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Emirates International University
Engineering and IT Faculty
Dep. Oil and Gas Engineering

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قسم هندسة النفط والغاز

EMIRATES INTERNATIONAL UNIVERSITY
FACULTY OF ENGINEERING AND INFORMATION TECHNOLOGY
OIL AND GAS ENGINEERING DEPARTMENT

OPTIMIZATION OF PETROLEUM PRODUCTION SYSTEM IN HALEWAH FIELD (BLOCK - 5)

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

BY:
MAEEN AL-SHADADI
ALI SALAH
MOHAMMED SALAH
ESAM ALAJI
ASEEL AL-KUHILI
MOHAMMED AL-MAMARI

SUPERVISOR
PROF. YASIN SALEH

SANA'A
DECEMBER, 2019

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 **Optimization of Petroleum Production System in Halewah Field (Block 5)** 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.

Project Supervisor: **Prof. Yassien Saleh**

Date: ………………….

Signature: ………………….

ABSTRACT

The topics covered in this project explain the main components of typical petroleum production system and also the optimal practical methods and techniques to optimize oil production of the entire system on a safe and cost efficient manner.

This project represented the fundamentals of petroleum production system.it started with simple introduction to the petroleum production system. After that, it exhibited a comprehensive description of the essential components of the entire system. These components of system are basically categorized to a reservoir, well, and surface production facility.

Also described the properties or specifications of petroleum production system in Halewah field. And explained the following points: geological structure of reservoir and lithological description for drilled wells in reservoir, well completion design for some producer wells in field, and the surface processing equipment in production facility of Halewah field.

It provided the optimization plan on petroleum production system of Halewah Field (Block 5) as well as quantified the appropriate development aspects at different levels in the petroleum production system in reservoir, wells and surface production facility. These aspects had focused on the following issues: Evaluating and improving reservoir deliverability, Analyzing and optimizing wellbore production performance, and Operating efficiency criteria of surface production facility.

Finally, conclusion and recommendations are enclosed at the end of this project.

ACKNOWLEDGMENTS

First, we would like to express our special thanks of gratitude to our advisor Prof. Yassien as well as our respected academic management of Petroleum Engineering department in Engineering College at International Emirates University. Meanwhile, we are immensely grateful to our mentor Eng. Jamal for his constant support and guidance within the limited time frame to accomplish this project on the topic " Optimization of Petroleum Production System in Halewah Field (Block 5)".

Secondly, we would also like to thank our friends and the faculty staff, and fellow students in the Petroleum Engineering Department for their kind cooperation if needed.

Finally, we deeply thank our parents because of their highly love and support which were a constant inspiration to us in striving to succeed in our life.

Thanking all of you,

Team

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A. CHAPTER 1

SO: OIL SATURATION

BO: FORMATION OIL VOLUME FACTOR

GOR: GAS OIL RATIO

KO: PERMEABILITY OF OIL

μ_o: VISCOSITY OF OIL

HPU: HYDRAULIC POWER UNIT

POC: PUMP OFF CONTROLLER

ESP: ELECTRICAL PUMP

PCP: PROGRESSIVE CAVITY PUMP

LP: LOW PRODUCTION

HP: HIGH PRODUCTION

K.O, DRUM: KNOCK – OUT DRUM

TEG: TRIETHYLENE GLYCOL

BS/W: BASIC SETTLEMENT AND WATER

B. CHAPTER 2

TOC: TOTAL ORGANIC CARBON

RO: VITRINITE REFLECTANCE

YHOC: YEMEN HUNT OIL COMPANY

OM: ORGANIC MATTER

TVD: TOTAL VERTICAL DEPTH

MD: MEASURE DEPTH

CPF: CENTRAL PRODUCTION FACILITIES

LACT UNIT: CRUDE OIL CUSTODY METERING SKID

C. CHAPTER 3

HCL: HYDROCHLORIC ACID

HF: HYDROFLUORIC ACID

OIP: ORIGINAL OIL IN PLACE

EOR: ENHANCE OIL RECOVERY

PI, J: PRODUCTIVITY INDEX

IPR: INFLOW PERFORMANCE RELATIONSHIP

OPR: OUTFLOW PERFORMANCE RELATIONSHIP

FTP: FLOWING TUBING PRESSURE

FWKO: FREE WATER KNOCK OUT

VLP: VERTICAL LIFT PERFORMANCE

BS&W: BASIC SETTLEMENT AND WATER

CHAPTER ONE

1. INTRODUCTION

1.1. Overview

The role of a petroleum or production engineer is to maximize oil and gas production in a cost-effective manner. Familiarization and understanding of oil and gas production systems are essential to the engineers in oil and gas industry. This chapter provides some basic knowledge about production systems. More engineering principles with regards to optimization activities in petroleum production system will be discussed in the later chapters. As shown in **Fig. 1-1** (Sketch of petroleum production system), a complete oil or gas production system consists of a reservoir, well, flow line, separators, pumps, and transportation pipelines. The reservoir supplies wellbore with crude oil or gas. The well provides a path for the production fluid to flow from bottom hole to surface and offers a means to control the fluid production rate. The flow line leads the produced fluid to separators. The separators remove gas and water from the crude oil. Pumps and compressors are used to transport oil and gas through pipelines to sales points.

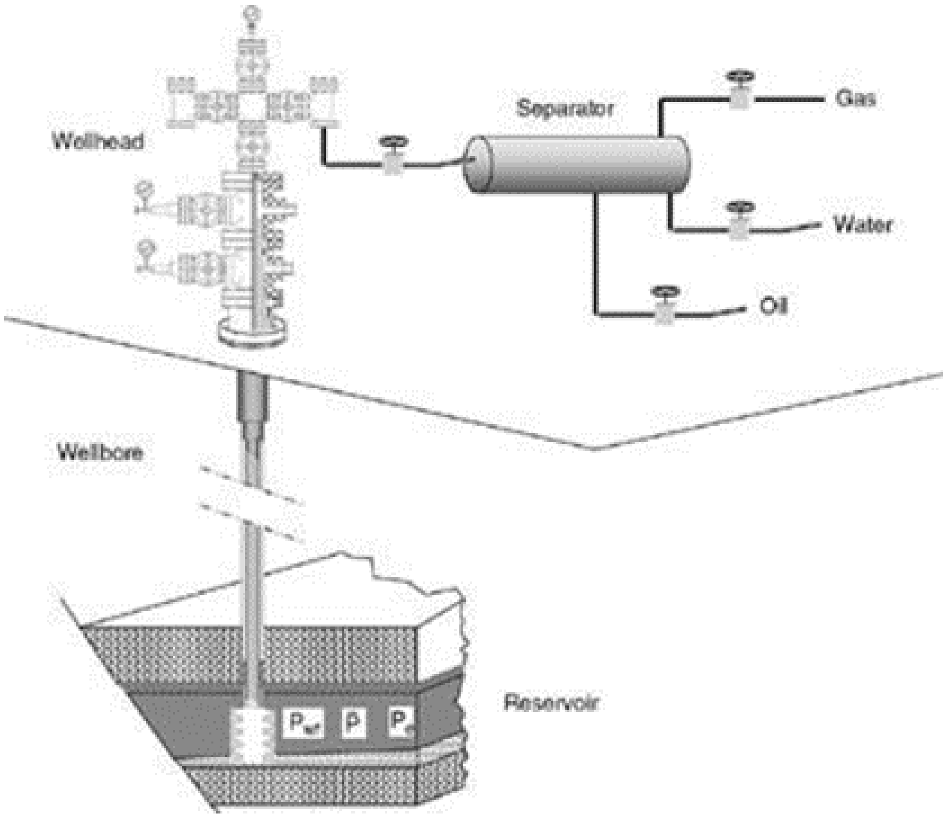


Figure 1-1 Sketch of petroleum production system

1.2. Aims and Objectives

1.2.1. Aims

The main aim of project is analyzing performance of each component of petroleum production system, such as reservoir, well, and surface facilities, in Halewah Field (Block 5) and applying optimal methods to optimize oil production at safe and cost efficient manner.

1.2.2. Objectives

The primary objectives of the study in the project are the following listed below:

1. To explain and describe in general the components of petroleum production system including the common types of each component in oil and gas industry.
2. To understand the essential function of each component in petroleum production system and its interaction with other components in system.
3. To present and describe the properties and specifications of petroleum production system components in Halewah Field (Block 5).
4. To investigate and analyze performance of each component of petroleum production system in Halewah Field (Block 5).
5. To identify the common problems and constraints that are encountered on performance of petroleum production system of Halewah field at different levels of the system.
6. To determine and develop optimal plan for entire production system of Halewah Field to remove production operations problems and obstacles to maximize hydrocarbon production rate and to minimize operating cost under various technical and economic constraints.
7. To come out with conclusion and recommendations points that will add positive value to the study of project.

1.3. Scope of The Project

The framework of the project will be carried out on the study of each component of petroleum production system of Halewah Field at Block 5. The study will focus on the performance of each component of petroleum system such reservoir, well, and surface production facilities in Halewah Field, main findings of production problems, and optimal solutions to remove these problems at safe and efficient conditions.

1.4. Project Question

What are the main production problems and constraints which are more likely to be experienced on petroleum production system of Halewah Field (Block 5)? What are the optimal practical methods and techniques that are applicable to maximize oil production of the entire system safely and efficiently?

1.5. Significance of The Project

The purpose of the study is to provide petroleum and production engineers a handy guideline on how to study, evaluate, analyze, and optimize petroleum production system. Furthermore, the study will also equip engineers with engineering principles and rules that will help them significantly in terms of designing and selecting the main components of petroleum production system in which maximum oil production physically achieved.

1.6. Block (5) & Halewah field Overview: -

1.6.1. Geological Structure of reservoir and Lithological Description for Drilled Wells in Halewah Field

1.6.1.1. Overview

Block 5 concession (**Fig. 1-2**) is located in (Marib-Shabwa) basin, With area of (280) Km^2.

- Block (5) operated by Jannah Hunt Oil Company.
- The main reservoirs in the block are (Alif Sand) and (Seen Sand).
- The partners in the Production Sharing Agreement with the Yemeni government are:
- KUFPEC (20%), EXON (15%), JANNAH Hunt (15%), NEWCO (15%), Total (15%), YICOM (20%).
- In General, it contains 5 fields with an average production of (35,000) BOPD.
- The total number of wells ware 92 until Des. 2011.
- The block is connected with the main pipeline of block 18 (Marib) by 40 Km long, and 12" Diameter of the pipeline.

- The produced is light oil in the different fields with a density between (35-48 API), in addition to a big gas reserve, which is neither invested nor exploited so far.

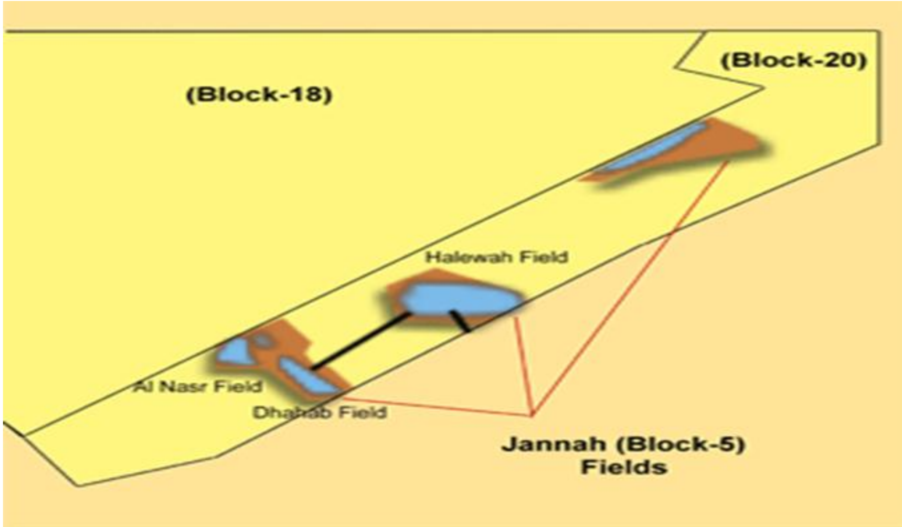
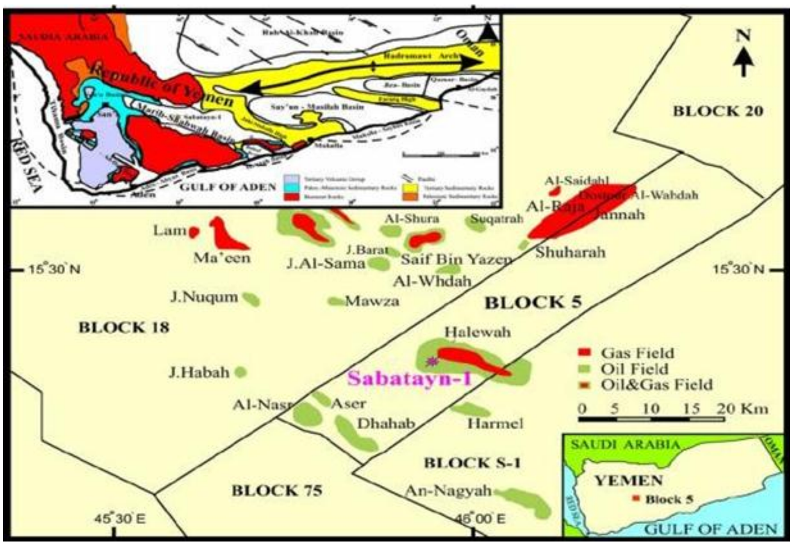


Figure 1-2 Block 5 concession



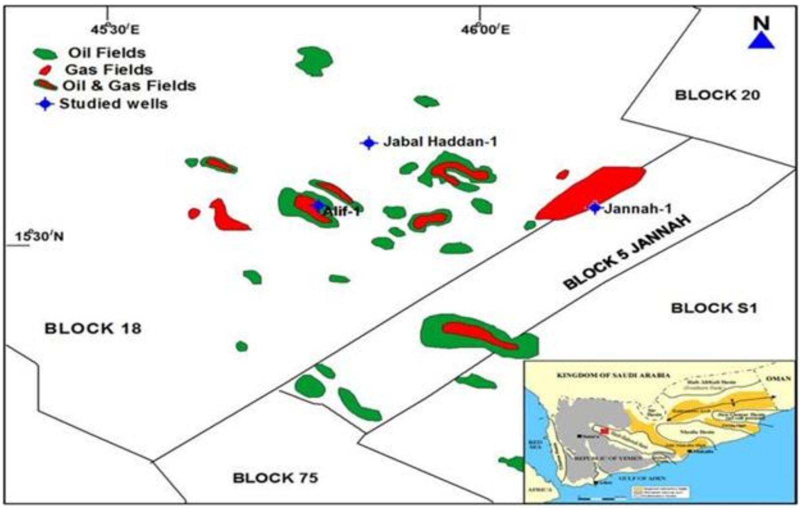


Figure 1-3 Location map of the oil and gas fields in the Marib- Shabowah Basin including representative studied wells (Jabal Haddan-1, Alif-1 and Jannah-1).

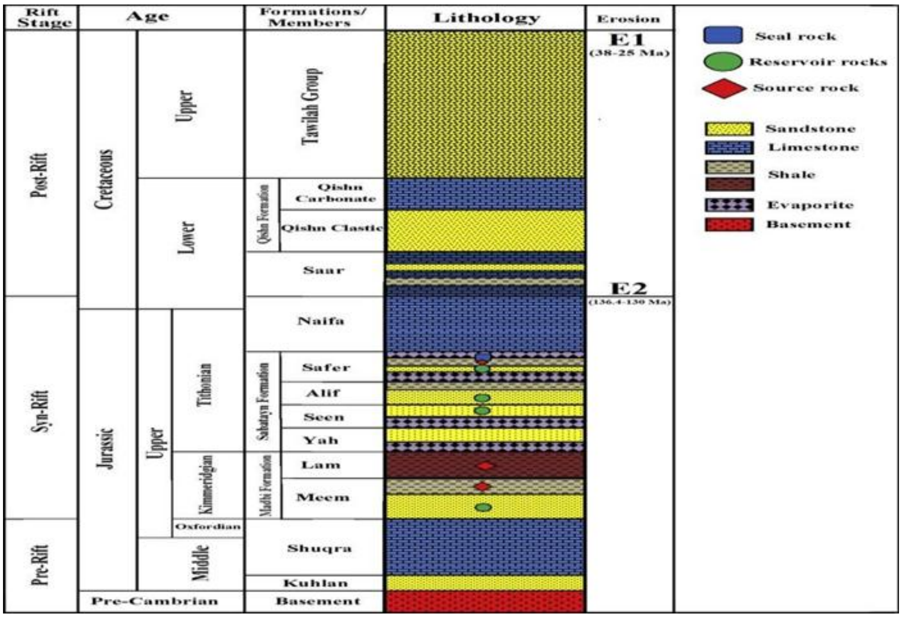


Figure 1-4 Regional stratigraphic nomenclature, Marib-Shabowah Basin, Republic of Yemen.

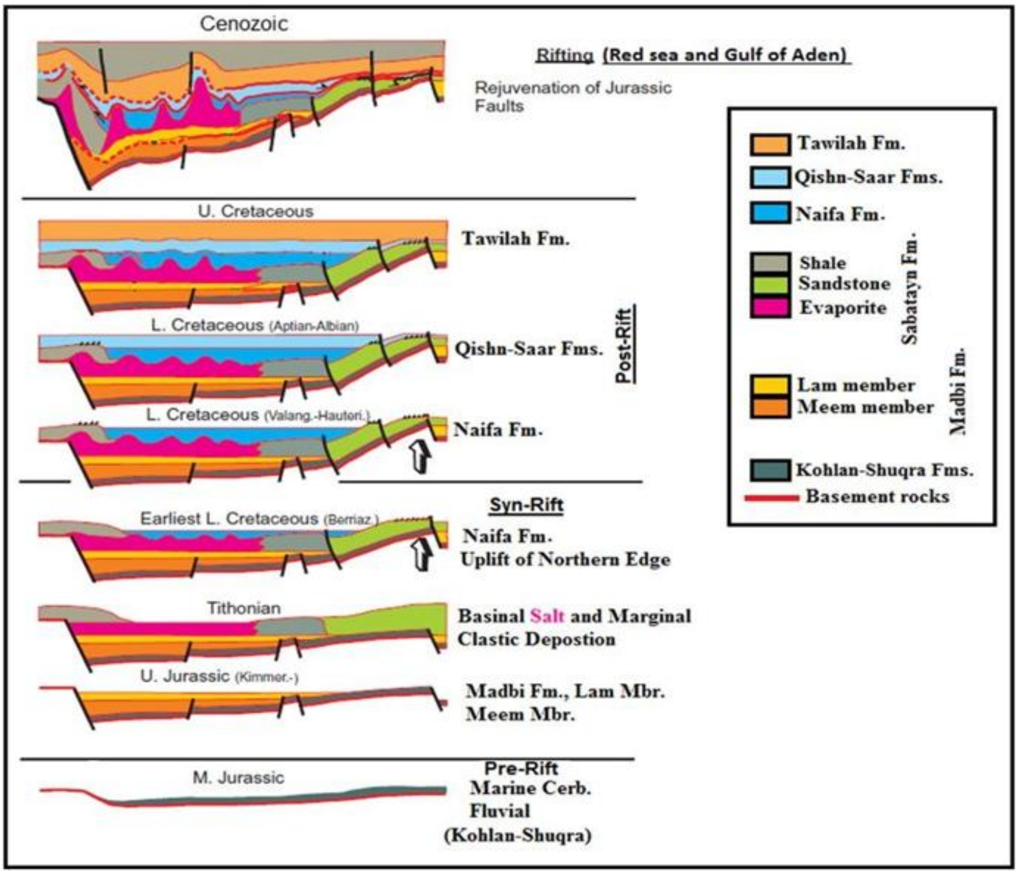


Figure 1-5 Tectono-stratigraphic, halokinetic, and petroleum generation history model of Marib-Shabowah Basin, western Yemen.

1.6.1.2. Lithological Description of drilled wells in Halewah Field

Halewah No. 6

D. TOP ALIF 1334 m

- 0335 – 0334 m Shale: light green, firm, subfissile, very calcareous, dolomite stringers.
- 0336 –0335 m Dolomite: dark brown, hard, micritic, tight, no show.

E. TOP ALIF SANDSTONE: 1336 m

- 0339 – 0336 m Sandstone: light brown, 20% intergranular porosity, good permeability.
- 0340 – 0339 m Shale: light green grey, firm, subfissile, very calcareous.
- 0348 – 0340 m Sandstone: light brown, 20% intergranular porosity, good permeability.

- 0351 – 0349 m Limestone: white, firm, micritic, sandy, tight.
- 0358 – 0354 m Sandstone: light brown, well sorted, 12% intergranular porosity.
- 0368 – 0363 m Sandstone: light brown, well sorted, 20% intergranular porosity, good permeability.
- 0398 – 0373 m Sandstone with Interbedded Shale
- 0411 – 0398 m Sandstone: light brown, 15% intergranular porosity, moderate permeability.

F. ALIF SAND BASE 1400 m

- 0414 – 0411 m Shale: medium grey, green grey, fissile, moderately hard.
- 0415 – 0414 m Sandstone: light brown, very fine to fine grained, well sorted, 15 % intergranular porosity, moderate permeability.
- 0464 – 0415 m Shale: moderately hard, tan brown, fissile, slightly silty.

Halewah No. 6

A. TOP ALIF 1305.5 m MD, 1279.76 m TVD, -315.96 m ss

- 1305.5 – 1314.5 m Shale: greenish grey, blocky, waxy to dull, hard to soft, non-fissile, very hard and dense.

B. Top of Alif Sandstone at 1314.5 m MD, 1288.47 m TVD, -324.67 m ss

- 1314.5 – 1317 m Sandstone: as below.
- 1317 – 1319 m Shale: greenish grey, platy, soft, dull.
- 1319 – 1323 m Sandstone: pale brown, fine to medium grained, friable.
- 1323 – 1324 m Shale: as above.
- 1324 – 1326 m Sandstone: pale brown, fine to medium grained, calcareous cement, quartzose.
- 1326 – 1328 m Shale: greenish grey, platy to splintery, soft, dull.
- 1328 – 1334 m Sandstone: light to medium brown, fine to medium grained, friable to hard.
- 1334 – 1336 m Shale: as above.
- 1336 – 1342 m Sandstone: pale brown, fine and medium grained, sub angular, well sorted.
- 1342 – 1343 m Shale: greenish grey, soft, platy to blocky.

- 1343 – 1358 m Sandstone: brown, fine grained, sub angular, well sorted, calcite cement, very friable, quartzose.
- 1358 – 1359 m Shale: as above.
- 1359 – 1361 m Sandstone: as above.
- 1361 – 1362 m Shale: as above.
- 1362 – 1371 m Sandstone: pale brown, fine to medium grained, sub angular, well sorted.
- 1371 – 1372 m Shale: as above.
- 1372 – 1376 m Sandstone: pale brown to brownish white, fine grained, sub angular, well sorted.
- 1376 – 1433 m Shale: blocky, non-calcareous, very soft, non-fissile, waxy.

1.6.1.3. Surface Processing Equipment in Production Facility in Halewah Field (Block 5)

Summary

Surface Production Facilities in Block 5 are installed in three Fields which are :

1) Halewah Field
2) Dhaba Field
3) Al Naser Field

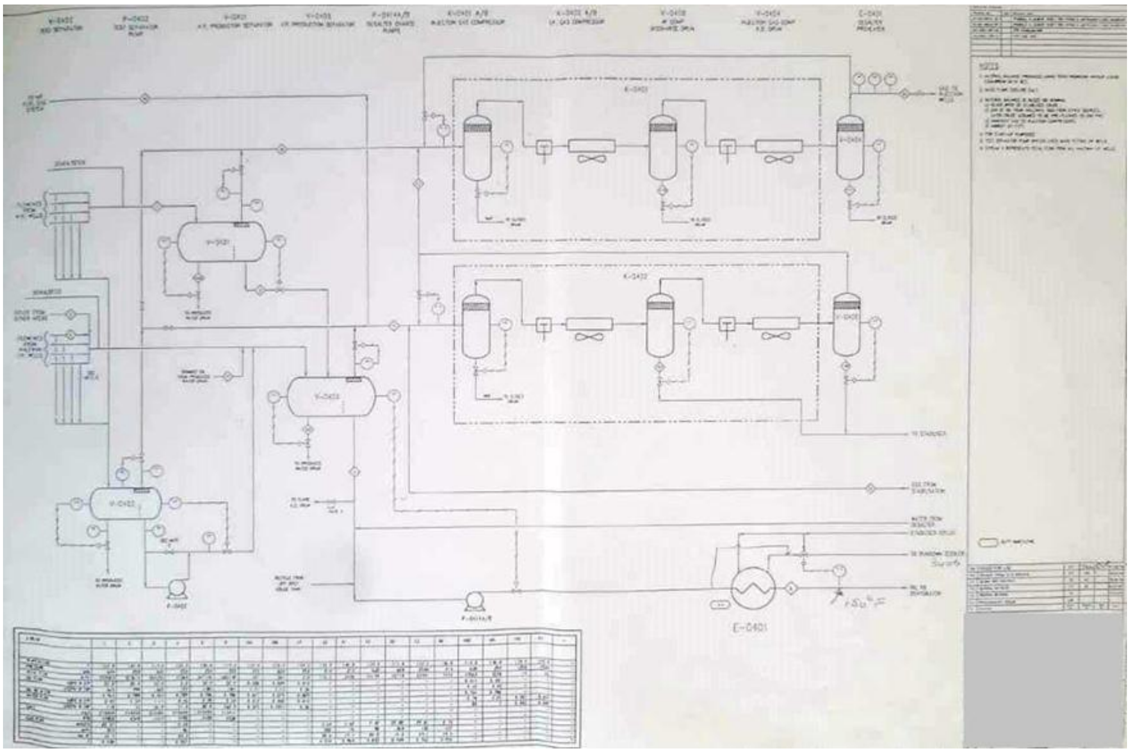


Figure 1-6 Halewah CPF Layout

List of surface processing equipment in production facility of Halewah Field (Block 5)

The Central Production Facility is located in Halewah Field. The list of equipment installed as per Halewah CPF Layout (**Fig. 1-6**) above are the following below:

1) **Gathering System:**

- HP Manifold: HP wells are connected to HP manifold via HP flowlines
- LP Manifold: LP wells are connected to LP manifold via LP flowlines.

Note: There is a Shipping line connected to LP Manifold to process crude oil received from Al Naser and Dhaba facilities.

2) **Separation System:**

- HP Production Separator: HP wells are diverted to HP Separation System. The Oil separated from HP separator is diverted to LP Production Separator for further processing.
- LP Production Separator: LP wells are diverted to LP Separation System.
- Test Separator: HP and LP wells are diverted to Test Separator individually based on Well Testing Schedule on regular basis.

3) Water Produced System:

- Water produced from HP, LP and Test Separators, Desolater, Dehydrator, and Skimming Tanks is diverted to Water Treatment System which consists of Produced Water Drum, Water disposal and injection pumps, and chemicals injection pumps.

4) Dry Oil Booster/Discharge Pumps:

- Test Separator pump: Oil produced from Test Separator is pumped to LP Production Separator.
- Desilter Charge Pump: Oil produced from LP production System is pumped to Desilter Pre-Heater for Oil Treatment System to meet Standard Specifications of Crude Oil.

5) Crude Oil Treatment System:

- Desilter Pre-Heater: Oil Produced from LP Production System, Stabilizer, and Skimming Tank is processing in Desilter Pre-Heater after that the Oil produced is diverted to Dehydrator, Desilter and Stabilizer for final process.

6) Storage and Shipping System:

- Storage Vertical Tanks: Oil produced from Processing System is stored in Tanks for settling time prior to shipping.
- Shipping Pumps: Multi-Stages Centrifugal Pumps installed at outlet of storage tanks to pump oil into export pipeline to SAFER CPF. Daily Crude Oil shipped to SAFER station is measured through LACT unit (Crude Oil Custody Metering Skid).
- Gas Treatment System:
    - HP Gas Compressor: Gas produced from HP Production Separator, LP Gas compressor, and Test Separator is diverted to HP Gas Compressor. Compressed Gas from HP Gas compressor is injected to wells and Gas Lift System.
    - LP Gas Compressor: Gas produced from LP Production Separator, Stabilizer, and Test Separator is diverted to LP Gas Compressor and HP Fuel Gas System.

7) **Flare System:**

- HP F.K.O Drum: Compressed Gas from HP Gas Compressor is diverted to HP F.K.O Drum to clean Gas from condensate, water and residuals.
- LP F.K.O Drum: Compressed Gas from LP Gas Compressor is diverted to LP F.K.O Drum to clean Gas from condensate, water and residuals prior to entering to suction of HP Gas Compressor.
- Gas Boot vessel: Oil produced from CPF process system is diverted to Gas Boot vessel to rid of Gas associated with Crude Oil prior to diverting to Storage Tanks.
- Vent Stack: Gas produced from Storage Tanks is diverted through vent valves to Vent Stack to Stabilize Crude Oil condition in Tanks.
- Flare Stack: Excessive Gas produced from CPF process system is diverted to Flare Stack to reach stabilization of Crude Oil process.

8) **Power Generation and Utilities:**

- Electric Generator (Black out) – Diesel Driven: Generator is used to feed Plant with an electricity once there is an emergency situation e.g. Plant shut down, maintenance of other generators, etc.
- Electric Generator – Fuel Gas Driven: Generator is used to feed Plant with an electrical power to process crude oil through treatment equipment of plant.
- Air, Water and Gas Utility System: It includes Air compressors, Water pumps, Fuel Gas produced from Gas Process system.

9) **Safety System:**

- Fire Protection System: It includes Fire Extinguishers, Fire Water System, Fire Detecting system, Fire Fighting Truck, Fire Fighting Team, Personal Protection Equipment.
- Emergency Shut Down System: It includes Alarms Detecting System, Emergency Shut Down Valves, Safety Relief Valves, Blow Down lines.

CHAPTER TWO

2. LITERETURE REVIEW

2.1. Petroleum Production Optimization.

Petroleum Production Optimization refers to the various activities **Fig. 2-1** of measuring, analyzing, modelling, prioritizing and implementing actions to enhance productivity of a field: reservoir/well/surface. Production Optimization is a fundamental practice to ensure recovery of developed reserves while maximizing returns. Production Optimization activities include:

- **Near-wellbore profile management**
  - Gas–water coning and fingering,
  - Near-wellbore conformance management
- **Removal of near-wellbore damage**
  - Matrix stimulation or acidizing
- **Maximize the productivity index**
- **Hydraulic fracturing**
  - Maximum-reservoir-contact well with multilateral completion
- **Prevention of organic and inorganic solid deposition in the near-wellbore/completion/pipeline**
- **Well integrity**
  - Prevention and remediation of casing and cement failure
- **Design of well completion**
  - Optimization of artificial lift performance at field and well level
  - Sand control management
- **Efficiency of oil and gas transport**
- **Design of surface facilities and fluid handling capacity**
- **Production system debottlenecking**

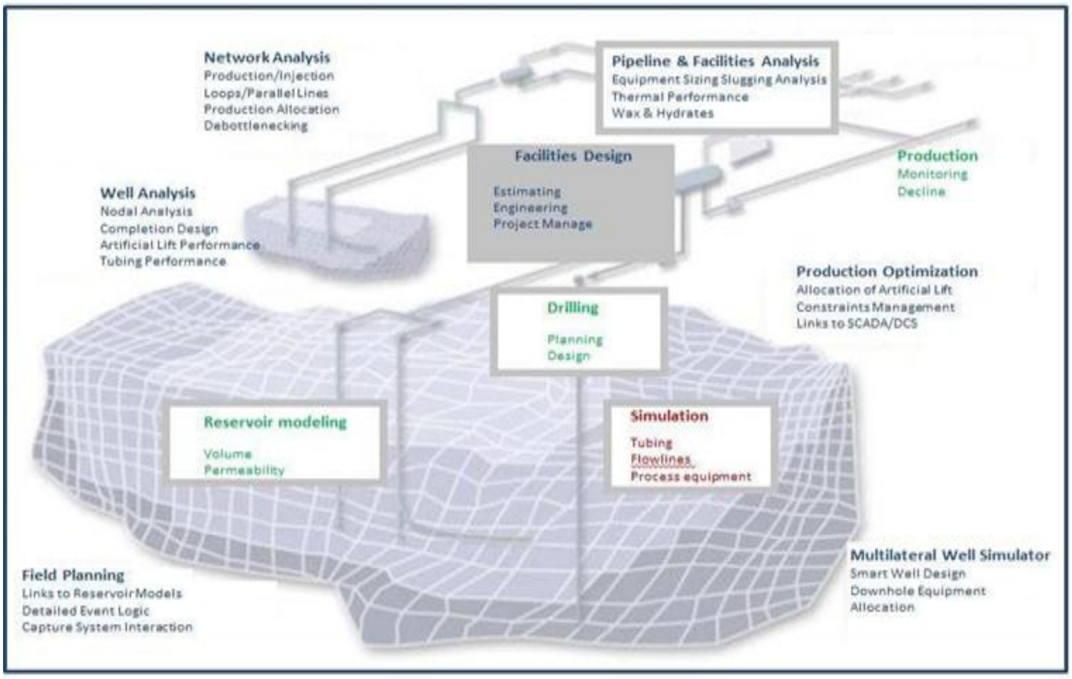


Figure 2-1 Various Approaches to Petroleum System Production Optimization

2.2. Components of Petroleum Production System

2.2.1. Reservoir

Petroleum deposits will be found only in those areas where geological conditions combine to form and trap them. Hydrocarbon, being less dense than water, migrate upward from the source beds until they escape at surface, or an impervious barrier is encountered. Oil and gas accumulates in partially sealed structures by expelling water from the porous rock. That part of the trap which contains hydrocarbons is called the reservoir. Generally, water underline the hydrocarbons in trap. An aquifer is a water bearing formation which is hydraulically connected to the reservoir. Both oil and gas are formed together in varying proportions in the sources beds and a gas cap is often found above the oil in the reservoir. Traps do at time act to segregate oil and gas which were formed together so that they accumulate in different reservoirs.

2.2.1.1. Types of Petroleum Reservoir

Petroleum reservoirs are generally classified according to their geologic structure and their production (drive) mechanism. Geologic classification of petroleum reservoirs exists in many different sizes and shapes of geologic structures. It is usually convenient to classify the reservoirs according to the conditions of their formation as follows:

Dome and anticlines:

Dome and anticline are formed by uplifting and folding of the strata. When viewed from above the dome is circular in a shape, whereas the anticline is an elongated fold (**Fig. 2-2** Dome structure). Oil and gas migrate upward from source be until trapped by the impermeable cap rock (**Fig. 2-3** Oil and gas accumulation in an anticline).

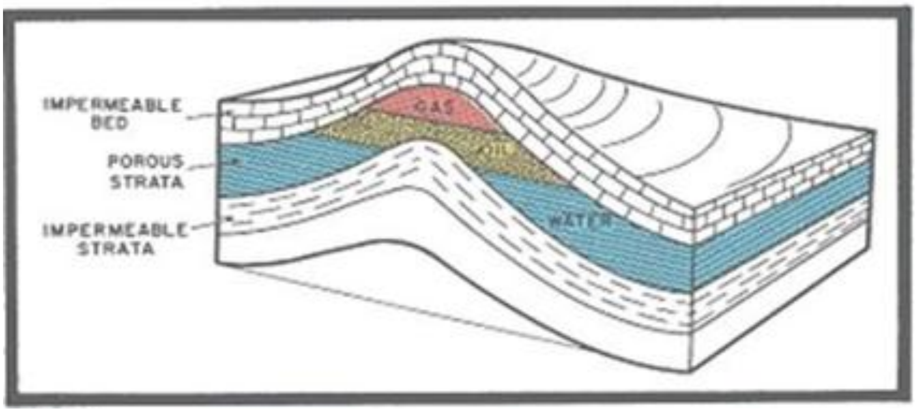


Figure 2-2 Dome Structure.

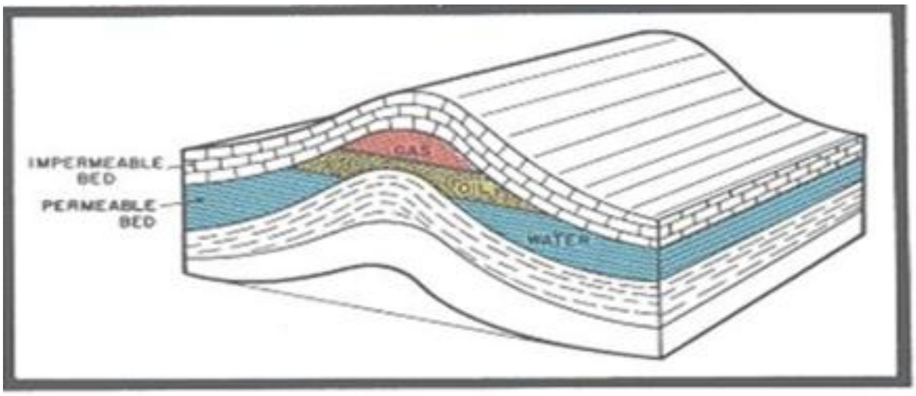


Figure 2-3 Oil And Gas Accumulation In An Anticline.

Salt dome and plug structures:

This commonly occurring geological structures is caused by intrusion from below a salt mass, volcanic materials, or serpentine in pushing up or piercing through the overlying strata the intrusion may cause the formation of numerous traps in which petroleum may accumulate. (**Fig. 2-4** Hydrocarbon accumulation associated with a salt dome).

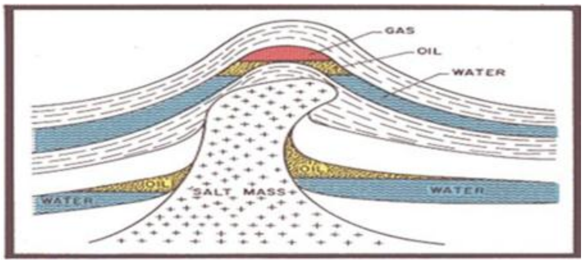


Figure 2-4 Hydrocarbon Accumulation Associated With A Salt Dome.

Structure associated with faulting:

Reservoirs may be formed along the fault plane where the shearing action has caused an impermeable bed to block the migration of oil and gas through the permeable beds (**Fig. 2-5** Trap formed by a fault).

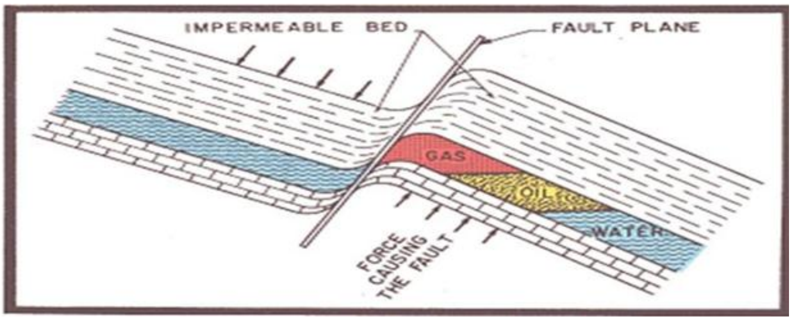


Figure 2-5 Trap Formed by A Fault.

Structure with unconformity:

This type of structure can be formed where more recent beds cover older, inclined formations that have been planned off by erosion (**Fig. 2-6**. Oil and gas trapped under an unconformity). A reservoir may be formed where oil and gas is trapped by an impermeable overlying layer.

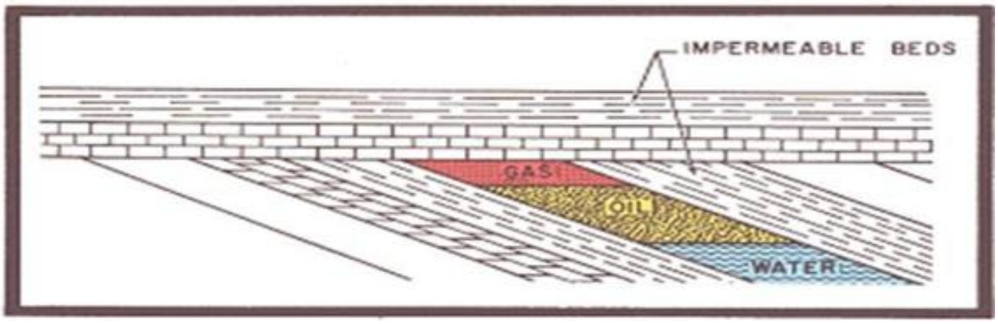


Figure 2-6 Oil and Gas Trapped Under an Unconformity.

Lenticular reservoirs:

Oil and gas may accumulate in pockets of the porous and permeable beds, or traps formed by pinch outs of porous beds, within a permeable bed. Lene type of reservoirs is formed where sand was deposited along an irregular of coastline, or by filling in an ancient river bed or delta. Similar productive zones occur in various porous sections in thick impermeable limestone beds. Pinch outs may occur near the edge of a basin where the sand progressively shale's out as the edge of the basin is approached. In river deposited sand bars, shales out frequently occur within a few hundred feet (**Fig. 2-7**. Upper bounds of the reservoir formed by change in permeability of a sand).

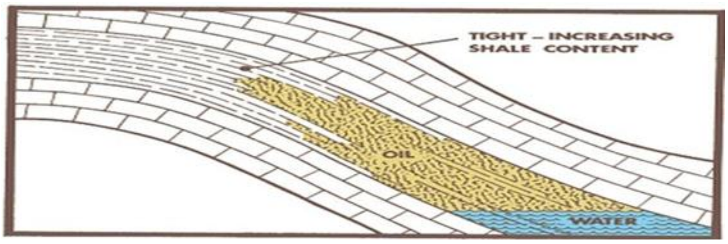


Figure 2-7 Upper Bounds Of The Reservoir Formed By Change In Permeability Of A Sand.

Reef traps:

A type of reservoir formed as a result of limestone reef buildups in the ancient oceans is shown in (Fig. 1-8. Reefs sometimes form reservoirs similar to that shown here). These reefs formed where the environmental conditions were favorable for certain marine animals and plants, and the remains of these organisms formed thick accumulations of limestones and dolomites. Local porosity in these reefs resulted from a combination of the original open space between rock grains and subsequent dissolving of the limestone by water moving through the rocks.

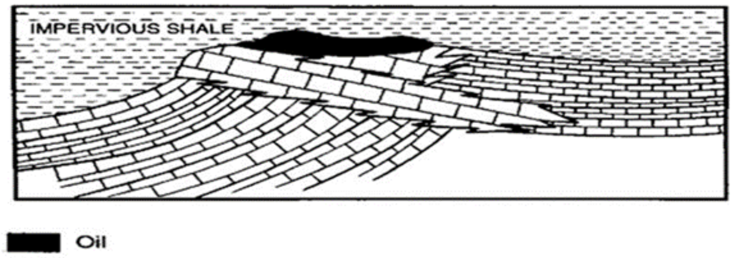


Figure 2-8 Reefs Sometimes Form Reservoirs Similar To That Shown Here.

2.2.2. Reservoir Drive Mechanisms

Oil can be recovered from the pore spaces of a reservoir rock, only to the extent that the volume originally occupied by the oil is invaded or occupied in some way. There are several ways in which oil can be displaced and produced from a reservoir, and these may be termed mechanisms or "drives". There one replacement mechanism is dominant, the reservoir may be said to be operating under a particular "drive". Oil reservoirs can be classified on the basis of boundary type, which determines driving mechanism, and which are as follows:

1) Solution gas drive (Dissolved or depletion drive) reservoirs.
2) Gas cap drive reservoirs.
3) Water drive reservoirs.

2.2.2.1. Solution gas drive reservoirs

If a reservoir at its bubble point is put on production, the pressure will fall below the bubble point pressure and gas will out of solution. Initially this gas may be a disperse, discontinuous phase, but, in any case, gas will be essentially immobile until some minimum saturation, and the equilibrium, or critical gas saturation, is attained (**Fig. 2-9**. Dissolved gas drive reservoir). The actual order of values for critical saturation are in some doubt, but there is considerable evidence to support the view that values may be very low in the order of 1% to 2% of the pore volume. Once the critical gas saturation has been established gas will be mobile, and will flow under whatever potential gradients may be established in the reservoir towards producing wells if the pressure gradient is dominant segregating verticality if the gravitational gradient is dominant. Segregation will be affected by vertical permeability variations in layers, but is known to occur even under apparently unfavorable conditions.

Initially the gas oil ratio of a well producing from a closed reservoir will equal solution GOR. At early times, as pressure declines and gas comes out of solution, but cannot flow to producing wells, the producing GOR will decline. When the critical gas saturation is established and if the potential gradients permit, gas will flow towards producing wells. The permeability to oil will be lower than at initial conditions, and there will be a finite permeability to gas so that the producing gas oil ratio will rise.

As more gas comes out of solution, and gas saturations increase, permeability to gas increases, permeability to oil diminishes and this trend accelerates.

Ultimately, as reservoir pressure declines towards abandonment pressure, the change in gas formation volume factor offsets the increasing gas to oil mobility ratio and the gas oil ratio trend is reversed; i.e. although the reservoir GOR may continue to increase, in terms of standard volumes, the ratio standard cubic ft./stock tank barrel may decline. In addition to the effect of gas on saturation of, and permeability to, oil, the loss of gas from solution also increases the viscosity of the oil and decrease the formation volume factor of the oil (**Fig 2-10** Oil Production rate/GOR/ Reservoir Pressure in dissolved gas drive reservoir).

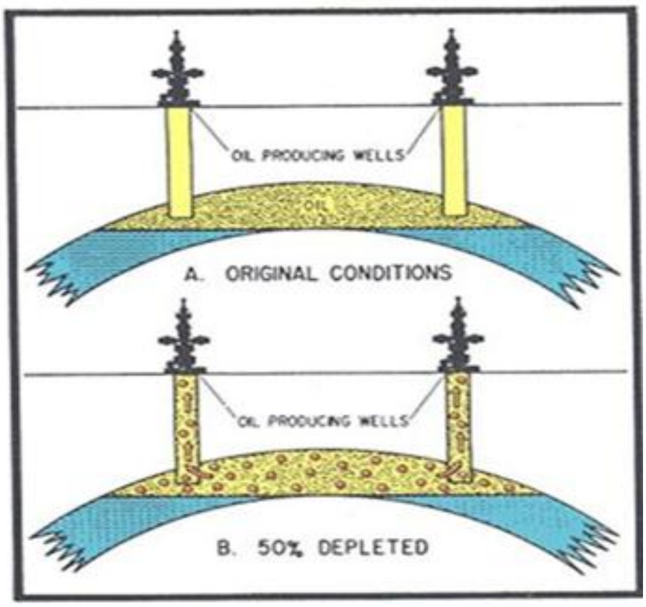


Figure 2-9 Dissolved Gas Drive Reservoir

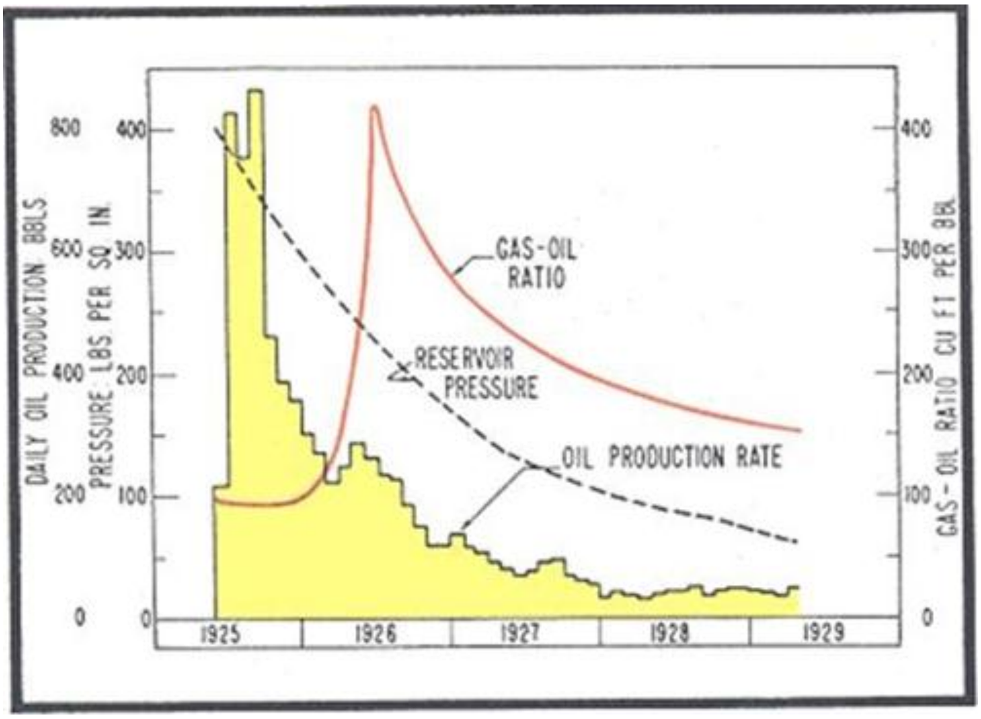


Figure 2-10 Oil Production Rate/GOR/ Reservoir Pressure In Dissolved Gas Drive Reservoir

2.2.2.2. Gas Cap Drive Reservoirs:

The general behavior of gas drive reservoirs is similar to that of solution gas drive reservoirs, except that the presence of free gas retards the decline in pressure. By definition the oil must be saturated at the gas oil contact, so that decline in pressure will cause the release of gas from solution, but the rate of release of gas from solution, and the buildup of gas saturation and of gas permeability, will be retarded. At higher prevailing pressures, oil viscosities are lower, and provided that the free gas phase can be controlled, and not produced directly from producing wells, better well productivities and lower producing gas oil ratios can be maintained. Under residual conditions the stock tank oil left in place is SO/BO and the smaller this factor the greater will be the oil recovery. Consequently, the higher the pressure at abandonment, the greater the value of Bo, and the smaller this term becomes. In addition, abandonment of wells and reservoirs depends primarily upon an "economic limit" the rate of production required to pay for operating costs, and direct overheads, and an oil flow rate, which depends upon, which will be greater at any given saturation (and so given Ko) under pressure maintenance conditions due to the lower oil viscosity than under depletion conditions.

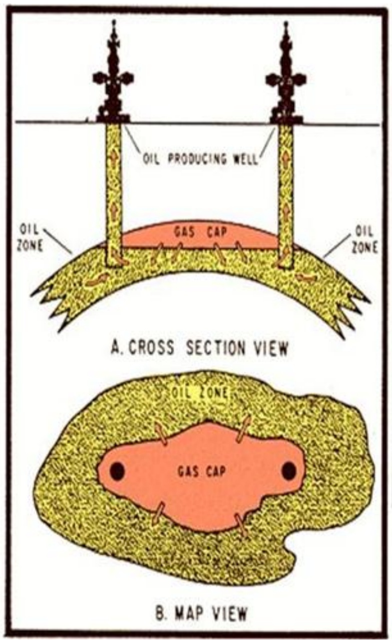


Figure 2-11 Gas Cap Drive Reservoir.

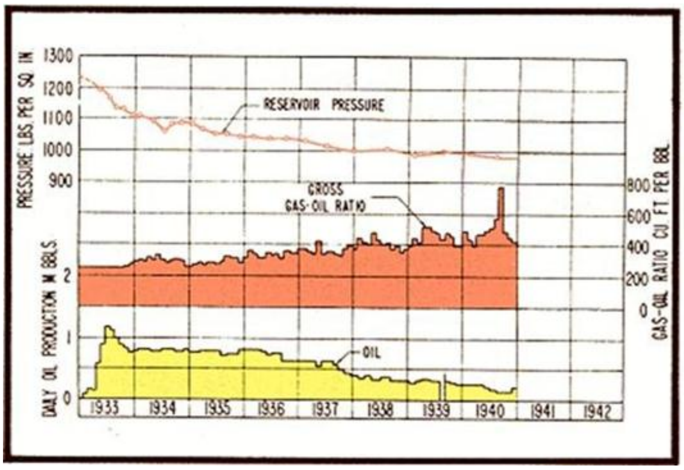


Figure 2-12 Production Rate-Gas Cap Drive Reservoir.

2.2.2.3. Water Drive Reservoirs:

If a reservoir is underlain by, or is continuous with a large body of water saturated rock (an aquifer) then reduction in pressure in the oil zone, will cause a reduction in pressure in the aquifer (**Fig. 2-13** Water drive reservoir). Although the compressibility of water is the total compressibility of an aquifer includes the rock pore compressibility making the total compressibility in the order of 8. The apparent compressibility of an aquifer can be substantially greater if some accumulation of hydrocarbons exists in structural traps throughout the aquifer. An efficient water driven reservoir requires a large aquifer body with a high degree of transmissivity allowing large volumes of water to move across the oil-water contact in response to small pressure drop.

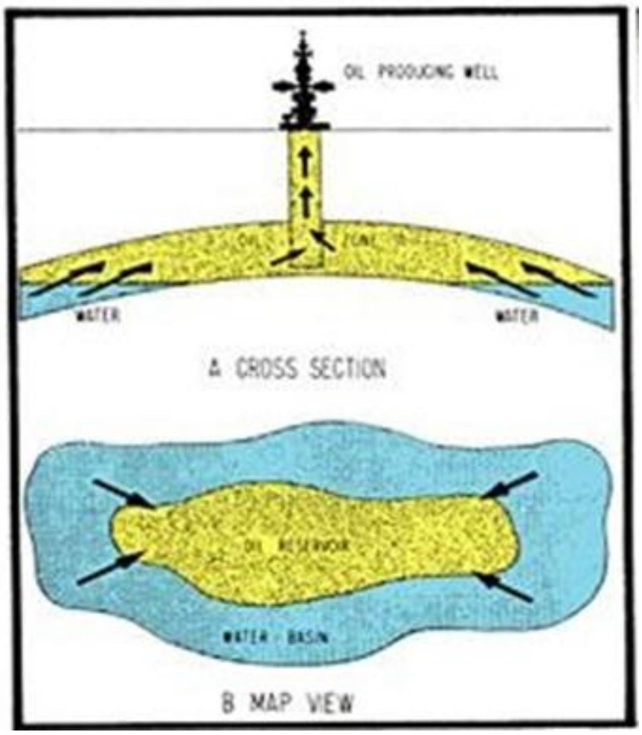


Figure 2-13 Water drive reservoir

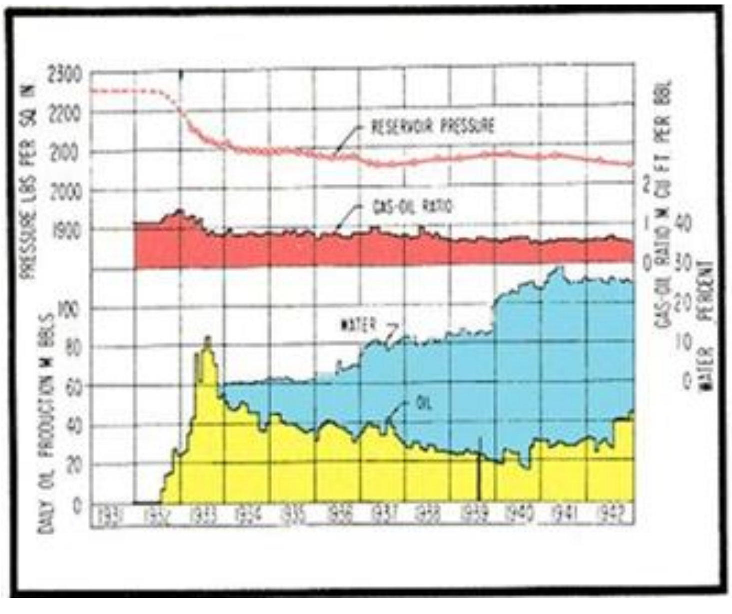


Figure 2-14 Production Rate / GOR / Reservoir Pressure In Water Drive Reservoir

This replacement mechanism has two particular characteristics. First, there must be pressure drops in order to have expansion, and secondly, the aquifer response may lag substantially, particularly if transmissivity deteriorates in the aquifer. A water drive reservoir is then particularly rate sensitive, and so the reservoir may behave almost as a depletion reservoir for a long period if offtake rates are very high, or as an almost complete pressure maintained water drive reservoir if offtake rates are Iow, for the given aquifer (**Fig. 2-14** Production rate / GOR / Reservoir pressure). Because of the similarity in oil and water viscosities (for light oils at normal depths) the displacement of oil by water is reasonably efficient, and provided that localized channeling, fingering or of water does not occur, water drive generally represents the most efficient of the natural producing mechanisms for oil reservoirs. As with gas cap drive reservoirs, the maintained pressures lead to lower viscosities and higher Bo values at any given saturation, reducing the saturation and minimizing the term SO/BO hence the stock tank oil left at any given economic limit. While reservoir drive mechanisms may be classified into the three categories we have discussed, most often two or more of these mechanisms act simultaneously in a combination drive (Fig. 1-15 Combination drive reservoir).

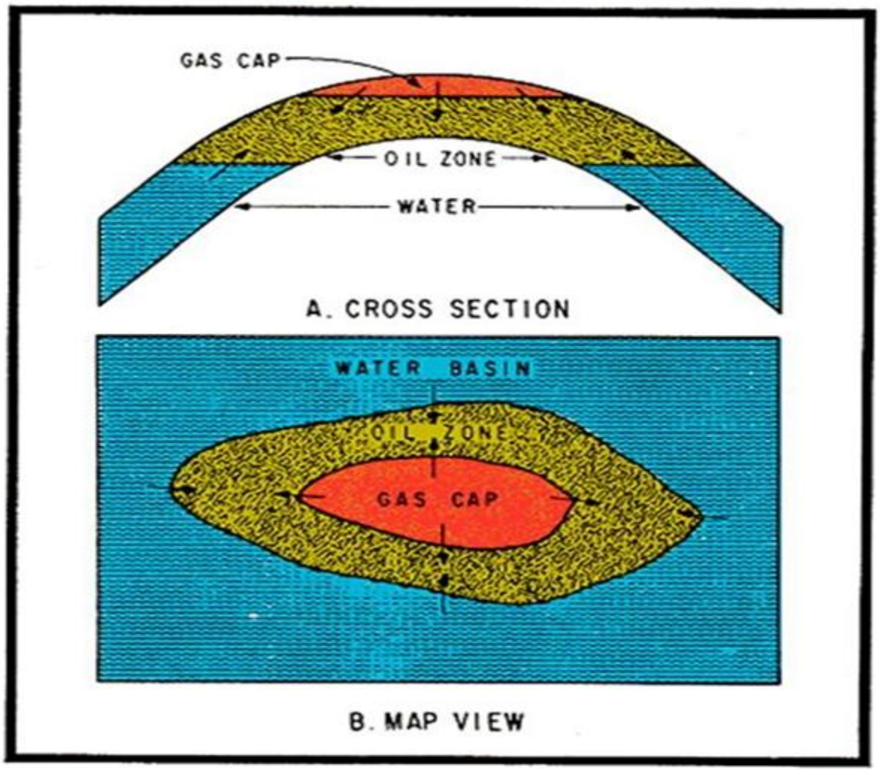


Figure 2-15 Combination Drive Reservoir

2.3. The Well

When the well is drilled, it must be completed. Completing a well consists of a number of steps; installing the well casing, completing the well, installing the wellhead, and installing lifting equipment or treating the formation if required.

2.3.1. Well Casing

Installing the well casing is an important part of the drilling and completion process. Well casing consists of a series of metal tubes installed in the freshly drilled hole. Casing serves to strengthen the sides of the well hole, ensure that no oil or natural gas seeps out of the well hole as it is brought to the surface, and to keep other fluids or gases from seeping into the formation through the well. A good deal of planning is necessary to ensure that the proper casing for each well is installed. Types of casing used depend on the subsurface characteristics of the well, including the diameter of the well (which is dependent on the size of the drill bit used) and the pressures and temperatures experienced throughout the well. In most wells, the diameter of the well hole decreases the deeper it is drilled, leading to a type of conical shape that must be taken into account when installing casing. The casing is normally cemented in place. There are five different types of well casing as per following below:

2.3.1.1. Conductor Casing:

It is usually no more than 20 to 50 feet long, and it is installed before main drilling to prevent the top of the well from caving in and to help in the process of circulating the drilling fluid up from the bottom of the well.

2.3.1.2. Surface Casing:

It is the next type of casing to be installed. It can be anywhere from 100 to 400 meters long, and is smaller in diameter than the conductor casing and fits inside the conductor casing. The primary purpose of surface casing is to protect fresh water deposits near the surface of the well from being contaminated by leaking hydrocarbons or salt water from deeper underground. It also serves as a conduit for drilling mud returning to the surface, and helps protect the drill hole from being damaged during drilling.

2.3.1.3. Intermediate casing:

It is usually the longest section of casing found in a well. The primary purpose of intermediate casing is to minimize the hazards that come along with subsurface formations that may affect the well. These include abnormal underground pressure zones, underground shales, and formations that might otherwise contaminate the well, such as underground salt-water deposits. Liner strings are sometimes used instead of intermediate casing. Liner strings are usually just attached to the previous casing with' hangers', instead of being cemented into place and is thus less permanent.

2.3.1.4. Production casing:

It is alternatively called the ' oil string' or ' long string', is installed last and is the deepest section of casing in a well. This is the casing that provides a conduit from the surface of the well to the petroleum producing formation. The size of the production casing depends on a number of considerations, including the lifting equipment to be used, the number of completions required, and the possibility of deepening the well at a later time. For example, if it is expected that the well will be deepened at a later date, then the production casing must be wide enough to allow the passage of a drill bit later on. It is also instrumental in preventing blowouts, allowing the formation to be 'sealed' from the top should dangerous pressure levels be reached. Once the casing is installed, tubing is inserted inside the casing, from the opening well at the top, to the formation at the bottom. The hydrocarbons that are extracted run up this tubing to the surface. The production casing is typically 5 to 28 cm (2 - 11in) with most production wells being 6 in or more. Production depends on reservoir, bore, pressure etc. and could be less than 100 barrels a day to several thousand barrels per day. (5000 bpd is about 555 liters/minute). A packer is used between casing and tubing at the bottom of the well.

2.3.1.5. Completion

Well completion commonly refers to the process of finishing a well so that it is ready to produce oil or natural gas. In essence, completion consists of deciding on the characteristics of the intake portion of the well in the targeted hydrocarbon formation. There are a number of types of completions, including:

Open hole completions:

They are the most basic type and are only used in very competent formations, which are unlikely to cave in. An open hole completion consists of simply running the casing directly down into the formation, leaving the end of the piping open, without any other protective filter (**Fig. 2-16** Open hole completion).

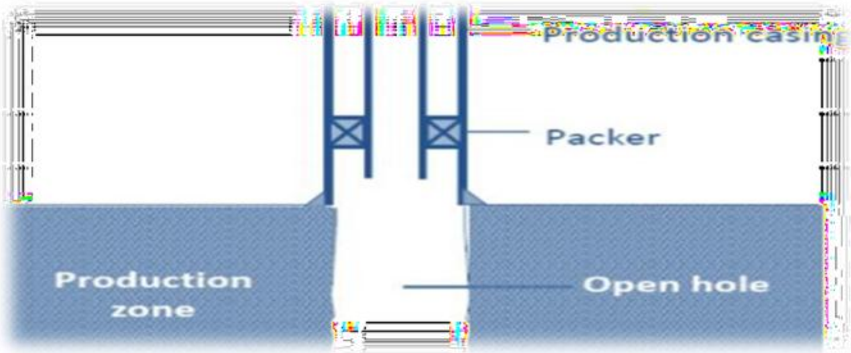


Figure 2-16 Open Hole Completion

Conventional perforated completions:

They consist of production casing being run through the formation. The sides of this casing are perforated, with tiny holes along the sides facing the formation, which allows for the flow of hydrocarbons into the well hole, but still provides a suitable amount of support and protection for the well hole (**Fig. 2-17** Perforated completions). In the past, ' bullet perforators' were used. These were essentially small guns lowered into the well that sent off small bullets to penetrate the casing and cement. Today, ' jet perforating' is preferred. This consists of small, electrically ignited charges that are lowered into the well. When ignited, these charges poke tiny holes through to the formation, in the same manner as bullet perforating.

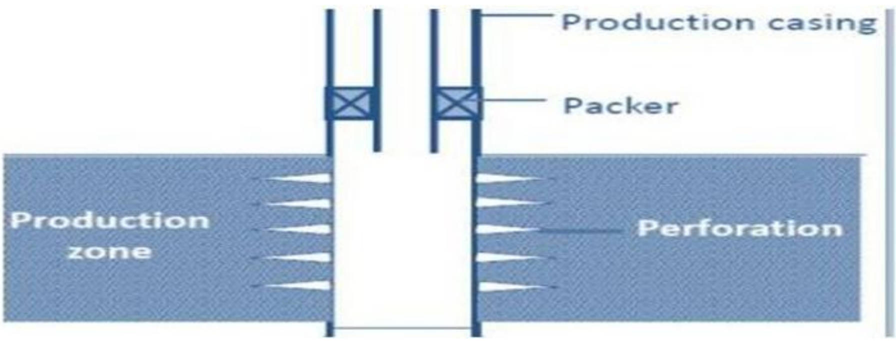


Figure 2-17 Perforated Completions

Sand exclusion completions:

They are designed for production in an area that contains a large amount of loose sand. These completions are designed to allow for the flow of natural gas and oil into the well, but at the same time prevent sand from entering the well (**Fig. 2-18** Screening completions). The most common method of keeping sand out of the well hole are screening, or filtering systems. Both of these types of sand barriers can be used in open hole and perforated completions.

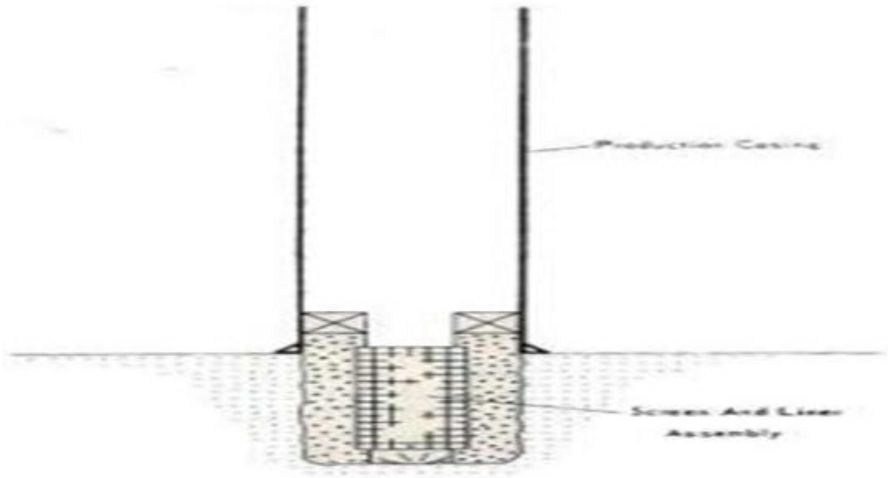


Figure 2-18 Screening completions

Permanent completions:

Those in which the completion, and wellhead, are assembled and installed only once. Installing the casing, cementing, perforating, and other completion work is done with small diameter tools to ensure the permanent nature of the completion. Completing a well in this manner can lead to significant cost savings compared to other types.

Multiple zone completion:

It is the practice of completing a well such that hydrocarbons from two or more formations may be produced simultaneously, without mixing with each other (**Fig. 2-19** Multiple zone completions). For example, a well maybe drilled that passes through a number of formations on its way deeper underground, or alternately, it may be efficient in a horizontal well to add multiple completions to drain the formation most effectively. When it is necessary to separate different completions, hard rubber ' packing' instruments are used to maintain separation.

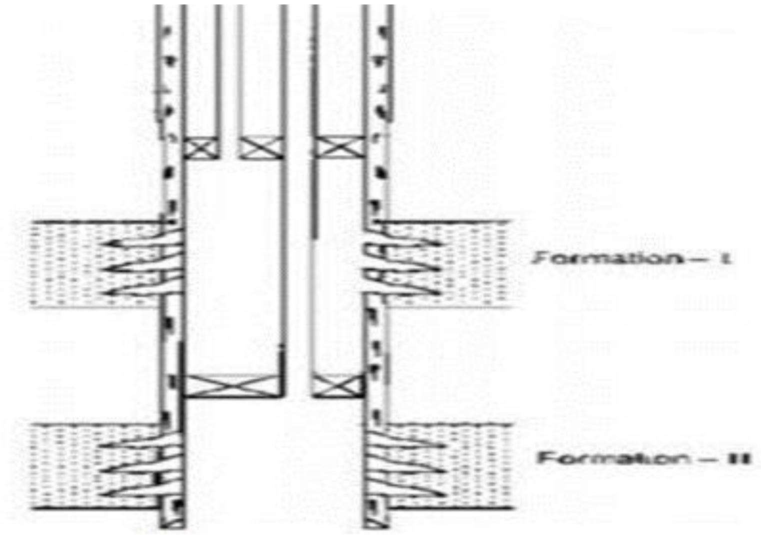


Figure 2-19 Multiple Zone Completions

Drain hole completions:

They are a form of horizontal or slant drilling. This type of completion consists of drilling out horizontally into the formation from a vertical well, essentially providing a ' drain' for the hydrocarbons to run down into the well. These completions are more commonly associated with oil wells than with natural gas wells.

2.3.2. Wellhead

Wellheads can be installed for Dry or Subsea completion. Dry Completion means that the well is onshore on the topside structure on an offshore installation. Subsea wellheads are located under water on a special sea bed template. The wellhead consists of the pieces of equipment mounted at the opening of the well to regulate and monitor the extraction of hydrocarbons from the underground formation. It also prevents leaking of oil or natural gas out of the well, and prevents blowouts due to high pressure formations. Formations that are under high pressure typically require wellheads that can withstand a great deal of upward pressure from the escaping gases and liquids. These wellheads must be able to withstand pressures of up to 140 MPa (1400 Bar).

The wellhead consists of three components: the casing head \ the tubing head \ and the Christmas tree. A typical Christmas tree composed of a master gate valve, a pressure gauge, a wing valve, a swab valve and a choke. The Christmas tree may also have a number of check valves. The functions of these devices are explained in the following paragraphs. At the bottom we find the Casing Head and casing Hangers. The casing will be screwed, bolted or welded to the hanger. Several valves and plugs will normally be fitted to give access to the casing. This will permit the casing to be opened, closed, bled down, and, in some cases, allow the flowing well to be produced through the casing as well as the tubing. The valve can be used to determine leaks in casing, tubing or the packer, and will also be used for lift gas injection into the casing. The tubing hanger (also called donut) is used to position the tubing correctly in the well. Sealing also allows Christmas tree removal with pressure in the casing.

Christmas tree components are: Master gate valve, wing valve, swab valve, and variable flow choke valve. The master gate valve is a high quality valve. It will provide full opening, which means that it opens to the same inside diameter as the tubing so that specialized tools may be run through it. It must be capable of holding the full pressure of the well safely for all anticipated purposes. This valve is usually left fully open and is not used to control flow. The pressure gauge, which is the minimum instrumentation, is placed above the master gate valve before the wing valve. In addition, other instruments such as temperature will normally be fitted.

The wing valve can be a gate valve, or ball valve. When shutting in the well, the wing gate or valve is normally used so that the tubing pressure can be easily read. The swab valve is used to gain access to the well for wireline operations, intervention and other work over procedures (see below), on top of it is a tree adapter and cap that will mate with various equipment.

The variable flow choke valve is typically a large needle valve. Its calibrated opening is adjustable in 1/64 inch increments (called beans). High-quality steel is used in order to withstand the high-speed flow of abrasive materials that pass through the choke, usually for many years, with little damage except to the dart or seat. If a variable choke is not required, a less expensive positive choke is normally installed on smaller wells. This has a built in restriction that limits flow when the wing valve is fully open. Christmas Tree shapes are Vertical (**Fig. 2-20**) or Horizontal Christmas trees where the master, wing and choke is on a horizontal axis. This reduces the height and may allow easier intervention. Horizontal trees are especially used on subsea wells.

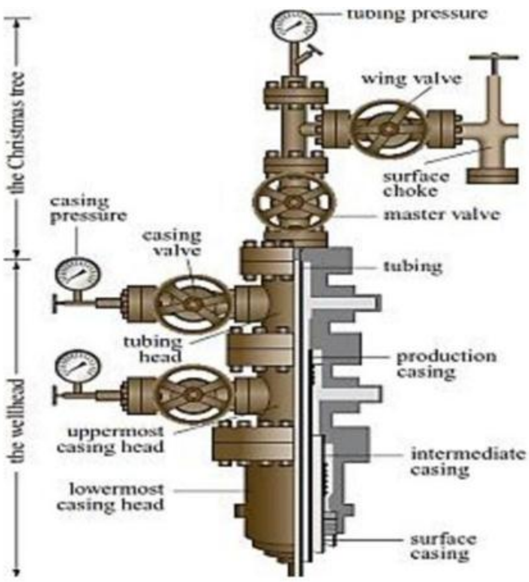


Figure 2-20 Vertical Christmas Tree

2.3.2.1. Types of Well

Subsea wells

Subsea wells are essentially the same as dry completion wells. However, mechanically they are placed in a Subsea structure (template) that allows the wells to be drilled and serviced remotely from the surface, and protects from damage e.g. from trawlers. The wellhead is placed in a slot in the template where it mates to the outgoing pipeline as well as hydraulic and electric control signals. Control is from the surface where a hydraulic power unit (HPU) provides hydraulic power to the subsea installation via an umbilical. The umbilical is a composite cable containing tension wires, hydraulic pipes, electrical power and control and communication signals. A control pod with inert gas and/or oil protection contains control electronics, and operates most equipment Subsea via hydraulic switches. More complex Subsea solutions may contain subsea separation/stabilization and electrical multiphase pumping. This may be necessary if reservoir pressure is low, offset (distance to main facility) is long or there are flow assurance problems so that the gas and liquids will not stably flow to the surface. Product is piped back through pipelines and risers to the surface. The main choke may be located topside.

Production and Injection Wells

Wells are also divided into production and injection wells. The former is for production of oil and gas; injection wells is drilled to inject gas or water into the reservoir. The purpose of injection is to maintain overall and hydrostatic reservoir pressure and force the oil toward the production wells. When injected water reaches the production well, this is called injected water break through. Special logging instruments, often based on radioactive isotopes added to injection water, are used to detect breakthrough. Injection wells are fundamentally the same as production wellheads other than the direction of flow and therefore the mounting of some directional component such as the choke.

Artificial Lift Wells

Production wells are free flowing or lifted. A free flowing oil well has enough downhole pressure to reach a suitable wellhead production pressure and maintain an acceptable well-flow. If the formation pressure is too low, and water or gas injection cannot maintain pressure or is not suitable, then the well must be artificially lifted. For smaller wells, 0.7 MPa (100 PSI) wellhead pressure with a standing column of liquid in the tubing is considered a rule-of-thumb to allow the well to flow. Larger wells will be equipped with artificial lift to increase production even at much higher pressures. Some artificial lift methods are:

A. Rod Pumps

Sucker Rod Pumps (**Fig. 2-21**), also called Donkey pumps or beam pumps, are the most common artificial-lift system used in land-based operations. A motor drives a reciprocating beam, connected to a polished rod passing into the tubing via a stuffing box. The sucker rod continues down to the oil level and is connected to a plunger with a valve. On each upward stroke, the plunger lifts a volume of oil up and through the wellhead discharge. On the downward stroke it sinks (it should sink, not be pushed) with oil flowing though the valve. The motor speed and torque is controlled for efficiency and minimal wear with a Pump off Controller (PoC). Rod pumps use is limited to shallow reservoirs down to a few hundred meters, and flows up to about 40 liters (10 gal) per stroke.

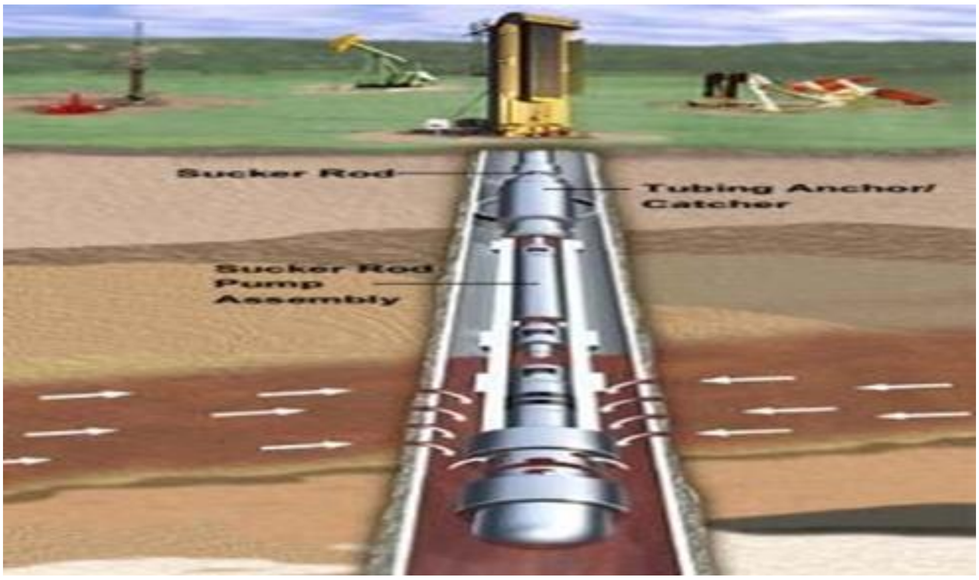


Figure 2-21 Rod pump

B. Downhole Pumps

Downhole pump inserts the whole pumping mechanism into the well. In modern installations, an Electrical Submerged Pump (ESP) is inserted into the well (**Fig. 2-22** Electrical Submerged Pump (ESP)). Here the whole assembly consisting of a long narrow motor and a multiphase pump, such as a PCP (progressive cavity pump) or centrifugal pump, hangs by an electrical cable with tension members down the tubing. Installations down to 3.7 km with power up to 750 kW have been installed. At these depths and power ratings, Medium Voltage drives (up to 5kV) must be used. ESPs works in deep reservoirs, but lifetime is sensitive to contaminants such as sand, and efficiency is sensitive to GOR (Gas Oil Ratio) where gas over 10% dramatically lowers efficiency.

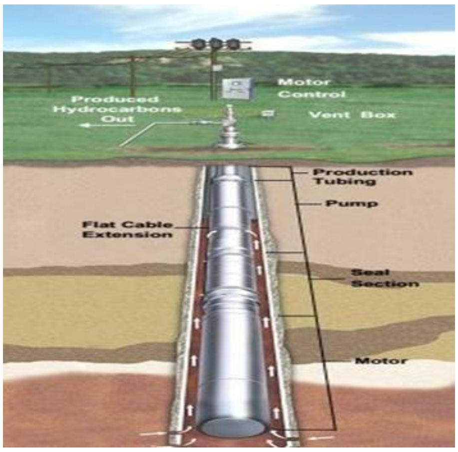


Figure 2-22 Electrical Submerged Pump (ESP)

C. Gas Lift

Gas Lift injects gas into the well flow (**Fig. 2-23** Gas lift). The downhole reservoir pressure falls off to the wellhead due to the counter pressure from weight of the oil column in the tubing. Thus a 150 MPa reservoir pressure at 1600 meters will fall to zero wellhead pressure if the specific gravity is 800 kg/m^2. (0,8 times water). By injecting gas into this oil, the specific gravity is lowered and the well will start to flow. Typically gas in injected between casing and tubing, and a release valve on a gas lift mandrel is inserted in the tubing above the packer. The valve will open at a set pressure to inject lift gas into the tubing. Several mandrels with valves set at different pressure ranges can be used to improve lifting and start up. Ill: Schlumberger oilfield glossary Gas lift can be controlled for a single well to optimize production, and to reduce slugging effects where the gas droplets collect to form large bubbles that can upset production. Gas lift can also be optimized over several wells to use available gas in the most efficient way.

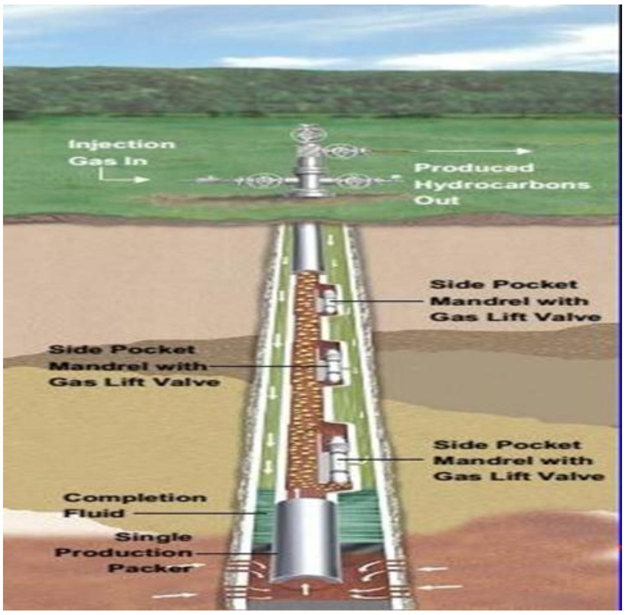


Figure 2-23 Gas lift

D. Plunger Lift

Plunger lift is normally used on low pressure gas wells with some condensate, oil or water, or high gas ratio oil wells (**Fig. 2-24** Plunger Lift). In this case the well flow conditions can be so that liquid starts to collect downhole and eventually blocks gas so that the well production stops. In this case a plunger with an open/close valve can be inserted in the tubing. A plunger catcher at the top opens the valve and can hold the plunger, while another mechanism downhole will close the valve.

The cycle starts with the plunger falling into the well with its valve open. Gas, condensate and oil can pass though the plunger until it reaches bottom. There the valve is closed, now with a volume of oil, condensate or water on top. Gas pressure starts to accumulate under the plunger and after some time pushes the plunger upwards, with liquid on top, which eventually flows out of the wellhead discharge. When the plunger reaches the wellhead plunger catcher, the valve opens and allows gas to flow freely for some time while new liquid collects at the bottom. After some preset time, the catcher will release the plunger, and the cycle repeats.

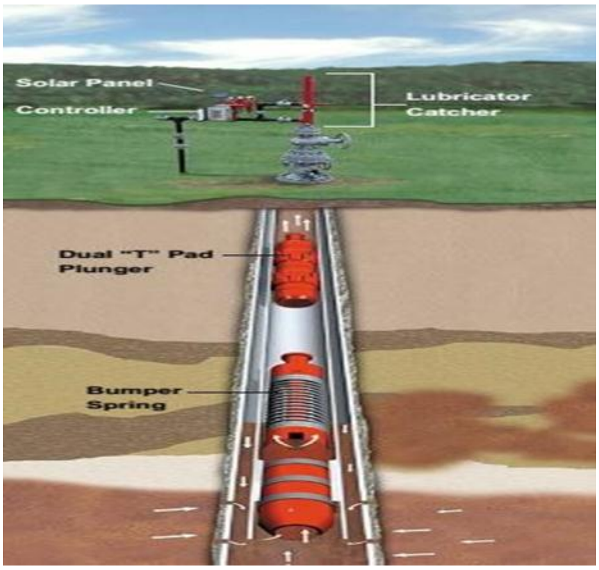


Figure 2-24 Plunger Lift

2.4. Oil and Gas Process in Surface Production Facility

2.4.1. Overview

The primary function of a production facility is to separate the well stream into three components, typically called phases (oil, gas, and water), and process these phases into some marketable products or dispose of them in an environmentally acceptable manner. **Fig. 2-25** shows overview of oil and gas process in surface production facility.

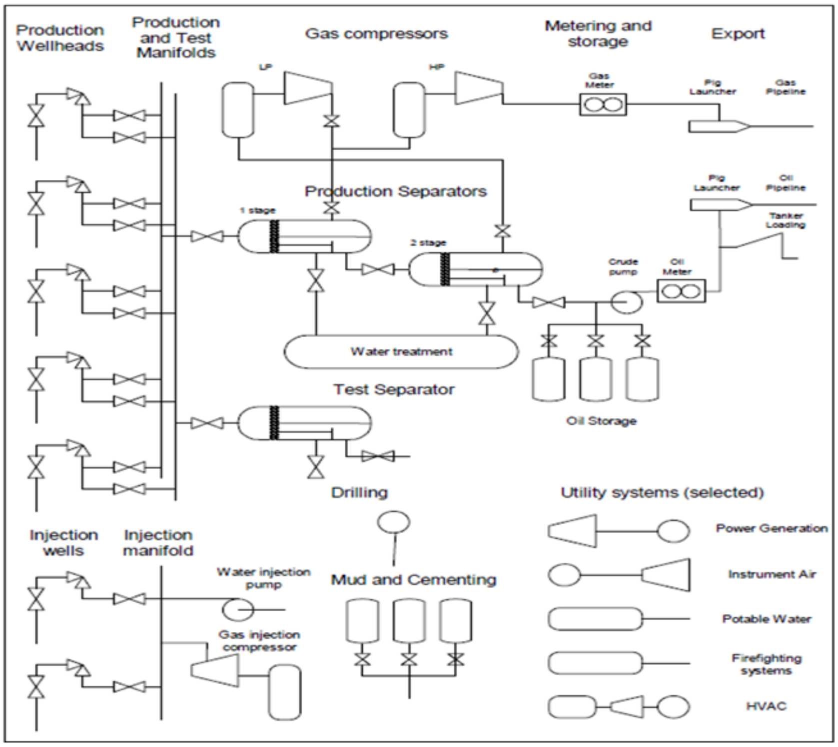


Figure 2-25 Overview of Oil and Gas Process in Surface Production Facility

2.4.2. Gathering System

Gathering system or manifold is a combination of pipes, fittings, and valves used to combine production from several sources and direct the combined flow into appropriate production equipment. A manifold may also originate from a single inlet stream and divide the stream into multiple outlet streams. Manifolds are generally located where many flow lines come together, such as gathering stations, tank batteries, metering sites, separation stations, and offshore platforms. Manifold headers are categorized to High production header, Low production header and HP/ LP Test headers. Manifolds also are used in gas lift injection systems, gas/water injection systems, pump/compressor stations, and gas plants and installations where fluids are distributed to multiple units. Production manifold accepts the flow streams from well flow lines and directs the combined flow to either test or production separators and tanks.

2.4.3. Oil, Gas and Water Separation System

The well-stream basically consists of crude oil, gas, condensates, water and various contaminants. The purpose of the separator is to split the flow into desirable fractions.

Types of separators can be classified based on stages of crude oil process and purpose of separator to the following categories:

2.4.3.1. First Stage Separator

First stage separator is normally the main separator in oil and gas process and its designed on principle of gravity of fluids. The main components and internal parts of first stage separator are pointed out below on **Fig. 2-26** and **Fig. 2-27** Production choke on production manifold reduces well pressure to the HP manifold and first stage separator to about 3-5 MPa (30-50 times atmospheric pressure). Inlet temperature is often in the range of 100-150 ºC.

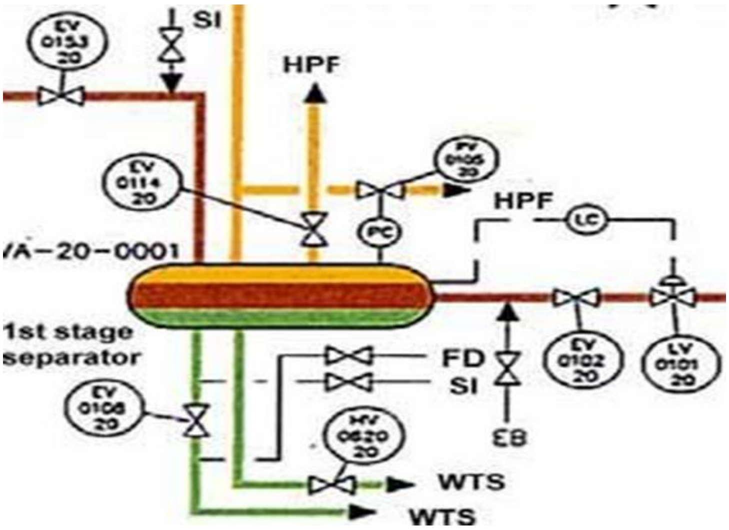


Figure 2-26 First Stage Separator

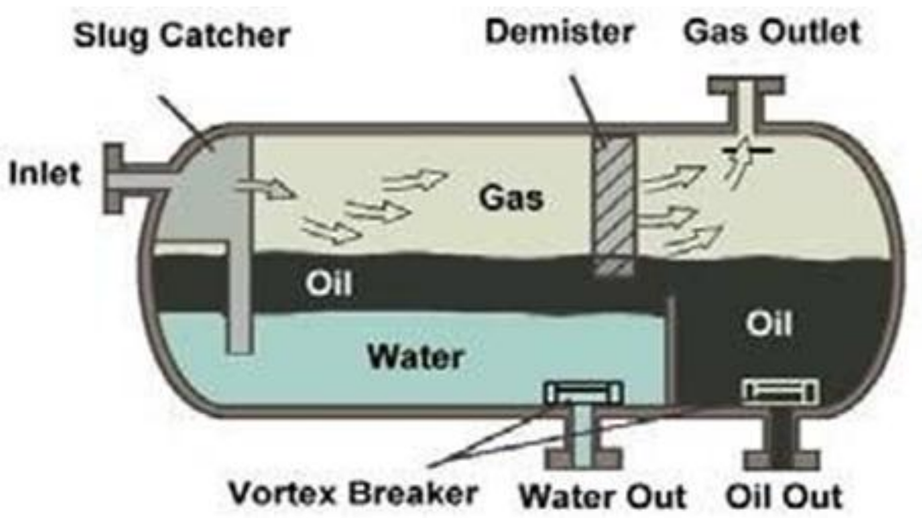


Figure 2-27 Internal parts of first stage separator

The pressure is often reduced in several stages. In this instance, three stages of separation are used to allow the controlled separation of volatile components. The idea is to achieve maximum liquid recovery and stabilized oil and gas, and to separate high volumes of produced water from wells at these stages.

2.4.3.2. Second Stage Separator

The second stage separator is quite similar to the first stage HP separator. In addition to output from the first stage, it also receives production from wells connected to the LP manifold. The pressure is now around 1 MPa (10 atmospheres) and temperature below 100ºC. The water content will be reduced to below 2%. An oil heater can be located between the first and second stage separator to reheat the oil/water/gas mixture. This makes it easier to separate out water when initial water cut is high and temperature is low.

2.4.3.3. Third Stage Separator

The third stage separator is the final separator which is a two-phase separator, also called a flash drum. The pressure is now reduced to atmospheric pressure of around 100 kPa, so that the last heavy gas components can boil out. In some processes where the initial temperature is low, it might be necessary to heat the liquid again (in a heat exchanger) before the flash drum to achieve good separation of the heavy components. As an alternative, when production is mainly gas, and remaining liquid droplets have to be separated out, the two-phase separator can be a knock- out drum (K.O. drum). After the third stage separator, the oil can go to a coalescer for final removal of water or oil (**Fig. 2-28**) and (**Fig. 2-29**). In this unit, water content can be reduced to below 0.1%. The coalescer is completely filled with liquid: water at the bottom and oil on top. Internal electrodes form an electric field to break surface bonds between conductive water and isolating oil in an oil-water emulsion.

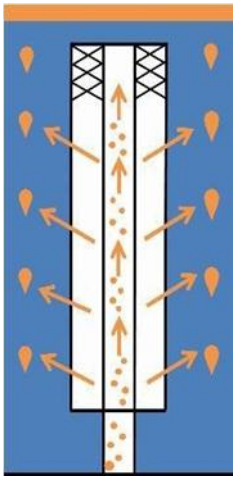


Figure 2-28 Coalescer (Oil separation from Water)

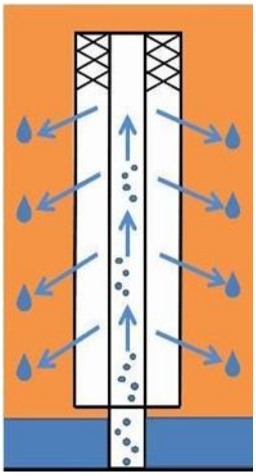


Figure 2-29 Coalescer (Water separation from Oil)

2.4.3.4. Test Separator

Test separator is used to separate the well flow from one or more wells for analysis and detailed flow measurement. In this way, the behavior of each well under different pressure flow conditions can be defined. This process normally takes place when the well is taken into production and later is taken into test at regular intervals (typically 1-2 months) in order to measure the total and component flow rates under different production conditions. Undesirable consequences such as slugging or sand can also be determined.

2.5. Oil, Gas and Water Treatment System

2.5.1. Oil Treatment System

As described above, the initial step in the oil treatment process is performed by a series of one, two or three stage separators. The pressure is gradually reduced and associated gas and free water, together with the solids are separated and drawn off from the well stream. This removes the bulk of the water and gas from the oil phase of the well stream before it passes to the next stage of the process. The next stage of the oil treatment process is to remove the dissolved salts from the oil phase. This can be achieved by using Heater treater and electrostatic dehydrator and/or Desilter units to produce a stabilized crude oil to meet the end user 's specification.

2.5.1.1. Heater Treater

A vessel that uses heat to break oil-water emulsions so the oil can be accepted by the pipeline or transport. There are vertical and horizontal treaters (**Fig. 2-30** and **Fig. 2-31**) The main difference between them is the residence time, which is shorter in the vertical configuration compared with the horizontal one.

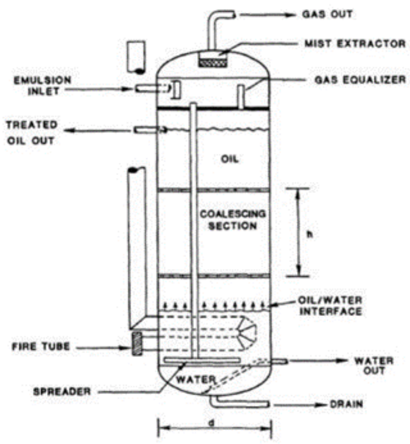


Figure 2-30 Vertical Heater Treater

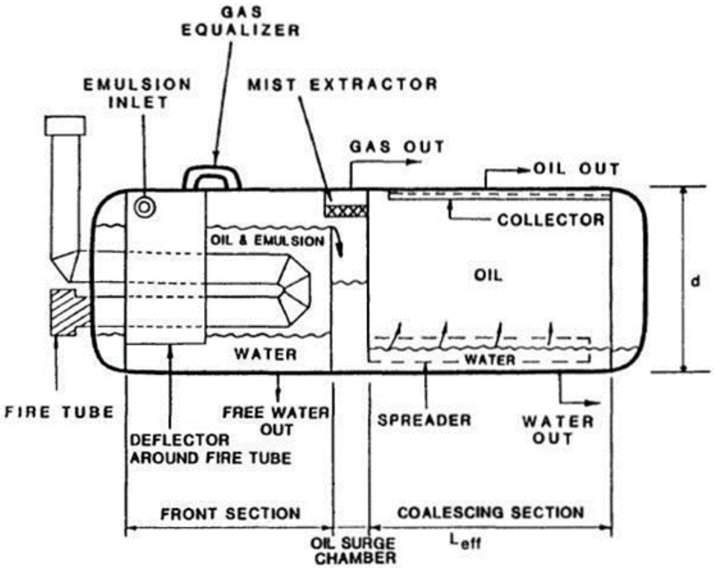


Figure 2-31 Horizontal Heater Treater

2.5.1.2. Electrostatic Desilter

The separated oil from separator and heater treater contains unacceptable amounts of salts which can be removed in an electrostatic Desilter (**Fig. 2-32**). The salts, which may be sodium, calcium or magnesium, chlorides. The disasters will be placed after the first or second stage separator depending on GOR and water cut.

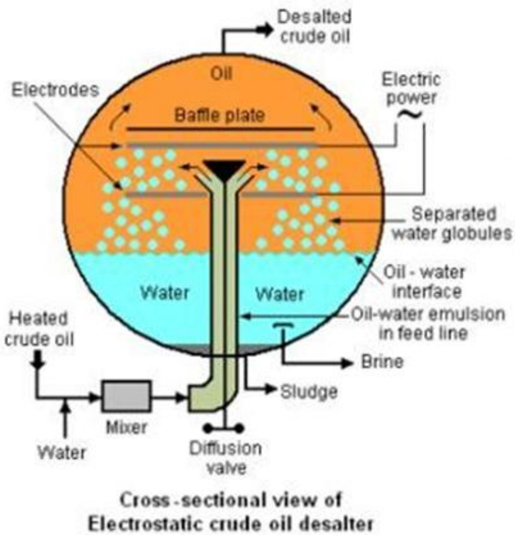


Figure 2-32 Electrostatic Desilter

2.5.2. Gas Treatment System

Gas treatment system consists of several stages. Each stage takes the gas from a suitable pressure level in the petroleum production system. All natural gas downstream from the separators still contain water vapor to some degree. Therefore, removing most of the water vapor from the gas stream process is required to prevent hydrates from forming when the gas is cooled in the transmission and distribution systems and prevents water vapor from condensing and creating a corrosion problem. The Gas stream can be processed through a list of processing equipment in production facility as per following below:

2.5.2.1. Dehydration unit

There are various types of gas-drying equipment available, but the most common type is glycol dehydration unit (**Fig. 2-33**). The purpose of this unit is to remove water from natural gas and natural gas liquids. When produced from a reservoir, natural gas usually contains a large amount of water and is typically completely saturated or at the water dew point. Thus, at low temperatures the water can either freeze in piping or, as is more commonly the case, form hydrates with CO_2 and hydrocarbons (mainly methane hydrates). The most common liquid used in absorption of water in dehydration unit is triethylene glycol (TEG).

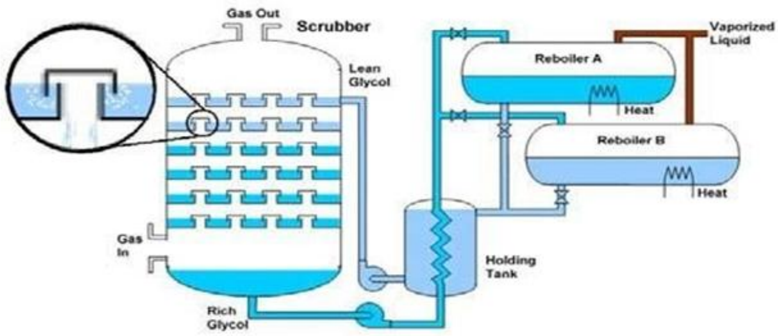


Figure 2-33 Glycol Dehydration unit

2.5.2.2. Heat Exchanger

Heat exchanger is a system used to transfer heat between two or more fluids. Heat exchanger is used in both cooling and heating processes. The fluids may be separated by a solid wall to prevent mixing or they may be in direct contact. Plate heat exchanger (**Fig. 2-34**) consists of a number of plates where the gas and cooling medium pass between alternating plates in opposing directions. Tube and shell exchanger (**Fig. 2-35**) contains tubes inside a shell filled with cooling fluid. The cooling fluid is often pure water with corrosion inhibitors.

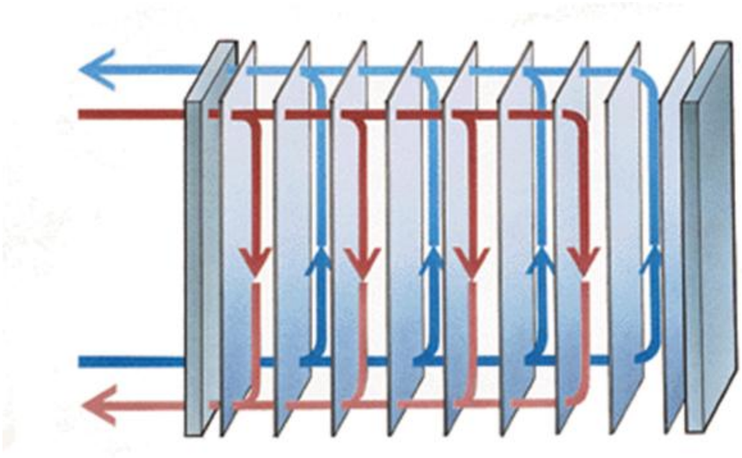


Figure 2-34 Plate heat exchangers

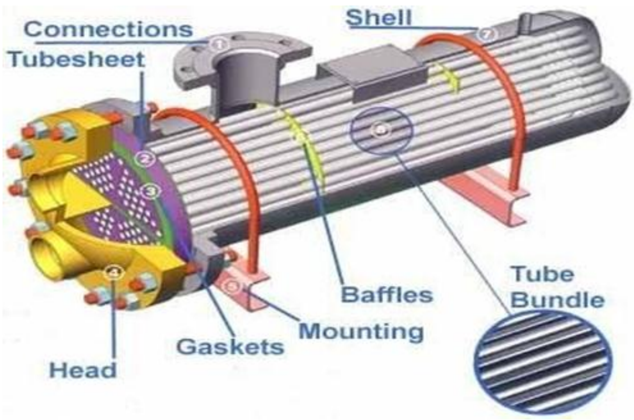


Figure 2-35 Tube and shell exchangers

2.5.2.3. Gas Compression

Compressors are used for providing gas pressure required to transport gas with pipelines and to lift oil in gas-lift operations. The compressors used in today ‘s natural gas production industry fall into two distinct types: reciprocating and rotary compressors. Reciprocating compressors are most commonly used in the natural gas industry. They are built for practically all pressures and volumetric capacities As shown in **Fig. 2-36** and **Fig. 2-37**. Rotary compressors are divided into two classes: the centrifugal compressor and the rotary blower.

Figure 2-36 Reciprocating compressors

Figure 2-37 Rotary compressors

2.5.3. Water Treatment System

When hydrocarbons (crude oil, condensate, and natural gas) are produced, the well stream typically contains water produced in association with these hydrocarbons. The produced water is usually brine, brackish, or salty in quality but in rare situations may be nearly fresh in quality. The water must be separated from the hydrocarbons and injected or disposed of in a manner that does not violate established environmental regulations. Typically, the produced water is separated from the hydrocarbons by passing the well stream through process equipment such as three-phase separators, heater-treaters, and/or a free-water knockout vessel. However, these gravity separation devices do not achieve a full 100% separation of the hydrocarbons from the produced water. The list of equipment which can be employed in the final process stage of produced water treating systems (**Fig. 2-38**) based on different methods are:

Skim piles, Skimmer tanks and vessels, Disposal piles, Skim piles, Parallel plate interceptors, Corrugated plate interceptors, Precipitators, Filters/coalesces (**Fig. 2-39**), Free-flow turbulent coalesces, Hydrocyclones (**Fig. 2-40**), Centrifuges, and Multimedia membrane.

Figure 2-38 Produced Water Treatment System

Figure 2-39 Hydrocyclones unit

Figure 2-40 Water Filtration System

2.5.4. Storage and Oil Transfer/Measurement System

2.5.4.1. Storage Tanks

Oil is stored in onboard storage tanks (**Fig. 2-41**) to be transported by shuttle tanker. The oil is stored in storage cells around the shafts on concrete platforms, and in tanks on floating units. On some floaters, a separate storage tanker is used. Ballast handling is very important in both cases to balance the buoyancy when oil volume varies. For onshore, fixed roof tanks are used for crude, floating roof for condensate. Rock caves are also used for storage.

Figure 2-41 Storage Tanks

2.5.4.2. Pumps

After separation, oil is transported through pipelines to the sales points. There are several types of pumps in oil industry, but the common ones are:

Centrifugal Pump

The most common type of pump found in the oil and gas industry is undoubtedly the centrifugal pump (**Fig. 2-42**). Centrifugal pumps contain one or more impellers that move fluid by rotation and draw fluid into the suction end of the pump and then, through centrifugal force, forces it out of the discharge end. This design allows the pumps to be used for a wide range of applications and are preferred for processes that handle low viscosity liquids and high flow rates. Centrifugal pumps can also handle dirty liquids or liquids with low viscosity as long as they do not contain air, vapors, or heavy amount of solids. Centrifugal pumps are used in the upstream oil and gas industry as part of tri-phase or multiphase pumping application. These pumps serve a wide variety of applications with many types such as electric submersible pumps, which are used as a water and oil separator in which water can be re-injected into a reservoir without the lifting it to the ground surface. They can transport a significant amount of low viscosity liquids in a short period and can pump several hundred gallons of liquid per minute if the product is compatible.

Figure 2-42 Centrifugal Pump

Positive Displacement Pump

In contrast to centrifugal pumps, a positive displacement pump (**Fig. 2-43**) does not use impellers to move the fluid. Instead, they utilize rotating or reciprocating parts to push transport the liquid into an enclosed volume. This design creates pressure, which drives the liquid to its destination. A positive displacement pump is ideal for higher viscosity liquids that are transported at a lower flow rate but a higher pressure. An example of a positive displacement pump is a chemical injection pump. Positive Displacement Pumps are utilized in the upstream phase of an oil refinery. They are a more compact unit, which increases the high-pressure ratio, making them among the most efficient types of pump, as well as a low-cost solution. Despite their affordability and efficiency, positive placement pumps do require extensive maintenance, partly due to mechanical part failures. They ‘re also noisier than a centrifugal compressor, which could raise issues in certain applications. Positive displacement pumps are not typically used in situations that demand high flow rates.

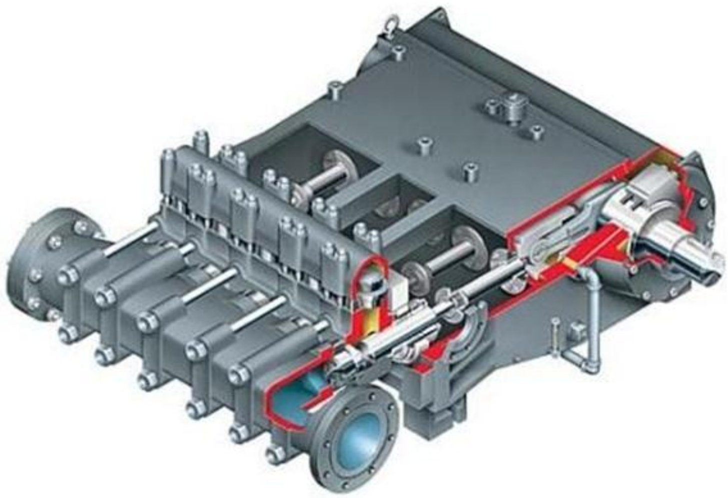


Figure 2-43 Positive Displacement Pump

Oil Transfer Pump

An oil transfer pump (**Fig. 2-44**) is used to transfer glycol from a well to a holding tank during the midstream and downstream phase of oil refinement. Due to the high volume of activity that an oil pump engages in, they require extensive maintenance and repairs to continue working correctly. Transfer pumps create a variation in pressure that pushes fluid from location to another. Industrial scale slurry pumps can operate on electric, solar, hydraulic or gas power. Oil companies use transfer pumps to move flammable or corrosive liquids like oil, gas, or chemicals. These types of pumps are safe to use for these applications because the components are manufactured with corrosion-resistant metals which hold up well in hazardous environmental conditions.

Figure 2-44 Oil Transfer Pump

Diaphragm Pump

A diaphragm pump (**Fig. 2-45**) is a type of positive displacement pump that uses both a valve and a diaphragm to draw oil and gas into a refinery chamber during the upstream and midstream phase of oil refinement. When the volume of a chamber increases, the pressure in the chamber reduces, and the fluid pours into the chamber. The diaphragm then moves down and forces the liquid out. Once the fluid has cleared the chamber, the diaphragm moves back into position, allowing more fluid to enter. This cycle continues while the pump is operating. Due to their unique design, diaphragm pumps can transport large volumes of liquid and are ideal for refineries that are located over sizable oil sources. Diaphragm pumps are also far more wear resistant than positive displacement pumps because they have fewer moving parts or friction points that wear down the components. However, diaphragm pumps do suffer from winks '– small gaps in the process that can slow down the flow of fluid. Winks and low pressure are likely to occur over long distances.

Figure 2-45 Diaphragm Pump

2.5.4.3. Pipelines

The pipelines (**Fig. 2- 46**) are by far the most economical means of large-scale overland transportation for crude oil, natural gas, and their products, clearly superior to rail and truck transportation over competing routes, given large quantities to be moved on a regular basis. Transporting petroleum fluids with pipelines is a continuous and reliable operation. Pipelines have demonstrated an ability to adapt to a wide variety of environments including remote areas and hostile environments. The pipelines are sized to handle the expected pressure and fluid flow rate.

Figure 2-46 Oil or Gas pipelines

2.5.5. Oil and Gas measurement system (LACT unit)

LACT unit is for the automated transferring and measuring of oil, condensate and natural gas liquids. The unit measures quantity and quality of the product transferred from seller to buyer. The buyer may receive the product by pipeline, tanker truck, barge or ship. LACT units are typically skid mounted and installed as a unit at a field facility. The complexity and arrangement of devices may vary but the typical unit includes:

Pump, Strainer, Deaerator (Air and Gas Eliminator), BS&W Probe, BS&W Monitor, Sample Probe, Sample Container, Diverter Valve, Meter, Prover Loop Connections, Control Panel.

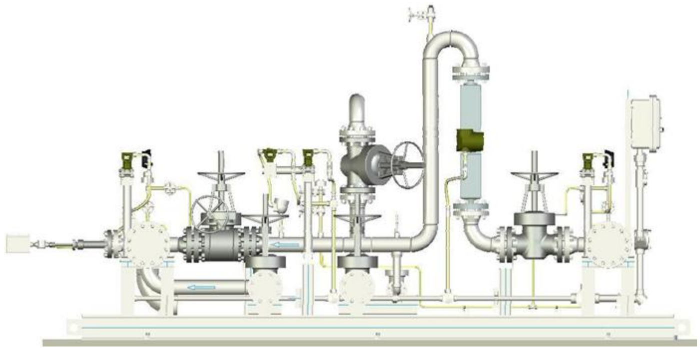


Figure 2-47 LACT unit

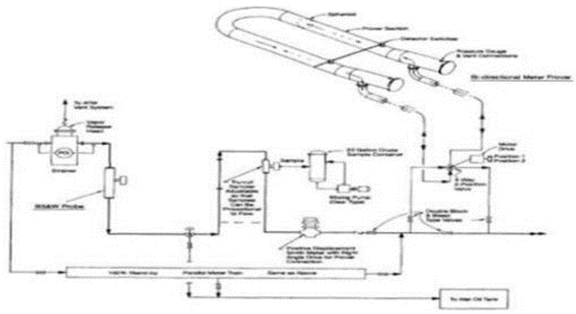


Figure 2-48 Prover Loop connections

2.5.6. Safety Control System

The purpose of safety systems is to protect personnel, the environment, and the facility. The major objective of the safety system is to prevent the release of hydrocarbons from the process and to minimize the adverse effects of such releases if they occur. The modes of safety system operation include: Automatic monitoring by sensors, Automatic protective action, and Emergency shutdown.

2.6. Nodal Systems Analysis of Oil and Gas Wells

Nodal system analysis is defined as a system approach to the optimization of oil and gas wells, and it is used to evaluate thoroughly a complete producing system. Every component in a producing well or all wells in a producing system can be optimized to achieve the objective flow rate most economically.

The objectives of nodal analysis are as follows.

1. To determine the flow rate at which an existing oil or gas well will produce considering wellbore geometry and completion limitations (first by natural flow).

2. To determine under what flow conditions (which may be related to time) a well will load or die.
3. To select the most economical time for the installation of artificial lift and to assist in the selection of the optimum lift method.
4. To optimize the system to produce the objective flow rate most economically.
5. To check each component in the well system to determine whether it is restricting the flow rate unnecessarily.
6. To permit quick recognition by the operator's management and engineering staff of ways to increase production rates.

2.6.1. Well Productivity

An ideal well productivity is the final goal of Production Optimization. In particular, well productivity is determined by a well inflow performance and a common approach is Nodal Analysis. It is a system analysis approach applied to analyze the performance of systems composed of interacting components.

The Inflow Performance Relationship (IPR) is defined as the functional relationship between the inflow production rate and the inflowing pressure at node. The Outflow Performance Relationship (OPR) is defined as the functional relationship between the outflow production rate and the outflowing pressure at node. The interaction of IPR and OPR is the Working Point of the system. Productivity Index (PI or J) expresses the ability of a reservoir to deliver fluids to the wellbore. Optimal well productivity is achieved by the use of an integrated approach of disciplines and operations.

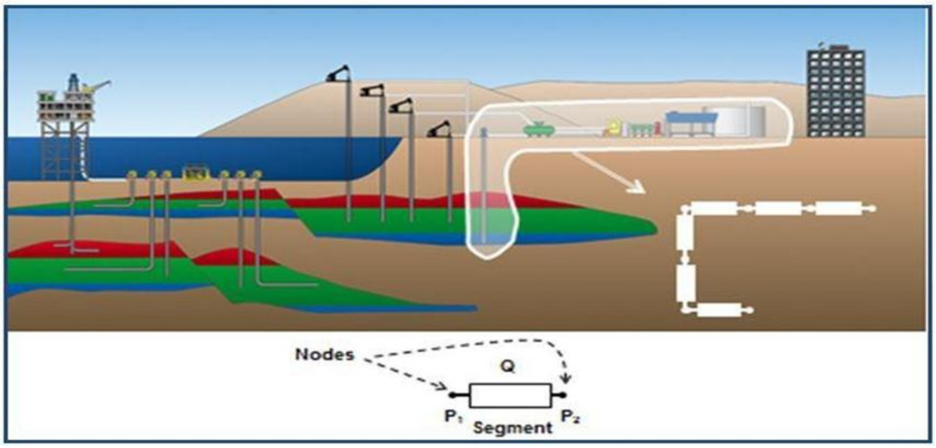


Figure 2-49 Well Performance Analysis

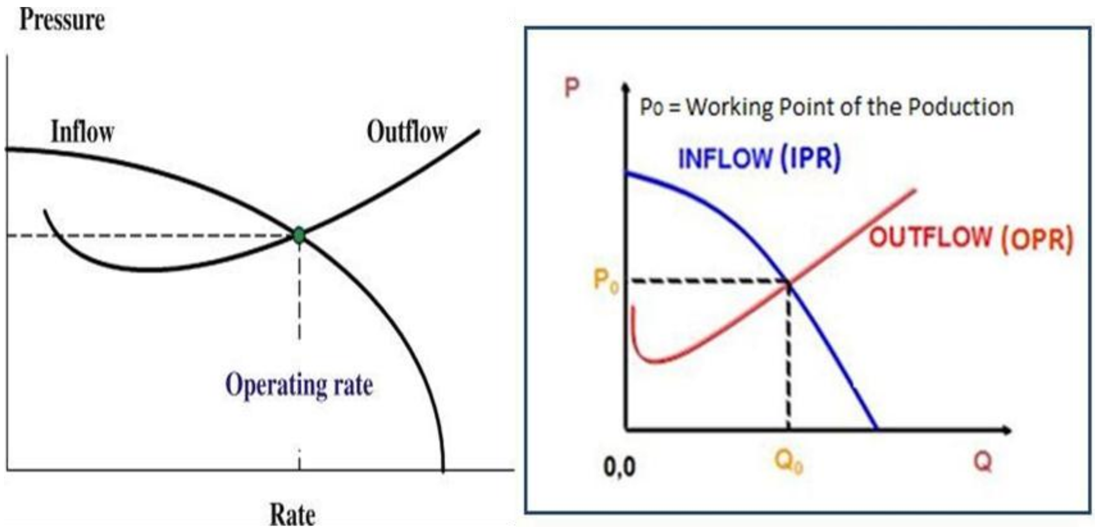


Figure 2-50 IPR and OPR interaction

For a naturally flowing production well, the solution node is placed at the bottom hole which results in the VLP accounting for the pressure drop from the wellhead to the bottom hole.

CHAPTER THREE

3. METHODOLOGY

3.1. Type of Data Required.

3.1.1. Well Production History

3.1.1.1. Halewah well No.6 Production History Plot

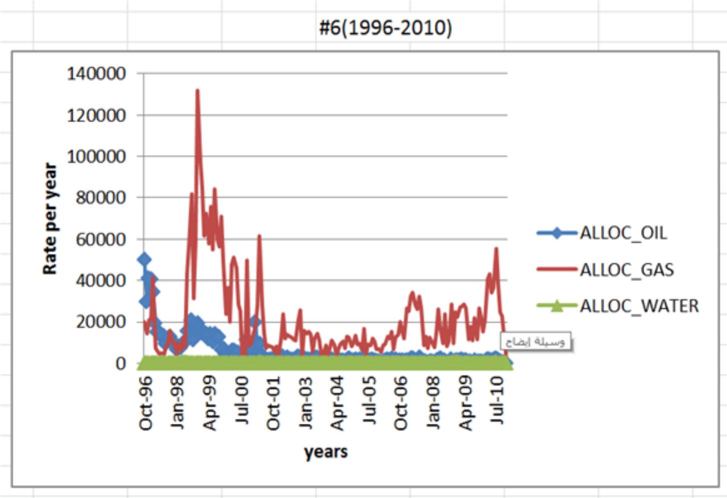


Figure 3-1 Halewah well No.6 Production History Plot

3.1.1.2. Halewah well No. 9 Production History Plot

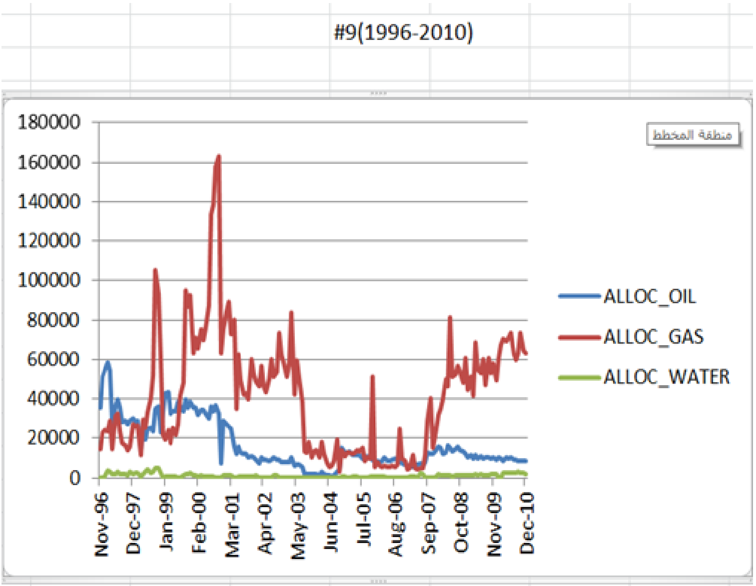


Figure 3-2 Halewah well No. 9 Production History Plot

3.1.2. Well Bottom Hole Pressure Survey

3.1.2.1. Halewah No.9 BHP Survey Plot

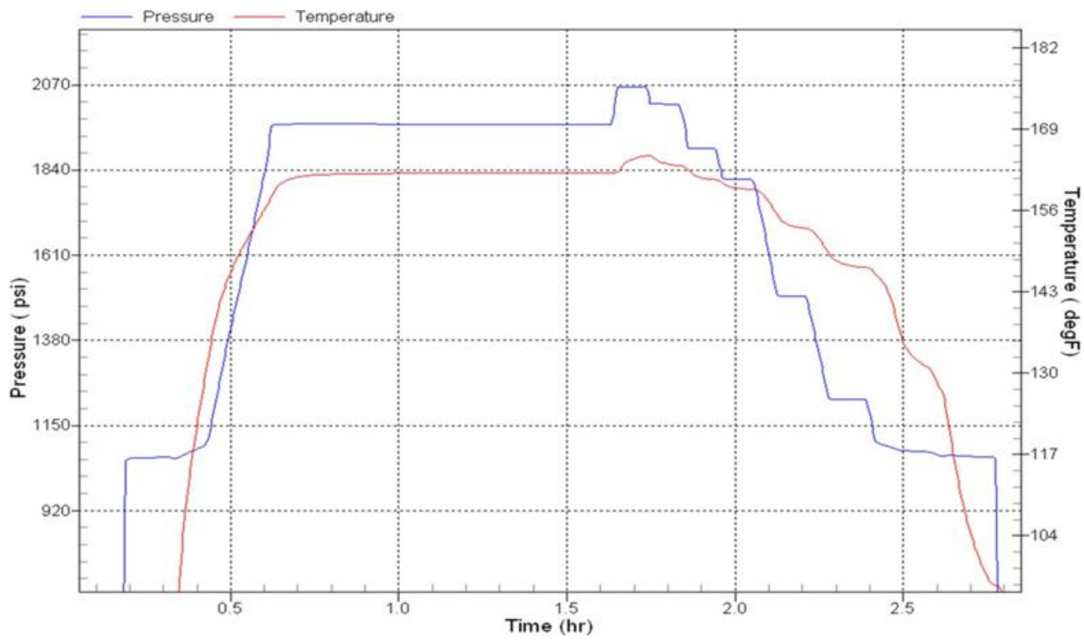


Figure 3-3 Halewah No.9 BHP Survey Plot

3.1.3. Well Test Data

3.1.3.1. Halewah No.6 Well Test Report

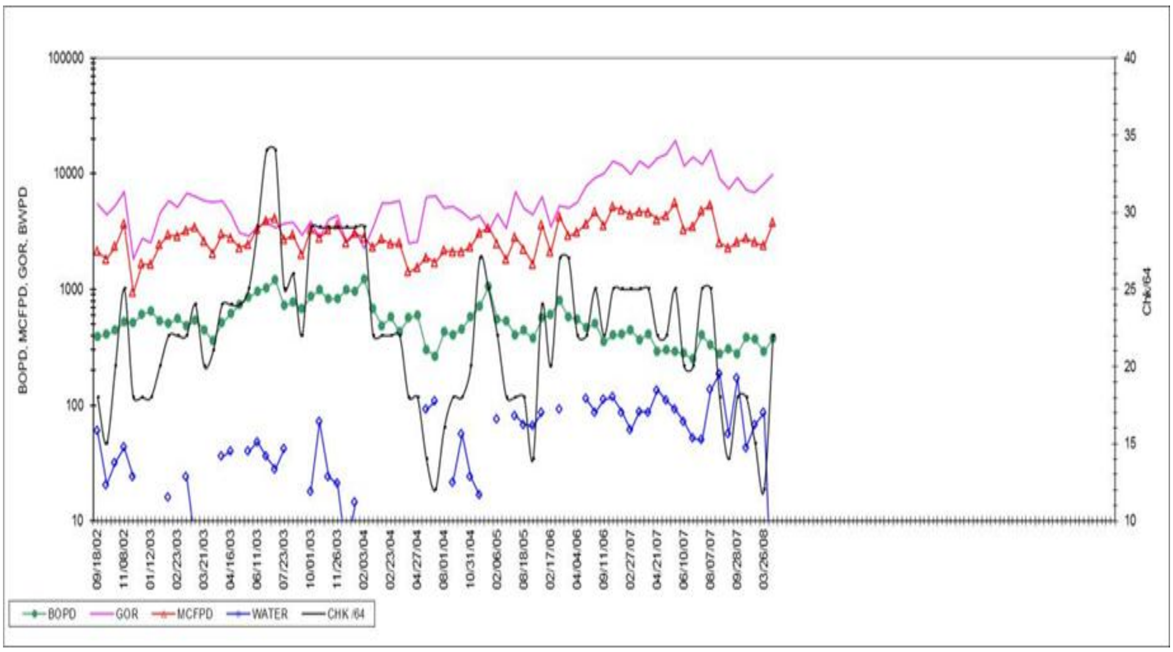


Figure 3-4 Halewah No.6 Well Test Report

3.1.3.2. Halewah No. 9 Well Test Report

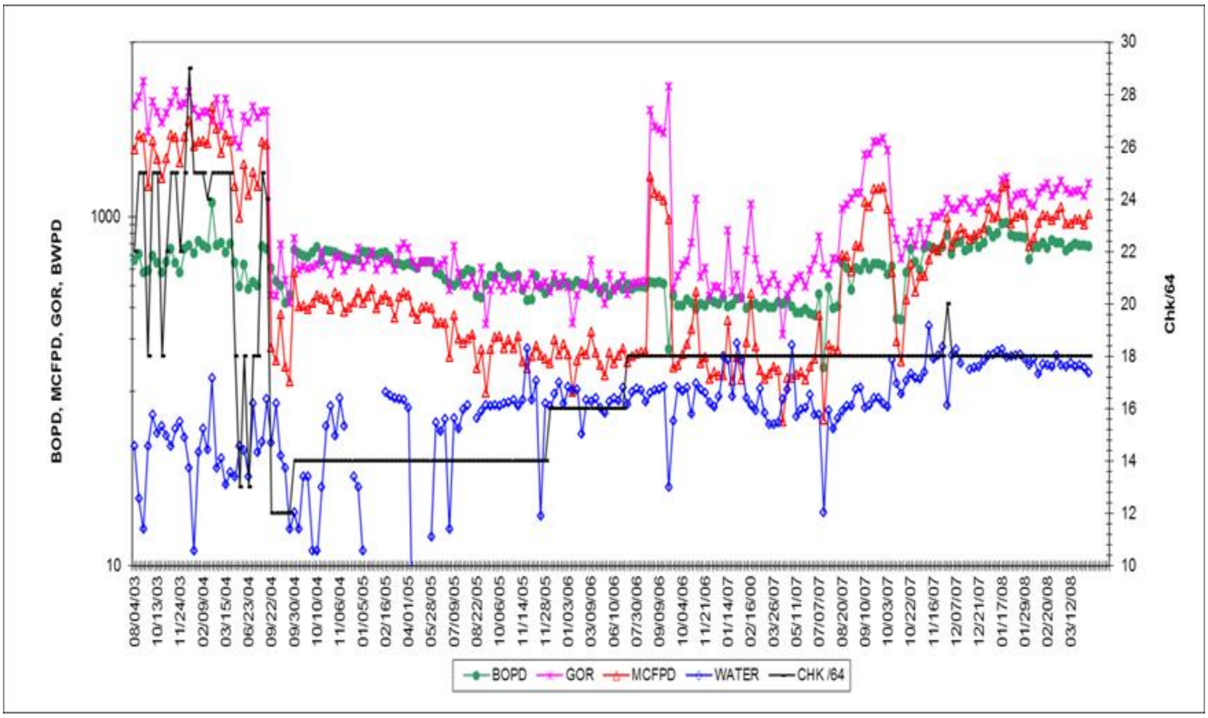


Figure 3-5 Halewah No. 9 Well Test Report

3.1.4. Reservoir and Fluid Data

3.1.4.1. Reservoir and Fluid Data H6

Reservoir Pressure: 2068 psig

Reservoir Temp: 166 Deg F

Oil Gravity: 45 API

Gas Gravity: 0.75

Water Salinity :300000 ppm

Water Cut: 10 %

Type	Label	Rate Multiplier	Measured Depth	True Vertical Depth	Pipe Length	Tubing Inside Diameter	Tubing Inside Roughness	Tubing Outside Diameter	Tubing Outside Roughness	Casing Inside Diameter	Casing Inside Roughness
			(feet)	(feet)	(feet)	(inches)	(inches)	(inches)	(inches)	(inches)	(inches)
Xmas Tree	Tbg Hgr	1	29	29							
Tubing	3 1/2" Tbg	1	1069.55	1069.55	1040.55	3.068	0.0006				
Tubing	3 1/2" Tbg	1	1758.53	1758.53	688.98	3.068	0.0006				
Tubing	3 1/2" Tbg	1	2247.38	2247.38	488.85	3.068	0.0006				
Tubing	3 1/2" Tbg	1	2650.92	2649.28	403.54	3.068	0.0006				
Tubing	3 1/2" Tbg	1	3074.15	3061.02	423.23	3.068	0.0006				
Tubing	3 1/2" Tbg	1	3231.63	3211.94	157.48	3.068	0.0006				
Tubing	3 1/2" Tbg	1	4342.97	4186.34	1111.34	3.068	0.0006				
Restriction	2.75" Nippl	1		4186.34		2.75					
Tubing	3 1/2" Tbg	1	4389.76	4227.36	46.7397	3.068	0.0006				
Tubing	3 1/2" Tbg	1	4399.61	4235.56	9.8501	3.068	0.0006				
Tubing	3 1/2" Tbg	1	4400.87	4236.59	1.26025	3.068	0.0006				
Restriction	2.635" Nippl	1		4236.59		2.635					
Tubing	3 1/2" Tbg	1	4432	4261.94	31.0801	3.068	0.0006				
Tubing	3 1/2" Tbg	1	4472	4294.53	40	3.068	0.0006				
Tubing	3 1/2" Tbg	1	4530.11	4341.86	58.1104	3.068	0.0006				
Casing	7" Csg	1	4603.02	4401.25	72.9097					7	0.0006
Casing	7" Csg	1	4803.15	4570.21	200.13					7	0.0006
Casing	7" Csg	1	4972.11	4711.29	168.96					7	0.0006

Figure 3-6 Downhole Equipment Data and Drawing

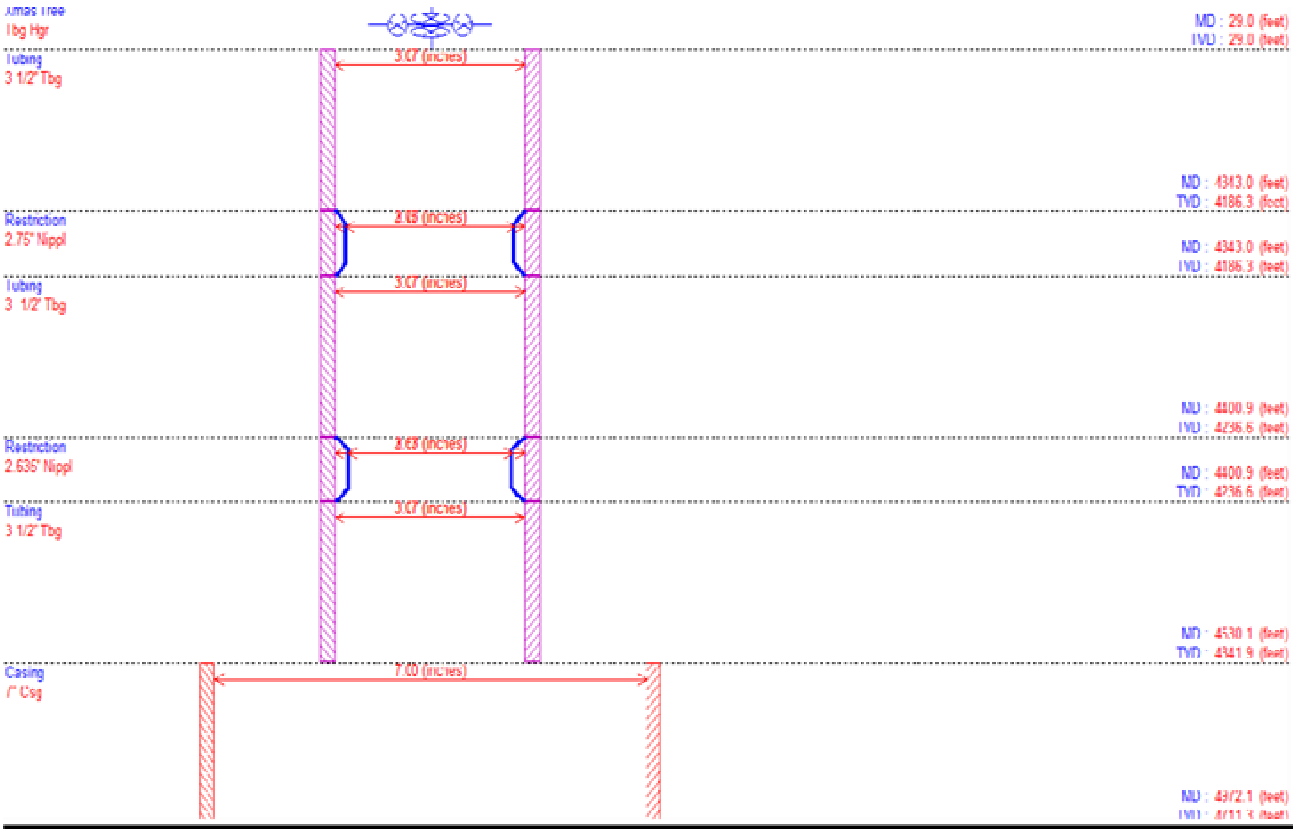


Figure 3-7 Downhole Equipment Drawing

3.1.4.2. Reservoir and Fluid Data H9:

Reservoir Pressure: 2068 psig

Reservoir Temp: 165 Deg F

Oil Gravity: 45 API

Gas Gravity: 0.75

Water Salinity :300000 ppm

Water Cut: 15 %

Type	Label	Rate Multiplier	Measured Depth	True Vertical Depth	Pipe Length	Tubing Inside Diameter	Tubing Inside Roughness	Tubing Outside Diameter	Tubing Outside Roughness	Casing Inside Diameter	Casing Inside Roughness
			(feet)	(feet)	(feet)	(inches)	(inches)	(inches)	(inches)	(inches)	(inches)
Xmas Tree	Tbg Hgr	1	29	29							
Tubing	3 1/2" Tbg	1	413.41	413.41	384.41	3.068	0.0006				
Tubing	3 1/2" Tbg	1	820.25	820.25	406.84	3.068	0.0006				
Tubing	3 1/2" Tbg	1	1425.59	1425.5	605.34	3.068	0.0006				
Tubing	3 1/2" Tbg	1	1797.99	1797.17	372.4	3.068	0.0006				
Tubing	3 1/2" Tbg	1	1921.03	1919.35	123.04	3.068	0.0006				
Tubing	3 1/2" Tbg	1	2611.81	2585.92	690.78	3.068	0.0006				
Restriction	2.75" Nippl	1		2585.92		2.75					
Tubing	3 1/2" Tbg	1	4198.06	4116.59	1586.25	3.068	0.0006				
Restriction	2.635" Nippl	1		4116.59		2.635					
Tubing	3 1/2" Tbg	1	4283.35	4198.89	85.29	3.068	0.0006				
Tubing	3 1/2" Tbg	1	4312.87	4227.47	29.52	3.068	0.0006				
Tubing	3 1/2" Tbg	1	4489.27	4398.87	176.4	3.068	0.0006				
Casing	7" Csg	1	4698.39	4602.06	209.12					7	0.0006
Casing	7" Csg	1	4865.72	4768.93	167.33					7	0.0006

Figure 3-8 Downhole Equipment Data

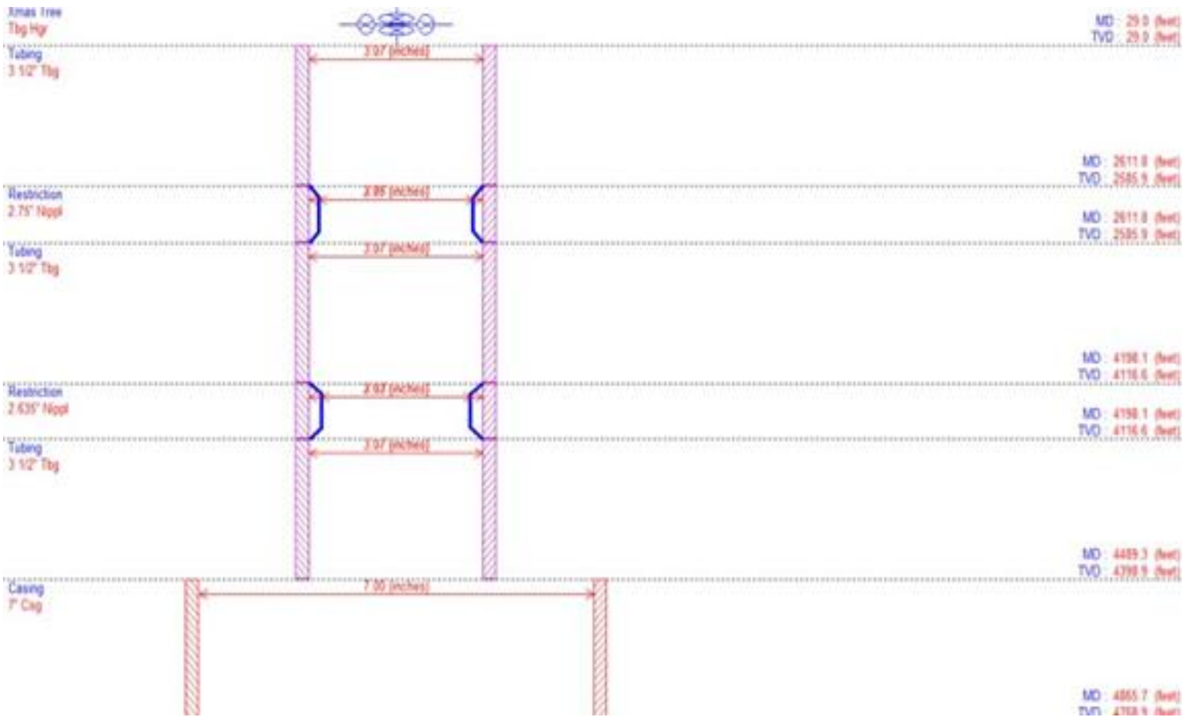


Figure 3-9 Downhole Equipment Drawing

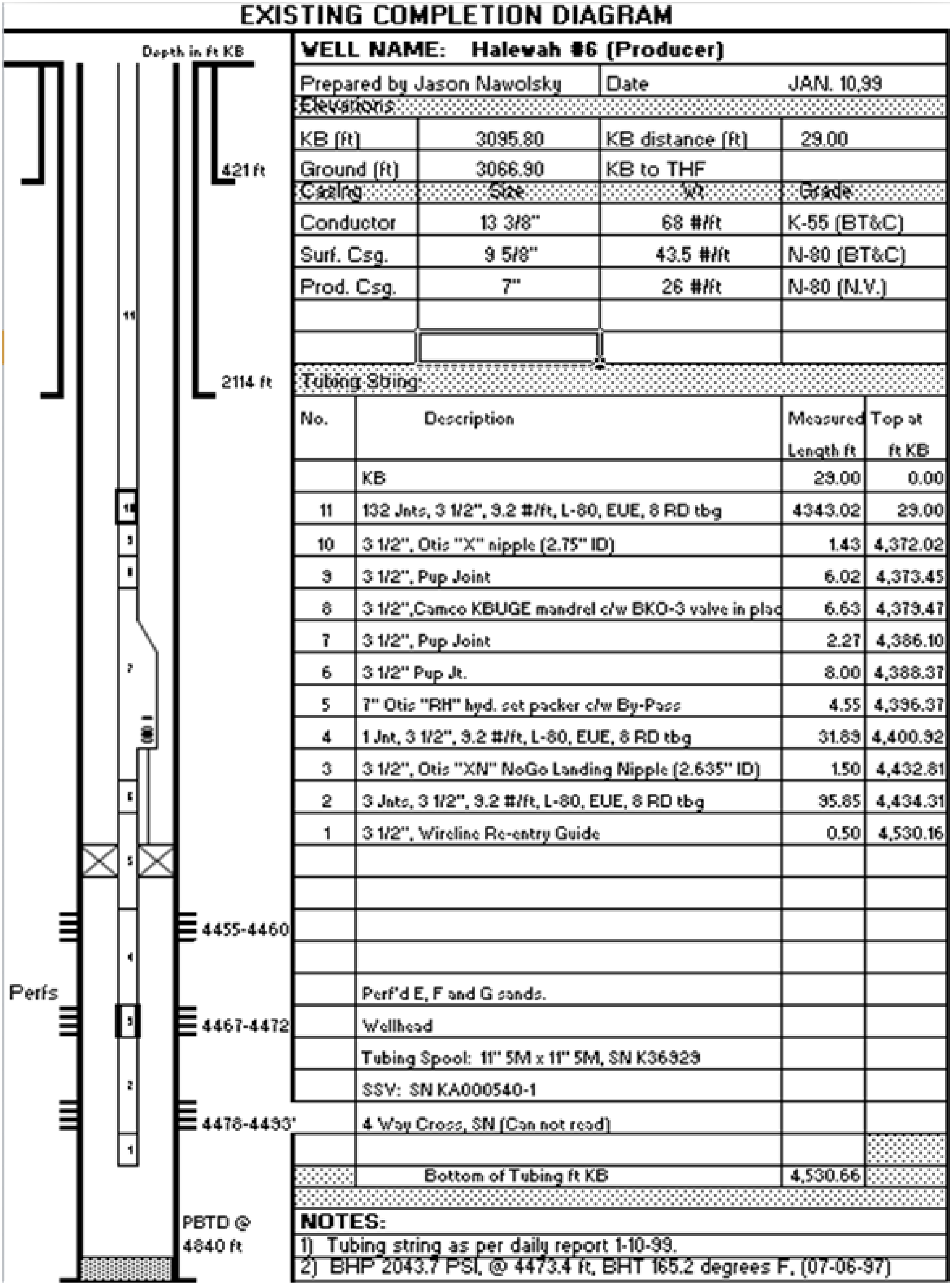
3.1.5. Well completion Design for Wells in Halewah Field (Block 5)

3.1.5.1. Halewah 6 Completion Description

Halewah No.6 well was approximately 250 KM southeast of Sana ‘a, Yemen, in the marib-jawf basin. This was the first development well in the Halewah field. Through the drilling water based mud was used and it was necessary to increase the density to 9.5 ppg, beginning at 462m in response to over pull on connections. The 8.5” hole section was deviated to the north, reaching the proposed target. The maximum hole angle was 33.7 degrees. It was anticipated that the safer2 would be overpressure and the mud density was raised to 12.5 ppg, as there was no indication of overpressure in the safer 2, the mud density gradually decreased and was 11.7 ppg, while drilling the Alif formation.

Table 3-1 Halewah 6 Well Data Summary

Items	Descriptions
Geographic location	Halewah – block 5
Basin	Marib - Jawf
Location coordinate	UTM zone 38 WGS 84, 1,695,487 mN 614,683 mE
Bottom hole	1,695,694 mN 614,704 mE
Well classification	Development
Ground level	934.8 m
Kelly bushings	943.6 m
Casing	13 3/8” @ 128 m 9 5/8” @ 722 m 7” @ 1514 m
Hole size	17.5” to 128 m 12.25” to 722 m 8.5” to 1514 m



EXISTING COMPLETION DIAGRAM

WELL NAME: Halewah #6 (Producer)

Prepared by Jason Nawolsky		Date	JAN. 10,99
Elevations			
KB (ft)	3095.80	KB distance (ft)	29.00
Ground (ft)	3066.90	KB to THF	
Casing	Size	Wt	Grade
Conductor	13 3/8"	68 #/ft	K-55 (BT&C)
Surf. Csg.	9 5/8"	43.5 #/ft	N-80 (BT&C)
Prod. Csg.	7"	26 #/ft	N-80 (N.V.)

Tubing String:

No.	Description	Measured Length ft	Top at ft KB
	KB	29.00	0.00
11	132 Jnts, 3 1/2", 9.2 #/ft, L-80, EUE, 8 RD tbg	4343.02	29.00
10	3 1/2", Otis "X" nipple (2.75" ID)	1.43	4,372.02
9	3 1/2", Pup Joint	6.02	4,373.45
8	3 1/2",Camco KBUGE mandrel c/w BKO-3 valve in plac	6.63	4,379.47
7	3 1/2", Pup Joint	2.27	4,386.10
6	3 1/2" Pup Jt.	8.00	4,388.37
5	7" Otis "RH" hyd. set packer c/w By-Pass	4.55	4,396.37
4	1 Jnt, 3 1/2", 9.2 #/ft, L-80, EUE, 8 RD tbg	31.89	4,400.92
3	3 1/2", Otis "XN" NoGo Landing Nipple (2.635" ID)	1.50	4,432.81
2	3 Jnts, 3 1/2", 9.2 #/ft, L-80, EUE, 8 RD tbg	95.85	4,434.31
1	3 1/2", Wireline Re-entry Guide	0.50	4,530.16
	Perf'd E, F and G sands.		
	Wellhead		
	Tubing Spool: 11" 5M x 11" 5M, SN K36929		
	SSV: SN KA000540-1		
	4 Way Cross, SN (Can not read)		
	Bottom of Tubing ft KB	4,530.66	

NOTES:

1) Tubing string as per daily report 1-10-99.

2) BHP 2043.7 PSI, @ 4473.4 ft, BHT 165.2 degrees F, (07-06-97)

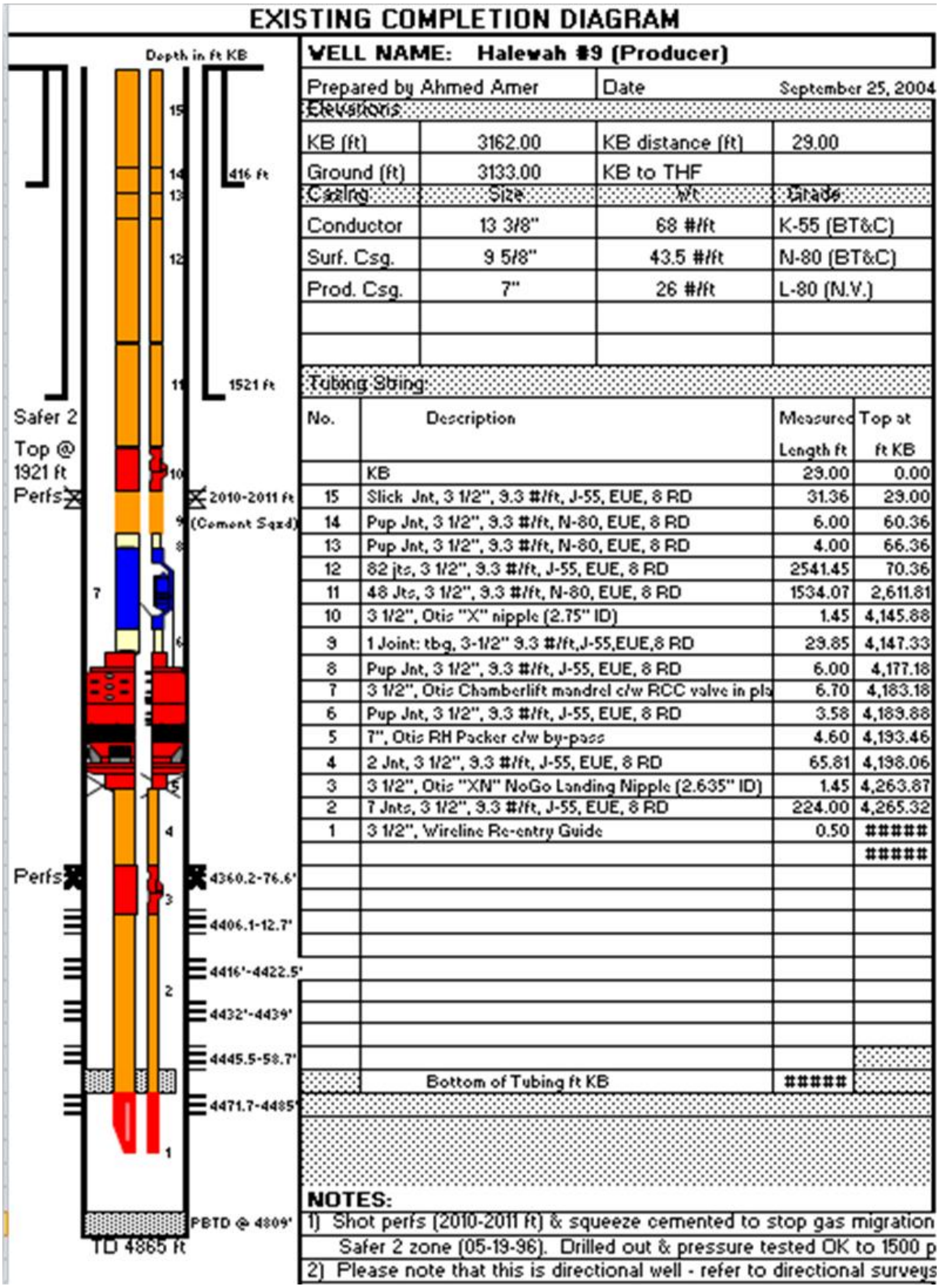
Figure 3-10 Well Completion Schematic

3.1.5.2. Halewah 9 Completion Description

The Halewah No.9 well was drilled approximately 250 KM east of the Yemeni capital of Sana 'a, in the marib-jawf basin. This was the fifth development well in the Halewah field. Through the drilling, at the 12.25" hole section was drilled to 461 m, into the Azal limestone, with a gel-chem mud. Shortly before the Azal shale was penetrated, the rig began experiencing fluid losses of up to 100 bbl./hour and a total loss of returns after the shale itself was penetrated. Total returns were regained by a depth of 381 m.

Table 3-2 Halewah 9 Well Data Summary

Items	Descriptions
Geographic location	Halewah - Block 5
basin	Marib- Jawf
Location coordinate	
Bottom hole	
Well classification	Development
Ground level	954.9m
Kelly bushings	963.7m
casing	13 3/8" @ 127 m 9 5/8" @ 461 m 7" @ 1483 m
Hole size	17.5" to 127 m 12.25" to 461 m 8.5" to 1483 m
Sample interval	
Well status	Cased Alif oil wells.



EXISTING COMPLETION DIAGRAM

WELL NAME: Halewah #9 (Producer)

Prepared by Ahmed Amer		Date	September 25, 2004
Elevations			
KB (ft)	3162.00	KB distance (ft)	29.00
Ground (ft)	3133.00	KB to THF	
Casing	Size	Wt	Grade
Conductor	13 3/8"	68 #/ft	K-55 (BT&C)
Surf. Csg.	9 5/8"	43.5 #/ft	N-80 (BT&C)
Prod. Csg.	7"	26 #/ft	L-80 (N.V.)

Tubing String

No.	Description	Measured Length ft	Top at ft KB
	KB	29.00	0.00
15	Slick Jnt, 3 1/2", 9.3 #/ft, J-55, EUE, 8 RD	31.36	29.00
14	Pup Jnt, 3 1/2", 9.3 #/ft, N-80, EUE, 8 RD	6.00	60.36
13	Pup Jnt, 3 1/2", 9.3 #/ft, N-80, EUE, 8 RD	4.00	66.36
12	82 jts, 3 1/2", 9.3 #/ft, J-55, EUE, 8 RD	2541.45	70.36
11	48 Jts, 3 1/2", 9.3 #/ft, N-80, EUE, 8 RD	1534.07	2,611.81
10	3 1/2", Otis "X" nipple (2.75" ID)	1.45	4,145.88
9	1 Joint: tbg, 3-1/2" 9.3 #/ft,J-55,EUE,8 RD	29.85	4,147.33
8	Pup Jnt, 3 1/2", 9.3 #/ft, J-55, EUE, 8 RD	6.00	4,177.18
7	3 1/2", Otis Chamberlift mandrel c/w RCC valve in pla	6.70	4,183.18
6	Pup Jnt, 3 1/2", 9.3 #/ft, J-55, EUE, 8 RD	3.58	4,189.88
5	7", Otis RH Packer c/w by-pass	4.60	4,193.46
4	2 Jnt, 3 1/2", 9.3 #/ft, J-55, EUE, 8 RD	65.81	4,198.06
3	3 1/2", Otis "XN" NoGo Landing Nipple (2.635" ID)	1.45	4,263.87
2	7 Jnts, 3 1/2", 9.3 #/ft, J-55, EUE, 8 RD	224.00	4,265.32
1	3 1/2", Wireline Re-entry Guide	0.50	#####
			#####
	Bottom of Tubing ft KB	#####	

NOTES:

1) Shot perfs (2010-2011 ft) & squeeze cemented to stop gas migration
Safer 2 zone (05-19-96). Drilled out & pressure tested OK to 1500 p
2) Please note that this is directional well - refer to directional surveys

Figure 3-11 Halewah 9 Well Completion Schematic

CHAPTER FOUR

4. ANALYSIS AND RESULTS

4.1. Nodal Analysis Study of Halewah No. 6 and Halewah No.9

4.1.1. Nodal analysis at Bottom Hole - Halewah well No.6

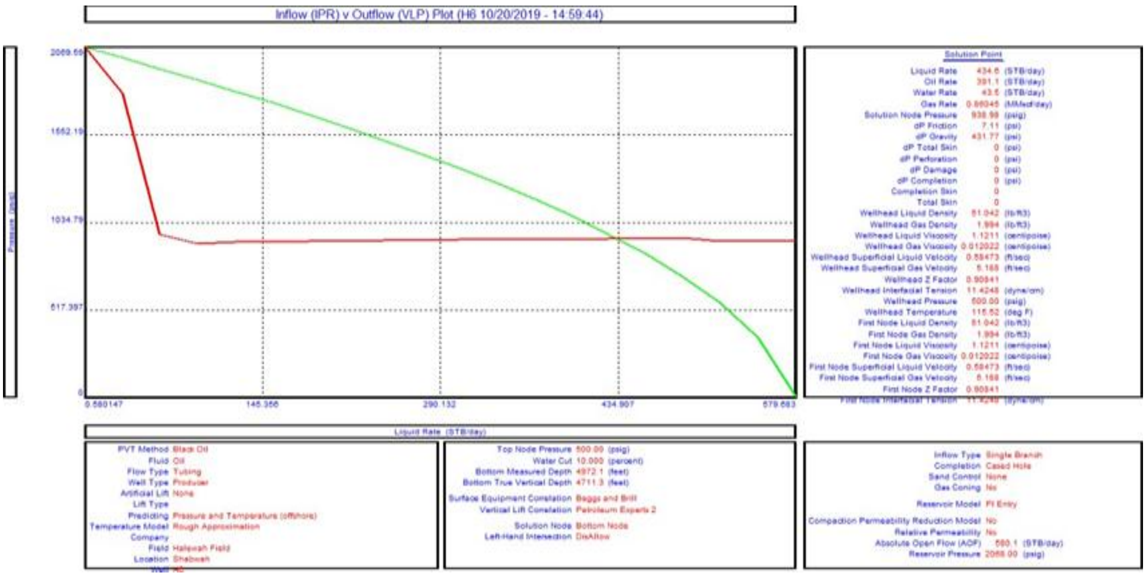


Figure 4-1 Inflow (IPR) V Outflow Plot H6

4.1.1.1. Solution Point:

Liquid Rate: 434.6 STB/ Day

Oil Rate: 391.1 STB / Day

Water Rate: 43.5 STB / Day

Gas Rate: 0.86045 MMscf/ Day

Solution Node Pressure (bottom hole): 938.98 Psig

Top Node Pressure: 500 psig

4.1.2. Nodal analysis at Bottom Hole for Halewah well No.9

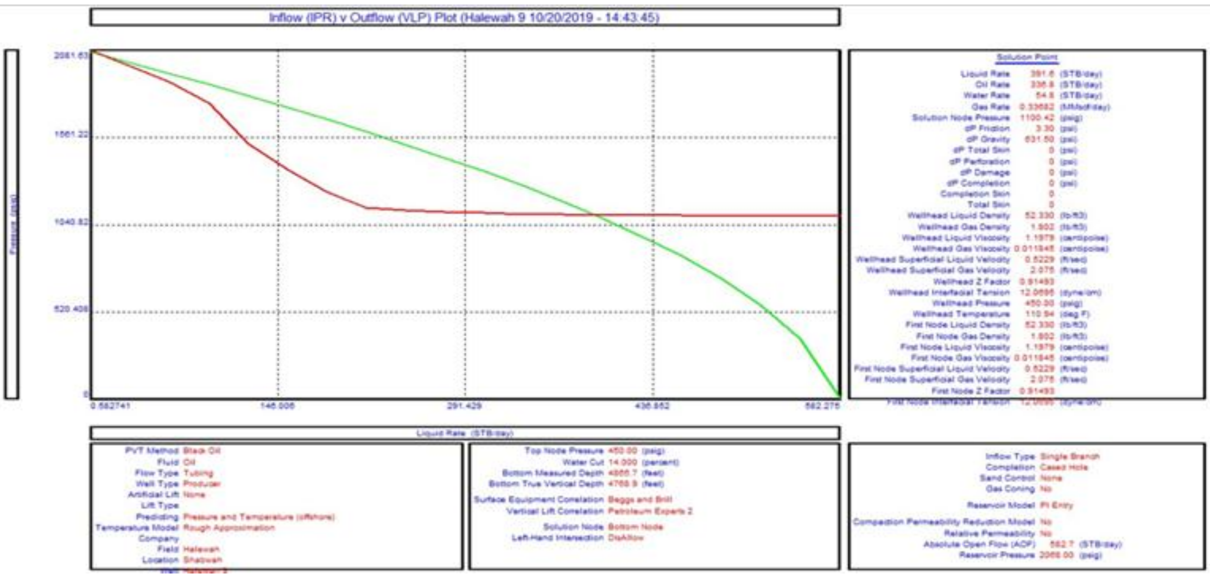


Figure 4-2 Inflow (IPR) V Outflow Plot H9

4.1.2.1. Solution Point:

Liquid Rate: 391.6 STB/ Day

Oil Rate: 336.8 STB / Day

Water Rate: 54.8 STB / Day

Gas Rate: 0.33682 MMscf/ Day

Solution Node Pressure (bottom hole): 1100.42 Psig

Top Node Pressure: 450 psig

4.2. Evaluation of Halewah Field Formation

The principal objectives of formation evaluation are to evaluate the presence or absence of commercial quantities of hydrocarbons in formations penetrated by, or lying near, the wellbore and to determine the static and dynamic characteristics of productive reservoirs. Another objective is to detect small quantities of hydrocarbons which nevertheless may be very significant from an exploratory standpoint. A further objective is to provide a comparison of an interval in one provide a comparison of an interval in one well to the correlative interval in another well. Two producer wells Halewah No. 6 and Halewah No. 9 were selected for evaluation study on Halewah Field Formation.

4.2.1. Halewah Well No. 6

The undifferentiated top Azal formation was a series of interbedded sandstone, limestone, dolomite, siltstone and shale. Minor oil shows were seen in dolomite with poor intergranular porosity and in limestone with traces of pinpoint porosity starting depth from 355m to 495m. The oil shows consisted of spotty light to dark brown oil staining, pale yellow fluorescence and slow streaming bright white cut fluorescence. There were also similar minor oil shows in siltstone with poor intergranular porosity and limestone with traces of pinpoint porosity starting depth from 407m to 430m.

The top 3 meters of the Alif were shale, with the top of the Alif sand at 1341m. The upper part of the Alif sandstone starting depth from 1341 to 1370m was light brown, very fine to medium grained, surrounded, well sorted ,20%intergranular porosity, good permeability, and some calcareous cement with traces dark grey lithic fragments. Oil shows were very strong, even with light brown oil staining, bright straw fluorescence.

The upper part of the Alif sandstone has good porosity and permeability with oil bearing. It was not appearing a gas cap or water leg in this well.

Production formation on Halewah 6 well was perforated through wellbore completion per the following intervals: '4461-4455’, 4467-4472 ‘, 4478-4493 '

4.2.2. Halewah Well No. 9

Top Alif formation located at (1305-1376m) below the Alif shales. The Alif sandstone layers were seen between the depths of 1310 to 1376m.

These fine to medium grained sandstone layers were interbedded with laminae and interbedded of greenish grey shales. All of these sandstone layers displayed fire to good porosity from 6% to 20%, and most possessed a very pale brown oil stain. The quality of the fluorescence of these sandstone layers were difficult to assess. Gas reading show modest increase as this zone was penetrated, from a previous background of 1.42% total Gas, to a maximum of 3.81%, with good representation of heavier hydrocarbon. Alif sandstone in Halewah 9 well is likely capable of good rates of oil production.

Production formation on Halewah 9 well was perforated through wellbore completion per the following intervals: 4406.1- 4418.8', 4416'- 4422.5', 4432'- 4439', 4445.5 - 4504.2, 4471.7- 4485'

4.3. Reservoir Stimulation Plan

Stimulation is a term describing a variety of operations performed to improve reservoir productivity. Stimulation operations can be focused either on the wellbore or on the reservoir. They can be conducted on old wells and new wells and they can be also designed for remedial purposes. There are two main types of stimulation operations: Matrix stimulation and hydraulic fracturing. Matrix stimulation is performed below the reservoir fracture pressure in an effort to restore the natural permeability of the reservoir rock. Matrix stimulation is achieved by pumping acid mixtures (acidizing) into the near-wellbore area to dissolve the limestone and dolomite formations or the formation damage particles between the sediment grains of the sandstone rocks. Hydraulic fracturing is the most common mechanism for increasing well productivity.

Hydraulic fracturing is used to by-pass near wellbore damage and Increase well production by changing flow regime from radial to pseudo- linear, to reduce sand production and to increase access to the reservoir from the well bore.

Target formation in Halewah field is Alif sandstone as mentioned above from evaluation study on Halewah formation. Matrix Acidizing (combination of hydrochloric acid(HCl) and hydrofluoric acid (HF)) would be the proper stimulation treatment on sandstone formation in order to optimize reservoir productivity by removing the damage to the sandstone formation near the wellbore that occurred during drilling, cementing, and well completion processes, in addition to the host materials that exist in the naturally occurring rock formations. However, hydraulic fracturing, which is a well-stimulation technique, is the most suitable to wells in low- and moderate-permeability reservoirs that do not provide commercial production rates even though formation damages are removed by acidizing treatments. Nevertheless, Matrix acidizing on sandstone reservoirs is an essential step to ensure high production by removal of damage or by introducing new pathways.

4.4. Enhance Oil Recovery of Reservoir in Halewah Field

In the early stages of oil field development, reservoirs are mainly planned to produce oil naturally by intrinsic energy. The recoverable oil by the natural forces, including all various mechanisms (gas cap drive, water drive, solution gas drive, rock and fluid expansion, and gravity drainage), can be extracted up to 50% of original oil in place (OIP) (averagely 19%), and most of the oil will remain untouched in the reservoir (**Fig. 4-3** Oil production and EOR operation). For extracting more oil, other methods are chronologically utilized after the first natural flow mechanisms. Thus the first and second actions for enhancing oil recovery (EOR) after primary recovery are called secondary and tertiary recovery, respectively (**Fig. 4-4** Reservoir production and types of EOR). In the secondary recovery period most focuses are on the reservoir energy maintenance. This aim is performed by water flooding or gas injection. In gas injection, gas is injected to the gas cap to prepare the required energy of oil drive. The process of gas injection to the gas cap is not as effective as water flooding. Tertiary recovery processes include all methods conducted to extract irrecoverable oil by the two first production stages. The earliest possible determination of the drive mechanism is a primary goal in the early life of the reservoir, as its knowledge can greatly improve the management and recovery of reserves from the reservoir in its middle and later life.

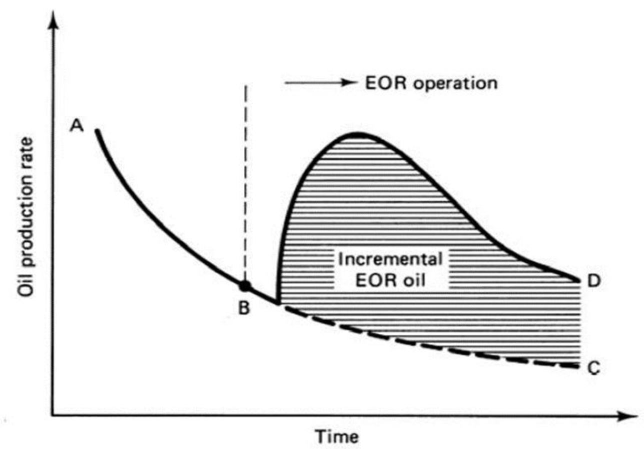


Figure 4-3 Oil Production and EOR Operation

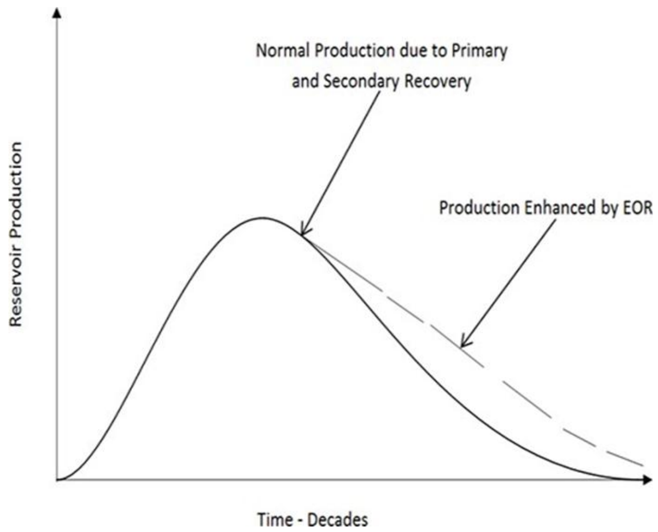


Figure 4-4 Reservoir Production and Types of EOR

4.4.1. Oil Recovery Drive Mechanism of Reservoir in Halewah Field:

The primary mechanism drive of Halewah field reservoir is solution gas drive (dissolved gas drive or depletion drive) by which dissolved gas in a reservoir will expand and become an energy support to produce reservoir fluid. Oil recovery from this type of reservoir is typically between 20% and 30% of original oil in place **Fig. 4-5** Reservoir pressure trends for Drive Mechanisms. When reservoir pressure is more than the bubble point (under saturated reservoir), no free gas presents in a reservoir **Fig. 4-6** Solution Gas Drive conditions. At this stage, the drive comes from oil and connate water expansion and the compaction of reservoir pore space. Because compressibility of oil and rock is very low, only a small amount of fluid can be produced and typically the volume is around 1-2% of oil in place. When the reservoir reaches the bubble point pressure, oil becomes saturated and free gas will present in a reservoir. Then the pressure declines less quickly due to the formation of gas bubbles in the reservoir that expand taking up the volume exited by produced oil and hence protecting against pressure drops. At the beginning, the produced gas oil ratio will be slightly decline because free gas in a reservoir cannot move until it goes over the critical gas saturation. Then gas will begin to flow into a well. When this happens, the GOR rises dramatically (up to 10 times) **Fig. 4-7** GOR trends for Drive Mechanisms. When pressure gets lower, more gas will be produced and oil production will decline and that will lead to a high GOR. **Fig. 4-6** Solution Gas Drive Diagram. This is not a good sign because reservoir pressure declines sharply with gas production and eventually energy sources in a reservoir will drop and oil cannot be produced unless the artificial lift systems are then instituted.

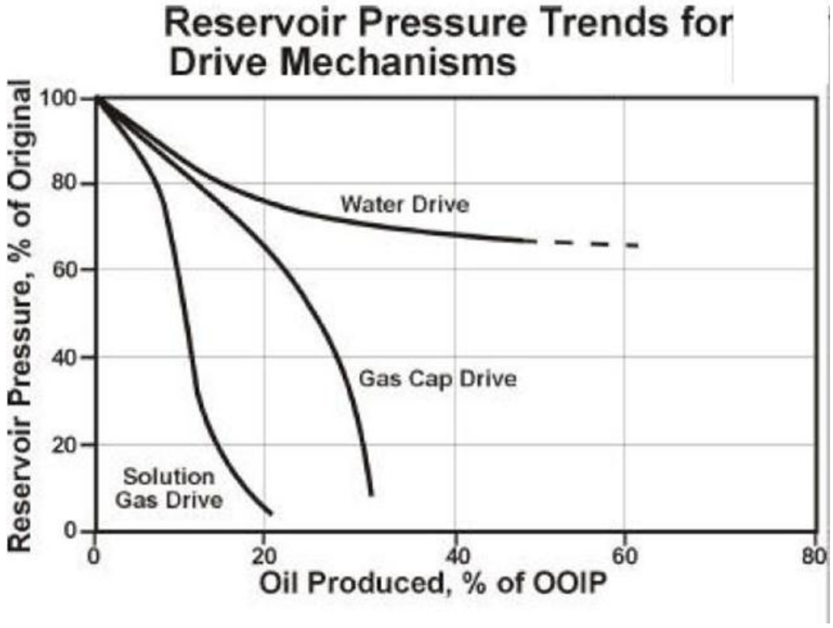


Figure 4-5 Reservoir Pressure Trends For Drive Mechanisms

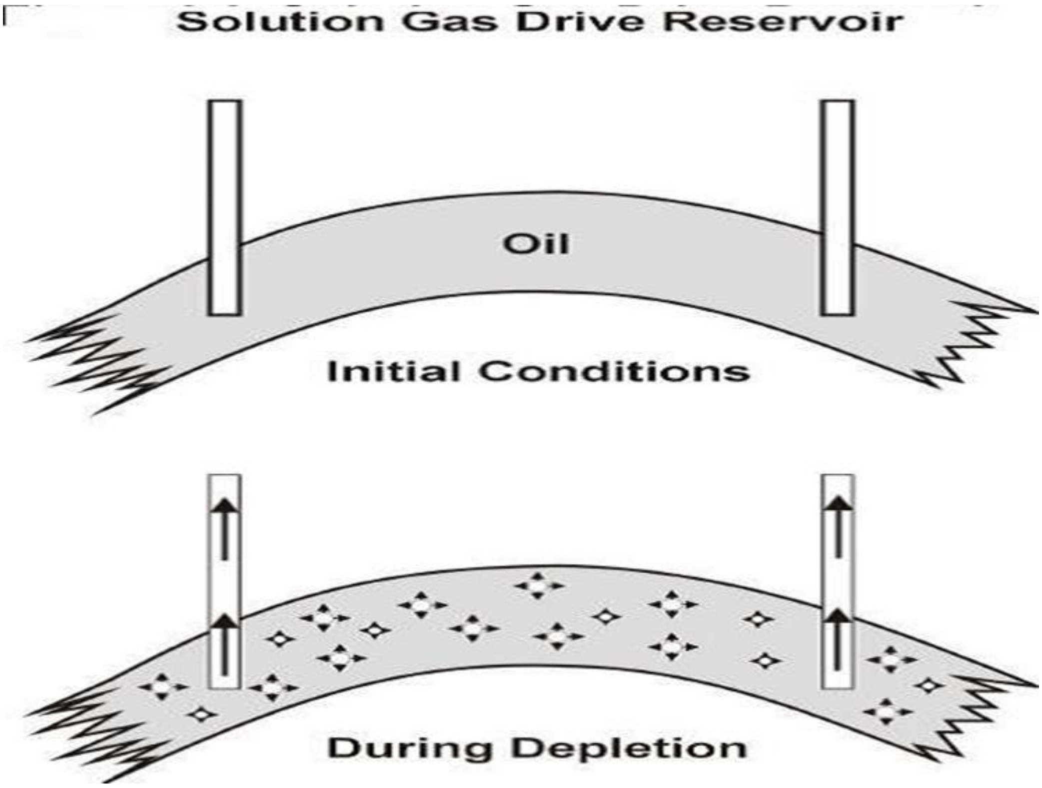


Figure 4-6 Solution Gas Drive Conditions

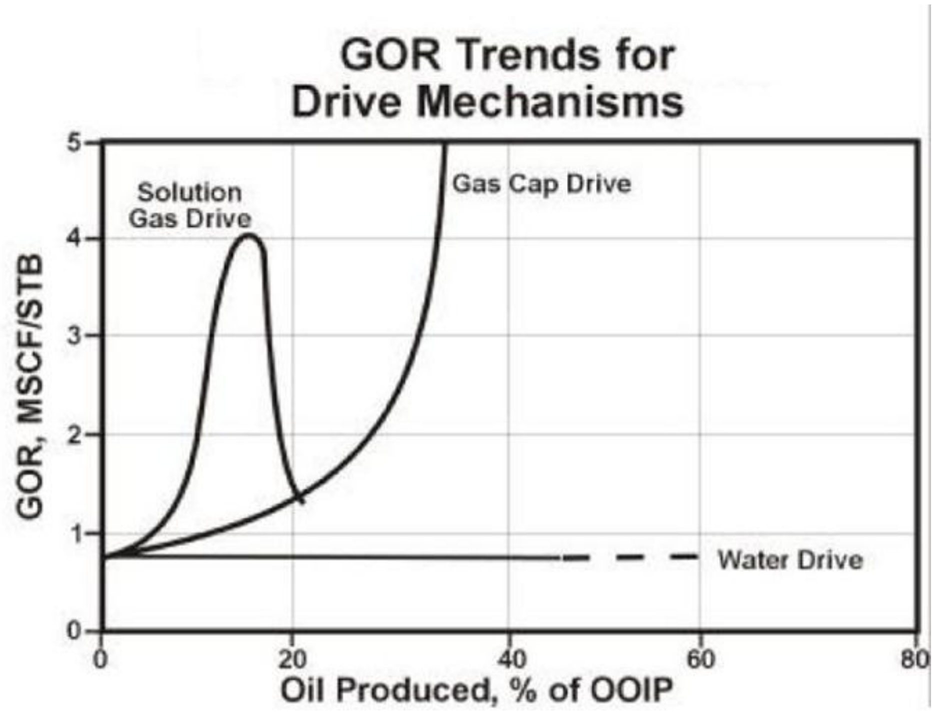


Figure 4-7 GOR Trends for Drive Mechanisms

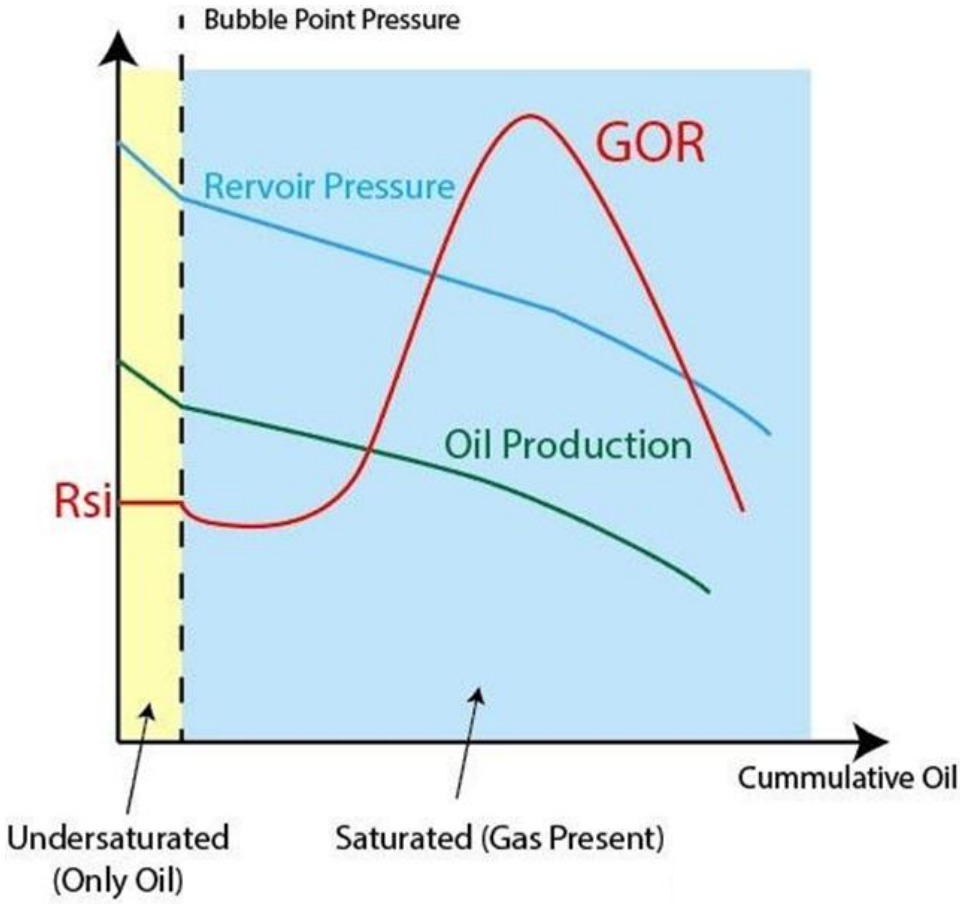


Figure 4-8 Solution Gas Drive Diagram

4.5. Identification of Reservoir Performance problems

The main production problem for reservoirs driven by mechanism of solution gas is forming of gas or water coning near wellbore area. Gas and water coning is described as the mechanism of underlying the upward movement of water and/or the down movement of gas into the perforations zones of a producing well (**Fig. 4-9** producing well with no coning and **Fig. 4-10** producing well subject to gas and water coning). Coning can seriously impact the well productivity and influence the degree of depletion and the overall recovery efficiency of the oil reservoirs.

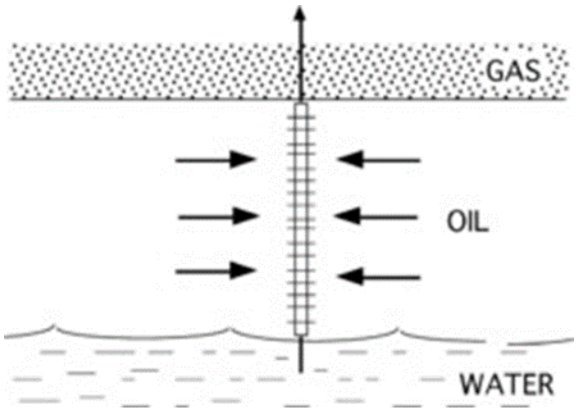


Figure 4-9 Producing Well with No Coning

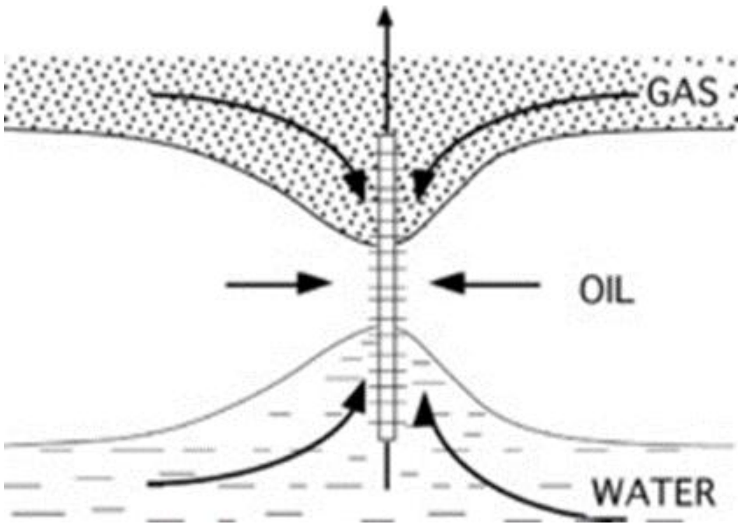


Figure 4-10 Producing Well Subject To Gas And Water Coning

There are also serious problems that affect production operations significantly, resulted from gas and water coning, include the following below:

- Costly added water and gas handling
- Gas production from the original or secondary gas cap reduces pressure without obtaining the displacement effects associated with gas drive
- Reduced efficiency of the depletion mechanism
- The water is often corrosive and its disposal costly
- The afflicted well may be abandoned early
- Loss of the total field overall recovery

4.6. Optimal Production Plan to enhance Oil Recovery from Reservoir in Halewah field

1. Reservoir pressure maintenance: Injecting gas or water into the reservoir during the course of its primary-production history to mitigate the reservoir ‘s pressure decline, to conserve its energy, and ultimately to improve oil recovery.
2. Defining the optimum length and position of the interval to be perforated in a well in order to obtain the maximum water and gas-free production rate.
3. Calculating and predicting the maximum flow rate that can be assigned to a completed well without the simultaneous production of water and/or free-gas.
4. Decreasing the well production rate until reaching the optimal rate below or equal to the critical production rate in order to avoid presence of gas and water coning at early stage of primary oil recovery.
5. Partial perforation or penetration selectively the well at the top of the reservoir in the case of water coning, and at the bottom of the reservoir in the case of gas coning, and close to the center of the pay zone in the case of simultaneous water and gas coning.
6. Side-tracking drilling operations on the reservoir to produce oil at maximum critical rate from horizontal section of reservoir instead of vertical section.
7. Re-completing the well at a different elevation to increase the distance between the gas-oil or water-oil contact and the perforated interval.

8. Infill Drilling: increasing the number of wells in an area by drilling wells in spaces between existing wells as part of a regular pattern.
9. Gas Shut-off treatment by squeezing of cement into gas or water entry source in the wellbore to minimize excessive gas or water production and maximize oil production.
10. Placement of an artificial barrier above or below the pay zone to suppress vertical flow of gas or water coning.

4.7. Analyzing and Optimizing Wellbore Production Performance

4.7.1. Identification of Well Performance Problems

The engineering work for sustaining and enhancing oil and gas production rates starts from identifying problems that cause low production rates of wells, quick decline of the desirable production fluid, or rapid increase in the undesirable fluids and rapid decline of reservoir pressure. For oil wells, these problems include low productivity, excessive gas production, excessive water production and sand production. For gas wells, the problems include low productivity, excessive water production, liquid loading and sand production. The main problems found on performance of Halewah wells (6 & 9) are: Low Productivity and Excessive Gas Production.

4.7.1.1. Low Productivity

Decreasing in the production rate than expected productivity from oil or gas well would be found from the basis of comparison of the well ‘s actual production rate and the production rate that is predicted by Nodal analysis. If the reservoir inflow model used in the Nodal analysis is correct ,the lower than expected well productivity can be attributed to one or more of the following reasons: Overestimate of reservoir pressure, reservoir permeability (absolute and relative permeability’s), Formation damage, Reservoir heterogeneity (faults, stratification, etc.), Completion ineffectiveness (limited entry, shallow perforations, low perforation density, etc.) ,and Restrictions in wellbore (paraffin, asphaltene, scale, gas hydrates, sand, etc.) . Therefore, these reasons can be evaluated on the basis of pressure transient data analyses and using data from production logging such as flowing gradient survey. Furthermore, the true production profile from different zones can be obtained based on production logging such as temperature and spinner flow meter logs.

4.7.1.2. Excessive Gas Production

Excessive gas production is usually due to channeling behind the casing such as preferential flow through high permeability zones, gas coning, and casing leaks.

The channeling behind the casing and gas coning problems can be identified based on production logging such as temperature and noise logs. Excessive gas production of an oil well could also be due to gas production from unexpected gas zones. This can be identified using production logging such as temperature and density logs.

4.7.1.3. Operating Efficiency Criteria's of Surface Production Facility

Oil and gas production flow rates and characteristics vary during the life of a well or field due to changing reservoir parameters. In many cases these changes in flow rates and production characteristics cannot be accommodated by the original production system or infrastructure, which could limit a well or a field production potential.

Standard Parameters for Designing and Selecting of Processing Equipment in Surface Production Facility

The main function of production facility is to separate the well stream into three components, typically called "phases" (oil, gas, and water), and process these phases into some marketable products or dispose of them in an environmentally acceptable manner. It is difficult to classify production facilities by type, because they differ due to production rates, fluid properties, sale and disposal requirements, location, and operator preference. Nevertheless, all of production facilities are designed and constructed based on standard parameters that meet optimal operations requirements on safe and cost effective manner. These standard parameters can be explained simply as per following below:

Basic System Configuration for Designing and Selecting of Oil and Gas Processing Equipment in Petroleum Production System

Wellhead and Manifold

The production system begins at the wellhead, which should include at least one choke, unless the well is on artificial lift. Most of the pressure drop between the well flowing tubing pressure (FTP) and the initial separator operating pressure occurs across this choke. Whenever flows from two or more wells are commingled in a central facility, it is necessary to install a manifold to allow flow from any one well to be produced into any of the bulk or test production systems.

4.8. Separation

Initial Separation Pressure

Because of the multicomponent nature of the produced fluid, the higher the pressure at which the initial separation occurs, the more liquid will be obtained in the separator. This liquid contains some light components that vaporize in the stock tank downstream of the separator. If the pressure for initial separation is too high, too many light components will stay in the liquid phase at the separator and be lost to the gas phase at the tank. If the pressure is too low, not as many of these light components will be stabilized into the liquid at the separator and they will be lost to the gas phase.

4.8.1. Stage Separation

4.8.1.1. Single stage separation

The fluids are flashed in an initial separator and then the liquids from that separator are flashed again at the stock tank.

4.8.1.2. Three-stage separation process

The liquid is first flashed at an initial pressure and then flashed at successively lower pressures two times before entering the stock tank.

4.8.2. Selection of Stages

The number of stages for oil and gas operation process is controlled by volume of incremental liquid recovery. The diminishing income for adding a stage must more than offset the cost of the additional separator, piping, controls, space, and compressor complexities.

4.8.2.1. Oil Treating and Storage

Crude requires dehydration before it can go to storage. Water-in-oil emulsions must be broken so as to reduce water cut and reduce salt content.

4.8.2.2. Gas Dehydration

Removing most of the water vapor from the gas is required by most gas sales contracts, because it prevents hydrates from forming when the gas is cooled in the transmission and distribution systems and prevents water vapor from condensing and creating a corrosion problem

4.8.2.3. Water Treating

When hydrocarbons (crude oil, condensate, and natural gas) are produced, the well stream typically contains water produced in association with these hydrocarbons. The water must be

separated from the hydrocarbons and disposed of in a manner that does not violate established environmental regulations. the produced water is separated from the hydrocarbons by passing the well stream through process equipment such as three-phase separators, heater-treaters, and/or a free-water knockout vessel.

4.9. Compressors

Gas produced from HP separator enter HP compressor and Gas produced from IP/LP separator and FWKO enters the first-stage suction scrubber of LP compressor. Compression heats the gas, so there is a cooler after each compression stage. At the higher pressure more liquids may separate, so the gas enters another scrubber before being compressed and cooled again.

4.10. Pumps

Pumps are normally needed to move oil through the LACT unit and deliver it at pressure to a pipeline downstream of the unit. Pumps are sometimes used in water treating and disposal processes. In addition, many small pumps may be required for pumping skimmed oil to higher pressure vessels for treating, glycol heat medium and cooling water service, firefighting, etc.

4.11. Lease Automatic Custody Transfer (LACT)

In production facilities oil is typically sold through a LACT unit, which is designed to meet API Standards and whatever additional measuring and sampling standards are required by the crude purchaser. The value received for the crude will typically depend on its gravity, basic settlement and water (BS&W) content, and volume.

4.12. Controlling of Oil and Gas Operations Process

4.12.1. Operation of a Control Valve

Control valves are used throughout the process to control pressure, level, temperature, or flow.

4.12.2. Pressure Control

The hydrocarbon fluid produced from a well is made up of many components ranging from methane, the lightest and most gaseous hydrocarbon, to some very heavy and complex hydrocarbon compounds. Because of this, whenever there is a drop in fluid pressure, gas is liberated where pressure control is important to control vessel pressure.

4.12.3. Level Control

Level controller is used to control the gas/liquid interface or the oil/water interface in process equipment.

4.12.4. Temperature Control

The way in which the process temperature is controlled varies. In a heater a temperature controller measures the process temperature and signals a fuel valve to let either more or less fuel to the burner. In a heat exchanger the temperature controller could signal a valve to allow more or less of the heating or cooling media to bypass the exchanger.

4.12.5. Flow Control

It is very rare that flow must be controlled in an oil field process. Normally, the control of pressure, level, and temperature is sufficient. Occasionally, it is necessary to assure that flow is split in some controlled manner between two process components in parallel, or perhaps to maintain a certain critical flow through a component. This can become a complicated control problem and must be handled on an individual basis.

4.12.5.1. Debottlenecking process in Petroleum Production system

Bottlenecking is a phenomenon where the performance or capacity of an entire system is limited by a single or limited number of components or resources. On other word, a bottleneck is one process in a chain of processes, such that its limited capacity reduces the capacity of the whole chain.

Debottlenecking is the process of identifying specific areas and/or equipment in oil and gas facilities that limit the flow of product (otherwise known as bottlenecks) and optimizing them so that overall capacity in the plant can be increased. In any oil and gas processing operation

The most common areas of bottlenecks in petroleum production plant include control valves, choke valves, Equipment capacity (Production Manifold, Production Separator, pumps, storage tanks, Gas compressor, Export pipeline, Heat exchanger and Dehydration unit, Heating and Desalting treatment unit, Water Treating system and rotating equipment.

4.12.5.2. Standard procedure to eliminate bottleneck in petroleum production system

- The first step in a debottlenecking process generally involves examining the overall operating conditions of a facility. In many instances this means comparing current operating parameters and system settings (flow rates, pipe diameters, pressures, etc.) with the design specifications of process equipment.
- The second step is understanding the limitations of a facility in which it is also a critical step in the debottlenecking process. While increasing throughput to some degree can be accomplished in nearly every refining process, it should never be done at the expense of safety.

Effective solution for debottlenecking process is building a simulation models for each individual piece of equipment under different conditions.

as well analyze the entire plant process. Having readily available engineering reference data is critical to run a well-balanced debottleneck assessment. These simulation models can be better calibrated using specific unit performance under a variety of conditions and pressures.

CHAPTER FIVE

5. CONCLUSION, RECOMMENDATIONS AND LIMITATION

5.1. Conclusion

The major concern for most of oil companies worldwide is optimization of petroleum production operations, especially when it comes to the issue of increasing production rates and reducing production cost at safe and efficient manner. Recognizing the various components of the petroleum production system and understanding their functions and interaction generally leads to improved system productivity through analysis of the entire system and determination of optimal methods and technology applications of production optimization.

The basic elements of the petroleum production system as described in chapter one includes the reservoir; wellbore; well completion and associated equipment; surface wellhead, flow lines, and processing equipment in surface production facility (Production manifold, Separators, Pumps, Air / Gas Compressors, Oil, Gas and Water Treatment and measurement equipment, Storage tanks, Power generators, export pipeline, etc.); and artificial lift equipment.

The main functions of an oil and gas production system are to:

- Provide a conduit for the flow of fluids from the reservoir to the off take point at surface.
- Separate the produced reservoir fluids (Oil, Gas and Water) from each other.
- Minimize the production or the negative effects of by-products.
- Measure the amounts of fluids produced and control the production process.
- Processes and treats the fluids, and prepares the fluids for storage and transfer to a purchaser.

For example, chapter two exhibited typical petroleum production system in Halewah field.

In petroleum fields, hydrocarbon production is often constrained by reservoir conditions, deliverability of the pipeline network, fluid handling capacity of surface facilities, safety and economic considerations, or a combination of these considerations. In general, the common production problems which are more likely experienced on most of petroleum production systems are:

- Near-wellbore / Formation skin damage
- Deposition of organic and inorganic solid in the near wellbore/completion/pipeline
- Low productivity of wells and excessive gas and water production
- Reservoir deliverability problems relevant to drive mechanism, rock and fluid properties
- Well integrity failure
- Poor well completion design including artificial lift and sand control system
- Petroleum production system bottlenecking

There are various approaches and technologies used to address different aspects of hydrocarbon production optimization in petroleum production system. Chapter 3 explained the main production problems and production optimization plan that can be performed at different levels (reservoir, well and production facility) in petroleum production system of Halewah field.

5.2. Recommendations

In general, production optimization aspects, along with reservoir management, are a central part of a company's field development and deliverability strategies. Key factor in production optimization is the capability to remove all production operations problems or obstacles that might be encountered on any component of petroleum production system whether on sub-surface level (reservoir to wellbore) or on surface level (well head to surface production facility). To achieve this goal successfully, there are an important guidelines need to be taken on consideration prior to implementation of production optimization applications on any petroleum production system. These guidelines are listed below on the following points:

1. Conduct an overall investigation plan on petroleum production system to identify the main problems or constraints that may impact the entire production of system significantly.
2. Carry out performance analysis for each component of petroleum production system including building and evaluating geological and production models of entire system using simulation programs and production surveillance applications.
3. Run field measurement survey periodically against all levels of petroleum production system in order to figure out if there is any deviation to optimum values of parameters in production operations settings.
4. Develop an optimization plan to maximize hydrocarbon production rate and to minimize operating cost under various technical and economic constraints.

5.3. Limitations.

There are common restrictions on the study, but the main one included are:

1. Extreme shortage of the Data required to run comprehensive analysis on each component of petroleum production system of Halewah Field.
2. Lack of the latest software's and insufficient input data to entirely evaluate the performance of each component in petroleum production system of Halewah Field.
3. Incapability to conduct frequent visits to Halewah field on regular basis in order to have exposure to all components of petroleum production system and interchange of information with operations staff in the field.

5.4. Future works

1. Pursuing of the study once all data are available on the place in order to add more valuable and positive results to the study.
2. Monitoring performance of each component of petroleum production system at later stages through appropriate production surveillance applications in order to achieve optimum production under constraints of operations conditions.
3. Applying the methodology of this study on petroleum production systems of other oil fields adjacent to Halewah Field for comparison purpose in terms of performance, productivity, constraints and development opportunities.

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