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1. INTRODUCTION

Petroleum industry is one of the most advanced industries in the world due to its great importance to the mankind. It has reached tremendous levels of advancement with time due to the exponential decrease in easily accessible resources. The petroleum extraction which was limited only to in land deposits have now extended to on shore deposits as well due to the great demand for petroleum and heavy consumption rates.

In this study, we are given the task of carrying out the preliminary level production planning for the Salathong on shore oil field. The lithology of the region and other characteristics of the regional geology is gathered through 5 exploratory drill holes.

The complete summary of the well log data are given in the table below.

Table 1: Well log data summary

Description			SLG 01	SLG 02	SLG 03	SLG 04	SLG 05
Water Depth			Not given	55m	50m	Not given	Not given
Clay layers	Depth		1200m	No	1200m	No	No
	Thickness		300m	No	1500m	No	No
Slow drilling	From		No data	No data	2130m	No	No
	To		No data	No data	2400m	No	No
Fluid loss		From	No	1700m	No	No	No
		To		1790m	No	No	No
Mud	WBM	From	0m	0m	0m	0m	0m
		To	2780m	1793m	3555m	850m	3250m
	OBM	From	No	No	No	850m	No
		To	No	No	No	3500m	No
Sand Intrusions	Depth			No	Encountered	No	No
Fault			No	No	No	No	have some fault blocks
Pressure Zones	High	Depth	2780m	No	No	No	No
		Thickness	No	No	No	No	No
	L	Depth	No	No	No	No	No

		Thickness	No	No	No	No	No
Casing			Partially retrieved	Pulled out	Remaining	Not Mentioned	Remaining
Logs	With casing		No	No	No		No
	Open-Hole		No	No	No	Core samples 8 1/2" interval	No
DST			No	No	Done		No
Hydrocarbon			Gas	No	Encountered	Encountered	No
Lithology Changes with previous wells			No	No	No	No	Yes

The expected production plan in terms of Barrels per day (BPD)

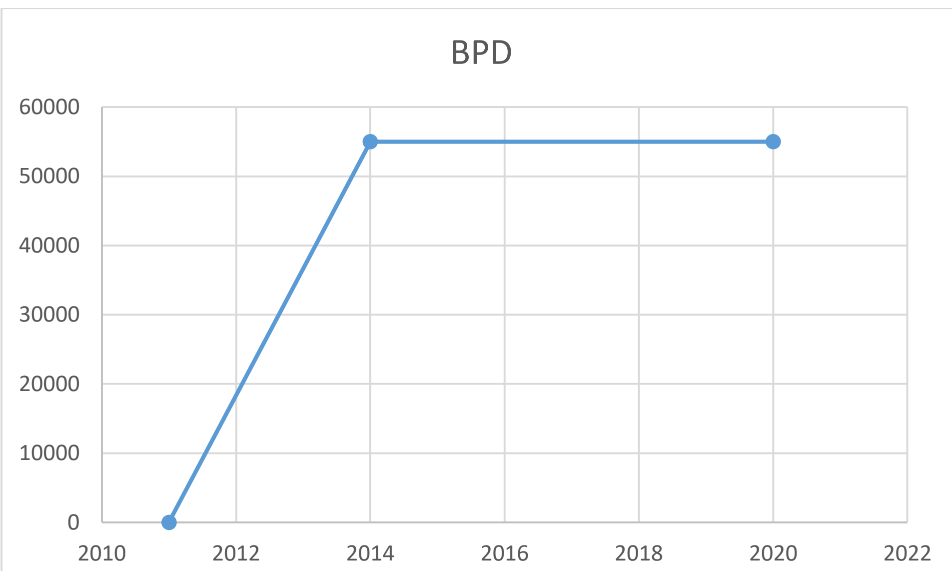


Figure 1: Expected production plan

During our study, we will provide the basic development of infrastructure so that the future expectations of the company can be easily achieved.

Following topics will be covered in detail for the study.

1. Exploratory well location and the determination criteria for the major prospectful regions.

2. Drilling method and selection criteria.
3. Drilling rig selection.
4. Mud weight calculation and design.
5. Casing design.
6. Cement calculation and design.

2. WELL LOCATIONS AND SELECTION CRITERIA

In the case study of developing a well program for the Salathong oil field, the selection of the production well location is one of the most challenging phases of the project. As in any other case where the well locations should be such that it facilitates the optimum extraction of the hydrocarbon, the financial constraints should be also considered for the profitability of the project in the long run.

The selection of well locations can be carried out in two phases.

1. The selection of the most prospectus locations for the available hydrocarbon.
2. The selection of the most economically viable locations to extract the prospected hydrocarbon reserve.

2.1 THE SELECTION OF THE MOST PROSPECTUS LOCATIONS FOR THE AVAILABLE HYDROCARBON.

This phase is usually done by the geologists after inspection of bore hole data and seismic data for the region. The most prospectus locations for the hydrocarbon extraction is decided upon the reservoir estimation for the available hydrocarbon quantity.

In the case of the Salathong field, the available data is less and therefore the prospectus area was identified under certain assumptions along with the well details of SLG1, 2, 3, 4, and 5. SLG 3 well consisted of the most useful data for the analysis.

Assumptions considered in the selection of the prospectus regions:

1. The hydrocarbon reserve quantity is sufficient enough for the expected production plan spanning for 10 years.
2. The hydrocarbon reserve is located at a constant depth and the variations of the reservoir layer in the horizontal plane is negligible.

The summary of exploration wells are given in Table 1

2.2 THE SELECTION OF THE MOST ECONOMICALLY VIABLE LOCATIONS TO EXTRACT THE PROSPECTED HYDROCARBON RESERVE.

The selection of the suitable locations were done using two selection algorithms.

A. Rank analysis
B. Decision taking flow chart

A. RANK ANALYSIS

After considering the well details, the selection of the most suitable locations were drawn up by a rank analysis giving each favorable and unfavorable conditions a weightage. The weights given to each favorable and unfavorable conditions are given below.

Table 2: Favorable conditions

Favorable Conditions	Value
1. Availability of Hydrocarbons	-20
2. Normal Pressure Condition	-8

Table 3: Unfavorable conditions

Unfavorable Conditions	Value
1. Fluid Losses	10
2. Fault Block	13
3. Clay Balling	10
4. Over Pressure Condition	8
5. Oil Spill	6
6. Change in Lithology	15

The Rank analysis for each well with their considered conditions were then analyzed to choose the most prospectus well location.

Table 4: Rank analysis

Condition	SLG1	SLG2	SLG3	SLG4	SLG5
Availability of Hydrocarbons	-20	0	-20	-20	0
Normal Pressure Condition	0	0	-10	0	0
Fluid Losses	0	10	0	0	0
Fault Block	0	0	0	0	13
Clay Balling	10	10	0	0	0
Over Pressure Condition	8	0	0	0	0
Oil Spill	0	0	0	6	0
Change in Lithology	0	0	0	0	15
Total	-2	20	-30	-14	28
Rank	3	4	1	2	5

According to the rank analysis, the SLG3 well proved to show superior characteristics for the production well location which implies that the production well locations should be located at a considerable range from the SLG 03 well.

B. DECISION TAKING FLOW CHART

In this analysis, considering the most influential conditions for the production well location higher up the hierarchy, the unsuitable locations were dismissed until the most suitable location was refined and left out.

The criteria used for the decision taking flow.

- Presence of hydrocarbon
- Over pressure zone and clay balling
- Oil spill

However in this analysis, the left out well being singled out does not emphasize the unavailability of the hydrocarbons in the vicinity of the other wells. It merely suggest that the most suitable location which will encounter the least amount of challenges and problems in the extraction process.

The well locations which refine at higher levels and eliminate in the lower levels may still have higher probability of encountering hydrocarbons and therefore the well location selection should not be blindly considering the singled out well number.

The most prominent way to justify all the valid reasons is to bias the selection process accordingly with several locations being considered.

In this case, SLG3 and SLG4 are such locations which should be considered in the decision making process.

The decision flow diagram is given below.

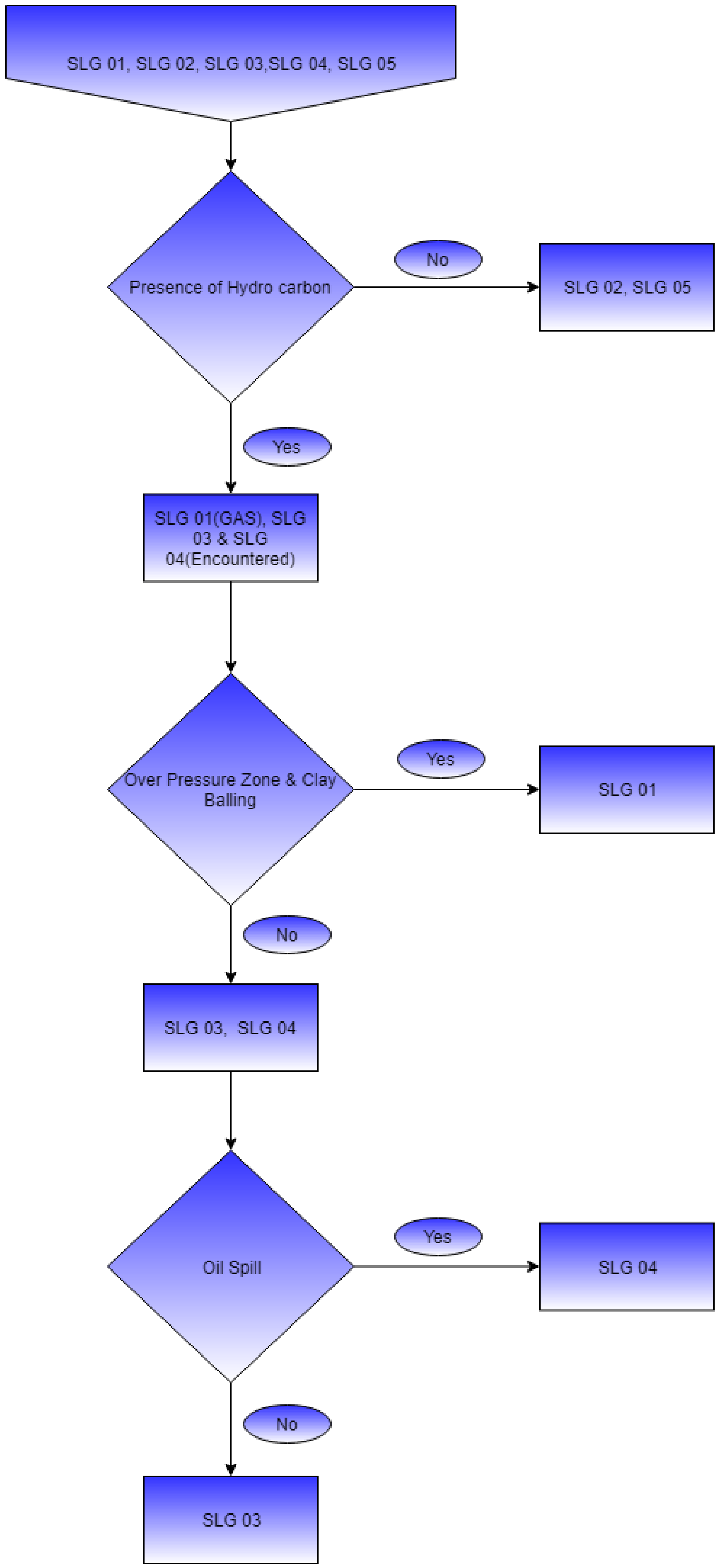


Figure 2: Decision taking flow diagram

3. DRILLING METHOD AND SELECTION CRITERIA

The following factors should be considered in selecting the drilling method.

- Surface location of the well (Well head)
- Location of the target
- Structure of the reservoir
- Expecting demand
- Economic considerations

3.1 PLAN VIEW OF THE FIELD AND PROSPECTING AREA.

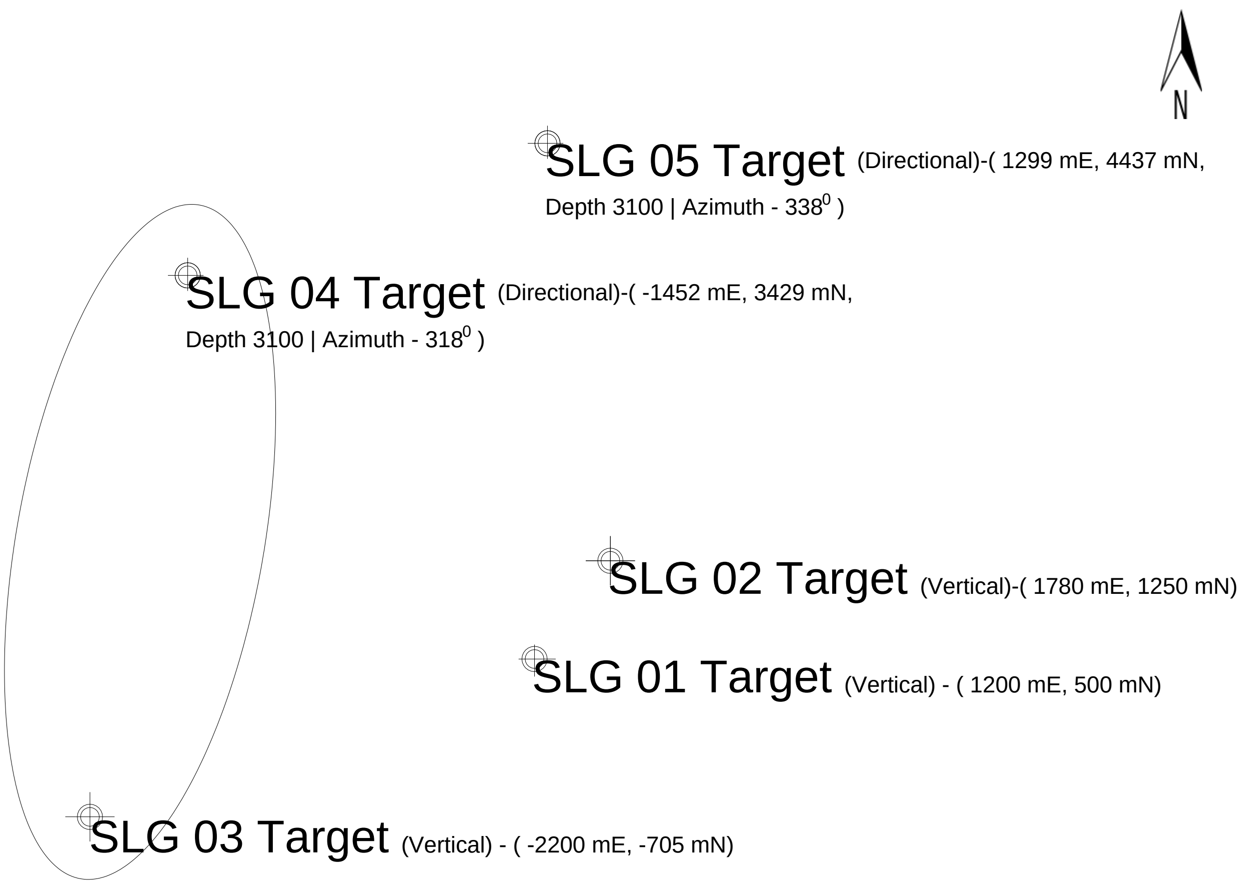


Figure 3: Plan view of the prospecting region

According to the given data prospecting area in between Well no 03 and Well no 04.

3.2 POSSIBLE DRILLING METHODS

CASE 01: - ONLY VERTICAL WELLS

- Rig should be move to each location.
- Time consuming.
- From top to target have to use casings for all wells.
- Some instruments like blow out preventers have to use for each well.
- Have to use subsea pipe line network.

CASE 02: - ONLY DIRECTIONAL WELLS

- Rig can be in one location.
- Relatively costly process.
- Easy to do final well completion process.
- Only one pay zone can be drained per horizontal well.
- The other disadvantage is the cost of horizontal wells which is 1.4 to 3 times more than a vertical well.

CASE 03: - VERTICAL AND DIRECTIONAL WELL COMBINATION

Here concern about the one vertical well and number of directional wells which are around the vertical well and are spread towards the reservoir from one main well head.

- Rig can be in one location
- Costly process
- Final constructions above the subsurface is relatively less.

According to the above-mentioned facts both 2nd and 3rd methods can be mentioned as good methods. Because some costs can be cut off with that method. Therefore, we identified that the best way is using the **one vertical well and two directional wells**. As the below figure.

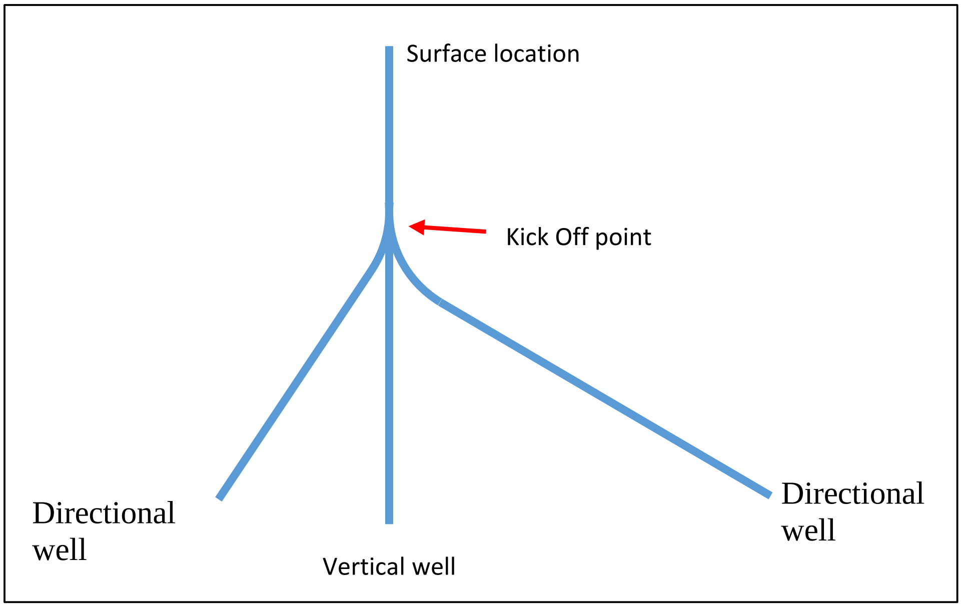


Figure 4: Proposed drilling method

3.3 KICK OFF POINT AND BUILD RATE DETERMINATION

KICK OFF POINT

When we consider the subsurface rock strata with given information Unconsolidated rock strata is ended at 500m below the surface and after that the claystone layer is started therefore it is good to start the buildup section at that depth. And kick off points of the previously drilled directional wells are located 500m below the surface. Therefore, kick of point of this development well can be used as the 500m below the surface.

BUILD RATE

Normally build rates are classified as below table shown;

Table 5: Build rate classification

Well Type	Buildup Rate (ft)	Radius (m)	Radius (ft)
Long radius	2^0 to 6^0/100 ft	915 to 305	3000 to 1000
Medium radius	6^0 to 60^0/100 ft	213 to 38	700 to 125
Short radius	1.5^0 to 3^0/ft	12 to 6	40 to 20

Buildup rate of the SLG 04 well is **0.096110871^0/100ft**

Buildup rate of the SLG 05 well is **0.338405635^{0}/100ft**

Average for two cases = **0.2**

In practically, the maximum dogleg severity is 6^{0} per 100ft. Therefore, in our case we can use 1 as our dogleg severity (DLS).

Therefore, radius of curvature for our directional wells can be taken as 1700m

Note….

Calculations are shown in annexes.

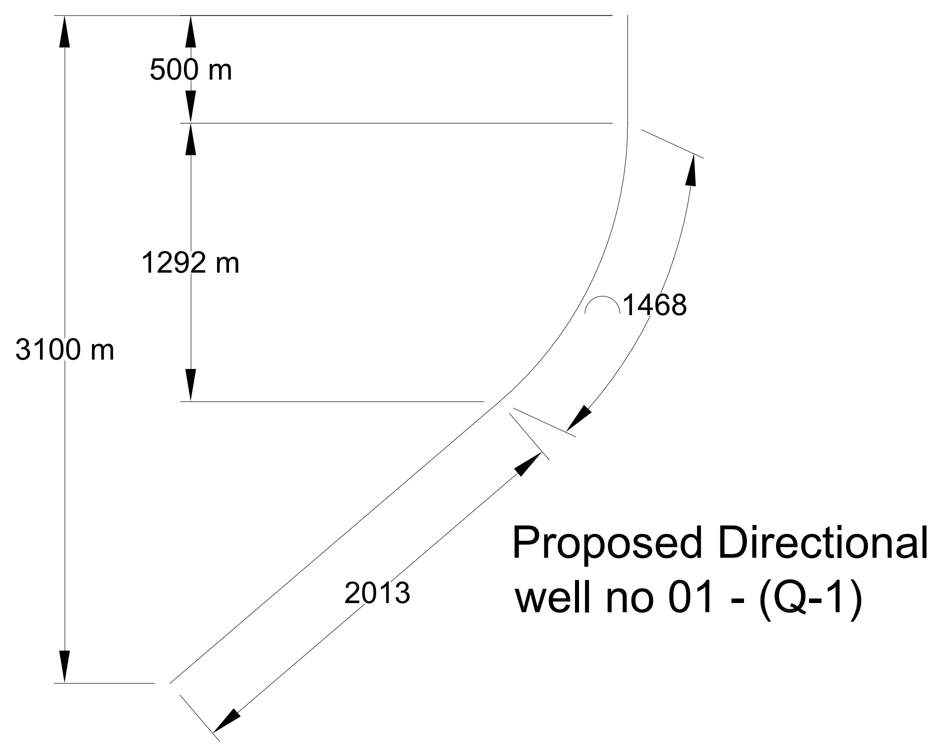


Figure 5Directional well Q-1 profile

Table 6: Directional well Q-1 calculations

Directional well Q-1						
Description		TVD (m)	MD (m)	INC. Deg.	INC. Rad.	AZIMUTH (Deg.)
Vertical section	Start point	0	0	0	0	10

	End point	500	500	0	0	10
Kick off point		500	500	0	0	10
Build up section	Start point	500	500	0	0	10
	End point	1792	1953.859267	49	0.855211333	10
Tangential section	Start point	1792	1953.859267	49	0.855211333	10
	End point	3100	3947.582304	49	0.855211333	10

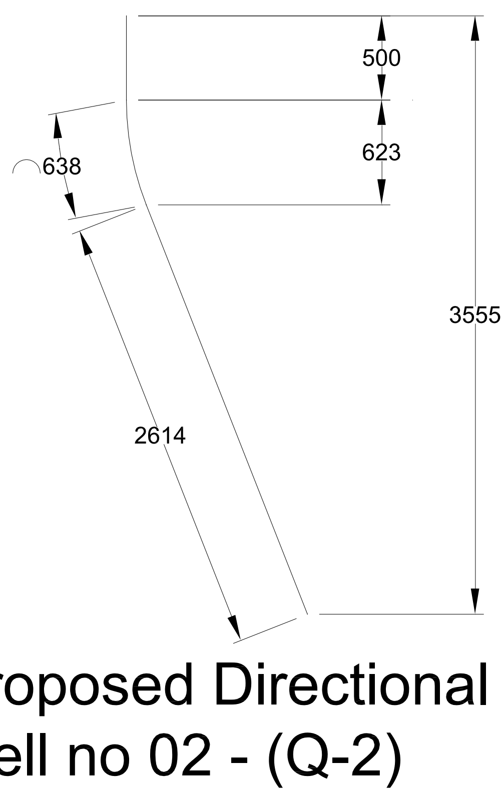


Figure 6: Directional well Q-2 profile

Table 7: Directional well Q-2 calculations

Directional well Q-2						
Description		TVD (m)	MD (m)	INC Deg.	INC. Rad.	AZIMUTH (Deg.)
Vertical	Start point	0	0	0	0	190

	End point	500	500	0	0	190
Kick off point		500	500	0	0	190
Build up section	Start point	500	500	0	0	190
	End point	1123	1123.082543	21	0.366519143	190
Tangential section	Start point	1123	1746.165086	21	0.366519143	190
	End point	3555	4351.18971	21	0.366519143	190

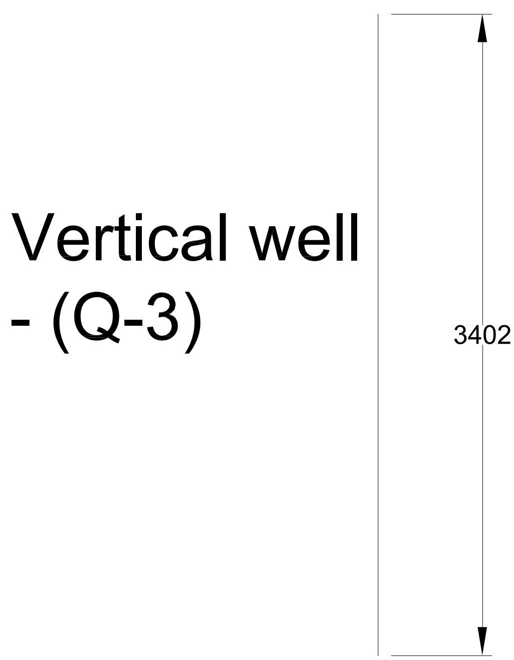


Figure 7: Vertical well Q-3 profile

4. DRILLING RIG SELECTION

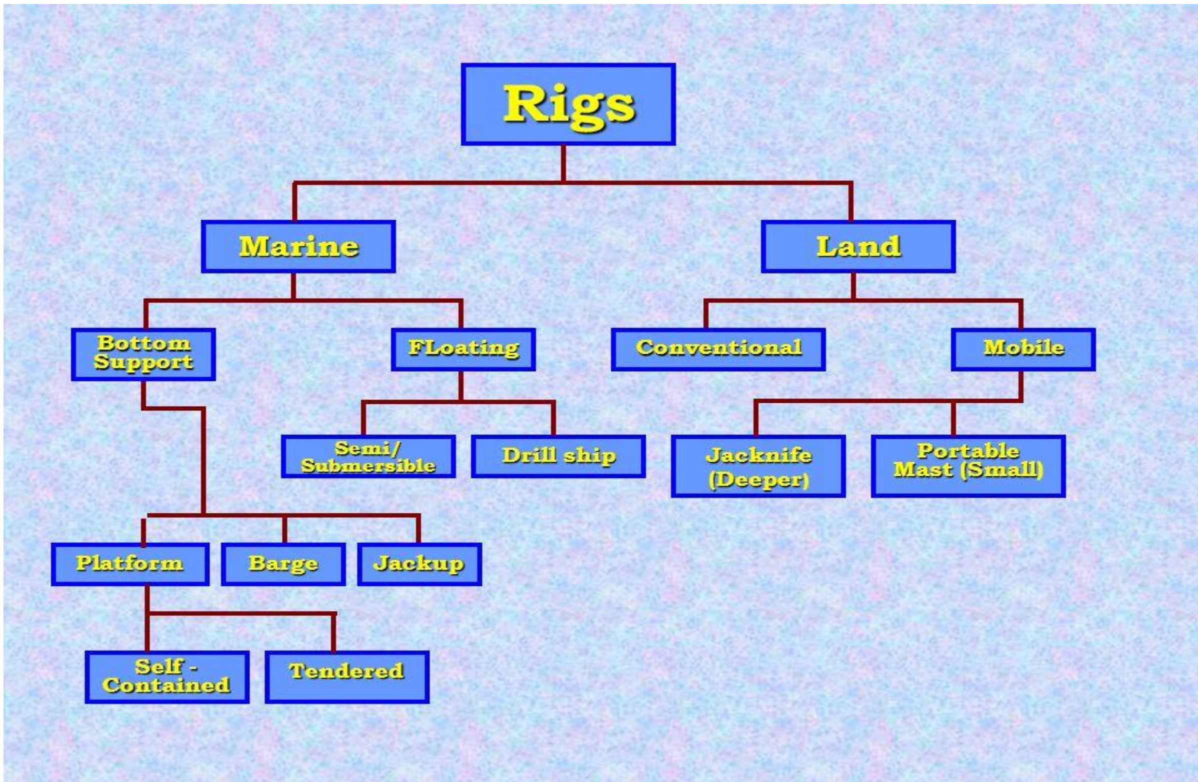


Figure 8: Types of rigs

Drilling rig selection is crucial. Offshore drilling is always a technical challenge. As the hunt for offshore hydrocarbons moves to further more remote and deeper waters, the technical challenge ever increases.

Offshore drilling for the exploration and production of hydrocarbons, both oil and gas will always start with an engineer making a selection of drill rig.

The type of drilling rig used will be dependent on a number of factors:

- **Geographical location of the well**
- **Depth of water the rig will operate**
- **Depth to be drilled**
- **Heat and pressure of the well.**

4.1 TYPES OF DRILLING RIGS

Once these factors have been considered, the engineer from the offshore oil and gas exploration and production (EP) company will traditionally hire the services of a specialized drilling company, and normally their drilling rig. Drilling rigs can come in the form of:

- A Jack-up Rig
- A semi-submersible Rig
- A Drill Ship

Each type of drilling rig will have its pros and cons.

JACK-UP DRILLING RIG

These kind of drilling rigs are more often the older drilling rigs in operation.

They typically operate in shallower water, depths of 250ft (76m) – 400ft (122m) and drill up to depths of 35,000ft (10,670m).

They are normally not self-propelled and require tow from tugs to move from one drill location to the next. On longer moves, the services of a heavy lift ship may be required, although this is an expensive option. Jack-up drilling rigs are typically the cheapest drilling rigs to hire.

SEMI-SUBMERSIBLE RIG

Semi-submersibles or semis as they are more often known are typically newer and seen as a next generation of drilling rig compared to a jack-up.

Through design, they are regarded as true deep water drilling rigs, typically drilling in water depths up to 7000ft (2130m) and drilling to depths of 35,000ft (10,670m), although the latest generation of semi-submersible drill rigs can operate at greater depths than this.

Like jack-up rigs, they too are not normally self-propelled and also need tugs to be moved them from one drill site to the next or a heavy lift ship on longer duration moves. Unlike jack-up rigs however, they also have the added expense of having to employ anchor handling ships to help secure them in place to the sea floor.

Due to a semi-submersible's design, they are more stable under tow, however the services of a heavy lift ship would still likely be sought if moving greater distances i.e. the Gulf of Mexico to Europe.

Some of the most modern generation of semi drilling rigs have been built with dynamic positioning systems, allowing them to work without the need for anchors.

DRILLSHIP

The latest generation of drill ships are seen as ultra-deep-water, and through the ever increasing need to reach hydrocarbons in tougher more remote locations, drill ships are often seen as the only viable option.

Because of this, much of the latest ground breaking technology will go into a new build drillship. The benefit of using drill ships over semis is the maneuverability, as it is able to not only move from one drill site to the next under its own steam but, at great distance and speed- typically 14knts as opposed to 4knts of a semi under tow.

This would take weeks off of a typical journey from the Americas to Europe or vice versa, equating to less operational down time. Also due to natural design, size and therefore storage, drill ships are also able to stay fully self-sufficient for much greater periods of time.

For example in 2012, Stena Drilling launched the Stena Icemax, the world's first drillship capable of drilling in ultra-deep-water within arctic conditions. As arctic and more harsh and remote hydrocarbon reserves become more viable, the likely hood of further harsh environment, self-sufficient drill ships being launched remains strong.

FIXED PLATFORM DRILLING

Drilling operations taking place in shallow waters on older fixed platforms will often have their own drilling facilities.

In this case the exploration and production company will traditionally hire in the services of a drilling company to conduct both maintenance activates and drilling operations on their fixed platform drilling rig. This arrangement is most common within the North Sea.

Table 8: Rig types comparison

Rig Type	**Jack-up**	**Platform**	**Semi-Submersible**	**Drill Ship**
Drilling Depth	35,000ft	35000ft	35,000ft	40,000ft +
Shallow/Deep	Shallow	Shallow	Shallow	Ultra-Deep Water
Operation Depth	250ft– 400ft	10ft-850ft	Up to 7000ft	18ft-12000ft

Transporting System	Tow from Tugs & Heavy Lift Ship	Fixed	Tow from Tugs	Self-Propelled
Costs	$180 million	$650 million	$200 million	$1.24 billion

4.2 RECOMMENDATION FOR THE GIVEN CASE:

The location of our field exploration wells is situated in Gulf of Palau New Garna in the Asia Pacific named Salathong Field. Severe **overpressures and under pressures** were encountered in some wells.

Also according to the government rules and regulations the operations should be **environmental friendly** and should have proper **waste disposal systems**.

According to the given data we have 55m overburden water depth and in the reservoir highest pressure is 4591.4 psig and the highest temperature is 373.81^{0} F. Total depth to be drilled is nearly 3183m.

By considering these data and the budget we can recommend **Jack-up rig** for the process because they typically operate in **shallower water depths** of 250ft (76m) – 400ft (122m) and drill up to depths of 35,000ft (10,670m).

They are originally were designed to operate in very shallow water. They have **low initial cost** and have low construction time than other rigs.

Also it offers a **steady and relatively motion-free platform** in the drilling position and mobilizes relatively quickly and easily. Jack up rigs looks strong because they offer operators a desirable option in a number of different offshore environments and long duration operations for several years.

5. MUD WEIGHT CALCULATION AND DESIGN

In the petroleum industry, mud weight is known as the density of the drilling fluid and the conventional units of measurement is pounds per gallon (ppg). The density of the drilling fluid must be controlled such that it provides enough hydraulic head to prevent any influx of the formation fluid but at the same time, not so high as to cause any loss of circulation or adversely affect the drilling rate and damage the formation. The drilling fluid or most commonly termed drilling mud serves many purposes.

5.1 FUNCTIONS OF DRILLING FLUIDS

1. Transport cuttings and dispose to surface.
2. Clean the drill bit from stuck material in the bit teeth.
3. Provide hydrostatic pressure to control the well while drilling.
4. Prevent excessive mud loss by the formation of mud cakes.
5. Cool down and lubricate the bit and drill string.

5.2 REQUIRED DATA FOR DRILLING FLUID SELECTION.

a. Pore pressure / fracture gradient plots to establish the minimum and maximum mud weights to be used on the well.
b. Offset well data from similar well in the area.
c. Geological plot of the prognosed lithology.
d. Basic mud properties required over each hole section.

Mud weight needed to control a well reflects the pore pressure of any permeable formation drilled. In well control, engineers determine the mud weight that will exert a pressure closer to the expected pore pressure. Several pressure criteria has to be determined prior to the selection of the drilling mud properties in order to prevent disastrous situations.

HYDROSTATIC PRESSURE

Hydrostatic pressure is the pressure caused by the density (or mud weight) and true vertical depth of a column of fluid. The hole size and shape of the fluid column have no effect on hydrostatic pressure.

The hydrostatic pressure at a given depth is governed by the following equation with mud density in ppg and true vertical depth in feet as units.

$$P_{hydrostatic} = 0.052 \times Mud\ density\ \times True\ vertical\ depth\ (TVD)$$

PORE PRESSURE

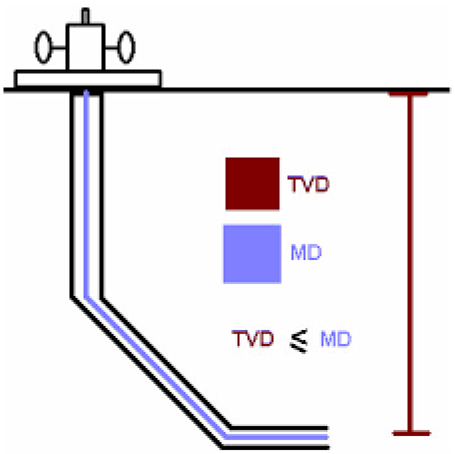
The pressure in the fluid in the pores of the sediment will only be dependent on the density of the fluid in the pore space and the depth of the pressure measurement.

The general pore pressure gradients from different fluids are given below.

Table 9: general pressure gradients for different fluids

Fluid	Density (ppg)	Pressure gradient (psi/ft)

Freshwater	8.335	0.433
Sea water	8.55	0.444
Salt water	8.95	0.465
Saturated saltwater	10	0.520



Measured depth - MD

Figure 10: True vertical depth and measured depth

NORMAL PRESSURE CONDITION

A normally pressured formation has a pore pressure equal to the hydrostatic pressure of the pore water. In usual conditions, wells are drilled in sediments characterized by 8.95 ppg saltwater and therefore the normal pressure gradient is considered to be 0.465 psi/ft.

ABNORMAL UNDER PRESSURE

Subnormal pressures are encountered in zones with pore pressures lower than the normal hydrostatic pressure.

ABNORMAL OVERPRESSURE

Abnormal overpressures are encountered in zones with pore pressures higher than the normal hydrostatic pressure of the pore fluids.

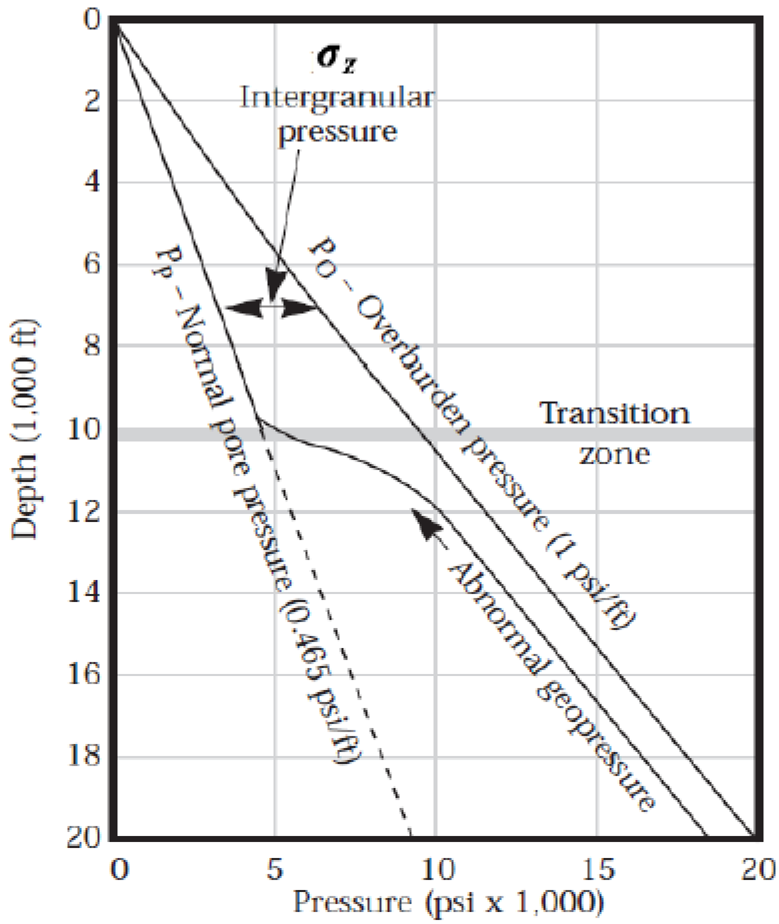


Figure 11: Normal pressure and overburden pressure graphs

There are many drilling fluid additives which re used to either change the mud density or change its chemical properties.

1. WEIGHTING MATERIALS (DENSIFIERS)

Table 10: Different types of weighting materials used

Material	Principal component	Specific Gravity	Hardness (Moh's Scale)
Galena	PbS	7.4 – 7.7	2.5 – 2.7
Hematite	Fe_2O_3	4.9 – 5.3	5.5 – 6.5
Barite	$BaSO_4$	4.2 – 4.5	2.5 – 3.5
Calcite	$CaCO_3$	2.6 – 2.8	3.0

2. VISCOSIFIERS

Two types of clays are usually used as viscosifiers.

- Bentonitic clay
- Attapulgite (or salt gel)

5.3 MAIN TYPES OF DRILLING FLUIDS

a. Water based mud – This fluid is the mud in which water is the continuous phase.
b. Oil based mud – Made up of oil as the continuous phase. Diesel oil is widely used. Commonly used in swelling shale formations. Major disadvantages of using oil based mud is that it contaminates the environment and therefore is hard to remove solids from the mud. Electrical logging is also much difficult when using oil based mud.

5.4 PRESSURE AND DEPTH ANALYSIS FOR THE SALATHONG WELLS

LITHOLOGY IN THE AREA

Table 11: Lithology in the Salathong region

Lithology	Depth range(feet)
Unconsolidated sand interbedded with siltstone and claystone	0 - 1049.8688
Reddish-Brown Claystone contained Hectorite with minor Coal, Pebbles and Limestone	500-1850
Gray-Green Claystone contained Chlorite with some Dolomite.	1850-2680
Highly Unconsolidated Sandstone with minor Siltstone interbedded.	2740-3150
Hard Dolomite	>3200

FOR THE OVERBURDEN DRILLING ABOVE THE RESERVOIR REGION.

Overburden normal pressure conditions are assumed.

Equivalent mud weight (ppg) = Pressure gradient (psi/ft)/ 0.052

The pore pressure gradient under normal pressure gradient is assumed to be 0.465 psi/ft

Calculated mud weight = 8.942 ppg

FOR THE RESERVOIR DRILLING.

The complete depth of the reservoir is partitioned into 4 stages. The main reason for this is the sudden variations observed in pressure over the reservoir region. Four basic trends were identified visually and these regions are given below.

Table 12: 4 stages of the reservoir

Stage	From (ft)	To (ft)
1	9110	9211
2	9211	9943
3	9943	10167
4	10167	10440

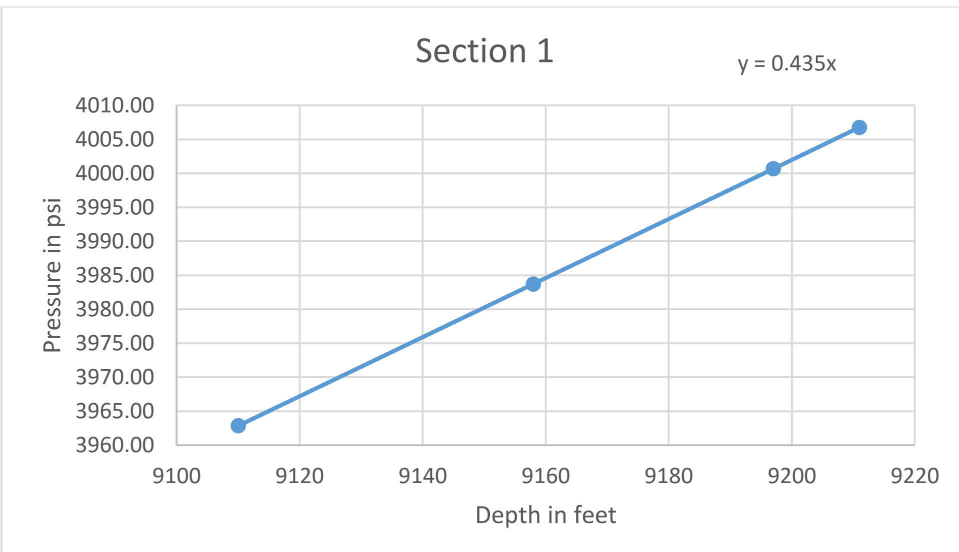


Figure 12: Pressure vs Depth graph for stage 1

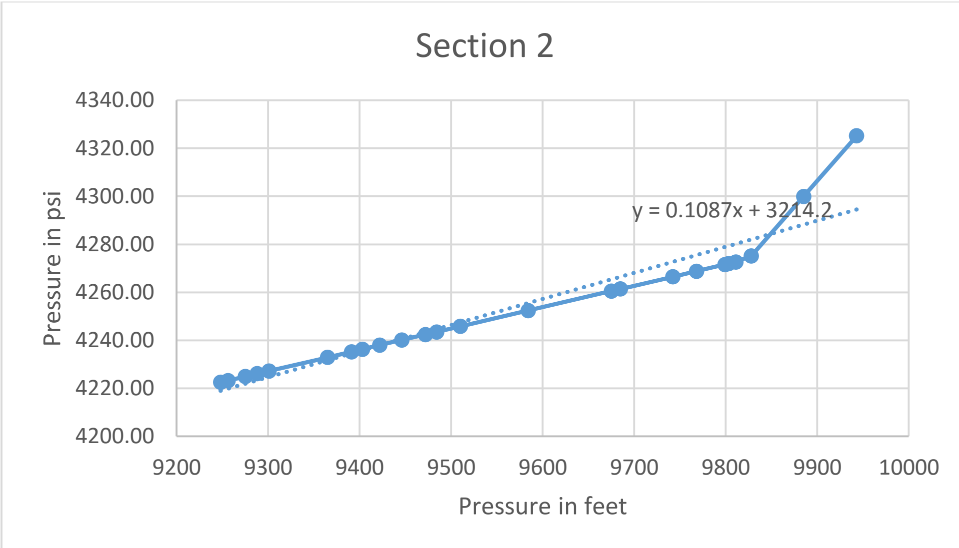


Figure 13: Pressure vs depth graph for stage 2

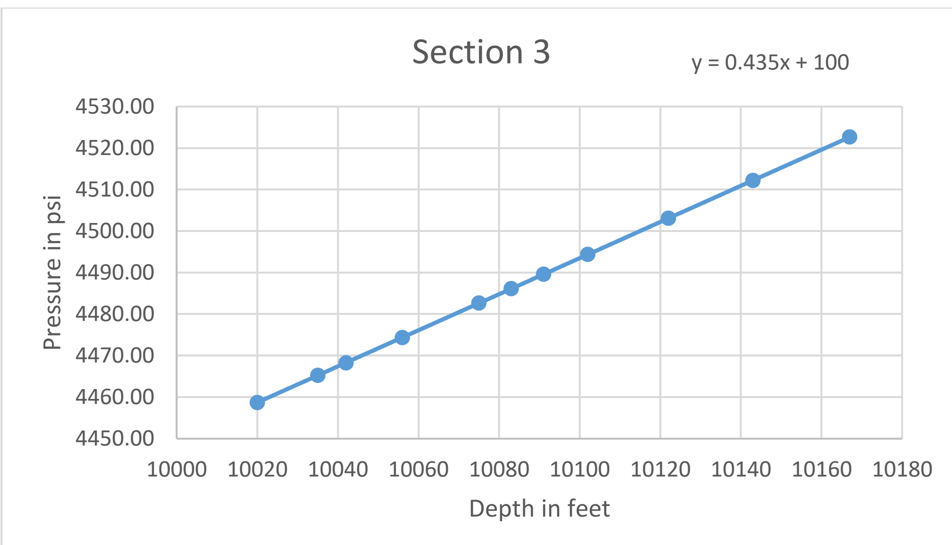


Figure 14: Pressure vs depth graph for stage 3

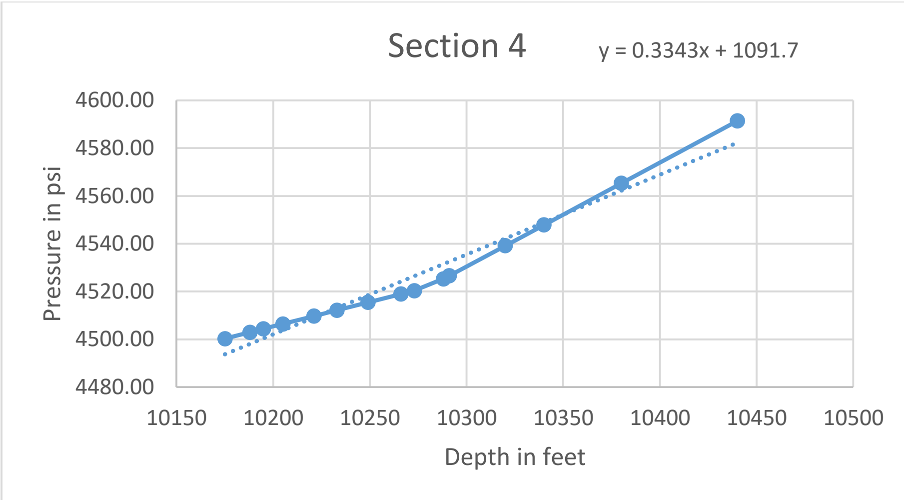


Figure 15: Pressure vs depth graph for stage 4

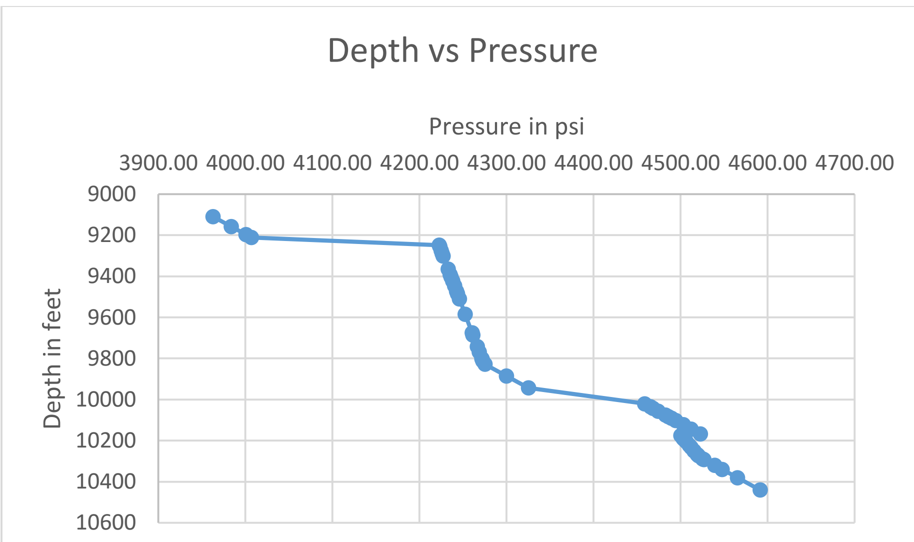


Figure 16: Pressure vs depth graph for the whole reservoir

CALCULATED PRESSURE GRADIENTS AND MUD WEIGHTS FOR EACH STAGE

Table 13: Pressure gradients and mud weights for each stage

Stage	Pressure gradient psi/ft	Mudweight in ppg
Section 1	0.435	8.365384615
Section 2	0.1087	2.090384615
Section 3	0.435	8.365384615
Section 4	0.3343	6.428846154

5.5 DESIGNING THE DRILLING FLUID

CONSIDERATIONS IN SELECTING A DRILLING FLUID

- Performance
  - Inhibition
  - Rheology
  - Fluid loss
  - Temperature
- Environment friendly nature of the fluid
- Safety to all the personnel
- Cost of the drilling fluid
- Technical availability.
- Ease of storage.

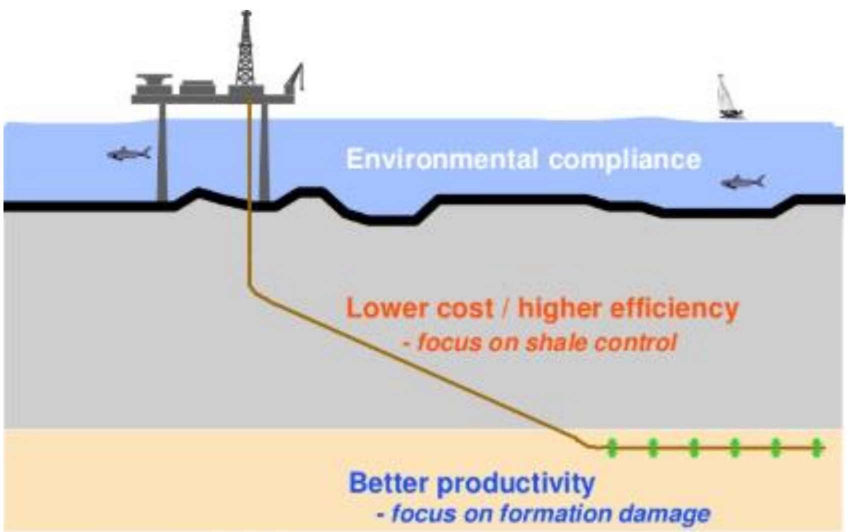


Figure 17: Considerations in selecting a drilling fluid

CLAY SWELLING

During the exploration stages, SLG 01 and SLG 02 wells encountered severe clay balling conditions while drilling using water based Bentonite non inhibited mud system and a water based Bentonite inhibited mud system. This suggests that the drilling fluid should be designed so as to accommodate for the clay balling issues. The requirement for the specially designed drilling fluid system to tackle the clay swelling conditions is further confirmed by the use of water based mud polymer inhibited mud system in the SLG 03 well which reduced the clay swelling problems significantly.

However it should be noted that the drilling conducted in the SLG 05 well encountered no clay swelling issues at all when a water based polymer with a new inhibitor mud system was used.

The type of clay swelling and the mechanisms are not highlighted in the problem statement. Therefore a general solution for the clay swelling will be sought out and designed as per the general conventions in the industry.

ADVERSE EFFECTS OF CLAY SWELLING

- Difficulties in running the casing.
- Agglomeration of drilled cuttings resulting in the poor hole cleaning efficiency.
- Development of thick cutting beds.
- Reduction of rate of penetration due to the balling of sticky clay on the drill bit.
- Promote well bore instability.

SOLUTIONS AVAILABLE TO TACKLE THE CLAY SWELLING CONDITIONS

1. Use of high concentrations of KCl or other electrolytes at concentrations of 2%-7% with water based drilling fluids.

2. Use of oil based drilling fluids.

3. Use of organic polymers and surfactants with water based drilling fluids.

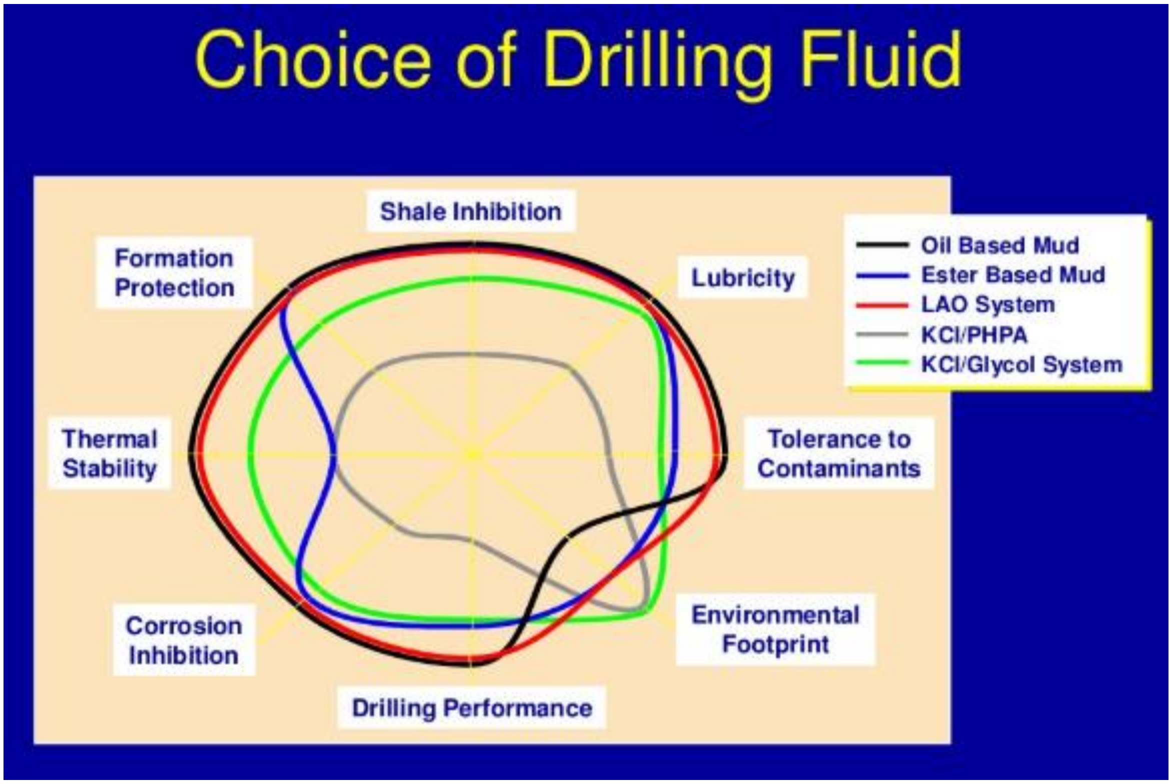


Figure 18: Different properties of drilling fluids

1. USE OF HIGH CONCENTRATIONS OF KCL OR OTHER ELECTROLYTES AT CONCENTRATIONS OF 2%-7% WITH WATER BASED DRILLING FLUIDS.

For over a several decades, operators and service company personnel in charge of drilling have routinely included 2% KCl as a hedge against clay swelling. However this method is decreasing in popularity due to the novel methods such as organic polymer and surfactant additives. The novel methods may still come across at the expense of new technology and high costs which still makes the conventional KCl based drilling fluid technically and economically feasible compared to other methods. The major drawback in this system is the ion exchange that takes place between the formation minerals and injected brines. This makes the effective levels of KCL lower by about 0.5% which can make a drastic impact on the penetration ability and the general productivity of the drilling fluid.

2. USE OF OIL BASED DRILLING FLUIDS.

Oil based drilling fluids were developed and introduced to the petroleum industry in the 1960s inorder to address the following drilling challenges.

- Reaction, swelling and slough of formation clays after being exposed to water based drilling fluids.
- Increment of down hole temperatures.

- Availability of contaminants to water based drilling fluids.
- Pipes getting stuck, torque and dragged.

Oil based drilling fluids pose major environmental concerns which makes it very much a non-environmental friendly drilling fluid type. This is clearly evident from the complaints received by the Palau New Garna government from the local fisherman about the occurrence of oil in the water surface. Although economic benefits are vital in petroleum production, the environmental and social concerns can never be neglected.

3. USE OF ORGANIC POLYMERS AND SURFACTANTS WITH WATER BASED DRILLING FLUIDS.

This is the latest technique used in drilling engineering to accommodate clay swelling problems. The gaining popularity is mainly due to the greater environmental concerns following major environmental impacts posed from the use of oil based drilling fluids. The legal constraints relevant to drilling and production, especially offshore has increased exponentially over the last few decades.

This has forced drilling companies to invest on research in finding a safe and environmental friendly solution which is also cost effective.

The major challenges in the development of such a swelling inhibitor are two fold

1. The nature of clay minerals are complex and heterogeneous which makes unique applications for site specific conditions.
2. Find the balance between the swelling inhibitions at the cost of higher drilling performances.

The specific drilling fluid designed should be able to withstand the typical **wellbore temperatures and pressures.**

VARIETIES OF SWELLING INHIBITOR MOLECULES

- Polyethylene glycol (PEG)
- Polypropylene oxide (PPO)
- Hydroxyethyl cellulose (HEC)
- Quaternary substituted HEC (HECell)

QUANTITY OF MATERIAL USED IN THE PREPARATION OF DRILLING MUD

The 3rd solution (i.e. the use of organic polymers and surfactants) will be adopted to drill the production wells due to its environmental friendly nature.

THE MUD RECIPE

- 30 ppb Bentonite
- 0.5 ppb CMC polymer and other polymer and surfactnts
- 0.5 ppb Caustic soda
- 0.25 ppb Sodium Carbonate
- Weighting material – Barite

Table 14: Volume calculation for the drilling mud design

Material	Density (ppg)	Volume (gallon)	Weight (lb.)
Drill water	8.34	40 221.718	335 499.1681
Bentonite	20	1 500	30 000
Polymers and surfactants	20	25	500
Caustic soda		Neglect	500
Na_2CO_3		Neglect	250
Barite	35	253.282	8 864.87
Total		**42 000**	**375 114.0381**

6. CASING DESIGN

6.1 DESIGN OBJECTIVE

The engineer responsible for developing the well plan and casing design is faced with a number of tasks that can be briefly characterized.

- Ensure the well's mechanical integrity by providing a design basis that accounts for all the anticipated loads that can be encountered during the life of the well.
- Design strings to minimize well costs over the life of the well.
- Provide clear documentation of the design basis to operational personnel at the well site. This will help prevent exceeding the design envelope by application of loads not considered in the original design.

There are major responsibilities when performing casing and tubing design;

- Ensure the well's mechanical integrity
- Optimize well cost
- Provide operations personal with maximum allowable loads

6.2 TYPES OF CASING

1. CASSION PIPE (26 TO 42 IN. OD)

- For offshore drilling only.

- Driven into the sea bed.
- It is tied back to the conductor or surface casing and usually does not carry any load.
- Prevents washouts of near-surface unconsolidated formations.
- Ensures the stability of the ground surface upon which the rig is seated.
- Serves as a flow conduit for the drilling mud to the surface

2. CONDUCTOR PIPE (7TO 20IN. OD)

- The outermost casing string.
- It is 40 to1, 000 ft in length for offshore.
- Generally, for shallow wells OD is 16 in. and 20 in. for deep wells.
- Isolates very weak formations.
- Prevents erosion of ground below rig.
- Provides a mud return path.
- Supports the weight of subsequent casing strings.

3. SURFACE CASING (17-1/2 TO 20 IN OD)

- The setting depths vary from 300 to 5,000 ft
- 10-3/4 in. and 13-3/8 in. being the most common sizes.
- Setting depth is often determined by government or company policy and not selected due to technical reasoning.
- Provides a means of nippling up BOP.
- Provides a casing seat strong enough to safely close in a well after a kick.
- Provides protection of fresh water sands.
- Provides wellbore stabilization.

4. INTERMEDIATE CASING (17-1/2 TO 9-5/8 IN OD)

- Also called a protective casing, it is purely a technical casing
- The length varies from 7,000 to 15,000 ft.
- Provides isolation of potentially troublesome zones (abnormal pressure formations, unstable shales, lost circulation zones and salt sections).
- Provides integrity to withstand the high mud weights necessary to reach TD or next casing seat

5. PRODUCTION CASING (9-5/8 TO 5 IN OD)

- It is set through the protective productive zone(s).
- It is designed to hold the maximal shut-in pressure of the producing formations.

- It is designed to withstand stimulating pressures during completion and work over operations.
- A 7-in. OD production casing is often used

6. LINER CASING

- A string of casing that does not reach to the surface
- Hang on the intermediate casing, by use of suitable packer and slips called liner hanger

6.3 CASING DESIGN FACTORS

LOAD CASES

Dividing the pipe rating by a corresponding load results in a design factor. If the design factor is greater than the minimum acceptable design factor, then the pipe is acceptable for use with that load.

$$DF = \frac{pipe\ rating}{planned\ load} \geq DF_{min}$$

6.4 FUNCTIONS OF CASING

- To keep the hole open and to provide a support for weak, or fractured formations.
- To isolate porous media with different fluid/pressure regimes from contaminating the pay zone
- To provide a passage for hydrocarbon fluids; most production operations are carried
- To provide a suitable connection for the wellhead connection

6.5 STRENGTH PROPERTIES

1. YIELD STRENGTH

a. Pipe body yield strength

b. Coupling strength

- API defined the yield strength as the tensile stress required to produce 0.5% of the gauge length
- Most common types of casing joints are threaded on both ends and fitted with a threaded coupling on one end only
- Joint strength may be lower or higher than the main casing, pipe body yield
- There are integral casing without coupling in which the threads are cut from internal-external upset

2. COLLAPSE STRENGTH

- Defined as the maximum external pressure required collapsing specimen of casing
- Four types of collapse are observed:
- Elastic (fails before deforms)

$$P_C = \frac{2E}{1-\mu^2} * \frac{1}{\frac{D}{t}[\frac{D}{t} - t]^2}$$

- Plastic (certain deformation takes place)

$$P_p = Y[\left| \frac{A}{\frac{D}{t}} - B \right| - C$$

Y = yield strength

A,B,C =Constants depend on the grades and steel

$\frac{D}{t}$ =Diameter thickness ratio, should be calculated first and If fails in the range given in table then get A,B & C and apply in equation

3. BURST STRENGTH

a. Plain end

b. Coupling

- It is defined as the maximum value of internal pressure required causing the steel to yield.
- It is calculated by Barlow's formula

P = 0.875 (2Yt/D)

- It gives the burst resistance for a minimum yield of 87.5% of pipe wall
- It allows 12.5% variation of wall thickness due to manufacturing defects.

CASING SPECIFICATIONS

- Casing is specified by: grade, weight per unit length, outside diameter and wall thickness, type of coupling, and length of joint.
- API defines three types of casing weight
- Nominal weight: normally based on the calculation, not exact, use for design and given in tables.
- Plain end weight: the weight of casing joint without inclusion of threads and couplings
- Threads and coupled weight

TYPES OF THREADS AND COUPLINGS

- In general, the casing and coupling are specified by the type threads cut in the pipe or coupling.

    • API round thread (LTC, STC)

    • Buttress thread

    • VAM thread

    • Extreme line threaded coupling

6.6 DESIGN CRITERIA

According to the casing design have to consider about following three basic forces;

- Collapse
- Burst
- Tension

These are the actual forces that exist in the wellbore. They must first be calculated and must be maintained below the casing strength properties.in other words, the collapse pressure must be less than the collapse strength of the casing and so on. Casing should initially be designed for collapse, burst and tension.

For directional wells a correct well profile is required to determine the true vertical depth. All wellbore pressures and tensile forces should be calculated using true vertical depth only.

COLLAPSE PRESSURE

- Considered as the hydrostatic pressure applied on outer surface of casing
- Zero at top and maximum at bottom
- Collapse pressure Pc = ρmgh
- Pc never exceeds the collapse resistance of the casing
- In designing for collapse, the casing is assumed empty for surface and production and partially empty for intermediate casing

BURST PRESSURE

- At the top of the hole the external pressure due to mud is zero and the internal pressure must be supported entirely by casing body.
- Burst is the highest at the top and least at the casing shoe. When production tubing at shoe can be higher than burst pressure at surface.

6.7 CASING SELECTION CALCULATION

- ➢ Casing calculation applied for all wells

Formation pressure gradient $= \frac{d(Hydrostatic\ pressure)}{dh}$

= pressure due to unit length of water

= h$\rho\mathcal{G}$

= (1m)*(1000kgm^{-3})*(10ms^{-2})

=10,000pa

=10,000*0.000145038

=1.4504psi/m

RECOMMENDED DESIGN FACTORS

- Collapse 1.125
- Burst 1.1

6.8 CASING SELECTION WITH THE EXPECTED SUB SURFACE DEPTH (TVD) AND FORMATION MUD DENSITY

Table 15: Casing selection

Casing type	Mud density	Sub-surface depth(m)(TVD)	Formation pressure gradient(psi/m)
Surface casing	0.465	500	1.4504
Intermediate casing 01	0.465	1700	1.4504
Intermediate casing 02	0.465	2500	1.4504
Production casing	0.435	3500	1.4504

STANDARDIZATION OF CASING

SURFACE CASING

Mud pressure = Mud density * Depth

= 0.465*500*3.281

= 762.795 psi

Formation pressure = Formation pressure gradient * depth

= 1.4504*500

=725.2 psi

BURST CASE

Standard of casing = Formation pressure * 1.1

=797.72 psi

COLLAPSE CASE

Standard of casing = Mud pressure* 1.125

=858.144 psi

According to above calculations surface casing selected is

K-55 20” Casing pipe

INTERMEDIATE CASING 01

Mud pressure = Mud density * Depth

= 0.465*1700*3.281

= 2593.50 psi

Formation pressure = Formation pressure gradient * depth

= 1.4504*1,700

=2,465.68 psi

BURST CASE

Standard of casing = Formation pressure * 1.1

=2,712.25 psi

COLLAPSE CASE

Standard of casing = Mud pressure* 1.125

=2917.69psi

According to above calculations intermediate casing 01 selected is;

P-110 133/8” Casing pipe

INTERMEDIATE CASING 02

Mud pressure = Mud density * Depth

= 0.465*2500*3.281

= 3813.98 psi

Formation pressure = Formation pressure gradient * depth

= 1.4504*2,500

=3,626.00 psi

BURST CASE

Standard of casing = Formation pressure * 1.1

=3988.6 psi

COLLAPSE CASE

Standard of casing = Mud pressure* 1.125

=4,290.525 psi

According to above calculations Intermediate casing 02 selected is

C-95 9 5/8" Casing pipe

PRODUCTION CASING

Mud pressure = Mud density * Depth

= 0.435*3500*3.281

= 4,995.32 psi

Formation pressure = Formation pressure gradient * depth

= 1.4504*3500

=5,076.4 psi

BURST CASE

Standard of casing = Formation pressure * 1.1

= 5,076.4*1.1

=4,626.78 psi

COLLAPSE CASE

Standard of casing = Mud pressure* 1.125

=4,656.13psi

Table 16: Summary of the vertical well casing design

Casing type	Depth (TVD)(m)	Depth (MD)(m)	Hole Diameter (Inch)	Description	Casing OD (Inch)	Casing ID (Inch)	No. of casing
Conductor	50	50	36.00	30" Conductor	30.000	20.000	7
Surface Casing	500	500	26.00	20" K-55 Casing pipe	20.000	19.00	53
Intermediate Casing 1	1700	1700	17.50	13 3/8" P-110 Casing pipe	12.615	12.347	128
Intermediate Casing 2	2500	2500	12.25	9 5/8" C-95 Casing pipe	8.835	8.835	203
Production Casing	3500	3500	8.50	7" K-55 Casing pipe	7.000	6.276	310

The casing calculations of the directional wells are attached in the annexure.

7. CEMENT CALCULATIONS AND DESIGN

7.1 FUNCTIONS OF CEMENT

- Restriction of fluid movement between permeable zones
- Provision of mechanical support of the casing string
- Protection of casing from corrosion

- Support of the well-bore walls to prevent collapse of formations

7.2 THE MANUFACTURE AND COMPOSITION OF CEMENT

- Raw material from calcareous and argillaceous rocks (limestone, clay, shale and slag)
- Dry raw materials finely ground and mixed in correction proportions (kiln feed)
- Chemical compositions of dry mix determined and adjusted
- Kiln feed fed at a uniform rate in a sloping rotary kiln
- The mixture travels at the lower end
- Powdered coal, fuel oil or gas, fired into the kiln
- Temperature reached to 2600-2800 F (1427-1538 C), calcined Chemical reactions of raw materials took place and a new material formed (clinker)
- The clinker varies in size from dust to particles of several inches in diameter
- The clinkers sent to air cooler, quenched and put into storage (storage time)
- The clinker ground with a controlled amount of gypsum (Portland cement)
- Cement packed and transported for customers
- Gypsum between 1 to 3% to control setting and hardening of Cement

7.3 CLASSES OF CEMENT

Nine API classes:

✓ Class A

- Depth surface – 6000 ft (1830 m)
- No special properties
- Similar to ASTM C 150,Type I

✓ Class B

- Depth surface – 6000 ft (1830 m)
- Moderate to high sulphate resistance
- Similar to ASTM C 150 Types II

✓ Class C

- Depth surface – 6000 ft (1830 m)
- High early strength

- Moderate to high sulphate resistance
- Similar to ASTM C 150 Types III

  - ✓ Class D

- Depth from 6000 ft – 10,000 ft (1830 m - 3050 m)
- Moderate and high sulphate resistance
- Moderately high pressure and temperature

  - ✓ Class E

- Depth from 10,000 ft – 14,000 ft (3050 m - 4270 m)
- Moderate and high sulphate resistance
- High pressure and temperature

  - ✓ Class F

- Depth from 10,000 ft – 16,000 ft (3050 m - 4270 m)
- Moderate to high sulphate resistance
- Extremely high pressure and temperature

  - ✓ Class G

- Depth surface – 8000 ft (2440 m), as basic cement, fine
- Can be used with accelerators and retarders for other specifications
- Moderate to high sulphate resistance
- No addition other than calcium sulphate or water

  - ✓ Class H

- Depth surface – 8000 ft (2440 m), as basic cement, course
- Can be used with accelerators and retarders for other specifications
- Moderate to high sulphate resistance
- No addition other than calcium sulphate or water

  - ✓ Class J

• Depth 12,000 – 16,000 ft (3660 m - 4880 m)

• Extremely high pressure and temperature

• Can be used with accelerators and retarders for other specifications

• Moderate to high sulphate resistance

• No addition other than calcium sulphate or water.

Class	Water,%	Depth, ft	Temp. F	Properties
A	46	0 – 6000	80-170	Ordinary class, normal properties, T.T. (90 min)
B	46	0 – 6000	80-170	HSR or MSR, T.T (90 min)
C	56	0 – 6000	80-170	MSR, HES, fine (90 min)
D(retarded)	38	6000-10000	170-290	HSR or MSR, coarse (120)
E(retarded)	38	10000-14000	170-290	HSR or MSR, (154)
F(retarded)	38	10000-16000	230-320	Only in HSR, (180)
G	38	ALL depths		HSR, or MSR, fine
H	38	ALL depths		OSR or MSR, coarse
J	38	12000-16000		For temp. > 230 F, HSR

M: Medium H: High O: Ordinary S: Sulfate R: Resistance E: earlyT.T. Thickening Time

Figure 19: 9 API classes of cement

7.4 CEMENT ADDITIVES

- The of API cement above are used for wells with moderate bottom hole conditions
- It is necessary to modify cement properties to meet specific well conditions such as deep wells, lost circulation zones, etc
- The chemicals can be classified as follows :-

    - Accelerators – reduce thickening time
    - Retarders – increase thickening time
    - Fluid Loss reducers – control amount of fluid loss to formation

- Weighting materials – increase/decrease density
- Lost circulation materials – seal off lost circulation zones

7.5 BASIC COMPONENTS OF CEMENT

Portland Cement

Component	Formula	Trade name	Amount %	Function
Tricalcium silicate	$3CaO.SiO_2$	C3S	50%	Fastest hydration Overall and early strength Protect sulphate attack
Dicalcium Silicate	$2CaO.SiO_2$	C2S	25%	Slow reacting Responsible for gradual increase in strength
Tricalcium Aluminate	$3CaO.Al_2O_3$	C3A	10%	Initial set and early strength
Tetracalcium Aluminum				Initial set and early strength
Ferrite	$4CaO.Al_2O_3.Fe_2O_3$	C4AF	10%	Low heat of hydration
Other oxides such as gypsium, sulphate magnesia, free lime			5%	

Figure 20: Basic ingredients of the cement

- The effect they have on properties of the cement have made it possible to develop cements for special applications by varying the raw material used in manufacture: By increasing C3S content a high early strength can be obtained.
- At low heat of hydration cement is made by decreasing both C3S and C3A.
- High amounts of C3A , due to its high reaction speed and exothermic reaction , decreases the setting time of the slurry.

- Hydration of cement gives off considerable heat about 80 calories per gram of cement (80 BTU/lb).
- Maximum release of heat is obtained about 4 to 6 hours after hydration.
- The selection of cement and additives broadly resolves into choosing an economical material that may be satisfactory placed to achieve the required specifications after placement.
- The difference between construction cement and oil well cement are:
    - No aggregate is added to oil well cement
    - Large volumes of water are used in oilwell cements to make the slurry pumpable.

CEMENT HYDRATION

- Dry cement mixed with water
- Slurry subjected to differential pressure and temperature
- Water is lost to formation by dehydration or evaporation
- Chemical reaction occurs (exothermal reaction)
- Hydrous compounds form an interlocking crystalline structure
- Structure bonds to casing and rock surfaces

PROPERTIES AFFECTING SELECTION OF CEMENT TYPE

- **Slurry density**

Should be the same as mud to minimize the risk or blowouts or lost circulation

- Measured using mud balance
- Low density are prepared with bentonite, pozzolan, gilsonite, perlite, Diatomacous earth
- Bentonite is used in concentration up to 35%, the rduction is due to water added.
- Each 1% of bentonite needs 4% of water.
- One sack cement equals 94 lbs (50 kg) and measure 1 cu. Ft density increases by adding barite, iron ores or galena aach 1% of needs 0.2% increase in mixing water.

- **Thickening Time**

- Determine the length of time the slurry can be pumped
- It is the time necessary for the slurry consistenecy to reach 100 poises under stimulated bottom hole pressure and temperature.
- Measured using cement consistometer

- Thickening time is affected by:
    - Pumping rate: eddies and currents resulting from turbulent flow increases thickening time.
- Fineness to which the clinker is ground
- Additives: accelerators to decrease thickening time, retarders to increase it.
- Accelerators are calcium chloride.
- Retarders are calcium lignosulphonate, pozzolan and CMHEC
- Accelarators are used to cement shallow wells and surface casings.
- Retarders are used for cementing deep and hot wells.

➢ **Cement Strength**

- Cement in oil wells is subjected to static and dynamic stresses
- Static stress due to dead weight of pipe; compressive stresses due to the action of fluid and formations
- Dynamic stresses resulting from drilling operation, especially the vibration of drill string
- To withstand these stresses a compressive strength of 500 psi after 24 hours period is needed
- High early strength possesses strength higher than ordinary strength in the first 30 hours.
- Density reduction materials always decreases cement strength
- Retarders reduce both early and late strength
- Fine sand increases final cement strength
- Strength retrograte between 80 to 120 C
- Silica flour is added to prevent temperature effect

➢ **Filtration**

- Water loss of neat cement is very high
- Laboratory tests show that up to 50% of mixing water is lost by filtration through rock or filter papers
- Presence of small thickness mud cake reduces filtration
- High density slurry results in higher filtration loss
- Additives to reduce filtration are bentonite, organic colloids (CMHEC)

➢ **Permeability**

- Naturally, permeability of set cement should be the lowest possible.
- Bentonite cements are known to be very permeable (values up to 10 md are reported, while special cements (latex cement) have permeabilities as low as one micodarcy.
- The following factors influence the permeability of the set cement:
    - Water/cemet ratios: High W/C ratio increases the permeability
    - Downhole conditions: high pressure and confinement due their compacting effects decrease the permeability of set cement

- **Corrosion Resistance**

- Set cement could be penetrated by corrosive liquids especially those containing CO3 or SO4 irons.
- Cement corrosion decreases the final compressive strength render the cement more permeable.
- Reduction of the hardening time improves the cement resistance to corrosion by corrosive fluids.

- **Bond Requirements**

- For clean surfaces (rock or metal) the bond increases with time and moderate temperatures.
- Mud cake and dirty casing surfaces reduce markedly between casing or rock and cement.
- Additives such as salt and fine sand increases the bond between casing and the set cement.

7.6 OIL WELL CEMENTING

Two general classifications of oil well cementing are :

1. Primary Cementing
2. Secondary or remedial cementing

PRIMARY CEMENTING

- Main objectives of primary cementing are :-

- to support the casing pipe
- to restrict the movement of formation fluids behind the casing

- Cement also provides the following advantages :-

- seal off zones of lost circulation (fractured formation)
- protect the casing from shock loads during drilling deeper section
- protect casing from corrosion

Secondary Cementing

- Most common secondary cementing jobs are :

- Circulation squeeze
- plug back cementing
- squeeze cementing

8. CEMENT AND CEMENTING METHOD SELECTION FOR GIVEN WELL

8.1 CEMENT SELECTION

Table 17: Variation of temperature of different strata

Depth (m)	Depth(ft)	Temperature(F)	Subsurface strata
0-500	0-1660	300 <	Unconsolidated sand, clay stone , siltone
500-1350	1660-4500	300	Clay stone, minor coal ,limestone
1350-2755	4500-9183	340	Clastone contain with chloride , some dolamite
2755-3165	9183-10550	340-371	Unconsolidated sandstone,asymmetric porosity
3200 >	10660 >	400 >	Hard dolomite, non porosity system

❖ According to the above data the following API types of cement can be used for the given depths:

Depth **0-500 m** : **A,B or C**

Depth **500-1350m** ; **A,B or C**

Depth **1350-2755m**; **E**

Depth **2755-3165m**; **F**

Depth **3200m >** ; **J**

- Should add some cement additives for:

  - **Accelerators** – reduce thickening time :

    0-500 m zone (because that zone law depth)

  - **Retarders** – increase thickening time :
    3200 > m zone (because that zone high depth)
  - **Fluid Loss reducers** – control amount of fluid loss to formation :

    0-500m and 2755-3165 (because that zone are unconsolidated)

    And add more C3S (tricalciam cilicate)-to provide early strength

Table 18: Summary of cement classes and additives to be used

Depth (m) Of sub layers	Depth(ft) Of sub layers	Temperature(F) Of sub layers	Selected cement API class	Subsurface strata	Selected additives	Objectives of additives
0-500	0-1660	300 <	A,B or C	Unconsolidated sand, clay stone , siltone	Accelerators, Lost circulation materials	reduce thickening time, seal off lost circulation zones

500-1350	1660-4500	300	A,B or C	Clay stone, minor coal ,limestone	Accelerators	reduce thickening time
1350-2755	4500-9183	340	E	Clastone contain with chloride , some dolamite	Weighting materials	Increase density
2755-3165	9183-10550	340-371	F	Unconsolidated sandstone,asymmetric porosity	Fluid Loss reducers and Retarders	control amount of fluid loss to formation, increase thickening time
3200 >	10660 >	400 >	J	Hard dolomite, non porosity system	Retarders	increase thickening time

8.2 CEMENTING METHOD SELECTION

In preliminary well design, we have to use single stage- primary cementing techniques

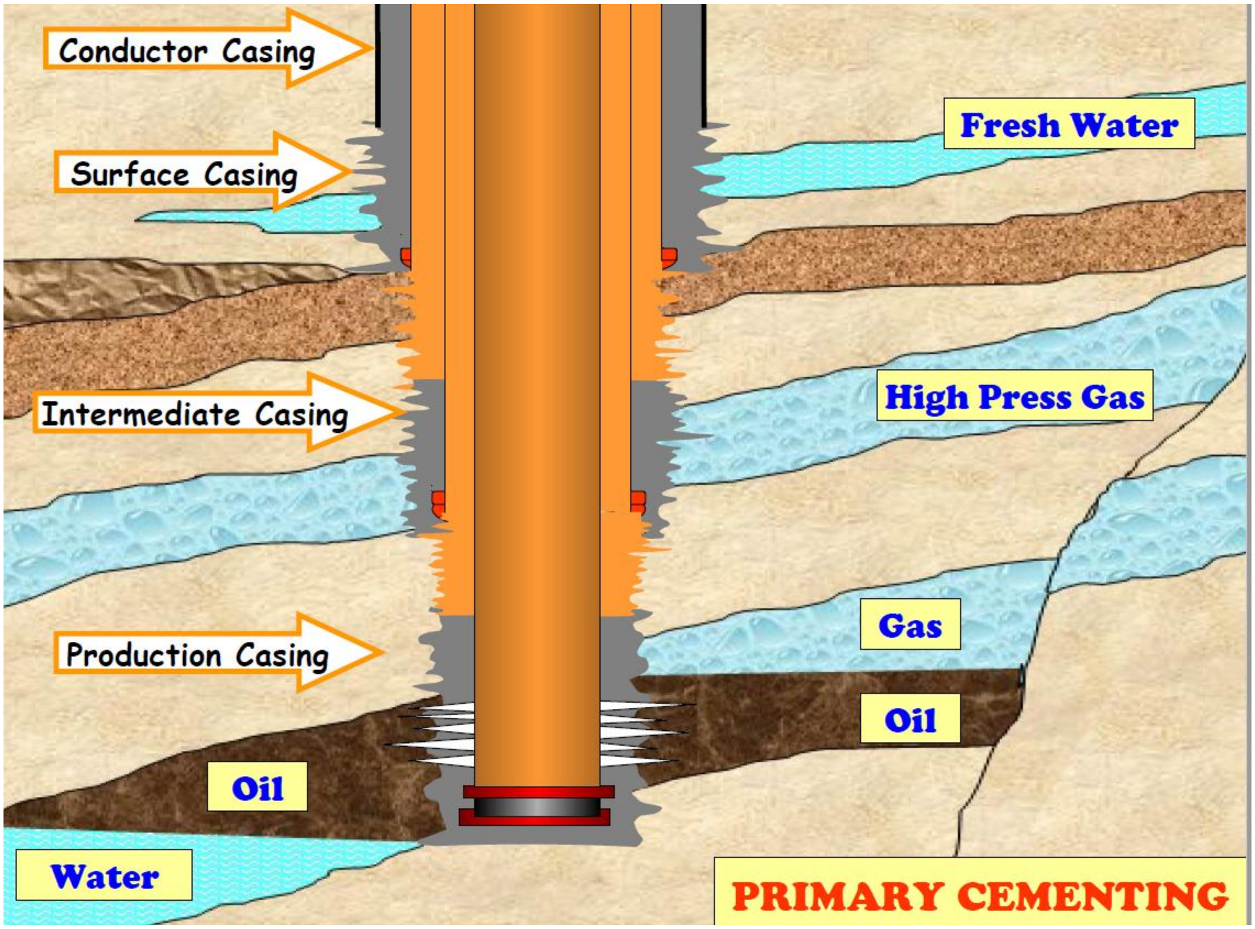


Figure 21: Primary cementing

Single Stage Cementing

- It is the Most common technique
- Normally accomplished by pumping one batch of cement down the casing between two rubber plugs.
- The bottom plug is placed in the casing, followed by cement slurry.
- When the batch of cement has been pumped into the casing, a top plug is released.
- The top plug is pumped down until it lands on the top of float collar, thus completing the cement job.

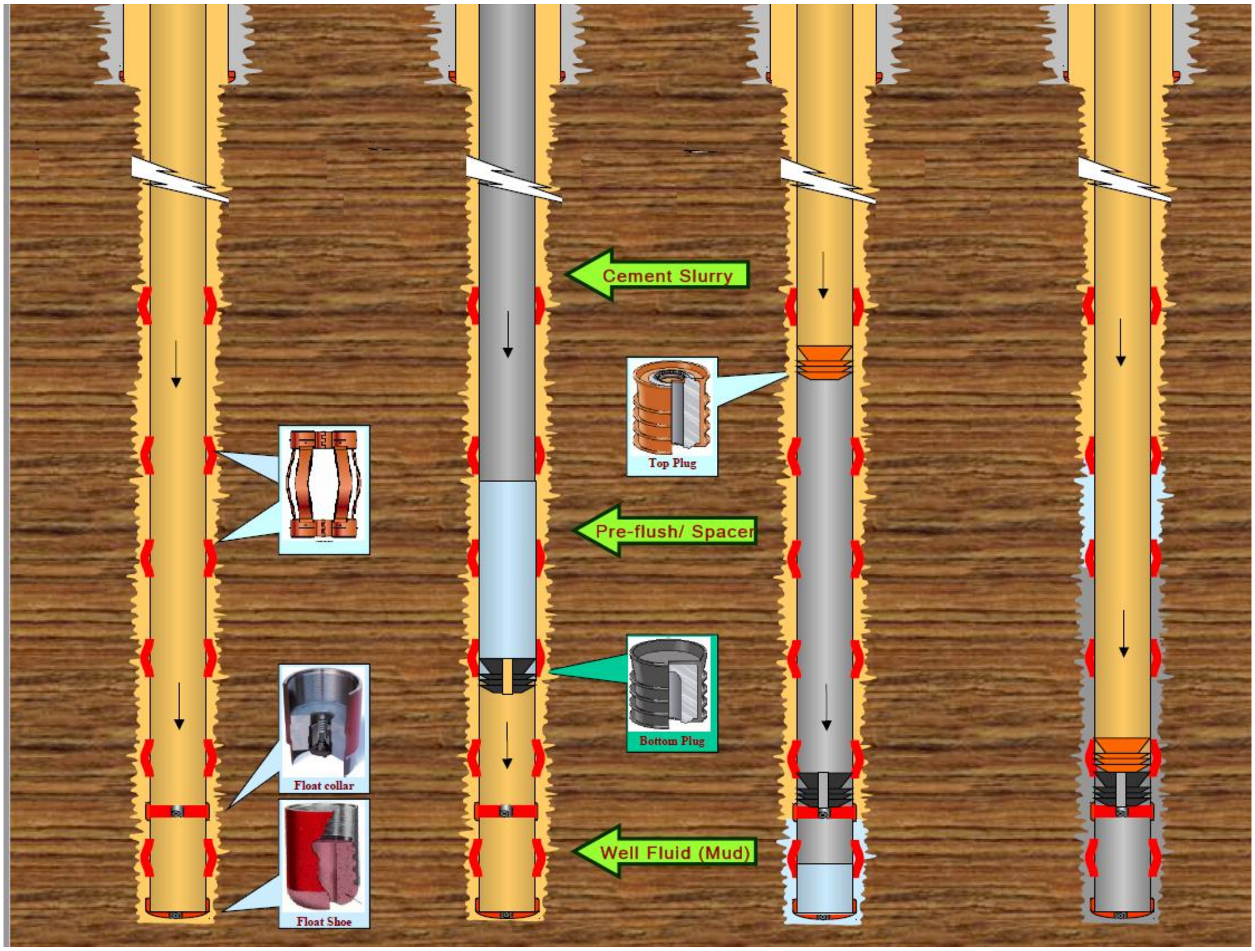


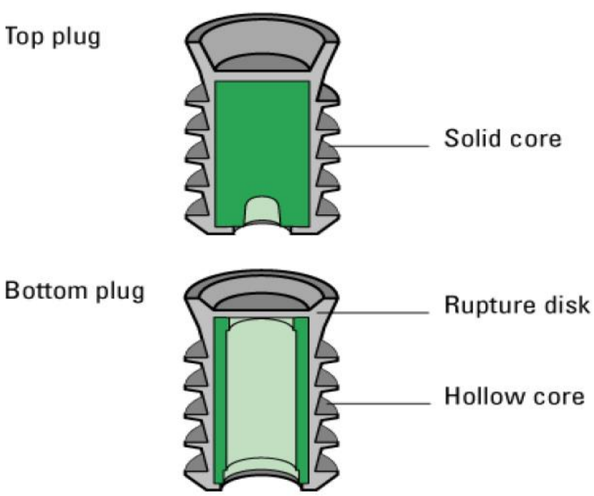
Figure 22: Single stage cementing

TOOLS USED:

Guide Shoe

Float Collar

Rubber Plugs



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10. ANNEXURE

10.1 RESERVOIR DRILLING 4 STAGES

Stage 1

Depth in feet	Pressure in psi
9110	3962.85
9158	3983.73
9197	4000.70
9211	4006.79

Stage 2

Depth in feet	Pressure in psi
9248	4222.53
9256	4223.24
9275	4224.93
9288	4226.09
9301	4227.24
9365	4232.94
9391	4235.25
9403	4236.32
9422	4238.01
9446	4240.15
9472	4242.46
9484	4243.53
9510	4245.85
9584	4252.43
9675	4260.53
9685	4261.42
9742	4266.49
9768	4268.81
9799	4271.57

9803	4271.92
9811	4272.63
9828	4275.18
9885	4299.98
9943	4325.21

Stage 3

Depth in feet	Pressure in psi
10020	4458.70
10035	4465.23
10042	4468.27
10056	4474.36
10075	4482.63
10083	4486.11
10091	4489.59
10102	4494.37
10122	4503.07
10143	4512.21
10167	4522.65

Stage 4

Depth in feet	Pressure in psi
10175	4500.28
10188	4502.94
10195	4504.38
10205	4506.43
10221	4509.71
10233	4512.17
10249	4515.45
10266	4518.93
10273	4520.37

10288	4525.28
10291	4526.59
10320	4539.20
10340	4547.90
10380	4565.30
10440	4591.40

10.2 MUD DESIGN CALCULATION

Base fluid – Water with specific gravity of 1

Specific gravity of Barite – 4.2

Specific gravity of Bentonite – 2.4

Specific gravity of polymers and surfactants mixture – 2.4

Weight of water – 8.34 ppg

Weight of each chemical required as per the mud recipe to produce 1000 bbl

Bentonite – 30 × 1000 = 30 000 lb

Polymers – 0.5 × 1000 = 500 lb

Caustic soda – 0.5 × 1000 = 500 lb

Sodium Carbonate – 0.25 × 1000 = 250 lb

Densities of material

Barite – 4.2 × 8.34 = 35 ppg

Bentonite – 2.4 × 8.34 = 20 ppg

Polymers – 2.4 × 8.34 = 20 ppg

Volumes of material

Bentonite – 30 000 ÷ 20 = 1 500 gallon

Polymers and surfactants – 500 ÷ 20 = 25 gallon

Let the volume of water = **X** gallons, and volume of Barite = **Y** gallons

Volumes of caustic soda and sodium carbonate are negligible since they will dissolve and contyribute to the weight of the fluid.

The planned mud weight for the overburden drilling is 8.365 ppg

Total weight (lb) ÷ Total Volume (gallon) = 8.942 ppg

$\{(8.34 \times X) + (30\ 000) + (500) + (500) + (250) + (35 \times Y)\} \div \{(1\ 500) + (25) + (X) + (Y)\} = 8.942$ (Eq 1)

Total volume required = 1 000 bbl = 1 000 × 42 = 42 000 gallon (US)

$42\ 000 = (1500) + (25) + (X) + (Y)$ (Eq 2)

Solve the 2 simultaneous equations

X = 40 221.718 gallon Y = 253.282 gallon