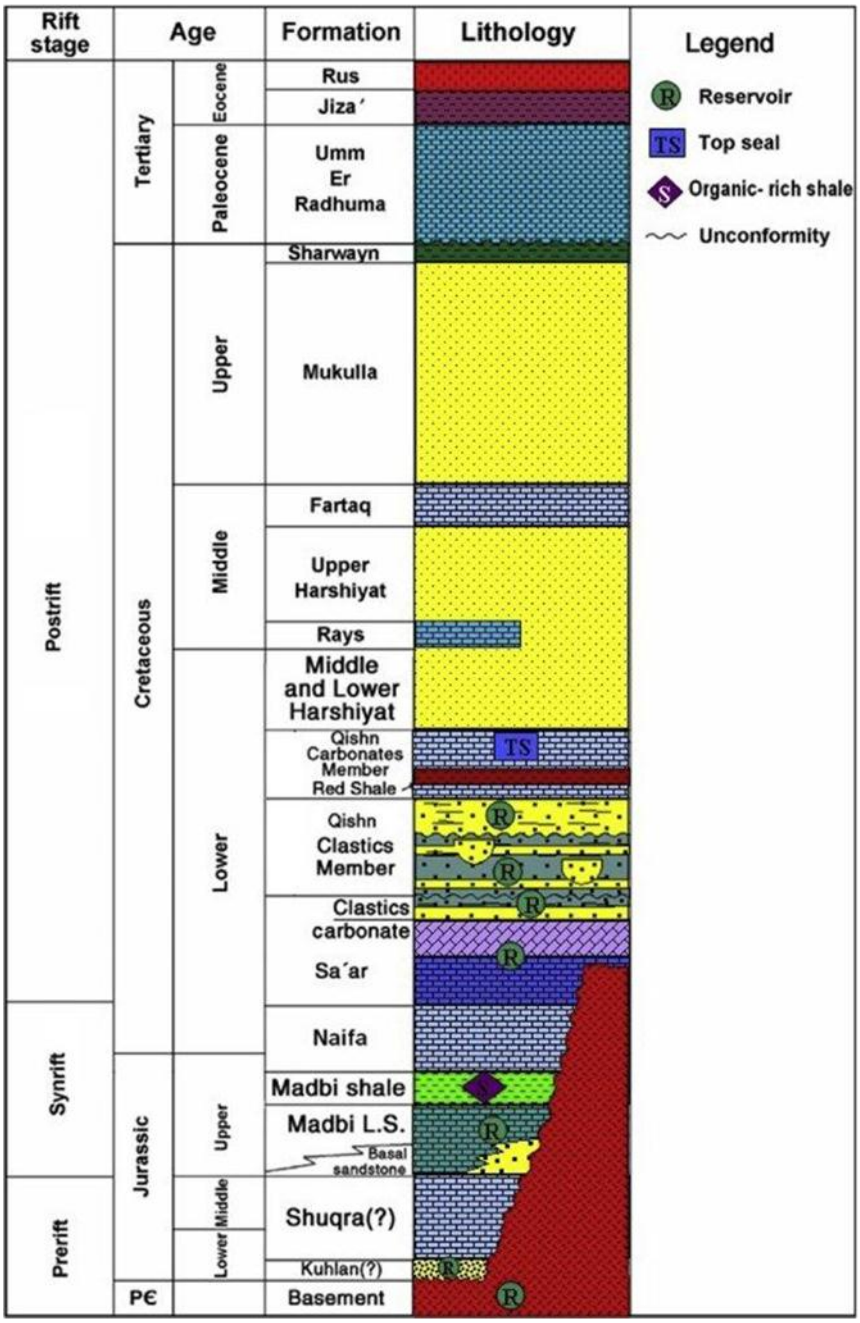


Figure 15 Regional stratigraphic nomenclature, Masilah Basin, Republic of Yemen

Stratigraphy of Sya'un-Masilah Basin

Basement

The basement of the Masilah Basin consists mostly of igneous and metamorphic com plex rocks of Proterozoic to early Cambrian age. This basement complex is overlain u nconformably by a Jurassic sequence.

Kuhlan Formation

In Early to Mid-Jurassic time, sandstone was deposited widely across Yemen, where thick sedimentation developed in lows formed before Jurassic time. This thick sandstone deposit is known as the Kuhlan Formation, and it is composed of siltstone and sandstone ranging to conglomerate with some streaks of limestone and green clay.

In Masilah Basin oilfields, the sandstone of the Kuhlan Formation is very fine to medium grained, well sorted, and possess of poor to good porosity.

Shuqra Formation

After deposition of the Kuhlan Formation, another marine transgression from the southeast reworked the sandstone and deposited shallow-marine carbonates (Shuqra Formation). The Shuqra Formation is Middle to Late Jurassic in age and consists predominantly of platform carbonate.

Madbi Formation

During the syn-rift sequence, horsts and nested fault blocks were developed, where differential compaction and drape anticlines occurred in the Upper Jurassic to Lower Cretaceous due to basement high. Upper Jurassic sediments, known as the Madbi Formation, were penetrated by wells drilled in the basin. This formation is generally composed of porous limegrainstone to argillaceous lime mudstone. The lithofacies of this unit reflects an open marine environment. This formation is divided into two members. The lower part of this formation is commonly argillaceous lime and basal sand and forms a good reservoir in some oil fields of the Masilah Basin. The upper member is called Madbi shale and is composed of laminated organic-rich shale and mudstone. The thickness of Madbi shale is 30-100 m.

Naifa Formation

During latest Jurassic to Early Cretaceous time, the rifting in the Masilah Basin continued, but the subsidence became slower. It was accompanied by the accumulation of carbonates as shallow-marine shelf deposits which constitute the Naifa Formation. The Naifa Formation consists mainly of silty and dolomitic limestone and lime mudstone with wackestone.

Saar Formation

The upper part of this formation is composed of very porous clastic carbonate overla in by the Saar dolomite facies. In Early Cretaceous time, sea level rose on relatively fl at ground, resulting in marine transgression and sedimentation of widespread shallo w-marine carbonate Saar Formation.

The Saar Formation is composed mainly of limestone, dolomitic limestone with some mudstone, and sandstone. Oil companies classified this formation into lower Saar ca rbonate and upper Saar clastic.

Qishn Formation

The Post-rift megasequence range in age from late Early Cretaceous to Tertiary time and rests unconformably on the syn-rift section. Late Early Cretaceous sediments, kn own as the Qishn Formation, consist of braided plain to fluvial and shallow-marine se diments deposited in the Masilah Basin. The Qishn Formation is divided into two me mbers, Upper Qishn Carbonate and Lower Qishn Clastic Members. The Upper Qishn Carbonate Member consists of laminated to burrowed lime mudstone and 6 wackest one interbedded with terrigenous mudstone and black fissile shales. These sediment s were deposited in deep water under alternating open and closed marine conditions . The Upper Qishn Carbonate Member is a regional seal rock in the Masilah Basin. Th e Qishn Clastic Member is composed mainly of sandstones, with shale and minor car bonate interbeds, deposited in braided river channels, and in shore face and shallow-marine settings.

Biyadh Formation

The Qishn Clastics Member is also referred to as the Biyadh Formation, in compariso n to the Biyadh Sandstone in Saudi Arabia and correlates with the Zubair Formation i n the Kuwait and Iraq.

Harshiyat Formation and Fartaq Formation

During the late Early Cretaceous, alternating regression and transgression occurred. This pattern deposited clastic (Harshiyat Formation) and carbonate rocks (Fartaq For mation) interbedded with each other.

Mukulla Formation and Sharwayn Formation

A similar pattern of sedimentation occurred in Upper Cretaceous time, where fluvial systems (Mukulla Formation) prograded southeast ward in the Masilah Basin. The La te Cretaceous Sharwayn Formation deposits are composed mainly of shale.

Umm Er-Radhuma Formation

The overlying Tertiary units comprise homogeneous argillaceous, detritus carbonates and hard, compacted, massive and bedded dolomitized fossiliferous limestone with l ocal chert nodules (Umm Er-Radhuma Formation) that changes to shales with minor 7 limestone bands in the upper levels (Jiza' Formation). Jiza'-deposits are widesprea d in the Early Eocene followed by the deposition of anhydrite beds (Rus Formation).

Overview

1.6. Block 43 (Nabrajah Field) -

1.6.1. Block 43 (Nabrajah Field) is placed in south Hoarem, Hadramout city, Yemen.

The block covers an area of 2,026 km^2, and operated by DNO company. The Revised Nabrajah Reserves, As previously reported confirmed the presence of oil in both the Basement and Qishn formations. The production from Qishn commenced in July 200 5from Qishn sandstone ~16 months after discovery. The oil measured 25.3 degrees A PI. Preliminary estimates indicate recoverable oil reserves of about 10 - 12 million ba rrels (of which DNO s share is some 5 - 6 million barrels before tax)

CHAPTER TWO

2. LITERETURE REVIEW

2.1. Geology

The Geology is the study of the solid matter that makes up the Earth. It includes studying the types of rocks the Earth is made of. Geologists, the scientists who specialize in geology, study many things. They look at how the Earth was formed. They examine how the Earth continues to change over time. Geologists even study rocks to find out what the Earth was like millions of years ago.

2.2. Basic of earth layer

The part of the Earth we live on is solid, but the inside of the Earth is very different. Earth has four different layers: the inner **core**, the outer core, the **mantle**, **crust**, and the **lithosphere**

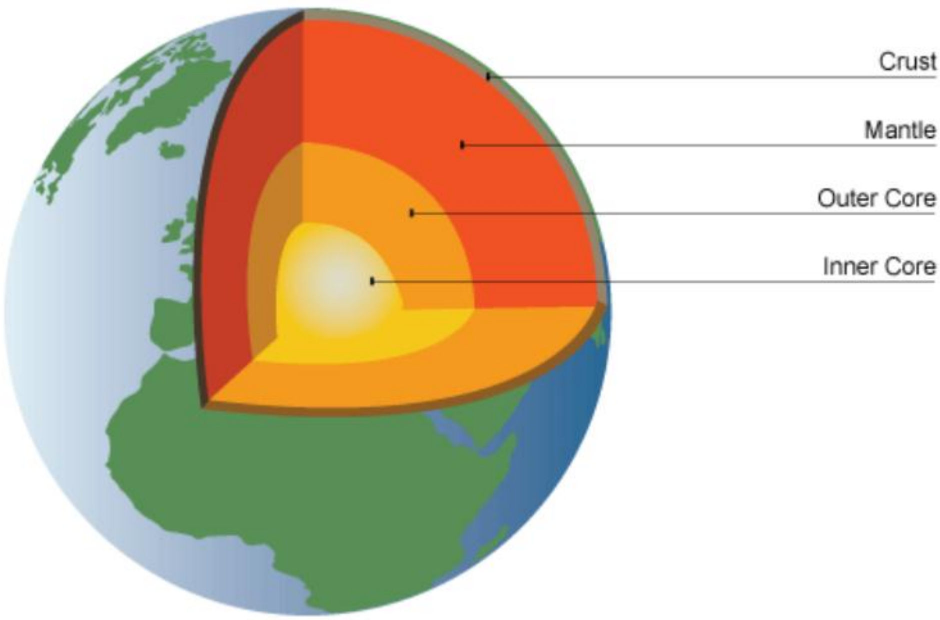


Figure 21 Cross Sectional View of the Earth Showing Internal

2.2.1. The Inner and Outer Core

The Inner and Outer Core When the Earth was formed, the heaviest materials sank to the center. These materials formed the Earth's core. They share the same name, but the inner and outer core are very different in their characteristic.

2.2.2. The Mantle

The thickest part of the Earth is the mantle. It begins about 25 miles (40 km) below the Earth's surface. It reaches 1,800 miles (2,897 km) deep into the Earth. The mantle is very hot. The parts near the core reach 4,000^o F (2,204^o C). The parts closest to the Earth's surface reach about 1,600^o F (871^o C). The mantle is solid, but the high heat causes the mantle to move slowly beneath the Earth's crust.

2.2.3. The Crust

We call the outside part of a loaf of bread the crust. We use the same word to describe the outer layer of the Earth. The crust is very thin. It contains less than one percent of the entire volume of the Earth. There are two types of crust: oceanic crust and continental crust. Oceanic crust lies beneath the oceans and is about five miles (8 km) thick. Continental crust is the rock that makes up the continents. It can range from about 20 to 25 miles (32 to 40 km) thick. The crust can reach 1,600^o F (871^o C) near the mantle. It is the same as the air temperature at the surface.

2.2.4. The Lithosphere

The rock near the Earth's surface is hard and solid. We call this layer of hardened rock the lithosphere. The lithosphere is made up of the crust and upper mantle. Think of it as the layer of solid rock that makes up the hard shell of the Earth.

2.3. Basic of layer process

The lithosphere isn't one solid rock. It's broken up into large plates. Scientists believe these huge plates of crust and upper mantle move about on the lower mantle. The theory that the lithosphere is made up of moving plates is called plate tectonics. The plates move very slowly. The average plate moves no more than about 4 inches (10 cm) a year. Yet, over hundreds of millions of years, the plates have moved long distances. Many scientists believe that continents were once joined (Conwana land) but have drifted apart due to plate tectonics.

2.4. The basic rock types

All the thousands of different rocks fall into one of four categories igneous, metamorphic, and sedimentary (Petroleum-Bearing Rock)

2.4.1. Igneous rocks:

We know that the temperatures inside the Earth are very hot. It is so hot that rocks a ctually turn into a liquid, called magma. This magma can cool beneath the Earth's cru st to form igneous rock. The main type of igneous rocks are granite, pumice, basalt, a nd obsidian. Magma sometimes erupts from the Earth's surface from a volcano. Wh en magma reaches the surface of the Earth, we call it lava. When lava cools, it forms igneous rock.

2.4.2. Metamorphic Rock:

Metamorphosis means to change from one thing into another. Metamorphic rock is rock that has changed from one type of rock to another by pressure or heat. For exa mple, after thousands of years of pressure and heat, limestone is changed into marbl e. Metamorphic rocks can be formed from igneous, sedimentary, or even other meta morphic rocks. The Common Metamorphic Rocks include slate, marble, soapstone, a nd quartzite.

2.4.3. Sedimentary rocks:

The small pieces of sediment collect together in layers called sediment beds. As the b eds get larger, the pressure squeezes the sediment together to form new rock. Sedi mentary rock is new rock formed from the sediment of older rocks. The Common Se dimentary Rocks include limestone, shale, sandstone, and gypsum.

2.5. Petroleum-Bearing Rock:

Sedimentary are the most important and interesting type of rock to the petroleum in dustry because most oil and gas accumulations occur in them; igneous and metamor phic rocks rarely contain oil and gas. All petroleum source rocks are sedimentary roc ks as well.

2.5.1. The rock cycle:

The rock cycle takes place over a very long period of time. It may take millions of yea rs for a rock to change from one type to another. Understanding the rock cycle can h elp us understand how the Earth was formed and continues to change. Igneous, met amorphic, and sedimentary rocks are related by the rocks cycle, the circular process by which each is formed from the others. Rocks are weathered form sediments, whic h is then buried. During deeper and deeper burial, the rocks undergo metamorphism and/or melting. Later, they are deformed and uplifted into mountain chains, only to be weathered again and recycled.

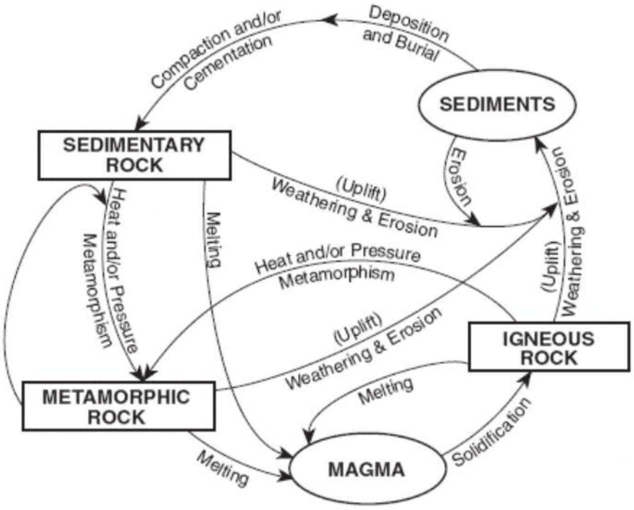


Figure 22 Rock Cycle in Earth's Crust

2.5.2. Geologic Time Scale:

Geologists built on the knowledge of their predecessors and started to build a world wide rock column. It is not continuous from the beginning of the time.

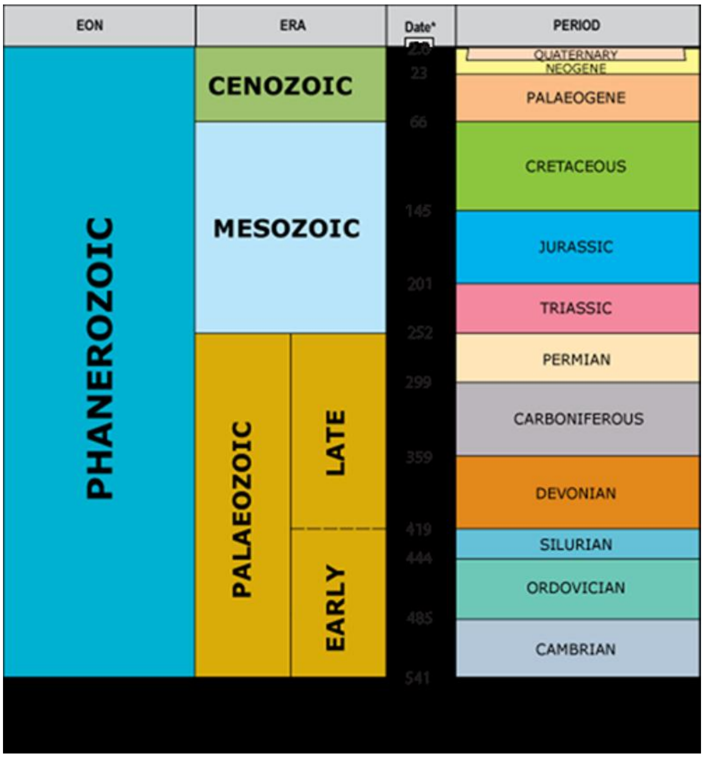


Figure 23 Geological Time Scale

2.5.3. Basic Classification and Types of Sedimentary Rocks (Two main groups):

2.5.3.1. Clastic sedimentary rocks:

Formed as a result of the weathering of fragmentation of per-existing rocks and min erals and classified on the basis of their textures, primarily the size of the grains.

2.5.3.2. Chemical or Biochemical sedimentary rocks:

Formed as a result of chemical processes. Primary carbonate deposition results from deposits formed by plants and animals that utilize carbonates in their life processes.

2.5.3.3. Types of Sedimentary Rocks that are Important in the Production of Hydrocarbons:

1) Sandstones (clastic sedimentary rock).
2) Carbonates (broken into two).

- Limestone: Formed chiefly by accumulation of shells and coral.
- Dolomites: Consists mainly of calcium carbonate and Magnesium.

3) Shale (Detrital fine-grained sedimentary rock) serve as a main cap rock.

4) Evaporates (Don`t form reservoir, but make excellent cap rocks and generate traps).

2.5.4. Source Rock and Hydrocarbon Generation

Source rock refers to the formation in which oil and gas originate. Hydrocarbons are generated when large volumes of microscopic plant and animal material are generall y deposited with fine clastic (Silt and/or clay) sediments in marine, deltaic, or lacustri ne (lake) environments. Over time the organic remains are altered and transformed i nto gas and oil due to certain factors such as Bacteria, high temperature and increas ed pressure of deep burial. Organically rich, Black -colored shale deposited in a quiet marine, oxygen depleted environment is considered to be the best source rocks.

The main potential source rock in Masila basin is Madbi formation (Organic-rich blac k shale) for the reservoir rock of Qishn formation.

The seal rocks cover the main reservoir (Qishn clastic) are represented by the Qishn c arbonate and Harshiyat shale.

The five Major Types of Hydrocarbons of Interest to Petroleum Exploration:

1. Kerogen/Bitumen
2. Crude Oil
3. Asphalt
4. Natural Gas.
5. Condensates

2.5.5. Exploration and Mapping Techniques

Exploration for oil and gas has long been considered an art as well as a science. It enc ompasses a number of older methods in addition to new techniques.

2.5.5.1. Subsurface Mapping

Geologic maps are a representation of the distribution of rocks and other geologic m aterials of different lithology and ages over the Earth's surface or below it. The geolo gist measures and describes the rock sections and plots the different formations on a map, which shows their distribution. Just as a surface relief map shows the presence of mountains and valleys, subsurface mapping is a valuable tool for locating undergr ound features that may form traps or outline the boundaries of a possible reservoir. Subsurface mapping is used to work out the geology of petroleum deposits. Three-di mensional subsurface mapping is made possible by the use of well data and helps to decode the underground geology of a large area where there are no outcrops at the surface.

2.5.5.2. Well Location Map

Well location map determines the coordinates (X -Y) in the field, by using the given d ata.

The drilling engineer is usually not responsible for selecting well sites. However, he must work with the geologist for the following reasons:

1. Develop an understanding of the expected drilling geology.
2. Define fault-block structures to help select offset wells similar in nature to the prospect well, identify geological anomalies as they may be encountered in drilling the prospect well.
3. A close working relationship between drilling and geology groups can be the difference between a producer and an abandoned well.

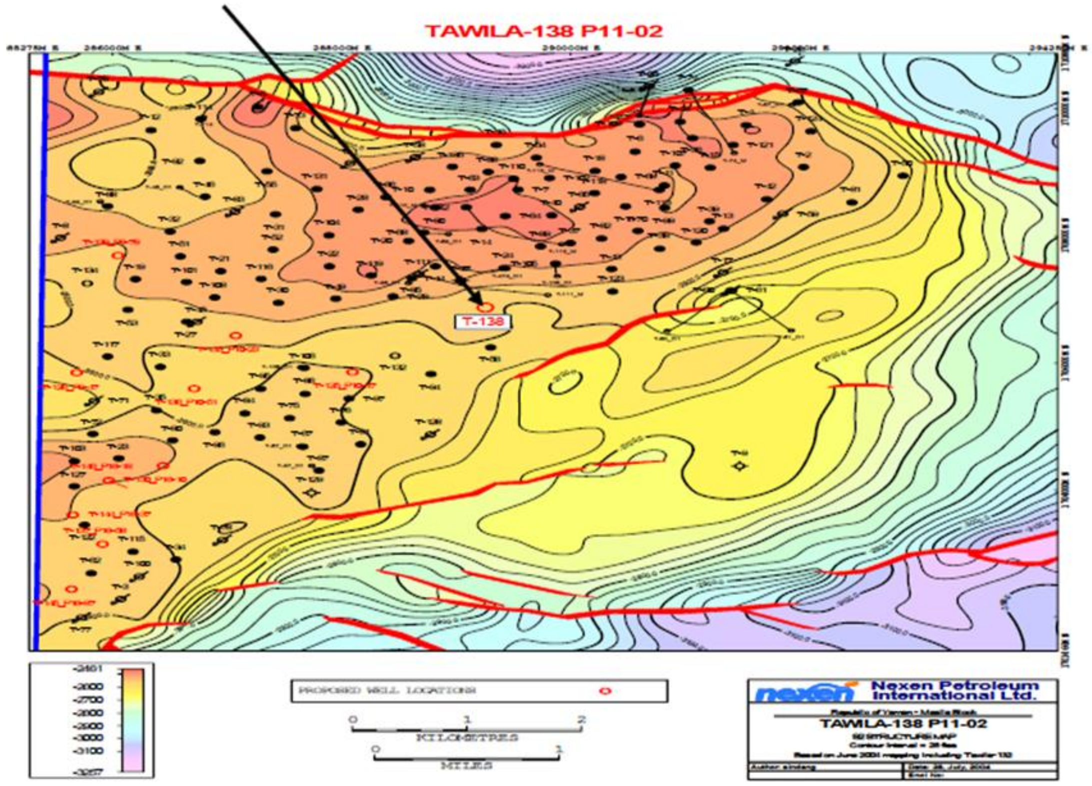


Figure 24 Location Map of Well 138 in Tawilah Field

2.5.5.3. Geophysical Surveys

Geophysics is the study of the earth by quantitative physical methods. Geophysical techniques such as seismic surveys, gravity surveys, and magnetic surveys provide a way of measuring the physical properties of a subsurface formation.

2.5.5.4. Structural Contour Maps

Contour maps show a series of lines drawn at regular intervals. The points on each line represent equal values, such as depth or thickness. The contour maps usually used to determine bulk volume for reservoir which help us to determine oil/gas initial in place (STOIIP).

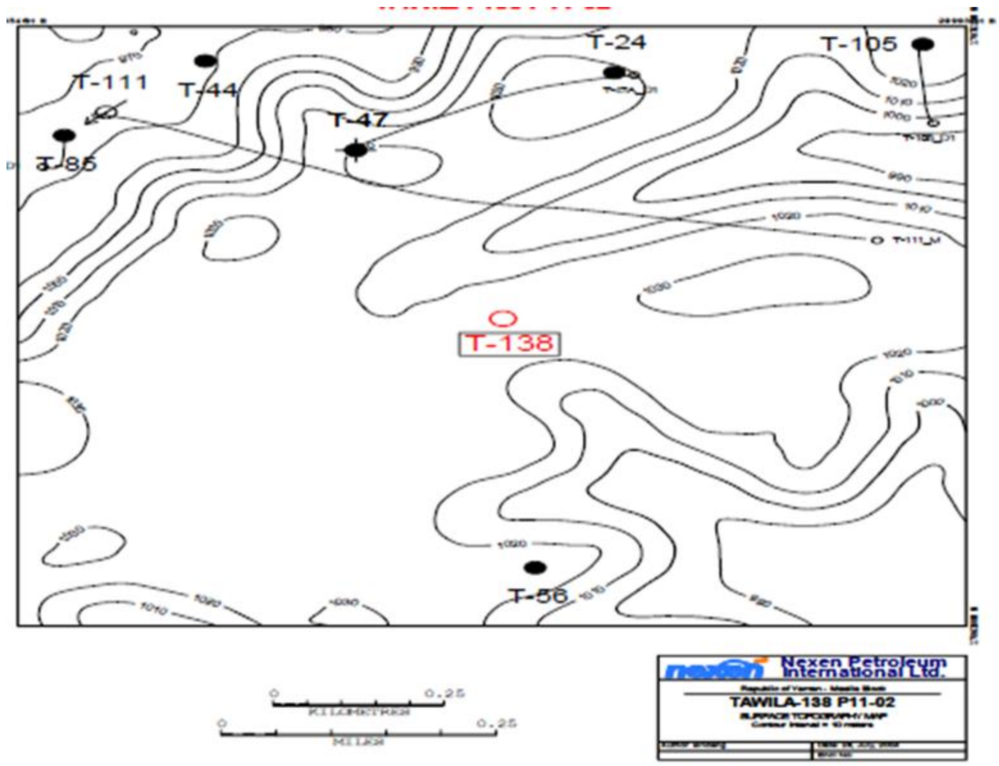


Figure 25 Location Map of Well 138 in Tawilah Field

2.5.6. Net Pay Maps

In a well, considering a single formation, the net-pay to gross-pay ratio (N/G) relates the fraction of the total hydrocarbon interval that is effectively contributing to recov erable hydrocarbon. Therefore, the contours of a net-to-gross ratio map will illustrat e at a glance how clean the formation and how it is distributed.

From well logs, the gross pay section is determined. Then, within this interval (again using logs) zone of shale, low porosity, and high-water saturation are located (using petrophysical cut off values). The thicknesses of these zones are subtracted for gross pay, which leaves net pay. Then, for that well location, the net-to-gross ratio is merel y the net pay divided by the gross pay. Determining reservoir volume from contour maps if we have a homogeneous, isotropic reservoir, then it would be valid to obtain volumetric estimates of the original hydrocarbon in place.

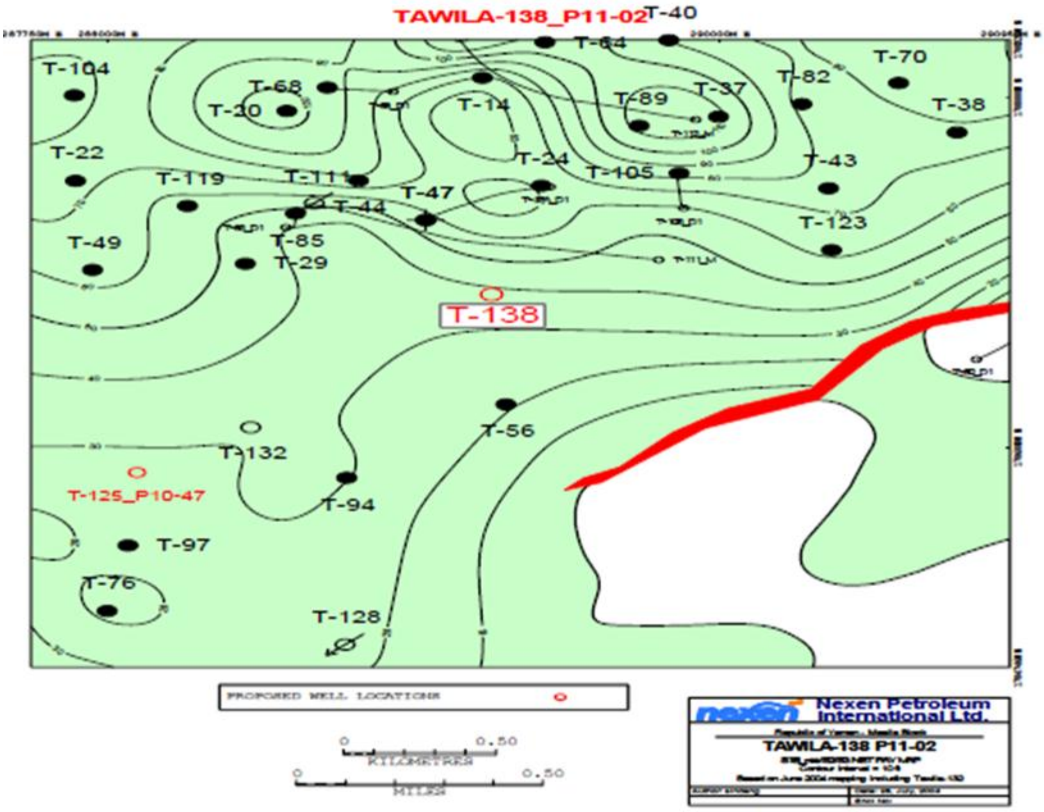


Figure 26 Net Pay Maps map in Well 138 at Tawilah Field

2.6. Drilling Engineering

The only way to know for sure if a trap contains a commercial amount of oil and gas i s to drill through the formation. The well is drilled using a rotary drilling rig. there can be thousands of feet of steel drill pipe with a bit on the end called the drill string sus pend in the well .by rotating the drill string from the surface the bit in the bottom is t urned and cut the hole. An important factor in the drilling process is the drilling mud, drilling mud is usually made of clay and fluid, is pumped down the inside of the drill pipe where it jets out of nozzles on the bit and return up the outside of the drill pipe to the surface. The drilling mud remove the rock chips made by the bit, called format ion cutting from the bottom of the hole and prevents them from clogging up the bott om of the well. The pressure of the drilling mud prevents any fluid from flowing out of the subsurface rock and into the well. (Norman J.HYNE,PH.D, 2012). It is generally not possible to drill a well through all of the formations from surface or the seabed t o the target depth in one-hole section. The well is therefore drilled in sections, with each section of the well being sealed off by lining the inside of the borehole with ste el pipe, known as casing**.** This casing strings made up of joints of pipe, of approximat ely 40ft in length, with threaded connections. Depending on the conditions encounte red, 3 or 4 casing strings may be required to reach the target depth. Wet cement is t hen pumped between the casing and the well walls to allow the casing to set in place . Cement is used primarily as an impermeable seal material in oil and gas well drilling . It is most widely used as a seal between casing and the borehole, bonding the casin g to the formation and providing a barrier to the flow of fluids from, or into, the form ations behind the casing and from, and into, the subsequent hole section.

2.6.1. Drilling Bit

A drilling bit is the cutting or boring tool which is made up on the end of the Drill stri ng. The bit drills through the rock by scraping, chipping, gouging or grinding the rock at the bottom of the hole. There are however many variations in the design of drill bi ts and the bit selected for a particular application will depend on the type of formati on to be drilled.

There are basically three types of drilling bit:

1. Drag Bits
2. Roller Cone Bits
3. Diamond Bits

2.6.1.1. Drag Bits

Drag bits were the first bits used in rotary drilling, but are no longer in common use. A drag bit consists of rigid steel blades shaped like a fish-tail which rotate as a single unit. These simple designs were used up to 1900 to successfully drill through soft for mations.

2.6.1.2. Roller Cone Bits

Roller cone bits (or rock bits) are still the most common type of bit used worldwide. The cutting action is provided by cones which have either steel teeth or tungsten car bide inserts. These cones rotate on the bottom of the hole and drill hole predominan tly with a grinding and chipping action. Rock bits are classified as milled tooth bits or insert bits depending on the cutting surface on the cones.

2.6.1.3. Diamond Bits

Diamond has been used as a material for cutting rock for many years. Since it was fir st used however, the type of diamond and the way in which it is set in the drill bit ha ve changed. The major disadvantage of diamond bits is their cost (sometimes 10 tim es more expensive than a similar sized rock bit). They are however cost effective whe n drilling formations where long rotating hours (200-300 hours per bit) are required. There are three types of Diamond Bits:

1) Natural Diamond Bits.
2) Polycrystalline Diamond Compact (PDC) Bits.
3) Thermally Stable Polycrystalline (TSP) Bits.

2.6.2. Drilling Fluid

Drilling fluid or drilling mud is a critical component in the rotary drilling process. Its p rimary functions are to remove the drilled cuttings from the borehole whilst drilling a nd to prevent fluids from flowing from the formations being drilled, into the borehol e. The drilling fluid must be selected and or designed so that the physical and chemic al properties of the fluid allow these functions to be fulfilled. However, when selecti ng the fluid, consideration must also be given to:

- The environmental impact of using the fluid
- The cost of the fluid
- The impact of the fluid on production from the pay zone

2.6.2.1. Functions and Properties of Drilling Fluid

The primary functions of a drilling fluid are:

- Remove cuttings from the Wellbore
- Prevent Formation Fluids Flowing into the We
- Maintain Wellbore Stability
- Cool and Lubricate the Bit
- Transmit Hydraulic Horsepower to Bit

The main functions of drilling fluid and the properties which are associated with fulfil ling these functions are summarized in Table 2.5.

Table 21 The main functions of drilling fluid

Function	Physical/Chemical Property
Transport cuttings from the Wellbore	Yield Point, Apparent Viscosity, velocity, gel strength
Prevent Formation Fluids Flowing into the well bore	Density
Maintain Wellbore Stability	Density, Reactivity with Clay
Cool and Lubricate the Bit	Density, velocity
Transmit Hydraulic Horsepower to Bit	Velocity, Density, Viscosity

- Type of Drilling Fluid

A drilling fluid can be classified by the nature of its continuous fluid phase.

There are three types of drilling fluid:

1. Water Based Mud
2. Oil Based Mud
3. Gas Based Mud

The two most common types of drilling fluid used are water-based mud and oil-base d mud.

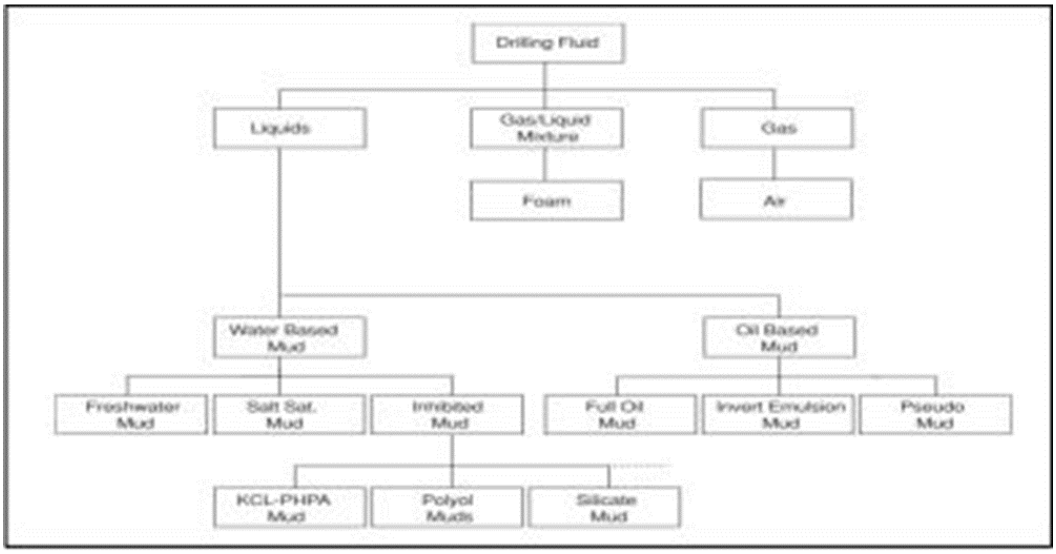


Figure 27 Type of Drilling Fluid

2.7. Well logging

Well logging, also known as borehole logging is the practice of making a detailed record (a well log) of the geologic formations penetrated by a borehole. The log may be based either on visual inspection of samples brought to the surface (geological logs) or on physical measurements made by instruments lowered into the hole (geophysical logs). Some types of geophysical well logs can be done during any phase of a well's history: drilling, completing, producing, or abandoning. Well logging is performed in boreholes drilled for the oil and gas, groundwater, mineral and geothermal exploration, as well as part of environmental and geotechnical studies.**[1]**

2.7.1. Wireline logging

The oil and gas industry use wireline logging to obtain a continuous record of a formation's rock properties. Wireline logging can be defined as being "The acquisition and analysis of geophysical data performed as a function of well bore depth, together with the provision of related services." Note that "wireline logging" and "mud logging" are not the same, yet are closely linked through the integration of the data sets. The measurements are made referenced to "TAH" - True Along Hole depth: these and the associated analysis can then be used to infer further properties, such as hydrocarbon saturation and formation pressure, and to make further drilling and production decisions.

Wireline logging is performed by lowering a 'logging tool' - or a string of one or more instruments - on the end of a wireline into an oil well (or borehole) and recording petrophysical properties using a variety of sensors. Logging tools developed over the years measure the natural gamma ray, electrical, acoustic, stimulated radioactive responses, electromagnetic, nuclear magnetic resonance, pressure and other properties of the rocks and their contained fluids. For this article, they are broadly broken down by the main property that they respond to.

The data itself is recorded either at surface (real-time mode), or in the hole (memory mode) to an electronic data format and then either a printed record or electronic presentation called a "well log" is provided to the client, along with an electronic copy of the raw data. Well logging operations can either be performed during the drilling process (see Logging While Drilling), to provide real-time information about the form ations being penetrated by the borehole, or once the well has reached Total Depth a nd the whole depth of the borehole can be logged.

Real-time data is recorded directly against measured cable depth. Memory data is re corded against time, and then depth data is simultaneously measured against time. T he two data sets are then merged using the common time base to create an instrum ent response versus depth log. Memory recorded depth can also be corrected in exa ctly the same way as real-time corrections are made, so there should be no differenc e in the attainable TAH accuracy.

The measured cable depth can be derived from a number of different measurements , but is usually either recorded based on a calibrated wheel counter, or (more accura tely) using magnetic marks which provide calibrated increments of cable length. The measurements made must then be corrected for elastic stretch and temperature.

There are many types of wireline logs and they can be categorized either by their fun ction or by the technology that they use. "Open hole logs" are run before the oil or g as well is lined with pipe or cased. "Cased hole logs" are run after the well is lined wit h casing or production pipe.

Wireline logs can be divided into broad categories based on the physical properties measured.

2.8. Completion (oil and gas wells)

Well completion is the process of making a well ready for production (or injection) af ter drilling operations. This principally involves preparing the bottom of the hole to t he required specifications, running in the production tubing and its associated down hole tools as well as perforating and stimulating as required. Sometimes, the process of running in and cementing the casing is also included. After a well has been drilled, should the drilling fluids be removed, the well would eventually close in upon itself. Casing ensures that this will not happen while also protecting the well stream from o utside incumbents, like water or sand.

2.8.1. Lower completion (Downhole Completion)

This refers to the portion of the well across the production or injection zone. The wel l designer has many tools and options available to design the lower completion accor ding to the conditions of the reservoir. Typically, the lower completion is set across t he productive zone using a liner hanger system, which anchors the lower completion to the production casing string. The broad categories of lower completion are listed below.

2.8.2. Barefoot completion

This type is the most basic, but can be a good choice for hard rock, multi-laterals and underbalance drilling. It involves leaving the productive reservoir section without an y tubulars. This effectively removes control of flow of fluids from the formation; it is not suitable for weaker formations which might require sand control, nor for formati ons requiring selective isolation of oil, gas and water intervals. However, advances in interventions such as coiled tubing and tractors means that barefoot wells can be su ccessfully produced.

2.8.3. Open Hole

The production casing is set above the zone of interest before drilling the zone. The z one is open to the well bore. In this case little expense is generated with perforations log interpretation is not critical. The well can be deepened easily and it is easily conv erted to screen and liner. However, excessive gas and water production is difficult to control, and may require frequent clean outs. Also, the interval cannot be selectively stimulated.

2.8.4. Open hole completion

This designation refers to a range of completions where no casing or liner is cemente d in place across the production zone. In competent formations, the zone might be le ft entirely bare, but some sort of sand-control and/or flow-control means are usually incorporated.

Open hole completions have seen significant uptake in recent years, and there are m any configurations, often developed to address specific reservoir challenges. There h ave been many recent developments that have boosted the success of openhole co mpletions, and they also tend to be popular in horizontal wells, where cemented inst allations are more expensive and technically more difficult. The common options for openhole completions are:

2.8.4.1. Pre-holed liner

Also often called pre-drilled liner. The liner is prepared with multiple small drilled hol es, then set across the production zone to provide wellbore stability and an intervent ion conduit. Pre-holed liner is often combined with open hole packers, such as swelli ng elastomers, mechanical packers or external casing packers, to provide zonal segre gation and isolation. It is now quite common to see a combination of pre-holed liner, solid liner and swelling *winky* elastomer packers to provide an initial isolation of u nwanted water or gas zones. Multiple sliding sleeves can also be used in conjunction with open hole packers to provide considerable flexibility in zonal flow control for th e life of the wellbore.[2]

This type of completion is also being adopted in some water injection wells, although these require a much greater performance envelope for openhole packers, due to th e considerable pressure and temperature changes that occur in water injectors.

Open hole completions (in comparison with cemented pipe) require better understa nding of formation damage, wellbore clean-up and fluid loss control. A key differenc e is that perforating penetrates through the first 6-18 inches (15–45 cm) of formatio n around the wellbore, whilst open hole completions require the reservoir fluids to fl ow through all of the filtrate-invaded zone around the wellbore and lift-off of the mu d filter cake.

Many open hole completions will incorporate fluid loss valves at the top of the liner t o provide well control whilst the upper completion is run.

There are an increasing number of ideas coming into the market place to extend the options for open hole completions; for example, electronics can be used to actuate a self-opening or self-closing liner valve. This might be used in an open hole completio n to improve clean-up, by bringing the well onto production from the toe-end for 10

0 days, then self-opening the heel-end. Inflow control devices and intelligent comple tions are also installed as open hole completions.

Pre-holed liner may provide some basic control of solids production, where the wellb ore is thought to fail in aggregated chunks of rubble, but it is not typically regarded a s a sand control completion.

2.8.4.2. Slotted liner

Slotted liners can be selected as an alternative to pre-holed liner, sometimes as a per sonal preference or from established practice on a field. It can also be selected to pr ovide a low-cost control of sand/solids production. The slotted liner is machined with multiple longitudinal slots, for example 2 mm x 50mm, spread across the length and circumference of each joint. Recent advances in laser cutting means that slotting can now be done much cheaper to much smaller slot widths and, in some situation, slott ed liner is now used for the same functionality as sand control screens.

2.8.4.3. Open hole sand control

This is selected where the liner is required to mechanically hold back the movement of formation sand. There are many variants of open hole sand control, the three pop ular choices being stand-alone screens, open hole gravel packs (also known as extern al gravel packs, where a sized sand 'gravel' is placed as an annulus around the sand c ontrol screen) and expandable screens. Screen designs are mainly wire-wrap or prem ium; wire-wrap screens use spiral-welded corrosion-resistant wire wrapped around a drilled base pipe to provide a consistent small helical gap (such as 0.012-inch (0.30 mm), termed 12 gauge). Premium screens use a woven metal cloth wrapped around a base pipe. Expandable screens are run to depth before being mechanically swaged to a larger diameter. Ideally, expandable screens will be swaged until they contact th e wellbore wall.

2.8.5. Horizontal open hole completions

This is the most common open hole completion used today. It is basically the same d escribed on the vertical open hole completion but on a horizontal well it enlarges sig nificantly the contact with the reservoir, increasing the production or injection rates of your well. Sand control on a horizontal well is completely different from a vertical well. We can no longer rely on the gravity for the gravel placement. Most service co mpanies uses an alpha and beta wave design to cover the total length of the horizont al well with gravel. It's known that very long wells (around 6000 ft) were successfully gravel packed in many occasions, including deepwater reservoirs in Brazil.

2.8.5.1. Liner Completions

In this case the casing is set above the primary zone. An un-cemented screen and lin er assembly is installed across the pay section. This technique minimizes formation d amage and gives the ability to control sand. It also makes cleanout easy. Perforating expense is also low to non-existent. However, gas and water build up is difficult to co ntrol and selective stimulation not possible the well can't be easily deepened and ad ditional rig time may be needed.

2.8.5.2. Perforated Liner

Casing is set above the producing zone; the zone is drilled and the liner casing is cem ented in place. The liner is then perforated for production. This time additional expe nse in perforating the casing is incurred, also log interpretation is critical and it may b e difficult to obtain good quality cement jobs.

2.8.5.3. Perforated Casing

Production casing is cemented through the zone and the pay section is selectively pe rforated. Gas and water are easily controlled as is sand. The formation can be selecti vely stimulated and the well can be deepened. This selection is adaptable to other co mpletion configurations and logs are available to assist casing decisions. Much better primary casing. It can however cause damage to zones and needs good log interpret ation. The perforating cost can be very high.**[3]**

2.8.5.4. Cased hole completion

This involves running casing or a liner down through the production zone, and cemen ting it in place. Connection between the well bore and the formation is made by perf orating. Because perforation intervals can be precisely positioned, this type of compl etion affords good control of fluid flow, although it relies on the quality of the cemen t to prevent fluid flow behind the liner. As such it is the most common form of compl etion...

2.8.6. Conventional completions

- Casing flow: means that the producing fluid flow has only one path to the surface through the casing.
- Casing and tubing flow: mean that there is tubing within the casing that allows fluid to reach the surface. This tubing can be used as a kill string for chemical injection. The tubing may have a "no-go" nipple at the end as a means of pressure testing.
- Pumping flow: the tubing and pump are run to a depth beneath the working fluid. The pump and rod string are installed concentrically within the tubing. A tubing anchor prevents tubing movement while pumping.
- Tubing flow: a tubing string and a production packer are installed. The packer means that all the flow goes through the tubing. Within the tubing you can mount a combination of tools that will help to control fluid flow through the tubing.
- Gas lift well: gas is fed into valves installed in mandrels in the tubing strip. The hydrostatic head is lowered and the fluid is gas lifted to the surface.
- Single-well alternate completions: in this instance there is a well with two zones. In order to produce from both the zones are isolated with packers. Blast joints may be used on the tubing within the region of the perforations. These are thick walled subs that can withstand the fluid abrasion from the producing zone. This arrangement can also work if you have to produce from a higher zone given the depletion of a lower zone. The tubing may also have flow control mechanism.
- Single-well concentric kill string: within the well a small diameter concentric kill string is used to circulate kill fluids when needed.
- Single-well 2-tubing completion: in this instance 2 tubing strings are inserted down 1 well. They are connected at the lower end by a circulating head. Chemicals can be circulated down one tube and production can continue up the other.

2.8.7. Completion components

The upper completion refers to all components from the bottom of the production t ubing upwards. Proper design of this "completion string" is essential to ensure the w ell can flow properly given the reservoir conditions and to permit any operations as a re deemed necessary for enhancing production and safety.[4]

2.8.8. Wellhead with situation control

Main article: Wellhead.

This is the pressure containing equipment at the surface of the well where casing stri ngs are suspended and the blowout preventer or Christmas tree is connected.

2.8.8.1. Christmas Tree

Main article: Christmas tree (oil well)

This is the main assembly of valves that controls flow from the well to the process pl ant (or the other way around for injection wells) and allows access for chemical sque ezes [clarification needed (definition)] and well interventions.

2.8.8.2. Tubing hanger

Main article: Tubing hanger

This is the component, which sits on top of the wellhead and serves as the main supp ort for the production tubing. [2]

2.8.8.3. Production tubing

Main article: Production tubing

Production tubing is the main conduit for transporting hydrocarbons from the reserv oir to surface (or injection material the other way). It runs from the tubing hanger at the top of the wellhead down to a point generally just above the top of the producti on zone.

2.8.9. Downhole safety valve (DHSV)

Main article: Downhole safety valve

This component is intended as a last-resort method of protecting the surface from the uncontrolled release of hydrocarbons. It is a cylindrical valve with either a ball or flapper closing mechanism. It is installed in the production tubing and is held in the open position by a high-pressure hydraulic line from surface contained in a 6.35 mm (1/4") control line that is attached to the DHSV's hydraulic chamber and terminated at surface to a hydraulic actuator. The high pressure is needed to overcome the production pressure in the tubing upstream of the choke on the tree. The valve will operate if the umbilical HP line is cut or the wellhead/tree is destroyed.

This valve allows fluids to pass up or be pumped down the production tubing. When closed the DHSV forms a barrier in the direction of hydrocarbon flow, but fluids can still be pumped down for well kill operations. It is placed as far below the surface as is deemed safe from any possible surface disturbance including cratering caused by the wipeout of the platform. Where hydrates are likely to form (most production is at risk of this), the depth of the SCSSV (surface-controlled, sub-surface safety valve) below the seabed may be as much as 1 km: this will allow for the geothermal temperature to be high enough to prevent hydrates from blocking the valve.[5]

2.8.9.1. Annular safety valve

On wells with gas lift capability, many operators consider it prudent to install a valve, which will isolate the A annulus for the same reasons a DHSV may be needed to isolate the production tubing in order to prevent the inventory of natural gas downhole from becoming a hazard as it became on Piper Alpha.

2.8.9.2. Side pocket mandrel

This is a welded/machined product which contains a "side pocket" alongside the main tubular conduit. The side pocket, typically 1" or 1½" diameter is designed to contain gas lift valve, which allows flow of High-pressure gas into the tubing there by reducing the tubing pressure and allowing the hydrocarbons to move upwards.

2.8.9.3. Electrical submersible pump

Main article: Submersible pump

This device is used for artificial lift to help provide energy to drive hydrocarbons to su rface if reservoir pressure is insufficient.

2.8.9.4. Landing nipple

A completion component fabricated as a short section of heavy wall tubular with a m achined internal surface that provides a seal area and a locking profile. Landing nippl es are included in most completions at predetermined intervals to enable the installa tion of flow-control devices, such as plugs and chokes. Three basic types of landing ni pple are commonly used: no-go nipples, selective-landing nipples and ported or safet y-valve nipples.

2.8.9.5. Sliding sleeve

Main article: Sliding sleeve

The sliding sleeve is hydraulically or mechanically actuated to allow communication b etween the tubing and the 'A' annulus. They are often used in multiple reservoir well s to regulate flow to and from the zones.

2.8.9.6. Production packer

Main article: Production packer

The packer isolates the annulus between the tubing and the inner casing and the foo t of the well. This is to stop reservoir fluids from flowing up the full length of the casi ng and damaging it. It is generally placed close to the foot of the tubing, shortly abov e the production zone.

2.8.9.7. Downhole gauges

This is an electronic or fiberoptic sensor to provide continuous monitoring of downh ole pressure and temperature. Gauges either use a 1/4" control line clamped onto th e outside of the tubing string to provide an electrical or fiberoptic communication to surface, or transmit measured data to surface by acoustic signal in the tubing wall. T he information obtained from these monitoring devices can be used to model reserv oirs or predict the life or problems in a specific wellbore.

2.8.9.8. Perforated joint

This is a length of tubing with holes punched into it. If used, it will normally be positi oned below the packer and will offer an alternative entry path for reservoir fluids int o the tubing in case the shoe becomes blocked, for example, by a stuck perforation g un.

2.8.9.9. Formation isolation valve

This component, placed towards the foot of the completion string, is used to provide two-way isolation from the formation for completion operations without the need f or kill weight fluids. Their use is sporadic as they do not enjoy the best reputation for reliability when it comes to opening them at the end of the completion process.

2.8.9.10. Centralizer

In highly deviated wells, this component may be included towards the foot of the co mpletion. It consists of a large collar, which keeps the completion string centralised within the hole while cementing.

2.8.9.11. Wireline entry guide

This component is often installed at the end of the tubing, or "the shoe". It is intende d to make pulling out wireline tools easier by offering a guiding surface for the tool st ring to re-enter the tubing without getting caught on the side of the shoe.

2.8.10. Perforating and stimulating

In cased hole completions (the majority of wells), once the completion string is in pla ce, the final stage is to make a connection between the wellbore and the formation. This is done by running perforation guns to blast holes in the casing or liner to make a connection. Modern perforations are made using shaped explosive charges, similar to the armor-penetrating charge used on antitank rockets (bazookas).

Sometimes once the well is fully completed, further stimulation is necessary to achie ve the planned productivity. There are a number of stimulation techniques.

2.8.11. Acidizing

This involves the injection of chemicals to eat away at any skin damage, "cleaning up " the formation, thereby improving the flow of reservoir fluids. A strong acid (usually hydrochloric acid) is used to dissolve rock formations, but this acid does not react wit h the Hydrocarbons. As a result, the Hydrocarbons are more accessible. Acid can also be used to clean the wellbore of some scales that form from mineral laden produce d water.

2.8.12. Fracturing:

This means creating and extending fractures from the perforation tunnels deeper int o the formation, increasing the surface area for formation fluids to flow into the well , as well as extending past any possible damage near the wellbore. This may be done by injecting fluids at high pressure (hydraulic fracturing), injecting fluids laced with ro und granular material (proppant fracturing), or using explosives to generate a high pr essure and high speed gas flow (TNT or PETN up to 1,900,000 psi (13,000,000 kPa)) a nd (propellant stimulation up to 4,000 psi (28,000 kPa)).

Acidizing and fracturing (combined method)

This involves use of explosives and injection of chemicals to increase acid-rock contact.

Nitrogen circulation

Sometimes, productivity may be hampered due to the residue of completion fluids, h eavy brines, in the wellbore. This is particularly a problem in gas wells. In these cases , coiled tubing may be used to pump nitrogen at high pressure into the bottom of the borehole to circulate out the brine.**[6]**

2.9. Production

The petroleum production is definitely the heart of the petroleum industry. Petroleu m production engineering is that part of petroleum engineering that attempts to ma ximize oil and gas production in a cost-effective manner. To achieve this objective, pr oduction engineers need to have a thorough understanding of the petroleum produc tion systems with which they work. To perform their job correctly, production engine ers should have solid background and sound knowledge about the properties of fluid s they produce and working principles of all the major components of producing well s and surface facilities.[5]

2.9.1. Petroleum Production System

A complete oil or gas production system consists of a reservoir, well, flowline, separa tors, pumps, and transportation pipelines. The reservoir supplies wellbore with crud e oil or gas. The well provides a path for the production fluid to flow from bottom ho le to surface and offers a means to control the fluid production rate. The flowline lea ds the produced fluid to separators. The separators remove gas and water from the c rude oil.[7]

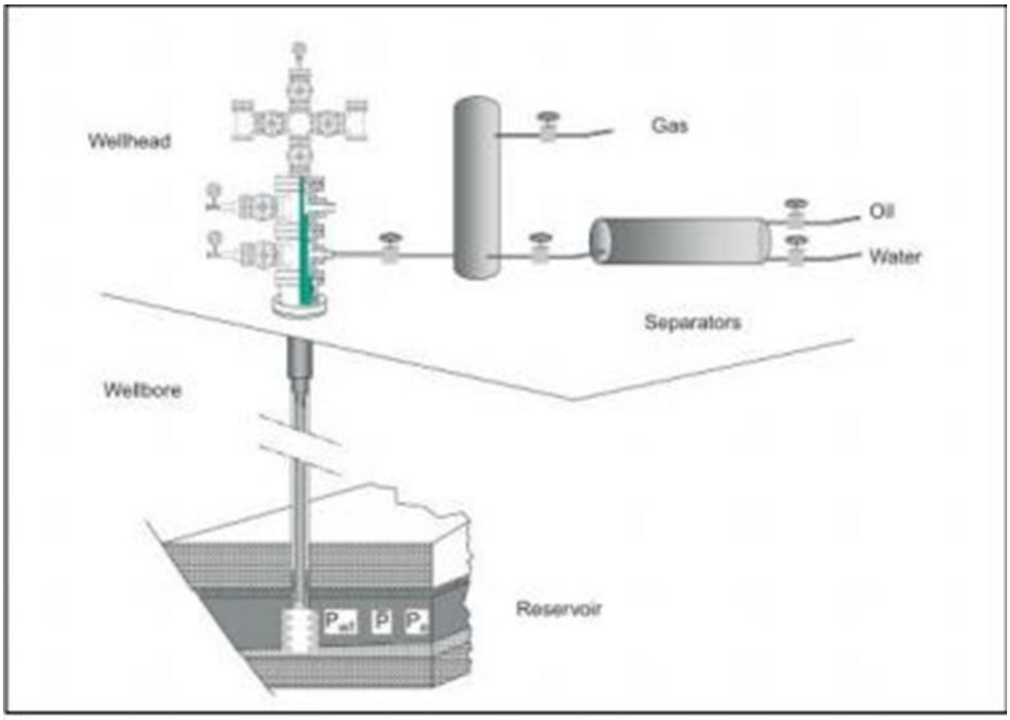


Figure 28 Sketch Of A Petroleum Production System

2.10. Artificial Lift Systems Overview Artificial Lift Systems

Making artificial lift decisions is primarily a process of choosing the lift method most applicable to expected surface, reservoir, fluid and operational conditions

2.10.1. Gas Lift

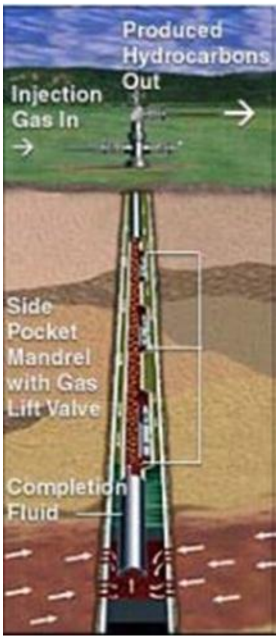
Gas Lift uses high pressure gas to reduce the density of the produced fluids, hereby l owering the hydrostatic load on the formation

Advantage

- Takes full advantage of the energy available in the reservoir
- Flexibility - can handle rates from 10 to 80000 bpd
- Valves may be retrieved by slickline or tubing
- Handle abrasives and sand

Disadvantage

- Must has a gas source
- Freezing and hydrates are problematic
- Difficulty depleting low productivity and low-pressure wells completely.



2.10.2. Reciprocating Displacement Rod Pumps

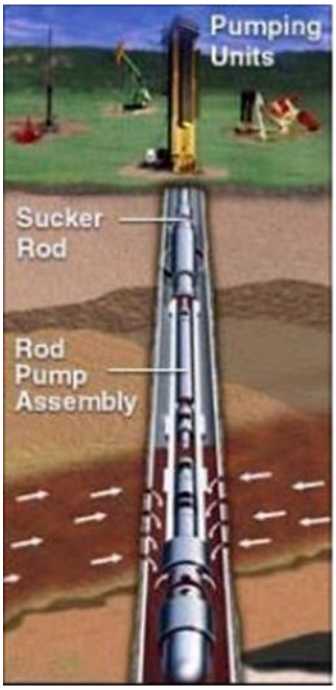
Rod Pumps combine a cylinder (barrel) and piston (plunger) with valves to transfer well fluids into the tubing and displace to the surface.

Advantage

- Most widely used lift method
- Simple application
- Low intervention cost
- Economic value less than 1,000 BPD

Disadvantage

- Restricted flow rates
- Potential wellhead leaks or spills
- Problems with deep producing intervals
- Restrictions in deviated wells



2.10.3. Progressing Cavity Displacement Pumps

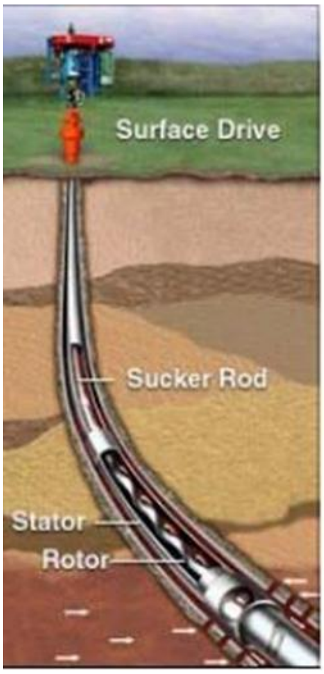
Progressing cavity pumps are based on rotary fluid displacement. This spiral system consists of a rotor turning inside a stationary stator.

Advantage

- Flexible application methods
- Reliable when properly applied
- Resistant to abrasives and solids
- Efficient power usage

Disadvantage

- Restricted setting depths
- Not compatible with some chemicals
- Limited operating temperatures Restricted flow rates



2.10.4. Hydraulic-lift Pumping Systems

Hydraulic systems transfer energy down hole by pressurizing a special power fluid, us ually a light refined or produced oil, that flows through well tubing to a subsurface p ump, which transmits the potential energy to produced fluids.[8]

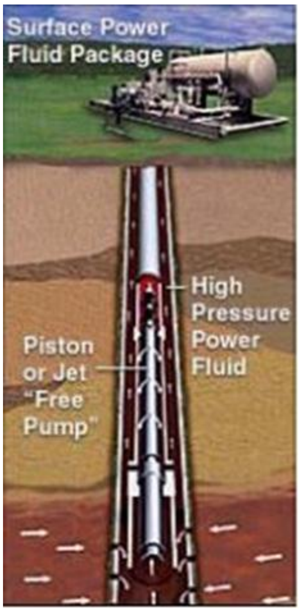
Advantage

- High volumes can be produced from great depths
- Pumps can be changed (circulated out) without pulling the tubing
- Heavy and viscous fluids are easier to produce after mixing with lighter power

fluids

Disadvantage

- Vulnerable to solids
- Least efficient lift method
- Well testing can be difficult due to power fluid included in the production stream.



2.10.5. Electric Submersible Centrifugal Pump (ESP)

Electric submersible systems use multiple pump stages, mated to a submersible elect ric motor on the end of tubing and connected to surface controls and electric power by an armor protected cable.[9]

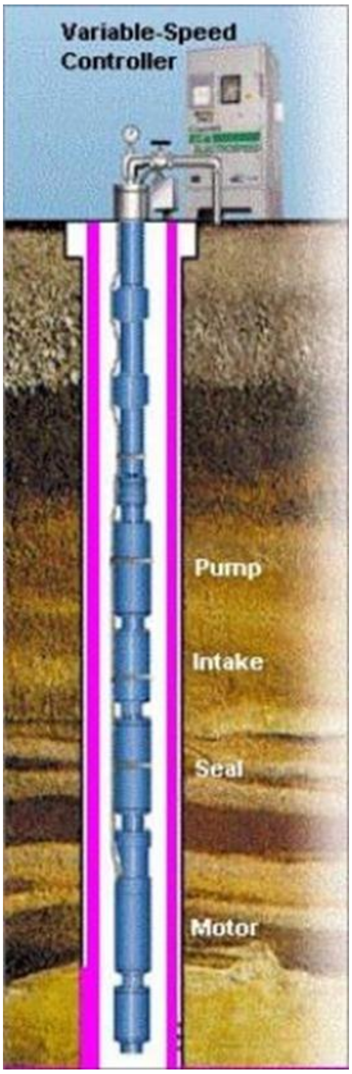
About 15 to 20 percent of almost one million wells worldwide are pumped with som e form of artificial lift employing electric submersible pumps. In addition, ESP system s are the fastest growing form of artificial lift pumping technology. They are often co nsidered high volume and depth champions among oil field lift systems.

Advantage

- Wide performance range and versatility
- Can operate in high angle and horizontal wells
- Most efficient and economical lift method on a cost-per-barrel basis

Disadvantage

- Tubing must be pulled to change or repair the pump
- Depth and GOR restrict capacity and operating efficiency
- Large volumes of gas can lock up the pump



CHAPTER THREE

3. METHODOLOGY

3.1. Introduction

This chapter discusses the methodology of using the analytical analysis methods to a chieve the objective of the research focusing on (Sand and Brocken shaft Failure of E SP). Also, it will explain the type of data that will be used to further studying the dev elopment and analysis of the project.

3.2. Type of Data

The research is mainly based on the following data:

1. Reservoir data
2. Production data
3. Geological data
4. Workover Report

Table 31 Data Type and Collection:

Reservoir Data	Production Data	Workover Report	Geological Data
Fluid type PVT	Flow rate	General Data	Formation tops
GOR Compressibility	Water- cut	Pump setting dept h	
Density Viscosity API	Pump intake press ure	ESP Diagrams	Deviation survey

These data will be obtained from available data that have been taken from Data Ban k of Block_ 43 Nabrajah, wells number (1-12-14-16-17).

3.3. Analysis Approach

The analytical method will be the main approach, which will be used to analyze and i nterpret the related data especially the production, reservoir and Daily work over re port data using petroleum software (Prosper).

3.4. Prosper Workflow

3.4.1. System Summary

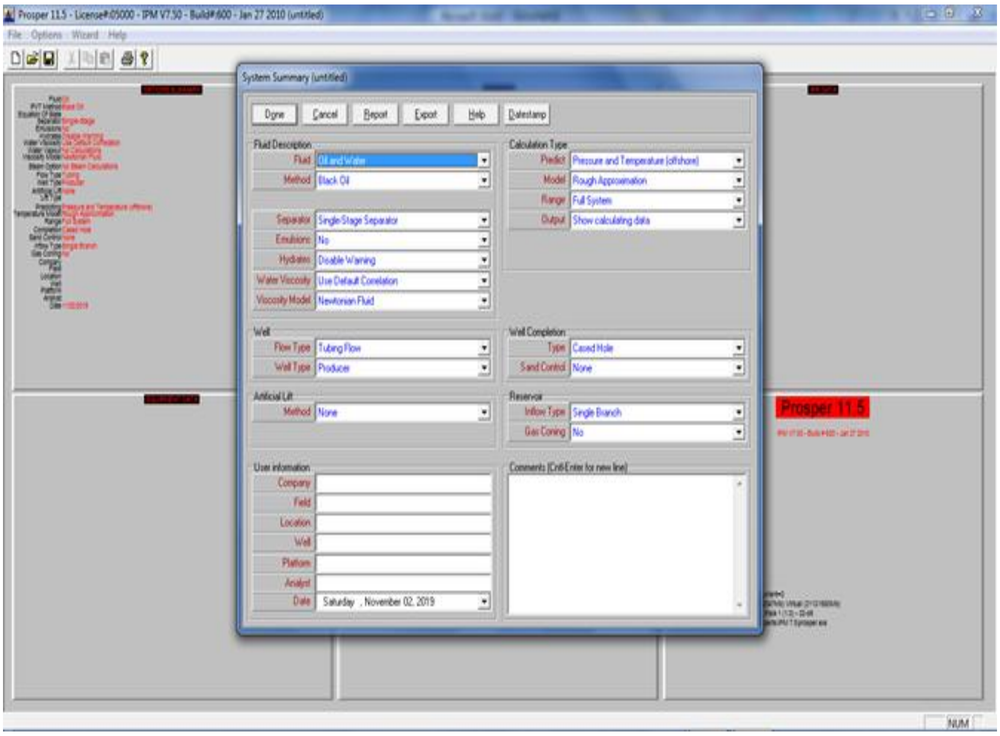


Figure 31 Prosper window - System Summary

- Use this screen in order to describe the type of system that you are attempting to model
- This data can, optionally, be displayed on the main screen if so desired

Table 32 System Summary Data

Fluid Description	• Fluid • Method • Equation of State Model • Separator • Emulsion • Hydrates Formation • Water Viscosity • Water Vapor
Well	• Flow type • Well Type
Artificial Lift	• Method • Type
Calculation Type	• Predict • Model • Range • Output
Well Completion	• Type • Gravel Pack
Reservoir	• Inflow Type • Gas Coning

3.4.2. PVT Data

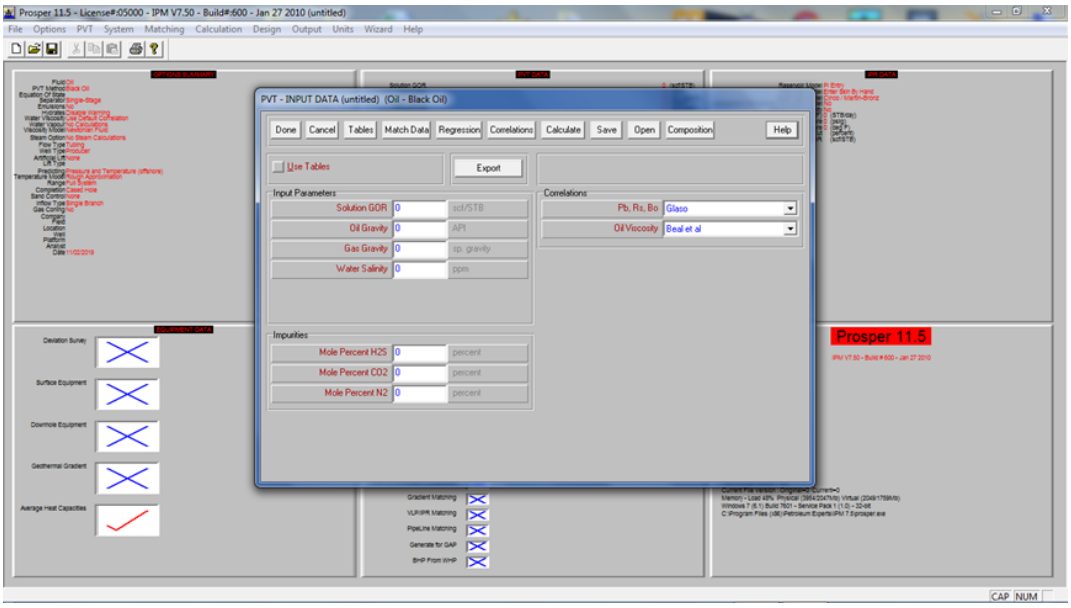


Figure 32 Prosper window - PVT Data

- To predict pressure and temperature changes through the reservoir, up the wellbore and along the surface flow lines it is necessary to accurately predict the fluid properties as both pressure and temperature change.
- The user must enter data that describes the fluid properties or enables the program to calculate them.

3.4.3. Inflow Performance Relation (IPR)

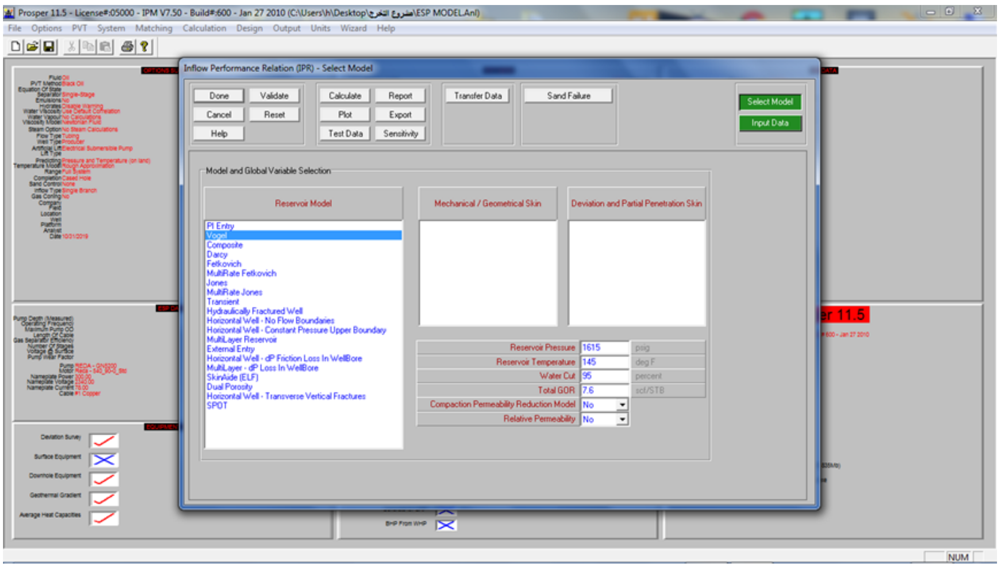


Figure 33 Prosper window – IPR

- About twenty inflow options are available. The choice depends upon the available information and the type of sensitivities that you wish to run. If multi-rate test data is available it can be input so that the modeled inflow matches the actual measured inflow in the well.
- The average reservoir pressure and reservoir temperature must be entered for all inflow performance models, however both the Multi-rate Fetkovich and Multi rate Jones models can be used to calculate the reservoir pressure. For multi-layer reservoirs only, the temperature is entered as reservoir pressure has no meaning.

3.4.4. ESP Design

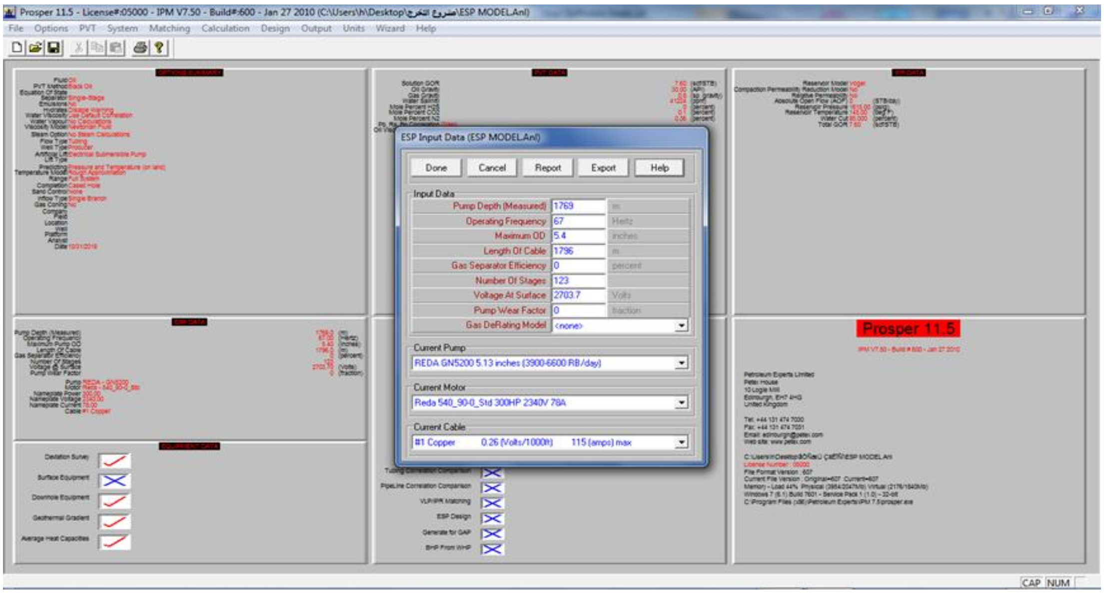


Figure 34 Prosper window - ESP Design

- Designing an ESP installation requires a systems analysis method that is different to that for a naturally flowing well. The ESP solution begins at the sand face, calculating the pressure drop up to the pump intake using standard the PVT and tubing size data at the user-specified production target rate. The ESP Design section allows the user to determine the required pump head to achieve a specified production rate and to select a suitable combination of pump and motor for the application.

3.4.5. Equipment Data

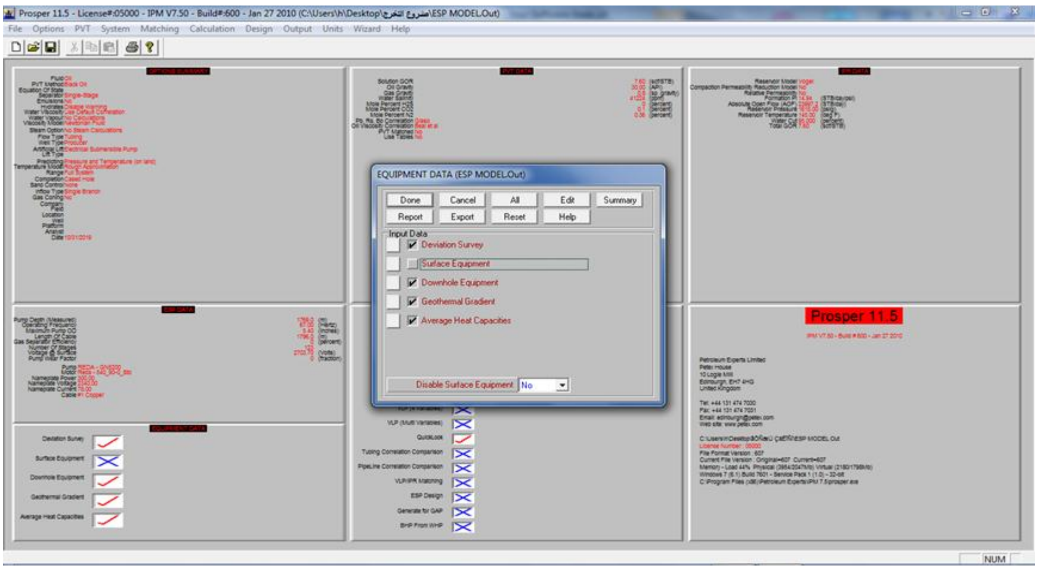


Figure 35 Prosper window - Equipment Data

- In these screens, enter equipment and survey information. The purpose of this option is to enter as much information, both down hole and at surface, for the calculation sections.
- The User select the categories individually by clicking on the item name, or in the box to the left of the item. To enter a section immediately, click the button at the left-hand end of choice. If this is the first entry into this screen, click on All. This option will enable all categories and the relevant screens will appear automatically when pressing the Edit button. Enter the data concerning the equipment and fill in the required parameters.

3.5. Expected Outcomes

The main expected outcomes of using such methodology is to Enhance ESP run life t hat used in Nabrajah field. The design will be based on the results of analyzing and Id entifying of:

- **Causes of ESP problems at Nabrajah field.**
- **Mechanical causes:**

Sand Production: Sand production was the cause of most problems in the field and in the ESP components.

- ❖ Nearly of failures occur in the Gas Separator Shaft due to the presence of sand which causes shaft broken, shaft twisted or shaft radial wear.
- ❖ Gas separator housing also affected by sand in the form of wide holes due to high erosion.
- ❖ Sand particles can also cause sever pump damage and pump stages heavy down thrust wear.

- **Electrical Causes**

- ❖ Electrical failures also take place in Nabrajah field which represent they occur in the four of phase to ground short or phase to phase imbalance or motor overload. Shorts occur due to the lower resistance and the ability of the current to pass through the well as a result of insulation damage or deterioration.
- ❖ Motor overload causes ESP tripping, this happens when the ampere is maximum than the MAL.

- **The best ESP environment to reduce the occurs of the problems.**
- **Running ESP Assembly**

❖ Ensure that the motor shaft is rotated to confirm that it rotates freely.

❖ The cable reel should be placed 20-30 meters away from the rig and in visual sight of the driller.

❖ It is very important that the cable is run straight up the tubing. Rotation of the tubing must not be allowed while running the pump.

❖ The recommended running and pulling speed for the ESP is 1000 ft/hr (or 35 joints per hour).

- **Start-up Procedure for New Wells**

This procedure is to be followed for the start-up of new wells. The purpose o f this procedure is to maximize and increase the ESP reliability and run life by minimizing pump failures due to sand slugging. By following this procedure, t he risk of sand exceeding a critical rate is greatly reduced.

1. Line up all valves from the wellhead to the production manifold.
2. Ensure that the sand detector, if installed, is hooked up and working.
3. Confirm VSC settings, with ‘VSC Parameter Sheet’, attached to controller.
4. Reduce Variable Speed Controller (VSC) under-load setting to 0 Amps.
5. Set VSC start frequency to 45Hz.
6. Allow stable pump operation for a minimum of 30 minutes.
7. Increase frequency by 2 Hz over a period every 60 minutes until achieving target running frequency. Target frequency is 60 hertz.
8. Set VSC under load to 80% of stable operating current.

CHAPTER FOUR

4. ANALYSIS AND DISCUSSION

4.1. Introduction

During its long history, the ESP system proved to be an efficient means of producing liquid from oil and water wells. Where the ESP unit is run on the tubing string and is submerged in well fluids. The electric submersible motor is at the bottom of the unit and is cooled by the well stream passing by its perimeter. It is connected to the protector section that provides many crucial functions for the safe operation of the unit. On top of the protector a pump intake or gas separator is situated which allows well fluids to enter the centrifugal pump and, at the same time, can remove low quantities of free gas from the well stream.

Liquid is lifted to the surface by the multistage centrifugal pump, the heart of the ESP system. The submersible motor is supplied with three-phase AC current via an electric cable running from the surface all along the tubing string. Produced fluids flow thorough the tubing string to the surface, where a special wellhead ensures feeding of the electric cable into the well. Surface equipment includes a junction box where downhole and surface electric cables are joined and a control unit (called “switchboard”) that provides measurement and control functions. The ESP unit receives AC electricity from a set of transformers which supply the required voltage by stepping up or down the voltage available from the surface electric network. The most important features making it a conventional ESP installation are:

Only liquid enters the centrifugal pump providing ideal conditions for the pump. The well must produce only a low amount of free gas at the pump suction that can easily be removed by the gas separator. The viscosity of the produced liquid is low, approaching the viscosity of water. The ESP motor is supplied with an AC current of a constant frequency, thus its speed and consequently that of the centrifugal pump are constant.

Although the above conditions are not always met, the conventional ESP installation can be applied in a great variety of field conditions. This chapter will discuss the components of such conventional installations and also details their main operational fea tures. Unusual conditions (like greater gas production, viscous crude, etc.) require th e use of special equipment.

The general advantages of using ESP units can be summed up as follows:

- Ideally suited to produce high to extremely high liquid volumes from medium depths. Maximum rate is around 30,000 bpd from 1,000 ft.
- Energy efficiency is relatively high (around 50%) for systems producing over 1,000 bpd. Can be used in deviated wells without any problems.
- Requires low maintenance, provided the installation is properly designed and operated. Can be used in urban locations since surface equipment requires minimal space.
- Well suited to the offshore environment because of the low space requirements. Corrosion and scale treatments are relatively easy to perform.

The general disadvantages of ESP are listed below:

- A reliable source of electric power of relatively high voltage must be available.
- Sand or abrasive materials in well fluids increase equipment wear. Special abrasion-resistant materials are available but increase capital costs.
- Repair of ESP equipment in oilfield conditions is difficult, faulty equipment must be sent to the manufacturer's repair shop.

4.2. The Submersible Pump

Pumps used in the petroleum industry for service on the surface or in a well can be cl assified in two broad groups: (a) displacement (or positive displacement) pumps and (b) dynamic pumps. Pumps in sucker-rod pumping or in PCP (progressing cavity pum p) installations belong to the first group, whereas the submersible pumps of ESP inst allations work on the dynamic principle. Within ESP pumps, driven by electric motors , the kinetic energy of the fluid is increased first, to be then partly converted to press ure energy that moves the fluid through the pump. Submersible pumps in ESP servic e operate with their shafts in the vertical position and are centrifugal pumps with the following main features:

- They are multistage pumps with several tens or hundreds of stages connected in series, their impellers are of the closed design, they have a single suction side, they are self-priming, and they have radial or mixed flow configurations.

Operational Basics of Centrifugal Pumps

A single-stage centrifugal pump is a simple machine driven by a prime mover providi ng a rotary motion and consists of two basic components: (a) the rotor, a rotating set of vanes, and (b) the stator, the stationary part containing the casing of the rotor, as well as the bearings and seals required for proper operation. The vanes in ESP pump s are contained in closed impellers, and the stationary part is called a “diffuser.”, dep icts one stage of a common multistage centrifugal pump in ESP service.

Liquid from the previous stage enters the impeller in an axial direction at a relatively low velocity and, due to the high rotation speed of the impeller’s vanes, attains a hig h velocity at the impeller’s discharge. Thus, the torque applied by the prime mover t o the pump is converted to kinetic energy by the vanes. The high-velocity liquid strea m then enters the diffuser (the pump’s stationary part) where conversion of its kinet ic energy to pressure energy takes place. The liquid leaving the pump stage at the dis charge of the diffuser, therefore, is at a higher-pressure level than it was at the inlet to the impeller; the operation of the stage having increased the flowing pressure. Sin ce the discharge of any stage is led to the intake of the next stage, the process repea ts and the pressure of the liquid pumped is accordingly increased. The energy conver sions inside the centrifugal pump described above are governed by the general ener gy equation describing the conservation of energy between two points in a flowing fl uid. This states that the change in the fluid’s energy content is equal to the work don e on the fluid.

The fluid flowing in the pump may have three forms of energy: potential, kinetic and pressure energy; of which the change in the potential energy due to elevation chang e is neglected because of the negligible vertical distances in the pump stage. Thus th e sum of pressure and kinetic energies must be constant and the energy input from t he prime mover is finally converted to an increase of fluid pressure. As discussed pre viously, the liquid’s energy content is increased by the rotary action of the centrifuga l pump’s vanes. Figure 4.2 illustrates the operation of the vanes in an impeller of the radial discharge type. Liquid from the axial intake enters the impeller, is rotated by the vanes contained in the impeller and leaves the impeller with a greatly increased velocity.

The figure shows an impeller with backward curved vanes, mostly used in ESP pumps, but radial and forward curved vanes are also possible. It should be noted that the cross-sectional area available for liquid flow between two successive vanes increases progressively as the liquid particles are moved towards the discharge. This indicates that conversion of kinetic energy to pressure energy first occurs in the impeller, to be completed in the diffuser of the pump stage. The diffuser bore accepts from below the hub of the impeller, and the next upper stage's impeller is fitted in the shirt bore on top. Diffusers are contained within the pump housing and the required number of stages is reached by stacking the right number of diffusers and impellers on top of each other. The pump shaft runs in the bore of the hub and turns the impeller with the help of keys fitted into the key-way of the impeller. In case of floating impellers, the impeller is free to move on the shaft in the axial direction, but is axially fixed to the shaft in pumps with so-called "fixed impellers." The pump's vanes are situated between the two disks (the top and bottom shrouds) of the impeller. Washers are provided on the top and the bottom contact surfaces to the diffuser to ensure low frictional forces between the moving impeller and the stationary diffuser.

Quite frequently, balancing mechanisms are provided to decrease the axial forces developing in the pump stage which include balance rings and balancing holes. Note that the balancing holes connect the inlet and the discharge sides of the impeller causing a definite drop in pump efficiency and a decline of pressure increase per stage; but at the same time they effectively reduce the magnitude of axial forces. Centrifugal pumps can be classified according to the direction of the impeller's discharge and belong to the radial, axial, or mixed flow groups. In ESP service, however, only radial flow and mixed flow pumps are used. Radial flow is used in smaller capacity pumps producing less than 3,000 bpd liquid, with mixed flow pumps used at higher rates.

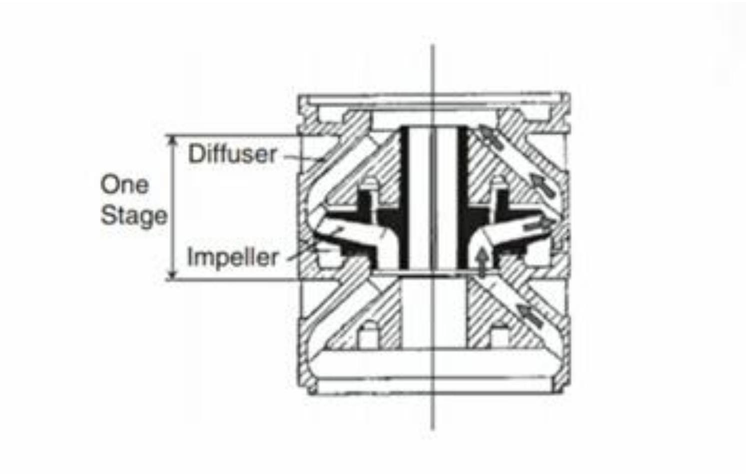


Figure 41 One stage of a centrifugal pump.

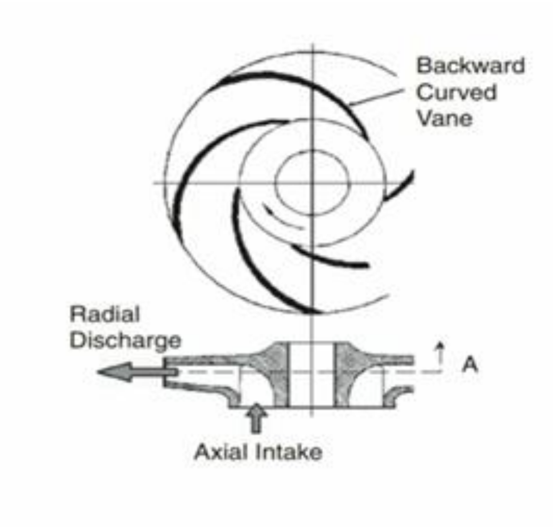


Figure 42 Liquid flow path and the vanes of an impeller.

and are used to achieve higher operational heads usually required in deeper wells. T his way several hundreds of stages can be run, the maximum number of stages being limited by one or more of the following factors:

- The mechanical strength of the pump shaft, usually represented by the shaft's horsepower rating.
- The maximum burst-pressure rating of the pump housing.
- The maximum allowed axial load on the unit's main thrust bearing (usually situated in the protector section).

4.3. The ESP Motor

Induction Motor

The electric motors used in ESP service belong to the most common type of electric motors and are three-phase, two-pole, squirrel cage induction motors. These work on the principle of the electromagnetic induction that states that an electric current is induced in any conductor moving in relation to a magnetic field. The magnetic field is generated in the stator, the standing part of the motor containing one coil for each phase. This field rotates with the changes of direction of the AC current because the electromagnets change their magnetic poles twice for every cycle of the AC current. The rotational speed of the magnetic field is the motor's synchronous speed, which depends on the frequency of the AC current and the number of poles the stator has:

$$N_{synch} = \frac{120f}{p}$$

where:

f ¼ frequency of the AC power, Hz

p ¼ number of poles in the stator.

Inside the stator, attached to the shaft of the motor, is the squirrel cage-type rotor consisting of short-circuited copper bars not connected to the power source. The rotating magnetic field maintained by the stator windings induces the flow of an AC current in the rotor, thus the rotor becomes a set of electromagnets. The magnetic poles of the rotor's field are attracted and repelled by the unlike and like poles, respectively, of the stator, and the rotor maintains the continuous rotation of the motor shaft. Since the operation of the motor depends on electromagnetic induction requiring a relative movement between the stator's (primary) magnetic field and the rotor's wires, it must be clear that the rotor must always revolve at a slower speed than the motor's synchronous speed. The speed difference is called the "slip" of the motor. It is sometimes defined as a percentage of the synchronous speed:

$$slip = \frac{N_{synch} - N}{N_{synch}}$$

Typical ESP motors behave very similarly to NEMA D motors and have a slip of 100–150 RPM at fully loaded conditions. Their synchronous speed at 60 Hz operation, according to Eq. 4.6, is 3,600 RPM, so actual speeds of 3,500 RPM or less can be expected at full load.

As seen from Eq. 4.6, the speed of the ESP motor depends mainly on the frequency of the AC power. Therefore, if driving of the submergible pump at different speeds is required, the change of the driving power's frequency is the most feasible solution; it is often used in ESP installations with variable speed drives.

4.4. The Protector or Seal Section

Main Functions

In small, non-industrial submersible pumps the electric motor is completely sealed against the produced liquid so as to prevent short-circuits and burning of the motor after it is contaminated with well fluids. Since the motor must be filled with a high dielectric strength oil, ESP motors operating at elevated temperatures, if completely sealed, would burst their housing due to the great internal pressure developed by the expansion of the oil. This is the reason why ESP motors must be kept open to their surroundings but at the same time must still be protected from the harmful effects of well fluids. This is provided by connecting a protector section between the motor and the centrifugal pump.

An ESP protector performs the following five very crucial functions and in so doing ensures the proper operation of the whole installation:

1. It ensures that no axial thrust load developing in the ESP pump's stages during operation is transmitted to the motor shaft. Thrust loads transmitted to the pump shaft are supported by the protector that contains the ESP unit's main thrust bearing. This thrust bearing must be capable of overcoming the net axial force acting on the pump shaft.

2. The protector isolates the clean dielectric oil with which the motor is originally filled from well fluids that are usually loaded with dirt, water and other impurities. It must ensure that no well fluid enters the motor during operation. This is a basic requirement because contamination of the clean motor oil can cause premature motor failures due to:

- The loss of lubrication in the structural bearings, and the consequently increased wear in bearing surfaces, and the decrease of the electrical insulation strength of the motor oil causing short circuits in the motor's stator or rotor windings.

3. It allows for the expansion and contraction of the high-quality oil the motor is filled with. Since the protector is connected directly to the motor, motor oil expanding due to well temperature and due to the heat generated in the motor can enter the protector during normal operation. Similarly, during shutdowns, the oil contained in the motor shrinks because of the decreased motor temperature and part of it previously stored in the protector can be sucked back to the motor space.
4. By providing communication between well fluids and the dielectric oil contained in the motor, the protector equalizes the inside pressure with the surrounding pressure in the well's annulus. Inside and out-side pressures being approximately equal, leakage of well fluids past the sealed joints and into the motor is eliminated. This feature:

- Allows the use of low pressure and consequently lower cost seals, and greatly increases the reliability of the ESP system.

5. It provides the mechanical connection between the motor and the ESP pump and transmits the torque developed by the motor to the pump shaft. The couplings on the protector's shaft ends must be capable of transmitting not only the normal operating torques but the much greater torques occurring during system startup.

4.5. The Gas Separator

The ESP pump is a dynamic device that imparts a high rotational velocity on the fluid entering the impeller, the amount of kinetic energy passed on being proportional to the density of the fluid pumped. Because of their great density, liquid particles receive a great amount of kinetic energy that, after conversion in the pump stage, increases the flowing pressure. On the other hand, although being subjected to the same high rotational speed, free gas cannot produce the same amount of pressure increase because the kinetic energy imparted on it by the impeller is significantly lower due to the much lower density of the gas phase. Because of these reasons the performance of centrifugal pumps always deteriorates if, along with the liquid, free gas also enters the pump suction. This is why centrifugal pumps should always be fed by gas-free, single-phase liquid to ensure reliable operation.

In spite of natural separation in the annulus and/or the operation of a gas separator, gas may eventually reach the pump. Free gas in the ESP pump rapidly ruins the pump’s efficiency and increased gas volumes may cause fluctuations of pump output causing surges in well production. Surging in the pump leads to cyclic changes in motor load and the current drawn by the motor starts to fluctuate accordingly forcing the surface motor controller to shut down the ESP unit. Frequent system shutdowns and restarts eventually damage the motor and the whole installation's run life is severely reduced.

The existence of free gas at pump suction conditions (pressure and temperature) affects the operation of the ESP pump is several ways:

- The head developed by the pump decreases as compared to the performance curve measured with water.
- The output of a pump producing gassy fluids fluctuates; cavitation can also occur at higher flow rates causing mechanical damage of the pump stages.
- In cases with extremely high gas production rates, gas locking may occur when no pumping action is done by the pump completely filled with gas.

Because of its many detrimental effects, the production of a considerable amount of free gas requires special treatment from the ESP operator. The simplest solution for producing wells with low gas production rates is detailed: the use of the reverse flow gas separator. The simplest and least efficient gas separator has been in use almost since the early days of ESP operations. It may also act as an intake for the centrifugal pump and can separate low to moderate amounts of gas with a limited efficiency. Th e separator is connected between the protector and the pump and directs the separ ated gas into the well's casing/tubing annulus.

The construction and operation of this type of gas separator, often called a "reverse flow gas separator," is illustrated in **Fig. 4-3**. It works on the principle of gravitational separation by forcing the fluid flow to change direction and allowing free gas to esca pe into the well's annulus. Well fluid containing free gas bubbles enters the separato r through the perforated housing. In the annular space formed by the housing and th e stand tube, gas bubbles rise but liquid flows downward. If bubble rise velocity is gr eater than the countercurrent liquid flow velocity, gas bubbles rise to the top of the separator and escape into the well's annulus through the upper perforations of the s eparator's housing.

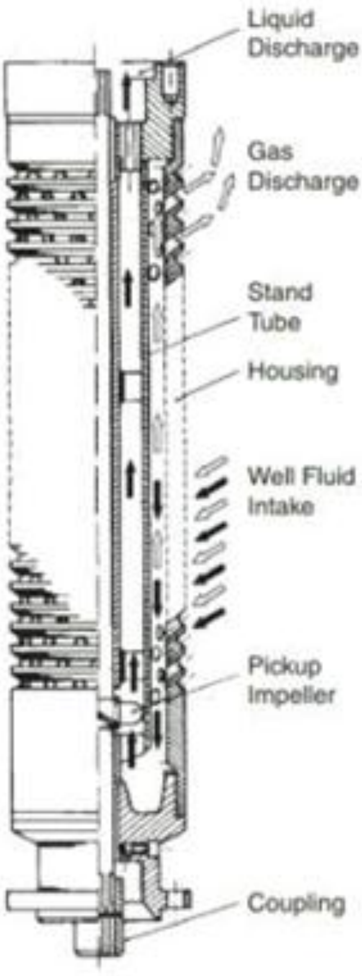


Figure 4.3 Construction of a reverse flow gas separator.

Liquid containing a reduced amount of free gas is sucked in by the pickup impeller at the bottom of the separator and is transferred to the ESP pump connected to the to p. The simplest gas separator described here is still in use in wells with low to moder ate liquid and gas rates where the low separation efficiency achieved by this constru ction is sufficient. The use of the reverse flow gas separator is inherently limited to lo w liquid rates since its operation is based on the existence of low fluid velocities insid e the housing/stand tube annulus. At higher rates normally encountered in ESP servi ce, the liquid velocity in that annulus is too high to facilitate the separation of free ga s bubbles. Therefore, in wells with substantial amounts of free gas production, more advanced separators with higher efficiencies have to be used, as discussed in a subse quent section.

The presence of free gas at pump intake and discharge involves additional implications in the design of the ESP installation.

- The two-phase mixture flowing from the intake through the pump stages undergoes a continuous change in pressure that modifies fluid properties like density and volume. The performance of the subsequent pump stages, therefore, will be different, if compared to a case where a single-phase liquid is pumped through all stages.
- In addition to the modified pump performance, the performance of the well tubing changes, too, because gas evolving in the tubing above the ESP unit decreases the average flowing density. This effect can considerably reduce the required pump discharge pressure and an appropriate correction in total dynamic head (TDH) calculations is needed. In more sophisticated solutions like computer programs, tubing pressure is calculated from a vertical multiphase pressure drop model.

In ideal conditions, wells producing gassy fluids would be produced at pump intake pressures above the well fluid's bubble point pressure so there is no free gas present at the pump suction. This would require a sufficiently great submergence of the pump below the dynamic liquid level causing a high flowing bottom hole pressure severely limiting the well's production rate. This is the reason why, in the majority of cases, specific solutions (non-standard installation types, gas separators, etc.) have to be considered when producing gassy fluids with ESP units.

4.6. The ESP Cable

Electric power from the surface is transmitted to the ESP motor through a special three-phase electric power cable leading from the surface to the motor connection. ESP cables work under extremely harsh conditions and must meet the following important requirements:

- They must be of small diameter so that they can fit in the annulus along the well tubing,
- They must maintain their dielectric properties under harsh well conditions such as:

- High temperatures,
- Aggressive fluid environments, and
- The presence of hydrocarbon and/or other gases.

- They must be well protected against mechanical damage occurring during running and pulling as well as normal operations.

The operating conditions of ESP cable are very unforgiving and the proper choice of i ts type and size in many cases has a direct impact on the life of the ESP installation. A properly selected and designed cable system, on the other hand, can be expected to stay operational for many years.

4.7. Surface Equipment

4.7.1 Wellhead

For ESP installations special wellheads are used to support the weight of the subsurf ace equipment and to maintain annular control. They have to provide a positive seal not only around the tubing but around the cable as well. Different solutions are avail able; the Hercules wellhead, where the downhole power cable is fed directly through the wellhead. In other wellheads, the power cable is cut at the wellhead and its end is equipped with a power connector. The surface power cable, coming from the switc hboard, also has a connector and the two are united in the wellhead; see Fig. 4.4. Thi s type of wellhead allows much higher wellhead pressure ratings than previous mode ls and is easier to use.

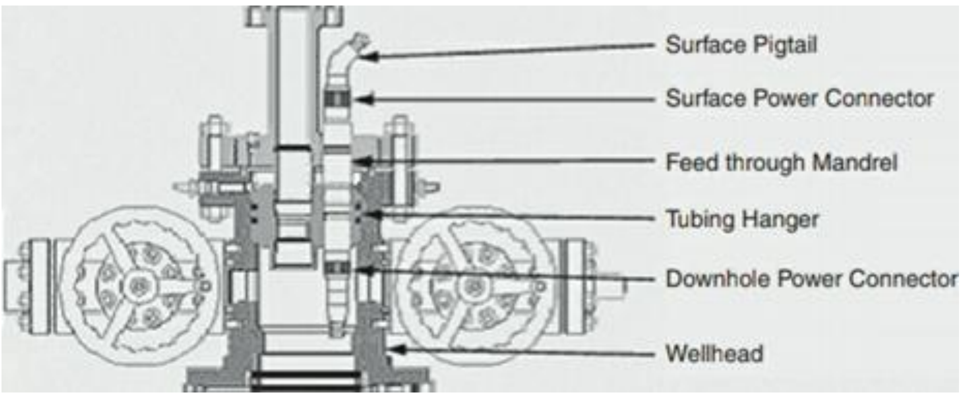


Figure 4.4 ESP wellhead with power connectors.

4.7.2 Junction Box

The power cable coming from the well should be connected to a surface electric cable leading to the switchboard. As seen in **Fig. 4.5** the two cables are joined in the junction box, also called a “vent box.” It is a ventilated, weatherproof box performing the following three important functions:

1. It provides the electrical connection between the downhole and the surface electric cables.
2. It vents any gas to the atmosphere which might reach this point due to migration of well gases up the ESP power cable. The venting of gas eliminates the danger of fire or explosion because gas is not allowed to travel in the cable to the switchboard.
3. It acts as an easily accessible test point for electrically checking the downhole equipment.

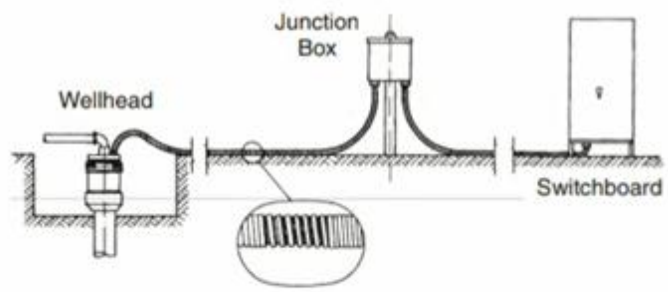


Figure 4.5 Surface arrangement of an ESP installation.

As shown in the figure, breaking of the ESP cable’s metal armor near the wellsite is a recommended precaution when gas migration in the cable is suspected. The junction box should be located at a minimum distance of 15 ft from the wellhead and should be elevated to 2–3 ft above the ground. Connection of the cables requires no splicing or taping and is, therefore, more reliable.

4.7.3 Switchboard

The switchboard is the control center of a conventional ESP installation and acts as a motor controller and, consequently, controls the operation of the whole installation. It has the following functions:

- Provides a controlled on/off switching of the ESP equipment to the power supply using high capacity switch disconnectors or vacuum contactors,
- Protects the surface and downhole equipment from a wide variety of problems, and
- Monitors and records the most important operating parameters.

Standard switchboards work under a constant electric frequency and vary in size, des ign, and power ratings. (Variable speed drives will be discussed in a later chapter.) Or iginally, ESP switchboards contained magnetic relays but today's sophisticated units utilize solid-state circuitry and provide more advanced functions and an instantaneo us response.

In addition to providing on/off switching from the electric network, the switchboard can protect the ESP equipment from problems occurring either downhole or on the s urface. The most important downhole problems a switchboard can prevent are:

- Overloading of the motor due to a multitude of several reasons like high liquid gravity, undersized motor, and so on.
- Underloading of the motor due to a pump-off condition or an oversized unit,
- Unbalanced currents, and
- Excessive number of starts.

Several malfunctions of the surface power supply may cause problems and the switc hboard is designed to protect against:

- Too high or too low input voltages,
- Voltage unbalance,
- Transient voltages (for example, lightning strikes), and
- Wrong phase rotation.

After automatic shutdown due to downhole or surface problems, the ESP unit is auto matically restarted after an adjustable time delay. The switchboard provides monitor ing of the most important operational parameters like line currents and voltages, po wer factor, and so on. For all parameters, setpoints can be input to trigger different a larms. The switchboard often contains a recording ammeter continuously recording t he current taken by the motor, facilitating the diagnostic analysis of the system's op eration. Displays of downhole measuring devices are also installed in the switchboar d. Current models can store operational parameters in memory for later retrieval an d can communicate by radio or wireline to central stations or the field's SCADA syste m.

4.8. Nabrajah Field ESP Failures

4.8.1 Types and Causes

- **Nab-1 (April 2004)**

A slight leak at the 2" ESP cable penetrator outlet on the wellhead and from the BPV. The well was killed by pumping water into the 9-5/8" casing valve. The o-ring seals o n the bull plug in the 2" ESP outlet were replaced, and the bull plug was re-tightened . The leak stopped.

- **Nab-1 (June 2006)**

Replace the existing ESP to restore the lost oil production which was estimated to b e ~500 bopd.

- Retrieve the existing JR12000, 73 stg, 900 HP ESP assembly.
- Install a replacement JR12000, 73 stg, 900 HP ESP assembly.

The performance of the existing ESP had been declining. The decline started when th e ESP was shut down during conducting a stimulation job. A total loss of 1400 bfpd h as been observed due to the ESP performance.

- **Nab-1 (June 2008)**

Replace the failed J12000R, 73 stage, 900 HP ESP assembly with one of the same typ e and size. It failed after the ESP had been shut-down for generator set service.The E SP assembly was inspected at surface, and the cause of the failure was found to be t hat the shaft was broken at the gas separator intake due to radial wear and the pum p intak stages showed heavy down thrust wear.

• **Nab-1 (April 2009)**

ESP was shut down while rectifying chemical injection pump power supply problems. The ESP started but could not be increased above 45.5 Hz. The target frequency is 61 Hz. Therefore, it was recommended to replace the ESP to restore the lost oil productio n rate, estimated to be about 500 bopd.

- Retrieve the existing J12000R, 73 stg, 900 HP ESP assembly.
- Install a replacement J12000R, 70 stg, 900 HP ESP assembly.

The new J12000R ESP, 70 stages, 900 HP assembly was installed on 5½”, 17.0 ppf, L-80, LTC/BTC tubing and landed with the pump intake at 1460.6 m md brt. This settin g depth was 156 meters shallower than the previous setting depth to avoid a series o f doglegs greater than 1^{o}/30 m which begin at 1494 m md brt.

- **Nab-1 (June 2010)**

The J12000R ESP, 70 stages, 900 HP assembly failed after having run 419 days. The pr oduction rate prior to the pump failing was 17,230 bfpd at 96.5% water cut, equating to 600 bopd. The cause of the ESP failure was determined to be a phase-to-ground e lectrical short in the lower motor.

- **Nab-12 (March 2008)**

Replace the existing GR5600 ESP assembly with a larger JR12000 ESP assembly, in order to better take advantage of the well's production capability. The gross fluid production and Watercut both increased over time to 7040 bfpd and 92.5%, respectively, at which time the well was shut in to pull the ESP assembly. Subsequent ESP speed-up, the well production increased from 7040 bfpd (530 bbl. oil, 6510 bbl. water) to 13,100 bfpd (865 bbl. oil, 12,235 bbl. water). The water cut increased from 92.5% to 93.4%.

- **Nab-12 (July 2009)**

Replace the existing failed J12000R ESP with a similar string to restore the lost oil production, the existing J12000R failed on a suspected broken shaft. Prior to the failure the well was producing at 16,350 bfpd with 93.8% water cut. Gas separator shaft was found to be twisted and broken below the splines and had a severe lateral play. The pump had a severe damage.

- **Nab-12 (December 2010)**

Replace the existing failed J12000R, 70 stages, 900 HP ESP with a similar string to restore well production. It failed on a suspected broken shaft. Prior to the failure the well was producing at 15,500 bfpd with 96.7% water cut at 62 Hz. The ESP was retrieved and found gas separator shaft broken. The new ESP assembly was started and the flow was cleaned up and the stabilized production rate was approximately 17,175 bfpd with 96.8% water cut at 60 Hz.

- **Nab-12 (February 2013)**

Replace the existing failed Reda J12000R, 70 stages, 900 HP ESP with General Electric TJ12000, 70, 900 HP ESP string to restore well production, After having run 804 days, the ESP failed on downhole electrical short. The well production prior to the pump failure was 16,098 bfpd with 98.4% water cut, giving an average of 254 bopd.

- **Nab-14 (June 2010)**

Upsize the existing GR5600, 204 stages, 450 HP ESP to a J12000R, 73 stages, 900 HP ESP to achieve a higher production rate and to take advantage of the well production capability. The well was producing 408 bopd in 6,632 bfpd at 93.8 % water cut prior to the commencement of this well service. The production and ESP performance res ults are listed below.

Table 41 Production and ESP Performance Results

Nabrajah-14	Oil, bpd	Water, bpd	Gas, m scfd	WC %	Pump Intake Pre ssure
Pre-Well Service	408	6,224	144	93.8	739
Post-Well Service*	448	7,732	157	94.5	322

- **Nab-14 (January 2011)**

Replace the existing failed Reda J12000R, 73 stages, 900 HP ESP with Reda J12000R 7 0 stages, 900 HP ESP string to restore the oil production. A decline of the well produc tion was observed from 8160 to 7925 bfpd. The pump gradually failed and its produc tion declined from 390 bopd, 7500 bwpd to 275 bopd, 6150 bwpd. It eventually faile d. The cause of the ESP failure was a broken shaft determined to be a phase-to-grou nd electrical short in the lower motor. A broken shaft between the two pumps, exact ly below the coupling at the top of second pump.

- **Nab-14 (August 2011)**

Replace the existing failed Reda J12000R, 70, 900 HP ESP with a similar ESP string to r estore the oil production. The ESP tripped on overload, upon checks it was found tha t one of the phases was grounded. The failed ESP was retrieved. Severe sand erosion was observed on the gas separator housing with three holes approximately 1 to 2 c m wide. It was also observed that the flow through the holes had started to cut the d ischarge pressure line and flat cable which eventually resulted in phase grounding ou t. A replacement Reda J12000R, 70 stages, 900 HP ESP assembly was installed and th e well was producing 360 bopd and 10,213 bwpd at 96.6% water cut.

- **Nab-14 (September 2012)**

Retrieve the existing failed Reda J12000R, 70 stages, 900 HP ESP with a similar ESP st ring to restore the oil production. After having run 388 days, the ESP tripped due to severe current imbalance between three phases of ESP motor. The well production p rior to the pump failure was 10,888 bfpd with 97.27% water cut, giving an average of 297 bopd. Gas separator (VGSA) was found cut 19 inches below the separator top w hich is suspected due to high sand production.

- **Nab-15 (September 2007)**

Replace the existing failed GR5600, 204stg, 450Hp with SN2600, 170stg, 250Hp ESP a ssembly. The ESP failed due to a confirmed downhole electrical problem. The existin g GR5600 ESP is currently operating outside of its optimum range in the down-thrust side because of the low productivity of the well.

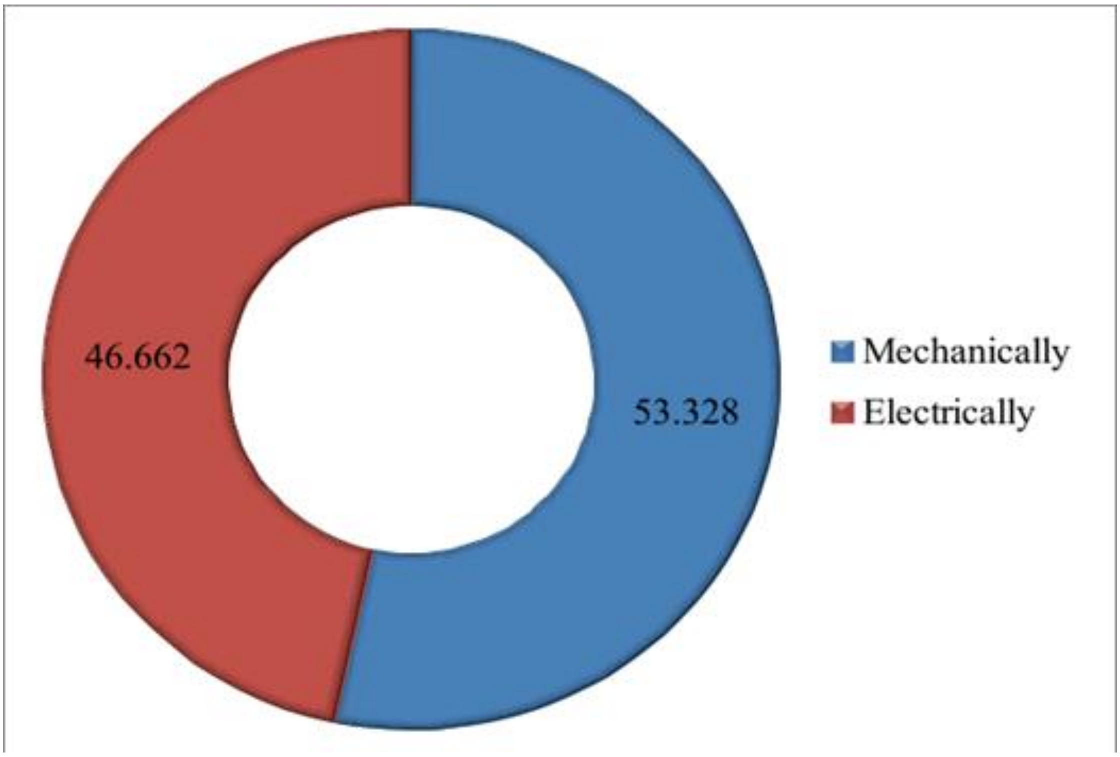


Figure 4.6 Nabrajah field failure types

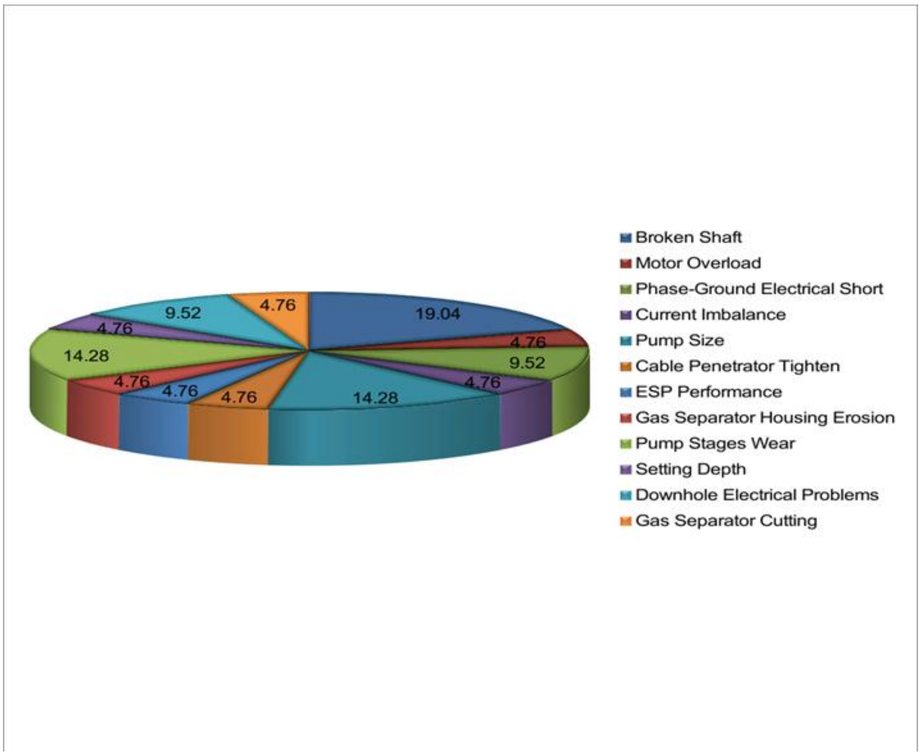


Figure 4.7 Nabrajah field failure modes

Figure 4.8 Broken shaft

Figure 4.9 Pump stages wear

Figure 4.10 Cable electrical short

4.8.2 Proposal for Improvement to Enhance ESP running life

4.8.2.1 Radial Wear Reduction

Production of abrasive solids along with well fluids has the greatest effect on the operation of the ESP pump where abrasive particles move with high local velocities. Abrasive damage caused in ESP pumps takes different forms and occurs in different parts of the pump, in the case of a fixed impeller pump, the possible wear points where sand damage can be classified as:

- Erosion in the pump stage,
- Abrasion in radial bearings (radial wear), and
- Abrasion in thrust washers and thrust bearings (axial wear).

In addition to pumps, other components of the ESP system are also affected by abrasives in the well fluid. Rotary gas separators (RGSs) are especially susceptible to abrasive wear because of the great centrifugal forces acting on the solid particles. The solids, hitting the separator housing with great speed, remove the layer of corrosion products from the metal surface that immediately corrodes again and the process repeats. This eventually may lead to a complete cutting of the separator housing, necessitating the use of special, abrasion resistant materials.

Over the years, manufacturers developed many modifications in pump design and introduced the use of different materials for fighting sand damage in ESP equipment. The common background for all designs is the use (on all influenced points in the pump stage) of materials hard enough to resist the harmful effects of abrasives. Since the most aggressive abrasive material, almost always present in well fluids, is sand, all materials harder than sand can be used at critical points in the pump stage.

Interestingly enough, soft materials like rubber can also be successfully used in journal bearings. In this case, due to the resilient nature of the material, sand particles entering the clearance between the rubber bearing and the metal journal while hitting the rubber do not remove any material because of the rubber’s deflection. In addition to this, sand particles cannot imbed in the soft rubber part. All these result in the s and particles working their way out of the bearing thus greatly reducing abrasive wear on the metal journal.

As discussed in the previous section, the severity of abrasive damage in submersible pumps increases in the following order:

1. Erosion in impellers and diffusers,
2. Axial wear in thrust bearings and up- and down thrust washers in floater pumps, and
3. Radial wear in radial (journal) bearings.

Erosion wear in pump stages can be minimized by using special metals (Ni-Resist, an alloy containing 18% nickel) for manufacturing of impellers and diffusers, instead of the less expensive gray iron, or by using hard surface coatings on endangered areas.

Axial abrasion is present in thrust bearings and the up- and down thrust washers of floater pumps. In the ESP unit's main thrust bearing, situated in the protector, extremely hard materials like ceramics (usually zirconia) are used for thrust runners and shoes. The wear of the washers used in floater pumps can be reduced by increasing their surface areas and by the proper selection of their materials.

Since radial abrasion is the most significant effect of sand damage in ESP pumps, the various ways of reducing it are detailed in the following.

The earliest solution to decrease radial wear was the placement of special radial bearings at regular intervals in the submersible pump. Such bearings contain a special resilient (usually rubber) bushing pressed into the diffuser bore where the pump shaft turns, see **Fig. 4.11**. The rubber bearing is fluted—that is, it has longitudinal grooves on its inside surface where sand particles are washed into and are continuously removed from by the fluid pumped. By fitting these bearings in several stages instead of the standard diffuser bore/impeller hub-type bearings, radial abrasion damage can be reduced. The shorter the distance between the special bearings (distributed evenly along the length of the pump shaft), the greater the radial stability of the pump shaft becomes.

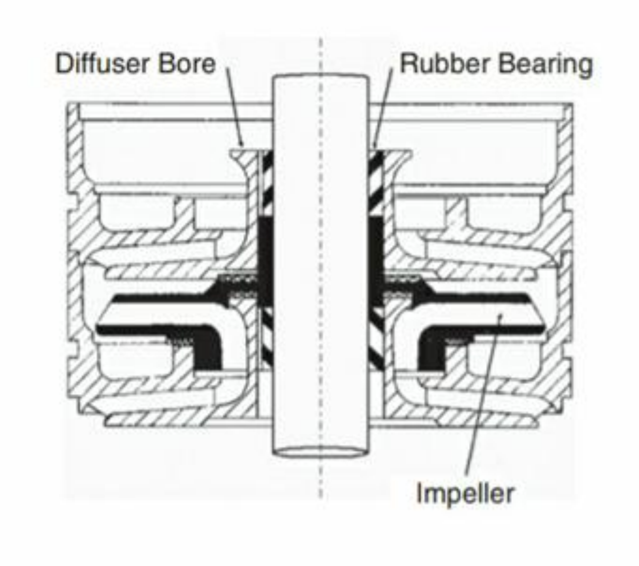


Figure 4.11 Construction of a resilient radial bearing

Hardening of wearing surfaces to decrease abrasion in radial and thrust bearings was also applied. Radial and axial stabilization is ensured by the use of special inserts ma de of materials of great hardness so that radial and axial wear can be minimized. A d etailed view of the pump stage is given in Fig. 4.12, where a hardened insert is fixed t o the diffuser in which a flanged sleeve with a similar hardness is turned by the pum p shaft. The radial and axial wear surfaces are, because of their great hardness, highl y resistant to abrasion damage.

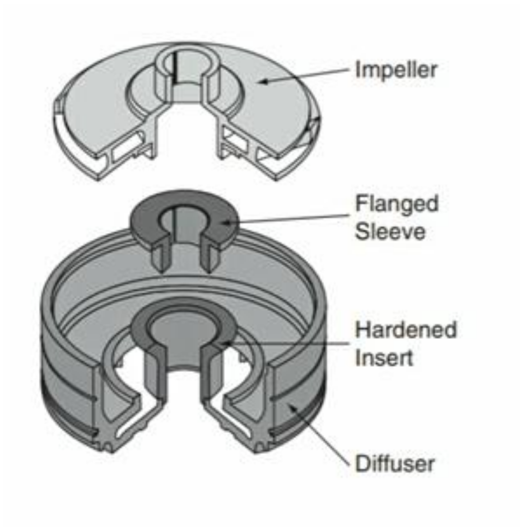


Figure 4.12 Modified pump stage used for abrasive service.

The use of special hard materials such as silicon carbide, tungsten carbide, or ceramics can greatly increase the abrasion resistance of ESP pump parts. The application of these materials in ESP pump bearings, however, proved to be unsuccessful because they are very brittle and are easily fractured if loaded at one point or on a line. Regular journal bearings are mounted into their housings by press fitting and this technique inevitably causes line loadings and an eventual failure of the bearing if very brittle materials are used. This is the reason why journal bearing designs had to be improved to facilitate the utilization of extremely hard materials.

The usual material selections in compliant bearings are zirconia bearings and journals, or zirconia bearings with silicon carbide journals. Zirconia is a ceramic material of great hardness that is virtually unaffected by abrasives in the well stream and can withstand temperatures up to 1,000 F. It has excellent lubrication properties and is not affected by the presence of H_2S or CO_2 gases.

4.8.2.2 Hybrid-X Gas/Sand/Solids Separator

The Hybrid-X Downhole Gas/Sand/Solids Separator is a revolutionary, patented technology that eliminates both gas and sand/solids pump interference. Using cyclonic motion and internal baffling, the simple and effective tool achieves downhole separation for production volumes. Specifically designed for treating production flows with higher gas volumes and significant sand/solids contamination, the Hybrid-X design provides several key benefits:

- No packer needed.
- Agitates and breaks up gas-fluid emulsions.
- Captures sand and solids in the mud joint.
- Clean, gas-free production fluid fills the pump intake, permitting greater production and pump efficiency.
- Reduces excessive pump wear, sticking plungers, surface equipment wears and damage, and fouling of the flow line and pump.
- Restores and optimizes rod pumping efficiency and extends component life.
- Increases production output and decreases maintenance costs.

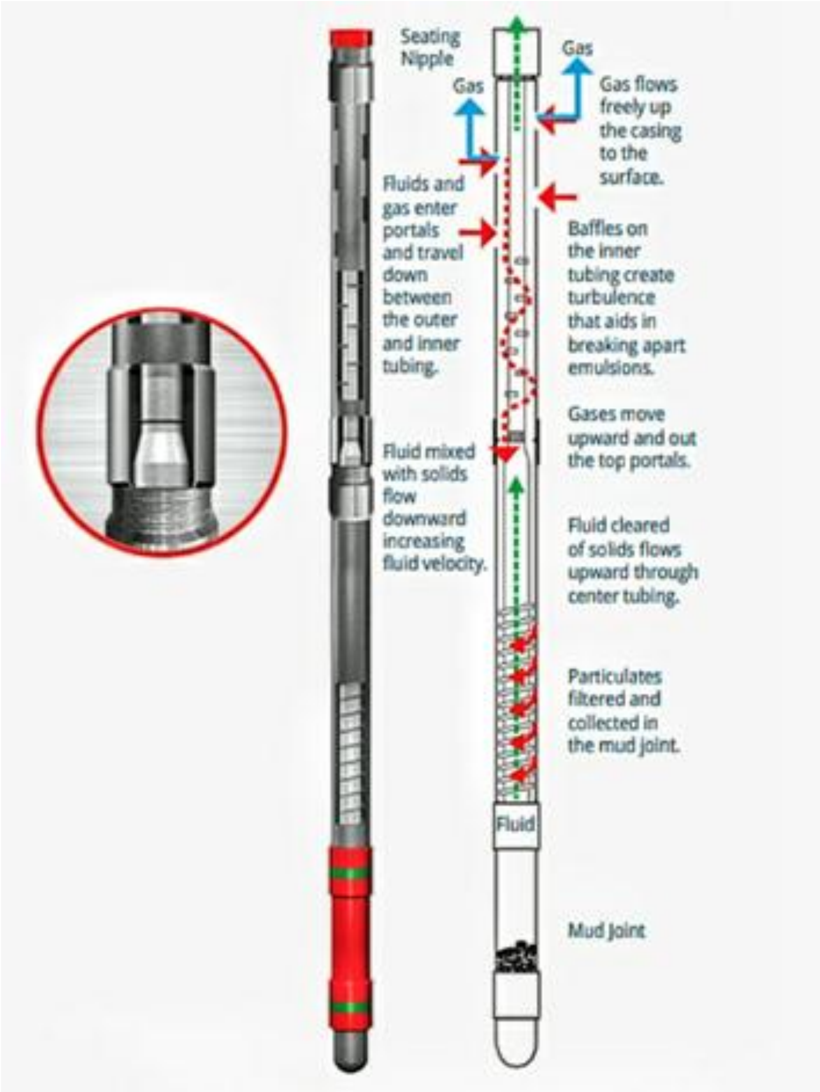


Figure 413 Hybrid-X Gas/Sand/Solids Separator

4.8.2.3 Permanent Magnet Motor

This type of motors is new in the oil and gas manufacturer, Total number of PMM in operation worldwide is 2,600+ units. it has different applications with temperature r ating of 200 ^{o}C and adjustable speed range up to 6,000 rpm. The operating principle of it is as following:

- 3-phase, oil-filled motor with permanent magnets mounted directly in the rotors sections. Rotors are installed with permanent magnets and laminations instead of rotor bars as in conventional motors. Rotor moving inside stator as a result of the force effecting on a conductor carrying current in magnetic field. As opposed to induction motor, permanent magnet motor uses a rotor with permanent magnets that enable a 8-10 percent increase in motor efficiency. For IM it is necessary to provide power to generate both the stator and rotor magnetic fields (flux), this requires more energy and increases electrical losses. The permanent magnets replace the rotor conductors which produce the rotor flux. Power needs only to generate the rotating stator field. This greatly reduces the energy to operate the motor.

- Torque is a function of Current.
- Speed is a function of Voltage.
- Voltage determines the speed of a PM motor not the frequency.
- The shaft speed rotation in PMM is managed by varying the current intensity, meanwhile for the IM, it should be done by changing the current frequency using corresponding frequency converters.
- Speed ranges: from 500 to 3500 (Standard Speed) and from 2000 to 6000 rpm (High Speed).

PMM advantages over IM Design

- Provide significant power energy savings.
- Increased power density results in reduced motor length (40% shorter and lighter).
- Low motor operation temperature-rise.
- 15% lower operating current.
- 10 to 20% increased efficiency at nominal power, up to 93%.
- 15% higher power factor, up to 0.96.
- Reduced electrical losses.
- Synchronous speed meaning no energy wasted on slip.
- Although it requires special drive functionality, it provides more optimal control.

CHAPTER FIVE

5. CONCLUSION AND RECOMMENDATION

5.1. Conclusion

The objective of this project was to enhance ESP run life in block 43 Nabrajah field, af ter studying some production wells found out the run life of most ESP was in betwee n 1-2 years. In order to enhance the ESP life, we had to study and analyze each ESP f ailure and come up with a solution to improve the performance as well as to enhanc e ESP running life. Most ESP failure can be concluded as following:

- Nearly 20% of the field ESP failures was the broken shaft, this type of failures known even before pulling out the ESP, since the production would be ceased, if the break occurs below the pump. Also, the motor load would be decreased because of the motor amp is less than the NRA.
  - Shaft broken occur due to sand stuck or hard starting the pump.
  - In the time they face this type of failures in the field the full ESP assembly were replaced.
- The second major failure was in the pump stages, these stages were affected by the production rate. When the production is lower than the ROR, the down-thrust wears severely as well as the upper-thrust wears, when the production is higher than the ROR.
  - They replaced the ESP due to severe pump damage, whenever they can avoid this problems by operating the ESP in ROR, and by selecting the optimum pump size.

• Electrical failures also take place in Nabrajah field which represent 46.6%, they occ ur in the form of phase to ground short or phase to phase imbalance or motor overlo ad. Shorts occur due to the lower resistance and the ability of the current to pass thr ough the well as a result of insulation damage or deterioration. Motor overload caus es ESP tripping, this happens when the ampere is maximum than the MAL.

After analyzing ESP failures, a set of recommendations proposed to enhance ESP life as mentioned below.

5.2. Recommendations

1. Sand Control using **HYBRID-XR™ GAS / SAND / SOLIDS SEPARATOR.** The **Hybrid-XR** Downhole Gas/Sand/Solids Separator is a revolutionary, patented technology that eliminates both gas and sand/solids pump interference. Using cyclonic motion and internal baffling, the simple and effective tool achieves downhole separation for production volumes depending on tool sizing.

   Specifically designed for treating production flows with higher gas volumes and si gnificant sand/solids contamination, the **Hybrid-XR** design provides several key b enefits:

   - No packer needed
   - Captures sand and solids in the mud joint
   - Reduces excessive pump wear, sticking plungers, surface equipment wears and damage, and fouling of the flow line and pump.
   - Increases production output and decreases maintenance costs.
2. Reposition ESP according to Total Dynamic Head that can be determine by reservoir performance which can give the sand more time to accumulate without reaching the intake point in ESP assembly.
3. Reduce the electrical failure by using Permanent Magnet Motor Which Provide significant power energy savings, Low motor operation temperature-rise, lower operating current, increased efficiency at nominal power, and Reduced electrical losses.
4. Reduction of Radial Wear
   - Erosion wear in pump stages can be minimized by using special metals (Ni-Resist, an alloy containing 18% nickel) for manufacturing of impellers and diffusers, instead of the less expensive gray iron, or by using hard surface coatings on endangered areas.
   - The earliest solution to decrease radial wear was the placement of special radial bearings at regular intervals in the submersible pump. Such bearings contain a special resilient (usually rubber) bushing.
   - The use of special hard materials such as silicon carbide, tungsten carbide, or ceramics can greatly increase the abrasion resistance of ESP pump parts

5.3. Limitations

- Limited time and Difficulties while gathering the data led to Limit the project objectives.
- Leak of referenced led to leak in advanced knowledge about ESP.
- Leak of data that is requires for building complete model using softwares.

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