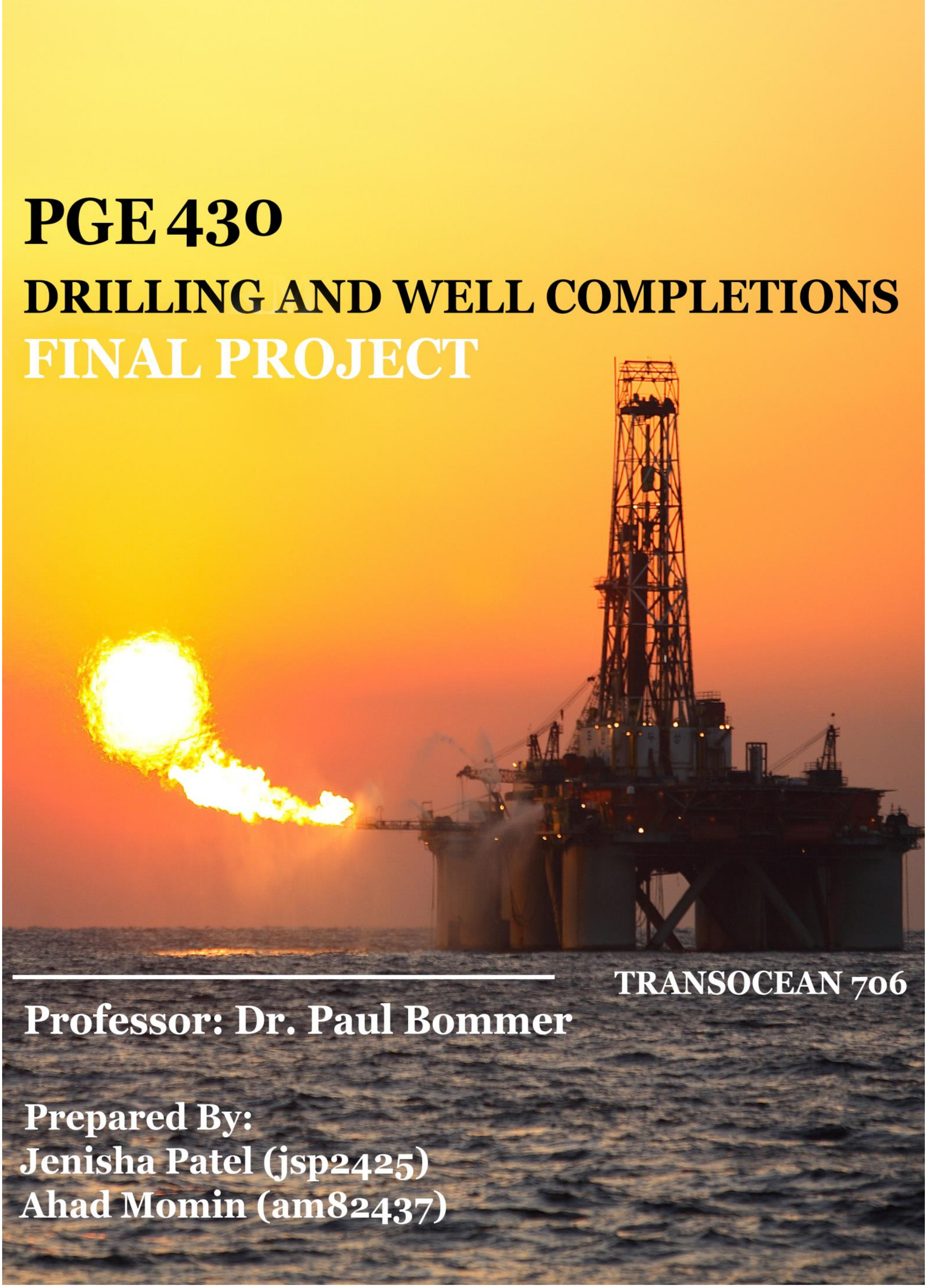

PGE 430
DRILLING AND WELL COMPLETIONS
FINAL PROJECT

TRANSOCEAN 706

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Introduction

This chapter covers the plan for drilling a mildly unconsolidated sandstone horizontal oil well, located 50 miles south of New Orleans, Louisiana, in the Gulf of Mexico. It also covers many of the industry standards and safety regulation that are associated with drilling and completions of an oil and gas well through the calculations and design processes such as rig selection, casing program etc.

Well Plan

The Gulf of Mexico Basin (GOM) is one of the world's great petroleum mega-provinces, with a hydrocarbon producing history stretching more than 100 years. Despite its maturity, the Gulf remains one of the most active and successful exploration provinces in North America, attracting numerous domestic and international exploration companies (Galloway, 2009). To determine the best method of drilling a horizontal well in a mildly unconsolidated sandstone formation in GOM, one must look at and analyze the formation in which he is planning to drill.

As shown in figure 1 and 2, the well is an offshore well located 50 miles south of New Orleans, Louisiana, in 5,000 ft. of water with a total measured depth (MD) of 23,000 ft. from the derrick floor. In figure 2, one can see that the formation starts at 18,000 feet (ft.), with a reservoir dip of 3° per mile from the NE to the SW. Approximately 1000 ft. above that is where one should intend to start the kickoff point for the entry into the pay zone which is 100 ft. thick.

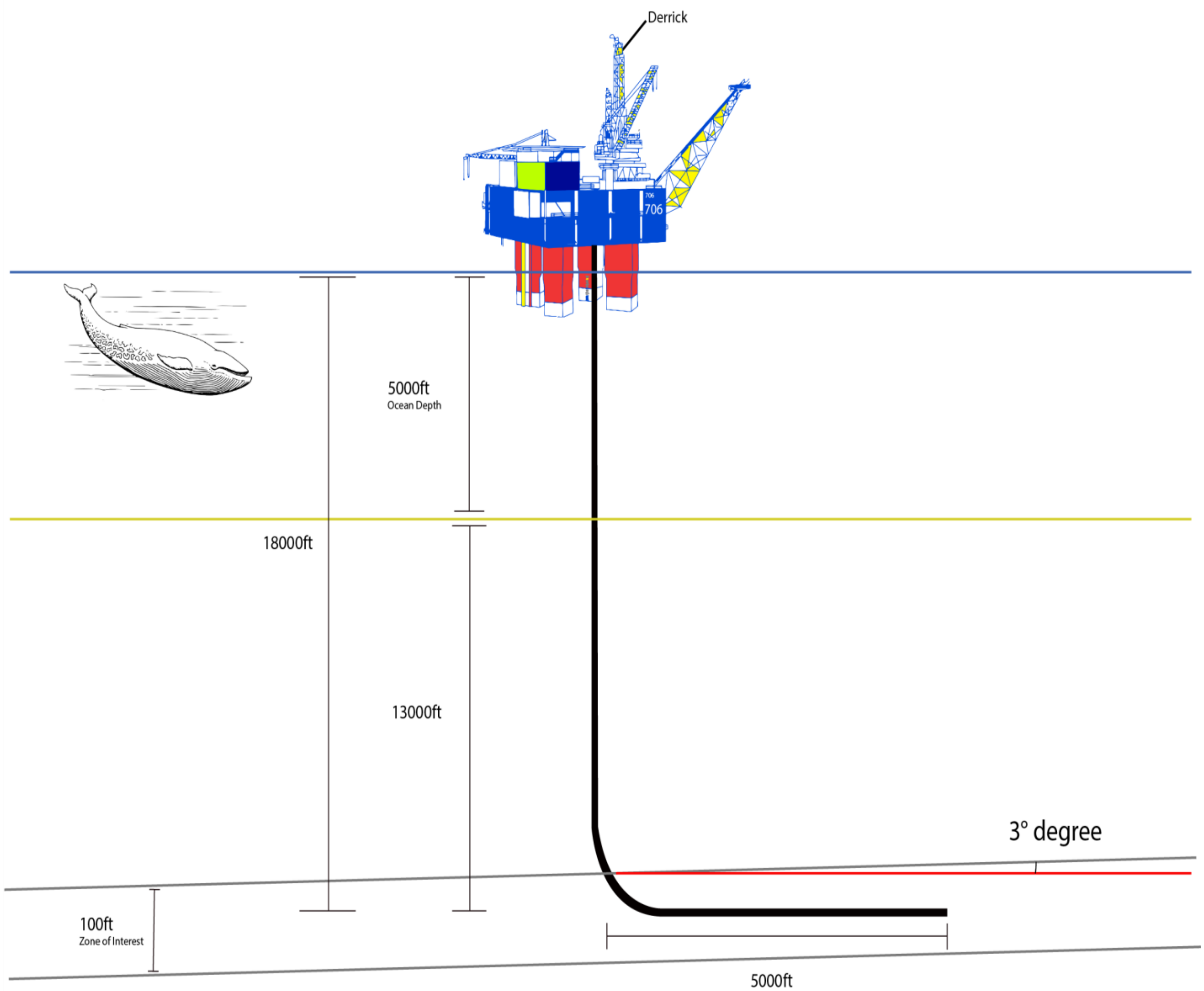
Figure 1: Location of Transocean 706

Figure 2: Horizontal Well Diagram

Offshore Louisiana Transocean 706
50 Miles south of New Orleans
Oct-20-2017, 11:00 am

TVD and MD measured from the derrick floor
Reservoir Dip: 3 deg per mile from the NE to the SW
100 ft Unconsolidated Sandstone Reservoir

TRUE VERTICAL DEPTH	18000 ft
MEASURED DEPTH	23000 ft
Ocean Depth	5000 ft



The reservoir is mildly unconsolidated sandstone and contains undersatured oil at a reservoir pressure that is above the bubble point pressure of 5,900 psia. It has a porosity of 28%, absolute horizontal permeability of 500 millidarcy (md) to air and vertical permeability of 100 md. It has a bottom hole temperature of 250 °F and initial bottom hole flowing pressure of 13,100 psia. The suggested tubing ID is 3.00” on bottom, crossing over to 4” ID.

Using this information, a drilling and completions program is designed, that is intended to minimize reservoir pressure drawdown while improving the flow rate. The program will discuss, the most suitable rig for the conditions listed above, a pipe program based on the mud window calculation, BHA, BOP and shoe testing schedule as well as the cost associated with these programs. This is done so to establish a drilling and completions program that is safe, usable, cost-effective and improves flow rate.

Rig Selection

Selection of correct drilling rig is a crucial step since they are not only used to drill holes, but also to lower and cement casing in the well, and provide other functions such as well logging, and well testing (Newtas Group Oil, 2017). If a rig is improperly selected it can cause many problems in the long run such as formation damage from poor solids control, low penetration rates, as well as high ultimate well costs and time. Therefore, while selecting a rig for this horizontal well some of the factors that were taken into consideration are: the geographical location of the well, depth of the water at which the rig will operate, the depth to the pay zone, heat and pressure of the well, the draw works and mast capacity, crown block and travelling block capacity, and the drilling line size and the pulling force.

Based on just the water depth of 5,000 ft. and the drilling depth of 18000 ft., submersible rig called Transocean 706 was selected, as shown in figure 3. The rig has a maximum water depth of 6,500 ft. and drilling depth of 25,000 ft. After further analyzing other information such as the derrick dimensions and the maximum hook load capacity of 1,300,000 lbs. it further strengthened the selection of this rig based on the calculation for tensile load of casing string 3 which happens to have maximum weight of pipe including the drill string. Some of the other aspects that further verify this selection of this rig are the rig’s station keeping system such as the mooring system that has electric drum winches with 1,000,000 lbs. static brake capacity, its 3 inch stud link chain. As well as, the Dynamically Positioned (DP) System with triple redundancy and its eight 2,800 kW azimuthing thrusters, these shows that the platform will be stable even in inclement conditions like wind and current power as well as ship movement (Transocean, 2017).

Other aspects that prove Transocean 706 is a reliable offshore rig for this project are the drawworks are rated to be able to operate up to 3,000 hp and 14 1¾-inch drilling lines. It also has a hydraulic rotary table with a 60½-inch diameter, which indicates that the pipe and tubing, as well as drill bits will not have any problem fitting since the biggest diameter equipment that will be lowered through it is 33". Surface well control equipment such as the Blow Out Preventers (BOPs) were also taken into consideration when selecting this rig. The Transocean 706 has an annular BOP that has a working pressure of 10,000 psi and BOP rams that is a 5 ram preventer system with a working pressure of 15,000 psi (Transocean, 2017). Based on these dual variable bore rams BOP capacity, in case problems incur; one will be able to shut in flow by closing the BOP valves and prevent any mishaps since it features a larger reservoir of packer rubber. This will ensure a long lasting seal, since when the BOP valves are closed, it will activate the packers and the rubber inserts will be displaced inward to close the packer around the pipe, sealing any flow of fluid (Transocean, 2017). The detailed pamphlet about Transocean 706 is also shown in figure 4 below.

Figure 4: Transocean 706 Rig Details (Transocean, 2017)

Transocean 706

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Deepwater Semi-Submersible

General Description

Design / Generation	Earl & Wright SEDCO 700 Class
Constructing Shipyard	Kaiser Steel Shipyard Oakland, CA. USA
Year Entered Service / Significant Upgrades	1976 / 1994, 2007
Classification	ABS +A1, DPS-2
Flag	Liberia
Dimensions	295 ft. long x 245 ft. wide x 130 ft. deep
Drafts	83 ft. operating / 21 ft. transit
Accommodation	150 persons
Displacement	34,339 st operating / 21,847 st transit
Variable Deck	4,409 st operating / 3,307 st transit
Transit Speed	up to 5 knots
Maximum Water Depth	6,500 ft. designed / 6,500 ft. outfitted
Maximum Drilling Depth	25,000 ft.

Drilling Equipment

Derrick	Woolslayers Companies Inc., 185 ft. high, with 50 ft. long, 40 ft. wide base.
Hookload Capacity	1,300,000 lbs. gross nominal capacity.
Drawworks	Oilwell E-3000, 3 x EMD M-79 electric motor; rated to 3,000 hp and 1,478,900 with 14 1-3/4 inch drilling lines.
Compensator	NOV Shaffer, with a 25 ft. stroke and 1,200,000 lbs with a locked compensator.
Rotary Table	Continental Emsco T-6050 60-1/2 inch hydraulic; rated to 1,000 st.
Top Drive	Varco TDS-4S, with a 650 st capacity and with GE 752 Hi-torque traction motors rated at 45,500 ft/lbs. continuous drilling torque in low gear.
Mud Pumps	3 X Oilwell A-1700 P.T. rated at 1,600 hp triplex pumps, each driven by 2 x EMD D-79-DC traction motors.
HP Mud System	Rated for 5,000 psi
Solids Control	4 x Derrick FCL 514 shale shakers

Power & Machinery

Main Power	6 x Caterpillar 3612 diesel engines rated at 3,640 kW, 900 rpm, each driving a 4,550 kVA Kato 8P12-4000 generator.
Emergency Power	1 x Caterpillar 3508B diesel engine rated 968 kW, 1,800 rpm driving a Kato 4P6-1800 generator.
Power Distribution	6 x EPD SCR, EPD, 11kv switchboards.

Storage Capacities

Fuel Oil	9,755 bbls.
Liquid Mud	2,400 bbls. Active / 3,300 bbls. Reserve
Base Oil	1,100 bbls.
Brine	5,000 bbls.
Drill Water	5,800 bbls.
Potable Water	1,324 bbls.
Bulk Material	(mud + cement) 18,760 cu.ft
Sack Storage	2,500 sacks

BOP & Subsea Equipment

BOP Rams	1 x GE Hydril Compact Triple (TRBOP) ram preventers and 1 x GE Hydril Compact Double (DRBOP) ram preventers, 18-3/4 inch, 15,000 psi. (5 ram preventer)
BOP Annulars	1 x Annuflex GX double assembly annular preventer, 18-3/4 inch, 10,000 psi.
BOP Handling	BOP crane 2 x 100 st main hoists and 2 x 15 st service hoists.
BOP Control	Cameron acoustic system
Marine Riser	Vetco 21 inch OD (19-3/4 inch ID), 18,787 flotation weight in air. API 51 x 80, 65 ft. long per joint. Riser buoyancy 47 inch OD.
Tensioners	8 x Control Flow dual riser tensioners, rated at 60 st each; with a 12.5 ft. stroke.
Diverter	60-1/2 inch 500 psi Vetco KFDS diverter with a 16 inch flow line.
Moonpool	20 ft. length x 20 ft. width.

Station Keeping / Propulsion System

Thrusters	8 x (4 at forward, 4 at aft) Rolls Royce 2,300 kW azimuthing thrusters; (0- 600 rpm, fixes pitch)
DP System	Kongsberg SPD32 SVC DPS-2 with triple redundancy.
Mooring System	2 x Baylor electric drum winches with 1,000,000 lbs. static brake capacity, 2 x 1,000 ft. of 3 inch stud link chain, no anchors.

Cranes

Crane #1	1 x 54 st National OS-435 pedestal crane.
Crane #2	1 x 67 st Seatrax S-9022 pedestal crane.

Other Information

Helideck	Rated for Sikorsky S-92 helicopters

Directional Plan

For the first part of this well design, a wellbore trajectory that will transition from vertical to horizontal as fast as possible is designed. This is done so to minimize the horizontal distance trajectory to reach the target pay-zone at 18,000 ft., with a horizontal attitude of 90 degrees. To accomplish this, the directional plan on canvas is used at the measured depth of 23,000 ft., and an angle of inclination and compass bearing at that depth were used. Based on the problem statement, an assumption, that wellbore is dipping 3 degrees per mile and is pointed in the North-West to South East compass bearing and that it is maintained all the way to the True Depth, is made. To establish an angle of inclination from 0 to 90 degrees, an assumption that the wellbore is drilled perfectly vertically at 0 deg inclination is made for this project. Generally, 1000 ft. is a standard practice in the industry to build the angle of inclination from 0 to 90 deg and a Dog Leg Severity (DLS) that cannot exceed 10-deg/100 ft. is used. So, using these practices to achieve the angle of inclination from 0 to 90 degrees, one gets a 900 ft. distance to build the angle. This calculation is also shown below in equation 1.

Equation 1:

$$DLS = 90deg/10 \times 100 = 900ft$$

Normally while drilling, as a directional drillers, one would like to have a smooth build angle, therefore an interval of 10 deg is used to build the angle to hit the pay zone at 18,000 ft at 90 deg. This smooth horizontal displacement was gained at approximately 18,400 ft. measured depth and a true vertical depth of 18,001.65 ft. This shows that it took 667.56 ft. to build the angle from 17,400 ft. kick off point, but that does not make much difference in terms of cost when drilling a horizontal well since they have very high return rate. These calculations are shown in table 1.1 and 1.2 respectively, and the corresponding figure 5 and 6 shows the wellbore trajectory with the build angle.

Table 1.1: Calculations for Horizontal Wellbore Trajectory

	DATA			RESULTS				
SUR	MD	INC	AZM	DLS	TVD	Total N	Total E	Horz
NUM	ft	deg	deg	deg/100'	ft	ft	ft	Displ-ft
1	17400	1	225.1	0.005747	17400	0.18	0.01	0.18
2	17500	10	225	9.000002	17,499.44	-6.59	-6.76	9.44
3	17600	20	225.1	10.00003	17,595.91	-24.85	-25.05	35.29
4	17700	30	225	10.00009	17,686.42	-54.67	-54.92	77.49
5	17800	40	225.1	10.00016	17,768.24	-95.15	-95.46	134.78
6	17900	50	225	10.00025	17,838.86	-145.04	-145.43	205.40
7	18000	60	225.1	10.00033	17,896.15	-202.85	-203.32	287.21
8	18100	65	225	5.000786	17,942.31	-265.50	-266.07	375.88
9	18200	75	225.1	10.00044	17,976.47	-331.81	-332.48	469.73
10	18300	83	225	8.000601	17,995.54	-401.11	-401.89	567.81
11	18400	90	225.1	7.000711	18,001.65	-471.60	-472.48	667.56

12	18500	93	225	3.001665	17,999.03	-542.22	-543.21	767.52
57	23000	93.1	225.1	0.141321	17,759.82	- 3,717.30	- 3,723.09	5,261.15

Table 1.2: Calculations for Horizontal Wellbore Trajectory

DATA	RESULTS	CALCULATIONS						
MD	TVD	INC	AZM	Course	Course	Overall	Course N	Course E
ft	ft	rad	rad	Length-ft	TVD-ft	Angle-rad	ft	ft
17400	17400	0.017	3.929	17400	17,400.00	0.017	0.179	0.012
17500	17,499.44	0.175	3.927	100	99.44	0.157	-6.765	-6.775
17600	17,595.91	0.349	3.929	100	96.47	0.175	-18.264	-18.291
17700	17,686.42	0.524	3.927	100	90.52	0.175	-29.822	-29.867
17800	17,768.24	0.698	3.929	100	81.81	0.175	-40.475	-40.536
17900	17,838.86	0.873	3.927	100	70.62	0.175	-49.898	-49.973
18000	17,896.15	1.047	3.929	100	57.29	0.175	-57.804	-57.892
18100	17,942.31	1.134	3.927	100	46.16	0.087	-62.653	-62.748
18200	17,976.47	1.309	3.929	100	34.16	0.175	-66.311	-66.411
18300	17,995.54	1.449	3.927	100	19.07	0.140	-69.302	-69.407
18400	18,001.65	1.571	3.929	100	6.11	0.122	-70.481	-70.588
18500	17,999.03	1.623	3.927	100	-2.61	0.052	-70.625	-70.732
23000	17,759.82	1.625	3.929	100	-5.32	0.002	-70.557	-70.664

Figure 5: Wellbore Trajectory from Vertical to Horizontal Section

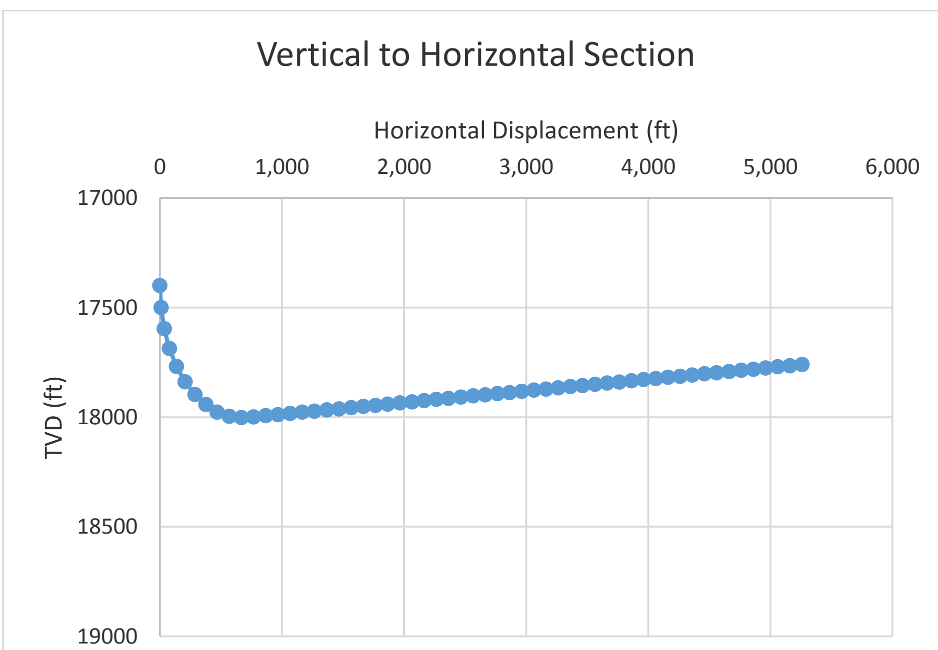
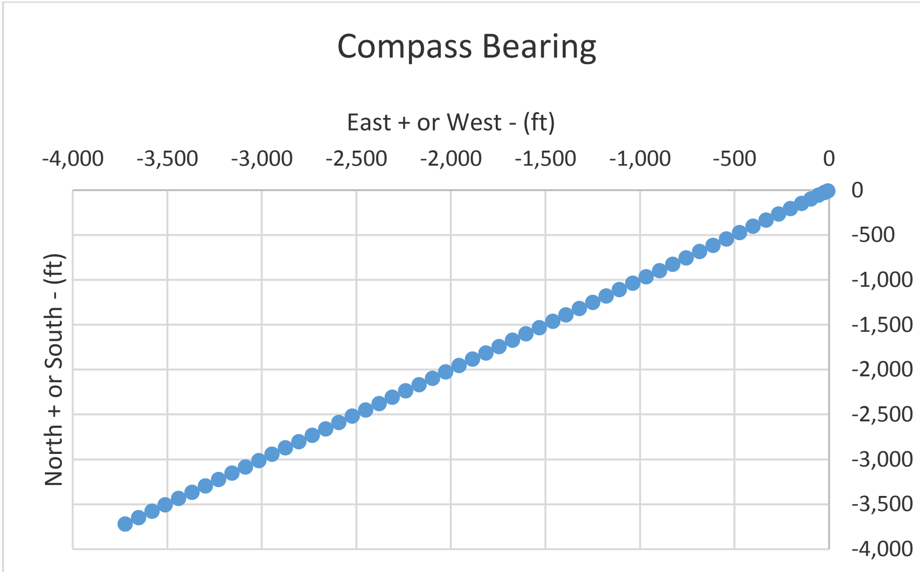


Figure 6: Compass Bearing of the Wellbore



The graphs show that the well is hitting the pay zone at 18,000 ft. and the hole is going in the correct compass bearing.

Mud Window

While drilling, the first thing one needs to be conscious of is how to keep the wellbore stable. Since one is drilling through unconsolidated sandstone, a proper seal needs to be installed to make sure that the well does not cave in. In order to do this, the right grade steel pipe that will be cased with cement at appropriate depths needs to selected. These depths are called casing points. The casing points are then drilled using a drilling fluid that has high enough density to prevent the pore fluids to flow into the well, prevent fractures and wellbore collapse. Sometimes it is possible to get the mud weight in wellbore so high that it causes the rock to fracture, similar to hydraulic fracturing. This can cause loss circulation in the wellbore, and in extreme cases it causes the bottom hole pressure to decrease and cause a blowout. Therefore, to determine an appropriate “window” of mud weight that will allow one to drill and prevent any problems, the pore pressure and the frac pressure were determined at every depth from the ocean floor (5000 ft.) to the zone of interest (18,000 ft.).

In order to determine the frac and pore pressure multiple stages of calculations were performed. First, the true vertical depth increments were calculated using equation 2. Where, TVD (true vertical depth) is the total depth from the ocean floor to the zone of interest, which is the unconsolidated sandstone formation where a horizontal well will be drilled. The number 24 in the equation is the number of depth intervals, but that number can be decreased or increased based on personal preference.

$$TVD\ Increment\ (ft) = D_{SW} + \frac{TVD - D_{SW}}{24} \qquad \textit{(Eq. 2)}$$

D_{SW} = Sea Water Depth (ft.) = 5000 ft.

TVD = True Vertical Depth (ft.) = 18000 ft.

Then, according to the well plan a normal pore pressure gradient of 0.465 psi/ft. is used for up to a depth of 6000 ft. And for the depths below 6000 ft., the pore pressure increases linearly up to the TVD, where the gradient is 0.65 psi/ft., therefore equation 3 is used to calculate the gradient. Using equation 3, we calculated the pore pressure at each depth using equation 4.

Derivation of equation 3

$$\nabla p_{fluid} = m * (TVD\ ) + b$$

0.465 psi/ft. = m(6000 ft.) + b*

0.65 psi/ft. = m(18000 ft.) + b*

$$\nabla p_{pore\ fluid} = (1.54E - 05) * (TVD\ ) + 0.3725 \qquad \textit{(Eq. 3)}$$

$$P_{\ pore} = TVD\ (ft) * \nabla p_{pore\ fluid} \qquad \textit{(Eq. 4)}$$

$$\nabla p_{pore\ fluid} = Normal\ Pore\ Pressure\ gradient\ (\frac{psi}{ft})$$

$$P_{pore} = Pore\ Pressure\ (psi)$$

Using the pore pressure that was calculated, the pore mud weight of the fluid is determined using equation 5. Where, a pore safety margin of 0.5 ppg is assumed to prevent any fluid flow or compressive wellbore failure (Bommer, Wellbore architecture, 2017). The safety margin number 0.5 was decided based on number of trials and error, where increasing the safety margin lead to a smaller mud window much smaller, where one would need to more than 7 casing strings which seems excessive. Then a smaller number less than 0.5 as safety margin was used, which gave a wider mud window but it also meant there is more room for error in terms of setting casing points. Therefore, safety margin of 0.5 gave reasonable results as well as number of casing strings needed with some leeway for formation failure and fluid flow.

$$MW = \frac{P_{pore}}{TVD} * \left(\frac{8.33\ ppg}{0.433\ (\frac{psi}{ft})} \right) + SM_{pore} \qquad \textit{(Eq.5)}$$

MW = Mud Weight (ppg)

$$P_{pore} = Pore\ Pressure\ (psi)$$

$$SM_{pore} = \ pore\ safety\ margin\ (ppg) = 0.5\ ppg$$

TVD = True Vertical Depth (ft.)

The frac mud weight is important in helping determine the casing points since it is essentially the total pressure represented as fluid density, above which leak off or formation damage may occur. So, it helps to determine what mud weight should be used to stay below the fracture mud weight and above pore mud weight to work inside the mud window.

First the over burden pressure is calculated, as shown in equation 6, and 7 respectively. For these calculations, Υ_{SW} (salt water specific gravity) of 1.02 and the Υ_{OB} (overburden or sediment specific gravity) of 2.3 is assumed (Bommer, Wellbore architecture, 2017).

$$\sigma_{OB} = 0.433 * D_{SW} * \gamma_{SW} + 0.433 * \gamma_{OB} * (TVD - D_{SW}) \qquad \text{(Eq. 6)}$$

$$\sigma_{OB} = Over\ burdern\ stress\ (psi)$$

$$\gamma_{SW} = sea\ water\ specific\ gravity = 1.02$$

$$\gamma_{OB} = overburden\ specific\ gravity = 2.3$$

$$\nabla p_{OB} = \frac{\sigma_{OB}}{TVD} \qquad \text{(Eq. 6)}$$

$$\nabla p_{OB} = Over\ burden\ pressure\ gradient\ \left(\frac{psi}{ft}\right)$$

Additionally, fracture gradient was estimated using Zoback's Equation as shown below.

$$\nabla p_{frac} = 0.32 * \left(\nabla p_{OB} - \nabla p_{pore}\right) + \nabla p_{pore} \qquad \text{(Eq. 7)}$$

$$\nabla p_{frac} = frac\ gradient\ (\frac{psi}{ft})$$

Finally using the frac gradient, the frac mud weight is determined as shown in equation 8. A frac safety margin of 0 is assumed, since safety in the pore mud weight calculation had already been accounted for.

$$MW_{frac} = \nabla p_{frac} * \left(\frac{8.33\,ppg}{0.433\left(\frac{psi}{ft}\right)}\right) - SM_{frac} \qquad \text{(Eq. 8)}$$

$$MW_{frac} = frac\ mude\ weight\ (ppg)$$

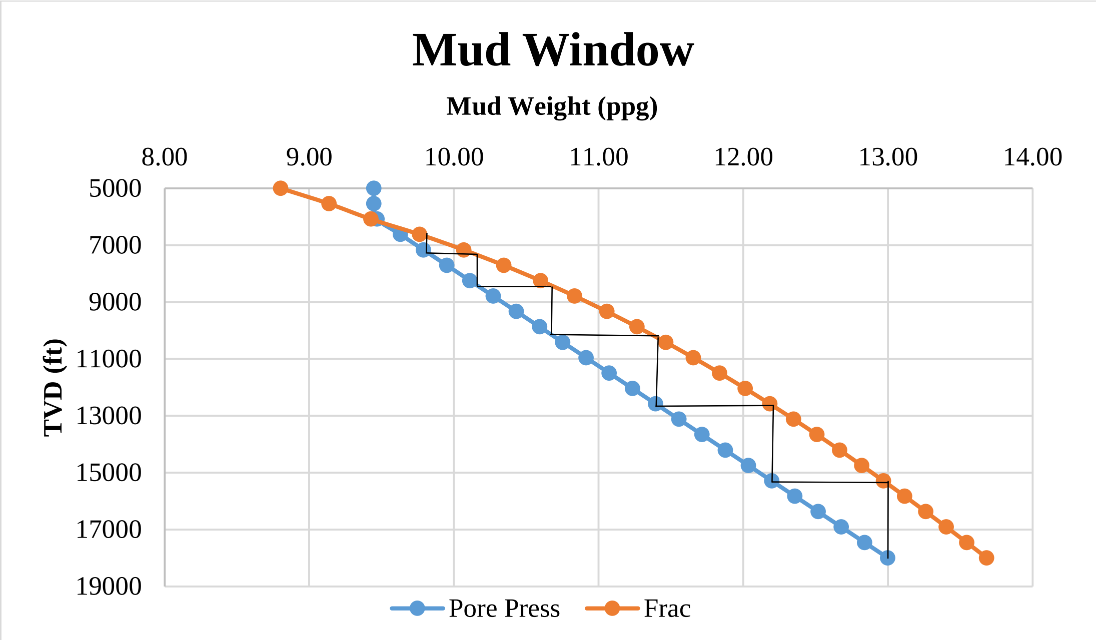
$$SM_{frac} = frac\ safety\ margin$$

Table 2 shows the calculated pore mud weight and frac mud weight at each depth from 5000 ft. to 18000 ft., and figure 7 shows the corresponding mud window plot.

Table 2: Mud Weight Calculations

TVD (ft)	Pore Grad (psi/ft)	Pore Press (psi)	Mud Wt (ppg)	OB Pressure (psi)	OB Grad (psi/ft)	Frac Grad (psi/ft)	Frac MW (ppg)
5000.00	0.47	2325.00	9.45	2208.30	0.44	0.46	8.80
5541.67	0.47	2576.88	9.45	2747.75	0.50	0.47	9.14
6083.33	0.47	2835.95	9.47	3287.19	0.54	0.49	9.43
6625.00	0.47	3143.73	9.63	3826.64	0.58	0.51	9.76
7166.67	0.48	3460.54	9.79	4366.08	0.61	0.52	10.07
7708.33	0.49	3786.40	9.95	4905.53	0.64	0.54	10.34
8250.00	0.50	4121.29	10.11	5444.98	0.66	0.55	10.60
8791.67	0.51	4465.21	10.27	5984.42	0.68	0.56	10.83
9333.33	0.52	4818.18	10.43	6523.87	0.70	0.57	11.06
9875.00	0.52	5180.18	10.59	7063.31	0.72	0.59	11.27
10416.67	0.53	5551.22	10.75	7602.76	0.73	0.60	11.46
10958.33	0.54	5931.29	10.91	8142.20	0.74	0.61	11.65
11500.00	0.55	6320.40	11.07	8681.65	0.75	0.62	11.84
12041.67	0.56	6718.55	11.23	9221.10	0.77	0.62	12.01
12583.33	0.57	7125.73	11.39	9760.54	0.78	0.63	12.18
13125.00	0.57	7541.95	11.55	10299.99	0.78	0.64	12.35
13666.67	0.58	7967.21	11.72	10839.43	0.79	0.65	12.51
14208.33	0.59	8401.51	11.88	11378.88	0.80	0.66	12.67
14750.00	0.60	8844.84	12.04	11918.33	0.81	0.67	12.82
15291.67	0.61	9297.21	12.20	12457.77	0.81	0.67	12.97
15833.33	0.62	9758.61	12.36	12997.22	0.82	0.68	13.12
16375.00	0.62	10229.05	12.52	13536.66	0.83	0.69	13.26
16916.67	0.63	10708.53	12.68	14076.11	0.83	0.70	13.40
17458.33	0.64	11197.05	12.84	14615.55	0.84	0.70	13.54
18000.00	0.65	11694.60	13.00	15155.00	0.84	0.71	13.68

Figure 7: Mud Window Plot



After plotting the mud weights for pore and frac, a mud window with appropriate kick and trip margins are achieved. This helps to determine how many casing strings are needed for this horizontal well at each depth. For this case, total of 7 casing strings are calculated including surface and conductor. The casing design is discussed further in the next section titled pipe program.

Pipe Program

Designing a proper casing program is extremely important in any type of oil and gas well design, since it ensures that the shallow formations are protected from the high pressures of the deeper zones. Casing will also allow to seal off the freshwater zones and isolate the producing zones (Bommer, Casing Design, 2017). Casing being one of the most fundamental parts of a well design and important part of drilling, it needs to be perfectly designed, and cemented before the production tubing is ran and completing the well.

In order to determine the best pipe program, the casing depths are configured using the mud window plot. The flat part of the black stair-steps line shown in figure 7 in the mud window plots shows the casing seating depth. Those depths essentially met the criteria of not going above the frac pressure, since if one were to use mud that is above the frac mud weight, it would fracture the formation, which could cause many problems such as loss of circulation or pressure changes. Using the pore pressure and frac pressure calculated at each depth one is able to determine that total of 7 casing strings are needed, which includes both the surface and conductor casing. Since, there are only three slots in the wellhead to cement and run the casing all the way to the top of the well, there will 2 liners and 5 casing strings used. The casing depths are also shown in figure 8 and table 3 for reference purposes.

Figure 8: Casing Strings and the Seating Depths Schematic

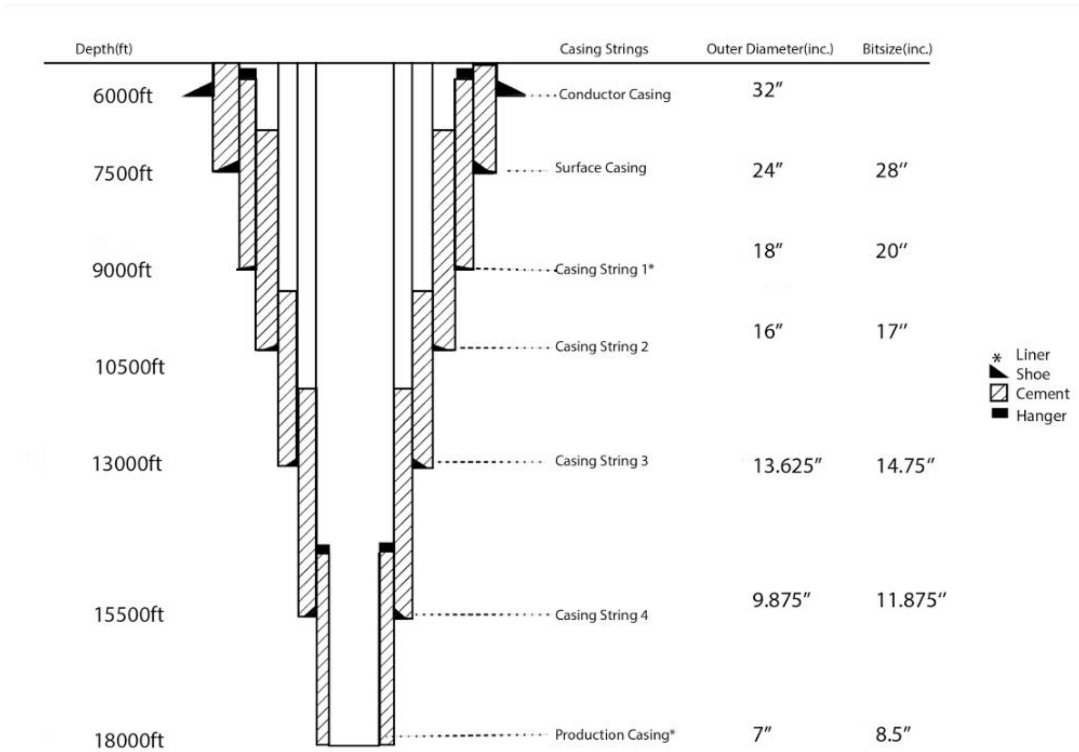


Table 3: Casing strings and their respective depth ranges

Casing Type	Mud Weight (ppg)	Frac MW (ppg)	Set Depth (ft)
Conductor	10	10.43	6000
Surface	10	10.43	7500
Intermediate (Liner)	10.43	10.91	9000
Intermediate (HPC set)	10.91	11.55	10500
Intermediate (HPC set)	11.55	12.36	13000
Intermediate (HPC set)	12.36	13	15500
Production (Liner)	13	13.68	18000

Before proceeding to calculate the pressures and tensile loading, the outer diameters and drill bit sizes of the pipes are evaluated to make the casing design effective. To meet the suggested tubing ID of 3.00" on bottom crossing over to 4.00" ID., Halliburton Redbook is used to get a production tubing that has an OD of 3.50" and ID of 3.00", at a weight of 10.3 lbs. /ft. (ppf). From the ID of the tubing, the coupling diameter were obtained, which is the diameter of the tubing at the joint; in this case it is 4.5". One of the considerations that were put into the tubing selection was the weight of the pipe. Since the higher the weight of the pipe, the thicker the pipe, it would also mean more expensive, and since one is also trying to minimize the cost of the project as engineers it is important that all the safety criteria are met as well as more cost efficient.

Usually when designing the casing program, one goes from the bottom of the well to the surface. Therefore, a production casing of 7" is established. This was done by taking into account the coupling of the production tubing, which is smaller than the inner diameter of the production casing. This established that the tubing will easily fit into our production casing.

Once the production casing of 7" was selected, the corresponding casing strings were decided to fit a drill bit that is approximately 1" larger than the casing diameter to make sure that when the string is cemented there is an 1" of it that surrounds the outside of the casing. As the well is drilled deeper the wellbore diameter decreases therefore after establishing the total diameter of the production casing, the next casing string, which is the casing string 4 was chosen. A 11.875" bit is used to install 9.875" of casing string 4. Based on this same analogy the casing string 3 of 13.63" will be installed using drill bit of 14.75", this is also the first liner. Then casing string 2 of 16" id installed using, 17" drill bit. The same method was used to install the rest of the other casing strings, which is also shown in table 3 for each corresponding casing seating depth.

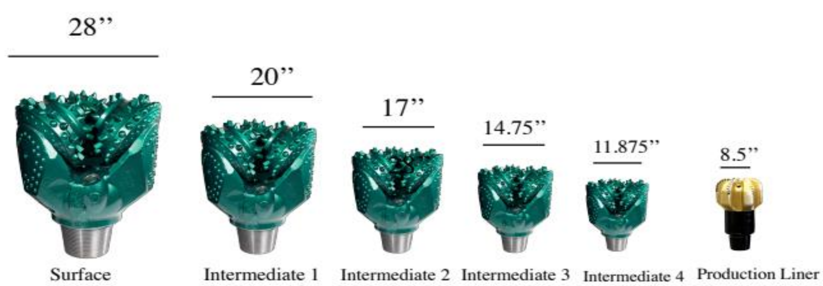
One of the important design consideration is the coupling diameter of the casing. One needs to make sure that the internal diameter of the casing string above the interested casing string is large enough to fit the coupling diameter of the casing below it. Also, another aspect that was considered is that the diameter of the drill bit size selected for the production casing is less the internal diameter of casing string 4 and so on to keep on drilling to the reservoir. The casing diameter, corresponding drill bits size and coupling diameter for each of the casing string was obtained from table 7.7 and 7.8 of the Applied

Drilling Textbook (Adams, Keith, & et. al., 1986). The casing string outer diameter and the drill bit size at each depth are also shown in table 4 and figure 9.

Table 4: Casing String Diameter and Drill Bit Sizes

Casing type	Set Depth (ft)	OD (inch)	ID (inch)	Drift Diameter (inch)	Coupling Type	Coupling Diameter (inch)	Bit Type	Bit Diameter (inch)
Conductor	6000	32	30	30	LONGRND	33		Jetted In
Surface	7500	24	21.5	21.562	LONGRND	25	Roller Cone	28
Intermediate 1 (Liner)	9000	18	16.5	17.052	BUTTRESS	19.625	Roller Cone	20
Intermediate 2 (HPC set)	10500	16	14.8	14.75	PECSNG	17	Roller Cone	17
Intermediate 3 (HPC set)	13000	13.63	11.88	11.875	PECSNG	14.375	Roller Cone	14.75
Intermediate 4 (HPC set)	15500	9.875	8.625	8.5	PECSNG	10.875	Roller Cone	11.875
Production (Liner)	18000	7	6.1	5.969	LONGRND	8	PDC drag bit	8.5

Figure 9: Drill bit sizes for references (not to scale), (Varel Oil and Gas, 2016)



Now finally after getting OD’s and pipe depths the calculations for Collapse, Burst and Tensile loading are calculated and compared with the Tenaris API steel pipe catalog to help determine which pipe grade fits best for each casing strings. A drilling fluid of seawater is assumed, which has a specific gravity of 1.02 for surface casing and oil base mud from casing string 1 to production casing, which has a specific gravity of 0.85. The pressure changes due to cooling and heating are ignored for the well and most of the time, the well is in thermal equilibrium unless it’s a well in a geothermal reservoir or when one is injecting a cold fluid. Overall, the pipe is designed for a worst-case scenario (Bommer, Casing Design, 2017).

In a well where there are numerous casing strings and large depths, one would want to economize. For the calculations of pressure resistance different kinds of casing that has the same OD but different strengths, weights, inner and drift diameters were studied to provide better understanding in terms of the pipe grade as well as the cost. However, in an offshore rig, casing cost is inconsequential so once a pipe met the required collapse, burst and tensile resistance, they were used.

The right grade and weight of pipe were determined by first calculating some of the design criterion such as the collapse pressure, burst pressure, and tensile load.

Collapse Pressure

Collapse pressure is the pressure at which the casing, or pipe will catastrophically deform as a result of differential pressure acting from outside to inside of the tube. So it’s very important to determine the collapse pressure of the pipe steel that one is choosing. Figure 9 shows how the pipe under a collapse pressure changes its shape over time.

Normally, one does not want anything inside the casing, but in this case, an assumption that seawater and oil based mud is inside the casing is made. Next a safety factor for the casing of 1.125 is assumed to prevent a collapse.

From Casing String 1 to Production Casing:

$$P_c = SF(P_e - P_i) = 1.125 * TVD * \left(\frac{MWpore}{8.33}\right) * (0.433) - 1.125 * (TVD) * (\gamma_{oil}) * (0.433) \quad \textit{(Eq. 10)}$$

$$P_c = Collapse\ Pressure\ (psi)$$

$$P_e = External\ Pressure\ (psi)$$

$$P_i = Inside\ Pressure\ (psi)$$

$SF = 1.125$ *(Traditional Industry used safety factor)*

$$\gamma_{oil} = Diesel\ Oil\ Specific\ Gravity = 0.85$$

$$MWpore = Pore\ mud\ weight\ (ppg)$$

For Surface Casing:

$$P_c = SF(P_e - P_i) = 1.125 * TVD * \left(\frac{MWpore}{8.33}\right) * (0.433) - 1.125 * (TVD) * (\gamma_{SW}) * (0.433)$$

$$\gamma_{SW} = Sea\ Water\ Specific\ Gravity = 1.02$$

The calculated collapse pressure value was then compared to API Steel Casing collapse pressure rating of the casing provided by the manufacturer, Tenaris.

Burst Pressure

Casing burst pressure is theoretically the internal pressure at which a joint of casing will fail. The casing burst pressure value is a key consideration in our offshore well-control and contingency operations and is a major factor in the well designing process.

The burst pressures are calculated using the equation 11 below:

$$Burst\ Pressure(Pb) = SF(Pi - Pe) \qquad \text{(Eq. 11)}$$

Where;

$SF = Safety\ Factor = \ 1$ *(Even if we exceed the minimum steel strength the pipe won't rupture or burst)*

$Pi = TVD * \frac{MWfrac}{8.33} * 0.433$

$Pe = (Top\ depth\ of\ the\ pipe) * \gamma_{SW}/\gamma_{Oil} * 0.433$

For example: production pipe = Casing string 4 TVD – 500 ft. (liner overlap)

No safety factor for burst pressure is used because the Barlow's equation 12, below for the material strength, it is defined by the minimal yield strength, which is by definition the end of the elastic limit. It's not where one thinks the steel is going to fail so there is considerable safety in that notion, where the strength of the pipe is not really calculated to the point of failure its calculated at the end of the elastic limit that's why a safety margin of 1 is used.

$$Burst\ Pressure(psi) = \frac{2*1(Safety\ Factor)*Minimum\ Yield\ Strength(psi)*thickness(in)}{Outer\ Diameter\ of\ the\ Pipe(in)} \qquad \text{(Eq. 12)}$$

In calculating burst pressure the internal pressure is higher than the external pressure. The burst load is different on the top of the casing and at the bottom of the casing and so the burst pressure at the top (equation 13) is used because that's where it's maximum. For the worst case one needs to consider the maximum burst pressure. As one goes shallower in the casing string, the burst pressure requirement increases. This is because the assumption that the internal pressure (P_i) remains constant throughout the casing string, however the external pressure calculation is different at the top and the lower end of the pipe. External pressure is the function of hydrostatic pressure and at lower depth it is minimum and at higher depth it is maximum. Ultimately, one gets a higher burst pressure when minimum external pressure is considered. For example, for casing string 2 the top depth is 5000 ft. so plugging in the (Pe) formula one gets the maximum burst pressure.

From Casing String 1 to Production Casing:

$$P_{b,top} = TVD * \left(\frac{MW_{frac}}{8.33}\right) * (0.433) - (D)\ \left(\frac{\rho_{oil}}{8.33}\right) * (0.433) \qquad \text{(Eq. 13)}$$

$$P_{b,top} = Burst\ Pressure\ at\ the\ top\ of\ the\ casing\ (psi)$$

$$\rho_{oil} = Diesel\ oil\ density = 7\ ppg$$

$$D = \ top\ of\ the\ pipe\ to\ the\ casing\ length\ (ft)$$

For Surface Casing:

$$P_{b,top} = TVD * \left(\frac{MW_{frac}}{8.33}\right) * (0.433) - (D)\ (\gamma_{SW}) * (0.433)$$

$$\gamma_{SW} = Sea\ Water\ Specific\ Gravity = 1.02$$

$$D = \ top\ of\ the\ pipe\ to\ the\ casing\ length\ (ft)$$

However, for casing string 1 and Production casing which are liners, it is a special case. Since the liners are not hanged all the way to the top one has the surface casing and casing above the production exposed. The P_i at the liners will be same as the P_i of surface and casing string 4 respectively, which is dangerous (high frac pressures of liners affects the casing above the liner). The exposed surface casing and casing string 4 is sensitive to the frac pressure of the shoe of the next deepest casing. To take care of that a burst pressure is needed at the surface and casing string 4 to withhold the burst pressures of the liners (next deepest casing).

Therefore, for the calculations of burst pressure (equation 14) for the casing string 4 and surface casing the P_i pressure were used for the liners attached to them. But for other casings, the burst pressure is calculated by calculating Pi at their own depth since they run all the way to 5000 ft.

For Casing String 4 (Liner)

$$P_b = TVD * \left(\frac{MW_{frac,n-1}}{8.33}\right) * (0.433) - (D) \left(\frac{\rho_{oil}}{8.33}\right) * (0.433) \quad \text{(Eq. 14)}$$

$$MW_{frac,n-1} = Frac\ mud\ weight\ in\ the\ casing\ below\ string\ 4\ (production\ casing\ string\ 5)$$

$$TVD = TVD\ of\ the\ liner\ (ft)$$

For Surface Casing (Liner):

$$P_{b,} = TVD * \left(\frac{MW_{frac,n-1}}{8.33}\right) * (0.433) - (D)\ (\gamma_{SW}) * (0.433)$$

$$MW_{frac,n-1} = Frac\ mud\ weight\ in\ the\ casing\ below\ surface\ casing\ (casing\ string\ 1)$$

$$TVD = TVD\ of\ the\ liner\ (ft)$$

Again the calculated burst pressure values were then compared to API Steel Casing burst pressure rating of the casing provided by the manufacturer, Tenaris.

Tensile Load

Finally, the tensile strength were determined for each pipe using trial and error method as well as comparing the burst and collapse pressure, this aided in calculating the tensile loading of each casing string using the equation 15 below. Where the weight of the casing is plugged in. For production liner the length of lateral needs to be considered, as well as the overlap of the liner at the casing above it that was assumed to be 5000 ft. Figure 11 shows the liner overlap. There were various grades of pipe that fit the criteria, but the weight of the pipe were narrowed down based on the grade as well as the burst and collapse pressure, since one would like to be as cost effective and also keep in mind the rig hookload capacity of 1,300,000 lbs.

$$Tensile\ Load = 1.8 * (Pipe\ Length) * (W) \quad \text{(Eq. 15)}$$

$$W = nominal\ linear\ mass\ of\ caisng\ \left(\frac{lbs}{ft}\right)$$

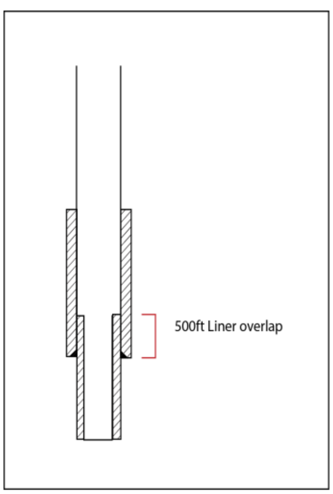


Figure 10: Liner Overlap

After finding the collapse pressure, burst pressure and the tensile load at each casing seating depth, the grade of the pipe were determine by comparing the calculated values to the manufacturer values of each grades of pipe at the various chosen outer diameter. The production casing will be an Q-125 liner casing, then casing string 4 is Q-125, casing string 3 is Q-125, casing string 2 is P-110, casing string 1 is N-80, surface casing is also X-80 and the conductor casing is X-40 grade pipe, that will essentially be jetted in to the seafloor. The table 5 below also shows the calculated collapse pressure, burst pressure and tensile loading. Table 6 shows the catalogue values of collapse pressure, burst pressure and tensile loading as well as the weight and grade of casing at each depth.

Table 5: Calculated values for collapse, and burst pressure and tensile loading

Casing Type	**Internal Pressure (psi)**	**External Pressure @Top (psi)**	**External Pressure @ Bottom (psi)**	**Tensile Load (lb)**	**Burst Pressure @Top (psi)**	**Burst Pressure @Bottom (psi)**	**Collapse Pressure (psi)**
Conductor							
Surface	5104	2208	3312	1335870	2896	1792	659
Intermediate 1 (Liner)	5104	2576	3897	489600	2528	1207	1002
Intermediate 2 (HPC set)	6304	1840	236	950400	4464	6068	1476
Intermediate 3 (HPC set)	8352	1840	574	1332000	6512	7778	2283
Intermediate 4 (HPC set)	10474	1840	5705	1186920	8634	4769	3447
Production (Liner)	12800	5521	344	460800	7279	12455	3447

Table 6: Catalogue values of collapse, burst pressure and tensile loading, and grade of pipe (Tenaris, n.d.)

Casing type	Weight Density (lb/ft)	Casing Grade	Body Yield Tensile Strength (lbs.)	Internal Yield Presure, Pb (psi)	Collapse Resistance, Pc (psi)
Conductor	331.39	X-40			
Surface	296.86	X-80			
Intermediate 1 (Liner)	136	N-80	3123000	5210	2470
Intermediate 2 (HPC set)	96	P-110	3065000	6920	2340
Intermediate 3 (HPC set)	92.5	Q-125	2950000	9670	5720
Intermediate 4 (HPC set)	62.8	Q-125	2270000	13840	11140
Production (Liner)	32	Q-125	1165000	14160	11720

Drill Bit Program

When determining which drill bit is optimal, one needs to consider one that has had proven success in the Gulf of Mexico, but also helps cut our operating costs. The Oil and Gas Journal stated many offshore oil and gas reservoir has used polycrystalline-diamond-compact (PDC) drill bits since the 1990s. Primary uses for this bit were reduction of drilling time by 50%. This bit has bullet like shape which increases junk slot area to evacuate cuttings at a faster pace. Another improvement in hydraulic configuration is it allows for both cooling and cleaning of the blade cutters which directly leads to a maximization in the rate of penetration. Smaller diameter steel frame puts a greater distance between the bit and borehole allowing for cuttings to reach surface faster. Some of the other criteria that were considered when selecting the bit type are the bearing life and rotating speed since, PDC/drag bits do not have any moving parts, and they last a very long time as well as thrive on high rotating speed. They also are 10-20 times greater than roller cone bits and have 2-3 times the rate of penetration (Rappold, 1995). This makes them an optimal choice for drilling through the lateral section of this wellbore.

For the vertical section of this wellbore one requires a higher weight on bit to cut the rock efficiently. Therefore, PDC/Drag bits would not thrive in this environment since they are not driven with enough force to fail the rock in compression. To combat this issue, roller cone bits will be used in the vertical section of the wellbore, since they thrive on large weight on bit and smaller rotating speed. Since, these bits are rotating at certain speed, they also have bearing life limitation. The number of allowable revolution which was calculated using equation 16.

$$Number\ of\ Revolutions\ =\ Section\ Length(ft)/\ Drilling\ rate(ft/hr)\ *RPM\ *\ 60(min/hr)$$

(Eq. 16)

The number of revolution were calculated based making assumption of RPM and drilling rate from table 5.12 of the Applied Drilling Engineering textbook. Then the calculated number of revolutions were compared to the bit bearing life of roller cone bits which is generally 1,000,000 rpm. These calculations are shown in table 7.

Table 7: Drill Bit Type and Number of Revolution

						Table 5.12 Medium soft sand		
Casing String No.	**TVD (ft)**	**Section Length (ft)**	**Bit Diameter (in.)**	**Bit type**	**Roller Cone Bit Bearing life (rev/min)**	**Req Rpm**	**Drilling Rate (ft/hr.)**	**Revolutions (rpm)**
Production Liner	18000	7500	8.5	PDC Bit				
Casing String 4	15500	10500	11.875	Roller Cone Bit	1000000	55	50	693000
Casing String 3	13000	8000	14.75	Roller Cone Bit	1000000	55	50	528000
Casing String 2	10500	5500	17	Roller Cone Bit	1000000	55	50	363000
Casing Liner 1	9000	1500	20	Roller Cone Bit	1000000	55	50	99000

Surface Casing	7500	2500	28	Roller Cone Bit	1000000	55	50	165000
Conductor Casing	**6000**	**1000**	**Jetted In**					
	5000							

Finally, the last criteria that went into the bit program was the torque required on the bit to break the rock. Since, roller cone bits thrive on weight on bit, one needs to consider the maximum allowable weight on bit. This torque was calculated using equation 17. The calculated results are shown in table 8.

$$T_b = 3.79 + 19.17\sqrt{\frac{ROP}{Nd}}\,(d)W_b$$

$T_b =$ torque required at the bit (ft-lb_f)

$ROP =$ anticipated drilling rate (ft/hr)

$N =$ bit speed (rpm)

$d =$ bit diameter (in)

$W_b =$ weight applied to the bit $(1{,}000\ \text{lb}_f)$ Eq. 17

$$Rotating\ Torque\ friction$$

$$T = r/12 * \mu * F sin\alpha$$

$$r = radius$$

Table 8: Calculated Torque on Roller Cone Bits

Casing String No.	**TVD (ft)**	**Chosen WOB*1000ft (ft-lbs.)**	**Rotating friction Torque (ft-lbs.)**	**Torque to Drill (ft-lbs.)**	**Total Torque (ft-lbs.)**	**Allowable Torque (ft-lbs.)**
Production Liner	18000					
Casing String 4	15500	42	207	2652	2858	45500
Casing String 3	13000	48	173	3359	3532	45500

Casing String 2	10500	49	140	3697	3837	45500
Casing Liner 1	9000	40	120	3273	3393	45500
Surface Casing	7500	27	100	2615	2715	45500

Based on the calculation one can see that there would be no considerable problems using the drill bits since the Transocean platform can handle a torque up to 45,500 ft-lbs.

Mud Program

Drilling muds are used when drilling the well to remove rock cuttings from the well, maintain wellbore stability, minimize formation damage, control corrosion as well as facilitate cementing and completion program. Water based mud (WBMs) have water as their continuous phase while oil based mud (OBM) have oil as its continuous phase. OBM has oil molecules that cannot penetrate into tiny organic and non-organic pores under the capillary pressure. OBM will not only allow to lubricate the pipes, but it also creates a thin mud cake, which will essentially help in reducing the risk of the pipe getting stuck in the borehole (Bommer, Introduction to Oil Based Mud, 2017). It is also important to recognize that OBM is relatively more expensive than WBM, and that it is hard to dispose of since it contains many harmful chemicals.

To make sure that the drilling mud provides proper lubrication to the wellbore, and that it is capable of bringing the drill cuttings to the surface, as well as cool, lubricate and support the bit and drilling assembly, there will be three different types of mud used. Seawater and WBM will be the assumed drilling mud when drilling the shallower sections because of their low cost, and Synthetic Oil Based Mud (SOBM) will be the drilling mud for deeper sections of the vertical as well as the lateral part of the wellbore since they cause lower friction.

Some of the criteria that went into determining the mud program are the mud type, the plastic yield low and high range, density as well as viscosity. Mud densities are important since they must fit the casing program and rock mechanics required in openhole to ensure wellbore pressures are properly controlled as the well is drilled deeper. To ensure that the formation does not fracture and/or a loss circulation event the yield point, and viscosity were assumed by taking the average of the high and low range from figure 11, the calculated values are shown in table 9.

Figure 11: Ranges of acceptable viscosity and yield point for clay/water muds (Adams B. T., Keith, K. M., Martin, C. E., et al., 1986)

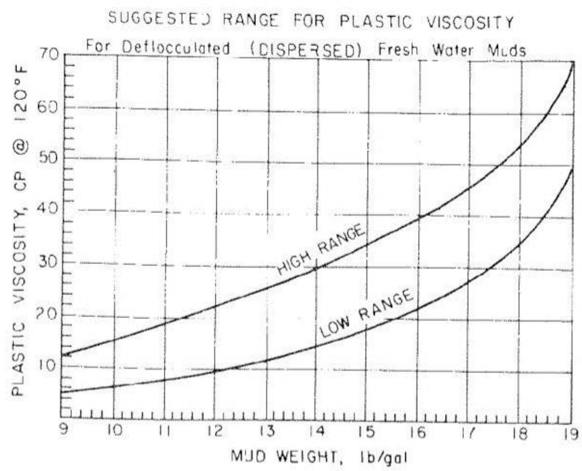


Fig. 2.30—Typical range of acceptable viscosities for clay/water muds.[5]

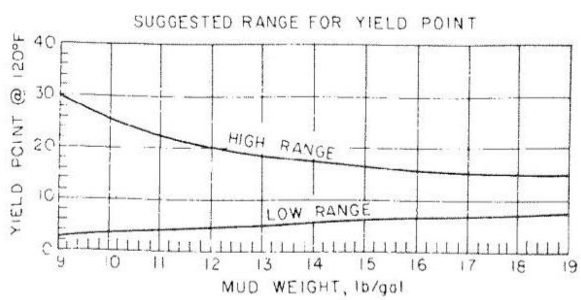


Fig. 2.31—Typical range of acceptable yield points for clay/water muds.[5]

Table 9: Calculated Yield Point (lb/100 sq.ft.) and Viscosity (cP)

			Yield Point(lbs/100 sqft) Chart			Viscosity(cp) chart		
Casing String No.	**TVD (ft)**	**Mud Type**	**High range**	**Low range**	**Calc. Yield Point**	**High range**	**Low Range**	**Calc. Viscosity (cp)**
Production (Liner)	18000	SOBM	19	5	12	27	12	19.5
Intermediate 4	15500	SOBM	19.7	4.5	12.1	25	11	18

(HPC set)								
Intermediate 3 (HPC set)	13000	SOBM	22	4	13	22	8	15
Intermediate 2 (HPC set)	10500	SOBM	24	3.5	13.75	18.5	7	12.75
Intermediate 1 (Liner)	9000	WMB	24.5	3	14	17.5	7.5	12.5

The next phase of calculation for mud program is the flow rate, since there needs to be a certain amount of flow rate needed to remove cuttings from the bottom of the home at a minimum and by the pressure and speed rating of the pumps at a maximum. Hole cleaning is an important aspect since, if rock chips fail to come to the surface through the drilling mud, it would create drag and possibly a stuck pipe (Bommer, Drilling Hydraulics, 2017). One of the other aspect that needs to be considered is the deviated wellbore foe this case. Inclined angles that are larger than 30 degrees, the rock cuttings tend to settle on the low side of the hole, and if enough settles then they might increase the torque and eventually stop mud circulation. To take these design problems into consideration, the yield point and viscosity, as well the transport index, and rheology factor were determined using Figure 12.1 and 13.2, and the calculated values are shown in table 10. While the bottoms up time for the rock cutting was determined using the hydraulics spreadsheet, and example calculation is shown in table 11.

Figure 12.1: Mud Properties (Luo., et. al., “Simple Chart…Requirements”, 1994).

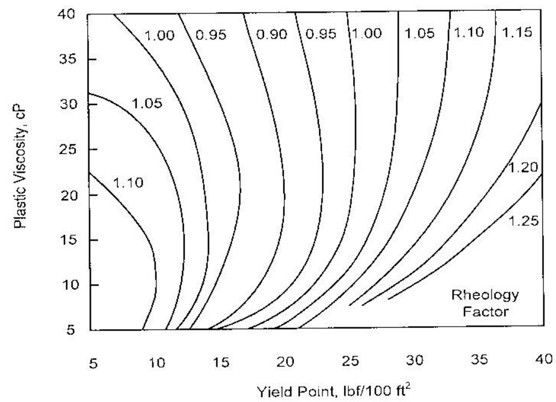


Figure 12.2: Maximum rate of penetration (ROP) that can be maintained with adequate hole cleaning (Luo., et. al., “Simple Chart…Requirements”, 1994).

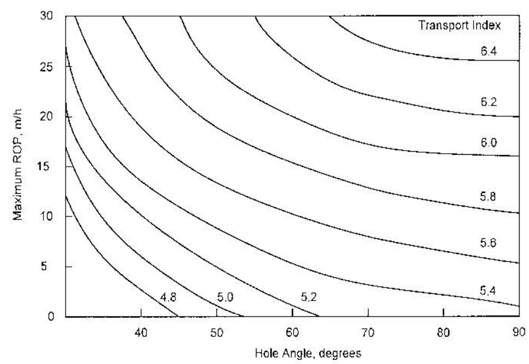


Table 10: Flow Rate, Transport Index and Other Calculated Mud Properties

			From graphs		Hydraulic sheet
Casing String No.	**TVD (ft)**	**q(flow rate)**	**Transport Index**	**RF**	**Cutting Bottoms up time (min)**
Production (Liner)	18000	403.495	6.6	1.05	371.2
Intermediate 4 (HPC set)	15500	353.656	5.5	1.05	379.1
Intermediate 3 (HPC set)	13000	378.458	5.5	1.05	431.1
Intermediate 2 (HPC set)	10500	400.659	5.5	1.05	425.4
Intermediate 1 (Liner)	9000	440.053	5.5	1	501.2

Table 11: Bottoms Up Time Example Calculations for Production Liner

Newtonian or Bingham Model	DATA	Units
Water Depth	5000	ft
Riser ID	21	in
Kill Line ID	3	in
Hole Diameter	8.5	in
Drill Pipe OD	6.625	in
Drill Pipe ID	5.901	in
Drill Pipe Length	23000	ft
BHA OD	5.5	in
BHA ID	3.5	in
BHA Length	5000	ft
Mud weight	13	ppg
Plastic Viscosity	19.5	cp
Yield Point	12	Lbf/100sqft
Flow Rate	403	gpm
Surface Equipment	479	equiv. ft of DP
Motor Diff Pressure	480	psi
Nozzle (32nds)		
13		
15		
12		
12		
12		
0		
Cutting Size	0.3	inch
Cutting Bottom Up Time	371.2	min

Cement Program

Cementing is an important part of the drilling process. It prevents fluid flow between subsurface formations and holds the casing in place.

This section of the report will deal with following calculations

1) Densities, Heights, and Sacks of Cement used in each casing string
2) Strength of cement in each casing string

Cement Selection

A proper well design is needed to place cement at each section of the casing to prevent any fracturing of formation. The 2 types of cements considered for this wellbore is the Class H neat and Class A with 8% Bentonite gel. Class A is a construction cement while class H has different chemistry and is considered as a work horse for oil and gas industry and can be used for any kind of well. The 24-hour curing time properties for both of these cement is shown in table 12 which were obtained from table 3.10 of the Applied Drilling Engineering Textbook (Adams B. T., Keith, K. M., Martin, C. E., et al., 1986). These properties to a fixed time, temperature and pressure to meet the wellbore requirements. Class H neat is used at the bottom of the wellbore to get a perfect seal. While, class A with 8% bentonite is used because the Bentonite clay added to class A causes density to decrease with larger yield, the cheaper mixture is achieved and, the thickening time is increased. Retarders are normally added to get larger yield, which is required to get fewer amount of sacks or one needs to adjust cement density that is close to Mud weight and less than frac mud weight.

Table 12: 24-Hour Curing Time for Class H neat and Class A with 8% Bentonite

24 Hour Curing Time					
Cement Mixture	Density (ppg)	Temp (°F)	24-hr Compressive Strength(Psi)	Pressure(Psi)	Slurry Yield (cu ft/sack)
Class "A" + 8% Bentonite	13.1	120°F	610 Psi	14.7 Psi (1 atm)	1.92
Class "H" Neat	16.4	250 °F	8300	3000 Psi	1.06

To establish the cement strength at the bottom of the well, where the temperature is highest, the compressive strength at 24 hour curing time is used. Where the assumption that the pressure increases by 100/1000 psi is made.

$$tensile\ strength = 8300/10 = 830psi. \quad \text{Eq. 18}$$

Calculating Cement Density and ratio of Class A + 8 % Bentonite and Class H in Surface Casing

The first problem of cementing comes from the surface casing. For this well, the cementing job for the surface casing, set at 7500ft, is needed all the way up through the annular space (2500ft) to the mud line. To accomplish this, one cannot exceed the fracture pressure of 4067.7 psi at that depth of the surface casing (7500ft). Then the density of cement that is required to get the cement height of 2500 ft is calculated as shown below, from its shoe till the ocean surface without fracturing. The top of the well is full of sea water. Thus, there is hydrostatic pressure on the top of the cement plus the pressure of cement acting on the depth of the casing. After balancing the equation, the cement density of 14.37 ppg is calculated for a height of 2500 ft.

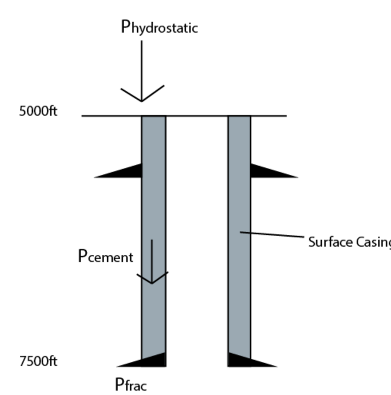


Figure 13: Frac Pressure Calculation Schematic

$$Pfrac = Ocean\ depth * (0.44psi) + \rho cemet * (length\ of\ Cement) * 0.052 \quad \text{Eq. 19}$$

$$4067.7 = 5000 * (0.44psi) + \rho cement * (2500ft) * 0.052$$

$$\rho cement = 14.37ppg$$

The $\rho cement$ calculated above is of the mixture of 2 cement. Thus, it will have some volume of Class H and Class A. The intent is to put the best cement (class H) at the bottom of the hole since the well requires drilling deeper (Bommer, Basic Cementing Principles, 2017). See table 13 for the calculated fractions of Class H and A cement needed.

Table 13: Fraction of Cement A and H needed for the Surface Casing

Casing String No.	**TVD (ft)**	**Pipe Length (ft)**	**Frac MW (ppg)**	**Cement Length (ft)**	**FH**	**FA**	**Cement Density (ppg)**	**Class H, Cement Height (ft)**	**Class A + 8% Bentonite, Cement Height (ft)**
Surface Casing	7500	2500	10.43	2500	0.3839	0.6161	14.37	956.8	1540.2

$\rho cemet = FA(\rho A) + FH(\rho H)$ Eq. 20

$FA + FH = 1$ Eq. 21

Solving simultaneously yields:

$FH = 0.3839$

$FA = 0.6161$

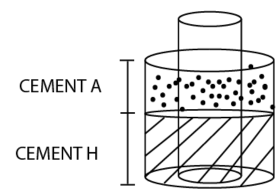


Figure 14: Cement A and H Height

The Cement Height for both Class H and Class A + 8% bentonite is calculated by multiply fractions with the total cement height.

$Class\ H\ Cement\ Height = FH * 2500ft = 956.8\ ft$

$Class\ A + 8\%\ bentonite\ Cement\ Height = FA * 2500ft = 1540.2\ ft$

Calculating Cement Density, Heights, and Cement ratio for Rest of the Casing Strings

Now, the calculations for the rest of the strings were performed in the similar way except the hydrostatic pressure is now the mud above the cement since the marine riser is attached after cementing the surface casing. Also, since at the very bottom of the well good cementing is required, Class H cement is used for casing String 3, 4 and production liner and, mixture of Class A + 8% bentonite and Class H in casing string 1 and casing string 2.

Thus, casing String 3, 4 and production liner has a $\rho_{cement}\ of\ 16.4ppg$ and calculate height while for rest of the other casing strings, the height of $1500ft$ is set and ρ_{cement} is calculated. The equations below were used to calculate the height of the

Using equation 22 and the previous equations 19, 20, and 21 the cement height and densities were obtained as shown in table 14.1 and 14.2.

$$Pfrac = 0.052(Mud\ Weight)(TVD - \boldsymbol{h_{cement}}) + 0.052(\boldsymbol{\rho_{cement}})\boldsymbol{h_{cement}} \quad \text{Eq. 22}$$

Note = For Production casing the entire lateral as well as some height of the vertical section is cemented to get the height of 8200ft.

Table 14.1: Cement Type for Each Casing String

Casing String No.	TVD (ft)	MW (PPG)	Frac MW (ppg)	Total Cement Length (ft)	Cement Type
Production Liner	18000	13	13.68	3000* + 5261.45	Class "H" neat
Casing String 4	15500	12.36	13	2455	Class "H" neat
Casing String 3	13000	11.55	12.36	2171	Class "H" neat
Casing String 2	10500	10.91	11.55	1500	Class "H" neat + Class "A" + 8% Bentonite gel
Casing Liner 1	9000	10.43	10.91	1500	Class "H" neat + Class "A" + 8% Bentonite gel
Surface Casing	7500	10	10.43	2500	Class "H" neat + Class "A" + 8% Bentonite gel

Table 14.2: Cement Height and Density Calculated for each Casing String

Casing String No.	FH	FA	Cement Height (H)	Cement Height (A)	Pfrac (psi)	Cement Density (ppg)
Production Liner	1.0000	0.0000	8200.0000	0.0000	12804.48	16.4
Casing String 4	1.0000	0.0000	2455.4455	0.0000	10478	16.4
Casing String 3	1.0000	0.0000	2171.1340	0.0000	8355.36	16.4
Casing String 2	0.6939	0.3061	1040.9091	459.0909	6306.3	15.39
Casing Liner 1	0.0636	0.9364	95.4545	1404.5455	5105.88	13.31
Surface Casing	0.3839	0.6161	959.7902	1540.2098	4067.7	14.37

Using the heights calculated above, the volume (equation 24) of each cement is calculated by multiplying each cement by annular areas (equation 23) of each casing string.

$$Aa = \pi/4\ (BIT^\wedge 2 - OD^\wedge 2)ft^\wedge 2/144 \quad \text{Eq. 23}$$

Volume of cement = Aa*Cement Length Eq. 24

Another aspect that need to be accounted for is the shoe tract. It is another term for float joint or a full-sized length of casing placed at the bottom of the casing string that is usually left full of cement on the inside to ensure that good cement remains on the outside of the bottom of the casing (Schlumberger, n.d.). The shoe track is used to calculate volume of cement by taking height of a collar up to 40 ft. and eventually adding the shoe track volume (equation 25) to class H cement volume, since it is at the bottom.

$$Shoe\ Track\ (bbl/ft) = ID\text{^}2/1029.4 \qquad \text{Eq. 25}$$

$$Volume\ (ft\text{^}3) = (Shoe\ Track\ * 40ft) * 5.69 \qquad \text{Eq. 26}$$

The total volumes of class H and Class A + Bentonite cement in ft^3 (equation 25) is converted into sacks using equation 27 by using the slurry yield of each cement as mentioned table 12. Extra 15% of cement is added for a fear of hole not being perfectly accurate. The calculation are shown in table 15 and 16.

$$Sacks = \frac{Volume\ of\ Cement}{Slurry\ Yield} \qquad \text{Eq. 27}$$

Table 15: Calculated Shoe Track and Annulus Area

Casing String No.	**Bit Diameter (in)**	**OD Pipe (in)**	**Drift ID Pipe (in)**	**Shoe Track(bbl/ft)**	**Annulus Area (ft2)**
Production Liner	8.5	7	5.969	0.034611386	0.126809078
Casing String 4	11.875	9.875	8.5	0.070186516	0.237255695
Casing String 3	14.75	13.625	11.875	0.136988173	0.174106819
Casing String 2	17	16	14.75	0.211348844	0.179987079
Casing Liner 1	20	18	17.052	0.282466198	0.414515697
Surface Casing	28	24	21.562	0.451641582	1.134464014

Table 16: Calculated Cement Volume and sacks of Cement Needed

Casing String No.	Vcement Class (H) (ft3)	Vcement Class(A) (ft3)	Add Excess	Sacks A	Sacks H
Production Liner	1039.83	0	15%	0	1128
Casing String 4	582.570	0	15%	0	632
Casing String 3	378.00	0	15%	0	410
Casing String 2	235.45	82.63	15%	49	255
Casing Liner 1	103.85	582.21	15%	349	113
Surface Casing	1191.64	1747.31	15%	1047	1293

Strength of cement in each casing string

The next important property of the cement is the strength of cement. Compressive strength is measured at a given temperature and pressure and at a given curing time. These three variables make a difference in compressive strength at different temperature. Compressive strength indicates the tensile strength and for most wells the tensile strength is the strength that fails easily as it is 10 times smaller than compressive strength.

Since, adjusting the density of slurry to get in place without creating the fracture at the bottom of the casing is a problem that need to be addressed. First, the Class H and Class A cement strength is adjusted at different depth. This allows the cement to be exposed to hydrostatic pressure where it finally exits the casing all the way down at the bottom of the well while it's still a slurry. Before the slurry hardens, it takes on the hydrostatic pressure. When the cement sets, it has some porosity and it has fluid in it which is pressurized with the hydrostatic pressure. The hydrostatic pressure is trapped inside the solid (Bommer). So, now the strength is adjusted by adding the hydrostatic pressure as shown in equation 28 and the calculated values are shown in table 17.

$$Adjusted\ Strenght = 24\ hour\ compressive\ Strength\ of\ Cement\ H\ or\ A - 3000psi + Hydrostatic \quad \text{Eq. 28}$$

Table 17: Calculations for the Adjusted Cement Strength

Casing String No.	TVD (ft)	Cement Type	24 compressive Cement Strength H (psi)	24 compressive Cement Strength A + Bentonite(psi)	Adjusted Cement Strength H (Psi)	Adjusted Cement strength A (Psi)
Production Liner	18000	Class "H" neat	8300	610	11924.80	
Casing String 4	15500	Class "H" neat	8300	610	13683.99	
Casing String 3	13000	Class "H" neat	8300	610	11803.82	
Casing String 2	10500	Class "H" neat + Class "A" + 8% Bentonite gel	8300	610	10666.33	5799.38
Casing Liner 1	9000	Class "H" neat + Class "A" + 8% Bentonite gel	8300	610	10129.47	4741.24
Surface Casing	7500	Class "H" neat + Class "A" + 8% Bentonite gel	8300	610	8177.70	3245.31

Next, the cement strength that will show up without getting cracked is calculated. If the crack is not avoided there can be a possibility of leak. Thus, the tensile strength is needed for cement for each casing before the cement is pumped. Cracks will appear as tensile failure in the cement if the inside of the wellbore is pressurized beyond what it was when the cement hardens (Bommer). For calculation of tensile failure for the casings, pore and frac pressures at the depth of the casing is used. The possible pressure increase in the well will be the difference of pore and frac that will show up in the reservoir as shown in equation 29.

$$Pressure\ Increase\ = Pfrac - Ppore \qquad \text{Eq. 29}$$

Then to tensile strength for the pressure increase inside the well, the rule of thumb that the tensile stress is about 100 psi per 1,000 psi of pressure increase is used as shown in equation 30 (Bommer).

$$Tensile\ Strength\ =\ Pressure\ Increase * (\frac{100psi}{1000psi})$$ Eq. 30

This calculated tensile strength is needed to be developed in solid to resist cracking as the pressure is increased.

So, to calculate pressure increase in casing string above liner equation 31 is used.

$$Pressure\ Increase\ in\ casing\ above\ liners\ =\ Pfrac\ of\ liner - Ppore\ of\ casing$$ Eq. 31

Then the compressive strength is calculated by multiplying tensile strength by 10 as shown in equation 32. Table 18 shows the calculation for tensile and compressive strength based on pressure increase.

$$Compressive\ Strength\ =\ Tensile\ Strength * 10$$ Eq. 32

Table 18: Calculation for Tensile and Compressive Strength for Pressure Increase.

Casing String No.	MW (PPG)	Frac MW (ppg)	Pfrac (psi)	Tensile Load (Psi)	Compressive load (psi)	Adjusted Cement Strength H	Adjusted Cement strength A
Production Liner	13	13.68	12804.48	63.65	636.48	11924.80	
Casing String 4	12.36	13	10478.00	284.23	2842.32	13684.00	
Casing String 3	11.55	12.36	8355.36	54.76	547.56	11803.82	
Casing String 2	10.91	11.55	6306.30	34.94	349.44	10666.33	5799.38
Casing Liner 1	10.43	10.91	5105.88	22.46	224.64	10129.47	4741.24
Surface Casing	10	10.43	4067.70	120.59	1205.88	8177.69	3245.31

The adjusted cement is way higher than the compressive load on the cement therefore, the cement program is a success.

<u>BHA and Drill String Selection</u>

Drill string is used when drilling a hole. The first section of the hole is drilled with a 20” bit and is 1500 ft. long. The drill string is run from the surface to the true vertical depth, hence it needs to be strong. To quantify that strength, von misses stress calculation is required but before that the selection of drill pipe is done using drill pipe table on canvas. Since, it is an offshore reservoir one needs to make sure to use stronger pipe despite having freedom of being able to use any pipes.

Table 19 shows the von Mises test conducted to check if the von Mises stress is allowable.

Table 19: Allowable von Mises Stress

Pipe OD	6.625	in
Pipe ID	5.9	in
Pipe Air Weight	27.7	Lbm/ft
Min Yield Strength	135000	psi
BHA Air Weight	242	Lbm/ft
BHA Length	300	ft
Internal Pressure	5000	psi
Mud Density	13	ppg
WOB	10200	Lbf
Rotary Torque	45500	ft-Lbf
True Vertical Depth	18000	ft
Polar Moment of Inertia	70.15862	in^4
Pipe Wall Area	7.131696	in^2
Hook Load	440731.2	Lbf
Axial Stress	80966.11	psi
Tangential Stress	45689.66	psi
Z constant	21.17996	in^3
Torsion Stress	25779.09	psi
von Mises Allowed Stress	83,291	psi
Is Allowed Stress Acceptable?	YES	using 80% safety factor.

Based on the von Mises stress calculation, the hole at the bottom is 8.5'' so the 6 5/8" Drill pipe of 27.7ppf S-135 is an acceptable choice. Since, the drill pipe should not be in compression because it will buckle and tool joints will loosen and starts to leak. Thus, bottom hole assembly is needed below the drill pipe.

Vertical BHA

To determine the vertical bottom hole assembly, first the WOB and the rpm needs to be determined. Table 5.12 from the Applied Drilling Engineering textbook is used to get the maximum WOB using equation 33. Assuming unconsolidated sand, the 3200 WOB and 55 rpm is selected for surface casing using the textbook table of 5.12 and similarly the other strings were calculated as mentioned earlier in table 7.

$$WOBmax = WOB * Bitsize \quad \text{Eq. 33}$$

$$WOBmax = 3200(20) = 64000lbs$$

Next the drill collar weight are checked to see if they will buckle since they are in compression. Since, drill collars are large diameter thick wall tube, where all the weight is lowered to push the bit into the formation, the drill collar weight needs to be more than 64000 lbs. to avoid drill pipe compression at all cost. A 20% of safety is added to get 76800 lbs as shown in equation 34.

$$WOBmax = 1.2 * Weight\ on\ bit\ Required\ in\ Unconsolidated\ sand * bit\ diameter$$

$$WOBmax = 76800ft \quad \text{Eq. 34}$$

The critical buckling force is calculated using buckling force excel spreadsheet on canvas. The purpose is to make sure the hole inclination is not perfectly zero, or otherwise it will buckle. The drill collars are not taken out during drilling from surface, since both diameters from about 20” to 11.785’’ can be used up to 11” OD to 3” bore drill collars. Buckling calculation are shown in table 20.

Table 20: Buckling Calculation for Drill Collars

Data		
Pipe OD	11	in
Pipe ID	3	in
Pipe Air Wt	298.7	Lbm/ft
Mud Wt	10.43	ppg
Bit Diameter	20	in
Angle of Inclination	0.5	deg
Moment of Inertia	714.691	in^4
Buoyed Pipe Wt	251.034	Lbm/ft
Hole Clearance	9.000	in
Critical Buckling Force	41,708	Lbf

From the above table one can see that the drill collars do buckle and exceed 76800 ft however, this is the best choice to make, or one can relax the WOB and increase the rpm. Therefore, the WOB is relaxed to avoid the collars buckling and then lengths for each drill collar and drill pipes are calculated at each section of the casing strings using equation 35 and 36.

$$WOB\ Relaxed\ for\ Casing\ 1 = 40{,}000\ Lbf$$

$$Length\ of\ Drill\ Collars = WOB\ relaxed / Weight\ of\ Drill\ collars \quad \text{Eq. 35}$$

$$Length\ of\ Drill\ Collars = (40000/298.7) = 134\ \text{ft.}$$

$$Length\ of\ Drill\ Pipe = (TVD) - Length\ of\ Drill\ Collars \quad \text{Eq. 36}$$

$$Length\ of\ Drill\ Pipe = (9000 - 134) = 8866\ \text{ft}$$

Similar calculations as shown in table 21, were performed for the rest of the casing string until the production string because that's where the well is deviated and it would require a horizontal Bottom Hole assembly. Drill collars and drill pipe lengths for each casing section have 30 joint foot and their corresponding calculation are shown in table 22.

Table 21: Maximum WOB and Critical Buckling Force

Casing String No.	MW (PPG)	Bit Diameter (in2)	WODB unconsolidated sand lbf/in	WOBmax (lbs)	Critical Buckling (lbf)	Chosen WOB (lbf)	Buckle
Production Liner	13	8.5	3900	10200	15577	10200	No
Casing String 4	12.36	11.875	3800	54150	131392	54150	No
Casing String 3	11.55	14.75	3700	65490	63952	60000	No
Casing String 2	10.91	17	3200	65280	50858	49000	No
Casing Liner 1	10.43	20	3200	76800	41708	40000	No
Surface Casing	10	28	3200	107520	30466	27000	No
Conductor Casing	10	Jetted In					

Table 22: Drill Collars Sizes and Properties

Casing String No.	Collars used	Collar Weight	Chosen WOB	Length of Collars(ft)	Length of Drill Pipe(f)	Collar Joints	Pipe Joints
Production Liner	6.5''- 3.1'' Drill collar	84.51	10200	121	22879	4	596
Casing String 4	11'' - 3'' Drill collar	298.7	54150	181	15319	6	511
Casing String 3	11'' - 3'' Drill collar	298.7	60000	201	12799	7	427
Casing String 2	11'' - 3'' Drill collar	298.7	49000	164	10336	5	345
Casing Liner 1	11'' - 3'' Drill collar	298.7	40000	134	8866	4	296
Surface Casing	11'' - 3'' Drill collar	298.7	27000	90	7410	3	247

<u>BHA Horizontal</u>

Parts to consider for horizontal Section of the well

Drill Pipe: 6.625" OD, 27.7 ppf, S-135

Heavy Weight Drill Pipe: 5.5" ID 3.5 in 30 foot joints.

Drill Bit size: 8.5"

Current Mud: OBM, 13 ppg, Yp=12 Lb/100 sqft, plastic viscosity = 19.5 cp.

The production (liner) casing of 7" OD is to be cemented in place. Multiple fracture jobs are to be done through this casing. The following data has been selected from the Bit operation file on canvas.

$$Rotation = 300\,rpm$$
$$WOB = (1000)(8.5) = 8500\,lbs$$
$$Top\ drive = 100\,rpm$$
$$Motor = 200\,rpm$$
$$Ti = 6.6$$
$$Rf = 1.05$$

Motor

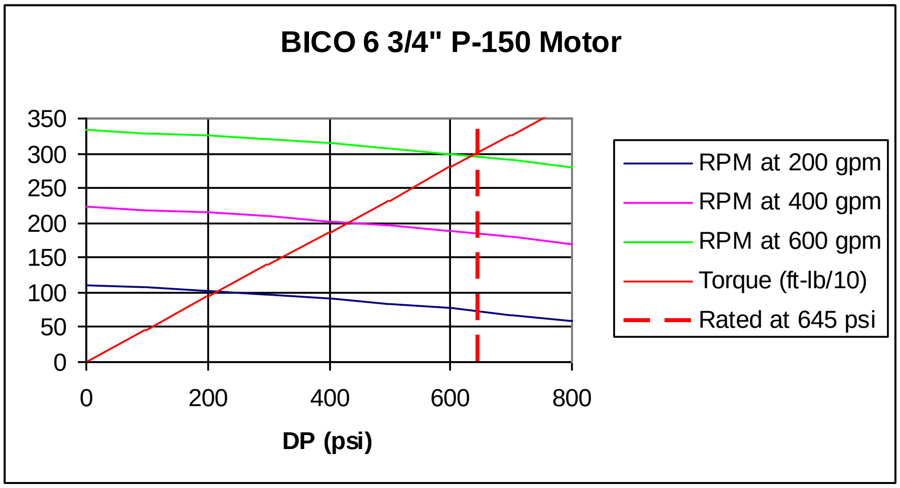
For the horizontal BHA, 8500 lbs. of WOB is adopted with the bit rotating at roughly 350 rpm. The rpm is established by putting the motor in the well. When the pumps are pumping mud through the well, it will turn the bit with some speed. Also, by changing the inclination (direction), some amount of rotary speed (top drive) will be added to keep the pipe moving on its own. This number is added to the motor speed to make the total of 350 rpm that is needed for this particular project scenario. In order to meet these requirement, 6 ¾'' P-150 motor is selected to complete the design.

This motor of 6 ¾'' diameter motor will easily fit in the 8 ½" bit. To calculate the directional pressure of this motor, Figure 15 is interpolated between 400-600 gallons per minute (gpm) (Bommer, Down Hole Motor, 2017). Assuming soft rock formation, the maximum rate of penetration (ROP) of 50-100ft/hr and 90-degree inclination is used. Using Figure 12.1 and 13.2, transport index of 6.6 is calculated and plugged into the equation 37. The transport index is then used to calculate the mud flow rate of 580 gpm. Where Figure 12.2 was used to get plastic viscosity of 19.5 cp and yield point of 12, in order to obtain the rheology factor of 1.05 for a mud density of 13 ppg.

$$TI = \frac{q\rho\,(RF)}{834.5} = \text{transport index}$$
$$q = \text{mud flow rate}\,(\text{gal/min})$$
$$\rho = \text{mud density}\,(\text{ppg})$$
$$RF = \text{rheology factor from Figure 1} \qquad \text{Eq. 37}$$

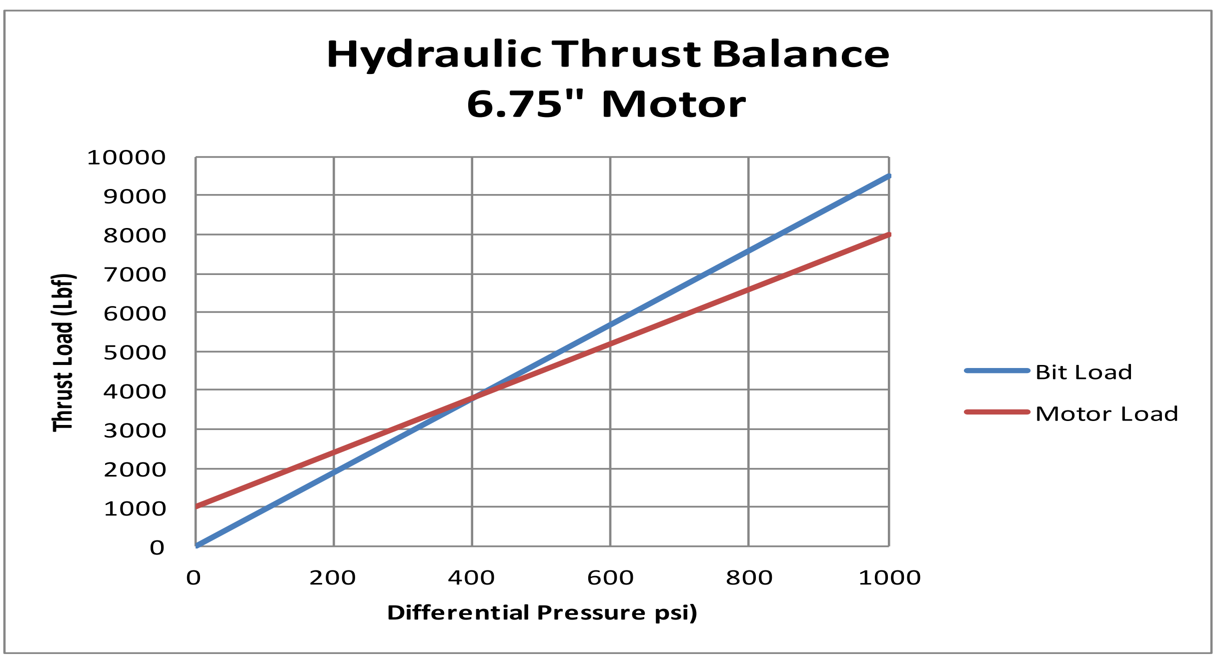
$$6.6 = q * 10 * 0.95 / 834.5$$
$$q = 403.44\,gal/min$$

Figure 15: Directional Pressure of P-150 Motor (Bommer, Down Hole Motor, 2017)



The next step is to perform interpolation using motor performance chart using Figure 15 which yields a differential pressure of 400 psi.

Figure 16: Hydraulic Thrust Balance for 6.75" Motor (Bommer, Down Hole Motor, 2017)



As the motor starts working when the pump is turned on, the pump is pumping at 403 gpm and must also supply 480 psi of differential pressure drop through the motor.

After taking care of the differential pressure, the torque that this motor will put up needs to be addressed. For 480 psi of differential pressure, 2300ft-lbs of torque from Figure 15 is obtained, which is much more than the needed amount. Therefore it is important that the life of the motor is accounted for and it is not being over loaded that what it can handle.

The life of the motor is tied to the thrust bearing. One can get the maximum life out of the thrust bearing if he/she runs it, essentially at zero/neutral status. Therefore, there are two things that are required to balance the thrust bearing.

1) The pressure drop of 480-psi of differential pressure that is being pumped through motor shows up as force acting across the thrust bearing. This force must be balanced by an equal and opposite force. Which will be supplied by putting part of BHA into compression. This bit weight would not show up on the bit, instead it would offset the thrust on the bearing. From figure 16, thrust load of approximately 4200 lb. is obtained (extra weight to supply to balance thrust bearing) at 480-psi differential pressure.
2) Since the 4200 lb. does not show up on the bit and 8500 lbs. of bit load is needed at the bottom of the hole, which is the choice of bit to keep drilling, the thrust bearing will be unbalanced again. To offset this 8500 lbs. force some of the pressure from the nozzle in the bit will be backed up. So, if 8500 lbs. is used, the bit load from figure 16 comes out to be approximately 900 psi. Then using hydraulics chart as shown in table 23, and the bit nozzles are opened up to make the bit nozzle pressure close to 900 psi, which will help keep the thrust bearing balanced.

Table 23: Hydraulics Chart Calculations with Bit Nozzles Sizes.

Newtonian or Bingham Model	
Water Depth	5000
Riser ID	18
Kill Line ID	3
Hole Diameter	8.5
Drill Pipe OD	5.5
Drill Pipe ID	3.5
Drill Pipe Length	23000
BHA OD	11
BHA ID	3
BHA Length	1300
Mud weight	13
Plastic Viscosity	15
Yield Point	12
Flow Rate	403
Surface Equipment	479
Motor Diff Pressure	480.0
Nozzle (32nds)	
12	
12	
11	
10	
10	
0	
Actual Nozzle D	0.771
Bit psi	890.4

$$F_{thrust} + FwoB = 4200 + 8500 = 12700 lbs.$$

This shows that 8500 lbs. is needed all the way out in the end of the horizontal part of the well.

Drill Pipe for Horizontal Section

After the selection of motor the next step is to select pipe that connects the horizontal part to the vertical section of the wellbore. There will certainly be 2 parts of the BHA, with three options to consider: drill pipe, heavy weight drill pipe and drill collars.

Considering our three options above to make sure if they will work in this wellbore and keeping in mind that 8500 lbs. is needed all the way down at the bit and the sliding friction, the total force on the pipes must be calculated. Generally, the entire assembly is rotated with top drive, which cuts sliding friction. However, here since the worst-case scenario is being used, the calculated total force on the pipes will allow one to know if the pipes are going to buckle.

Using equation 38 and 39 the sliding friction and the critical buckling force for the three options was calculated. These were calculated based on the drill pipe and drill collars dimensions in the report and are further discussed in the report.

$$Fs = uLw_{air\ weight}(1 - 0.0153\rho m) \qquad \text{Eq. 38}$$

$$Fs = \ Sliding\ Friction$$

$$u = \ friction\ factor$$

$$F_c = 2\sqrt{\frac{EIw\sin\alpha}{12r}}$$

$F_c =$ critical force at the onset of sinusoidal buckling $(\mathrm{lb_f})$

$E =$ Young's Modulus $(30x10^6$ psi for steel$)$

$I =$ tube moment of inertia $= \frac{\pi}{64}(OD^4 - ID^4)$ (in^4)

$w =$ buoyed unit pipe weight $(\mathrm{lb_f/ft})$

$\alpha =$ hole angle of inclination (deg)

$r =$ clearance between pipe and hole wall $= (D_{hole} - OD)$ (in)

$OD =$ pipe outer diameter (in)

$ID =$ pipe inner diameter (in)

$D_{hole} =$ hole diameter (in) Eq. 39

$\alpha = 93\ deg$

Heavy weight drill pipe considerations are shown in equation 40.

Heavy Weight Drill Pipe: 5.5” OD, 3.25’’ ID, 61.6 ppf (air weight) in 30-foot joints.

Sliding Friction = $Fs = (0.2)(5261.15)61.6\big(1 - (13)(0.0153)\big) = 51925.19\ lbs.$ Eq. 40

$$F_{total} = F_{thrust} + FwoB + Fs = 12700 + 51925.19 = 64625.19\ lbs.$$

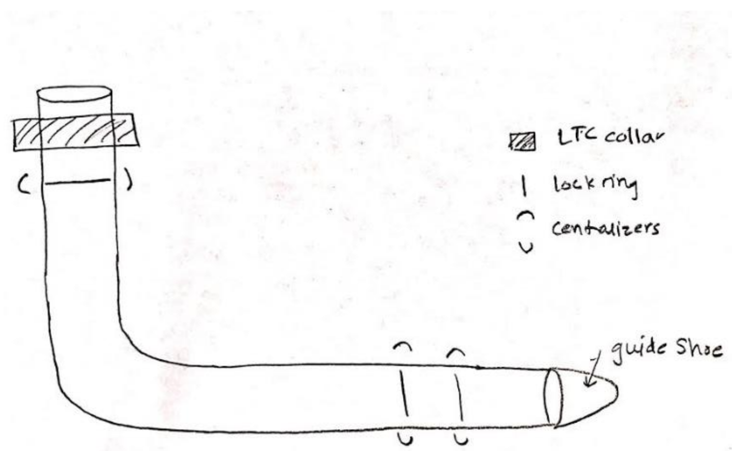
$$Criticle\ buckling\ = 80491\ \ lbs.$$

The total force pushed is lower than the buckling, which means the heavy drill pipe is unlikely to buckle and would work for this case. So, the bottom hole assembly for horizontal part will be the heavy weight drill pipe.

Hardware

Finally, the last aspect of BHA is the hardware's associated with the casing. The guide shoe is placed at the end of the casing to guide the casing pass any ledges. When cementing the casing, it is crucial to make sure that the casing is all around the wellbore evenly. One of the equipment that would help in holding casing from the bore hole and we would able to circulate cement is centralizers. Two centralizers, one on joint and another on collars of each pipe would be placed to ensure that the cement is even. The centralizers are held with lock ring to secure centralizers in the middle of the wellbore. Since the lateral is ft long of heavy weight drill pipe with 30 joint foot, this yields to a total of 351 centralizers in that 5261.15 feet interval, since there will be two centralizers. Finally in the 3000 ft. of cement in vertical section, one centralizer is put around each collar, which yields to a total of 200 centralizers. In total, there would be 551 centralizers placed in the wellbore.

Figure 17: Hardware Schematic



BOP and Shoe Testing Schedule and Plan

Establishing a Blow Out Prevention stack for an offshore platform is a critical design step for any oil and gas facility. Blow out happens when the pressure inside the borehole is less than the pore pressure. To make sure that the Transocean rig is capable of handling pressure changes, first the internal pressure at fracture at the shoe is calculated and then the drill pipe pressure is calculated using equation 41 and 42 respectively.

$$P_{iD} = P_{frac} + Casing\ Set\ Depth * 0.015 \qquad \text{Eq. 41}$$

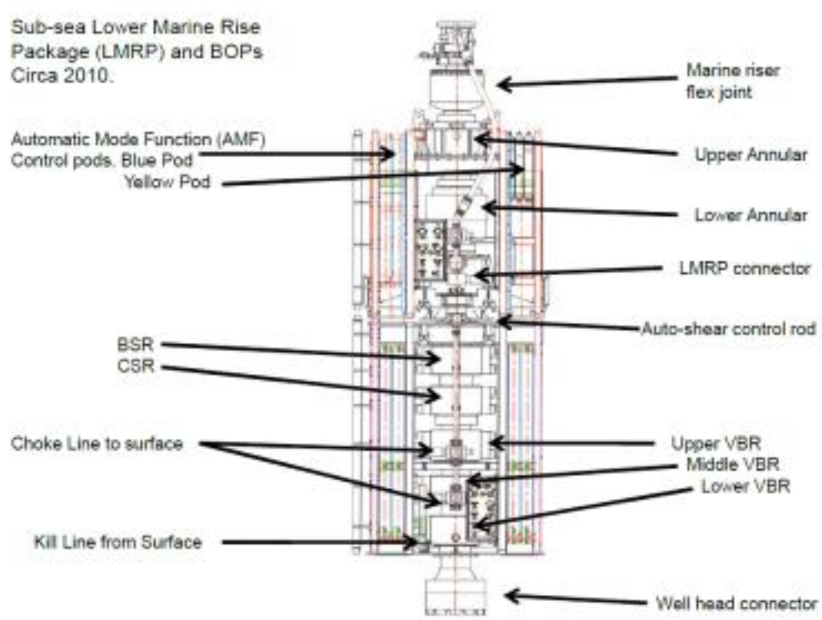
$$P_{iS} = P_{iD} - 0.052 * TVD * (P_{iD} + P_{atm}) * (MW_{air}) * \gamma_{Natural\ Gas} / (R * 7.48 * (Temp + 460))] \qquad \text{Eq. 42}$$

Table 24: Calculated Drill Pipe Pressure, and internal Pressure at Fracture at Shoe

Casing String No.	TVD (ft)	Section Length (ft)	MW (PPG)	Frac MW (ppg)	Cement Density (ppg)	Hydrostatic P (psi)	Fracture P (psi)	PiD (psi)	PiS (psi)
Production Liner	18000	7500	13	13.68	16.4	12168	12804.48	13194.48	11055.78
Casing String 4	15500	2500	12.36	13	16.4	9962.16	10478	10608	9199.871
Casing String 3	13000	2500	11.55	12.36	16.4	7807.8	8355.36	8485.36	7602.27
Casing String 2	10500	1500	10.91	11.55	15.39	5956.86	6306.3	6384.3	5877.095
Casing Liner 1	9000	1500	10.43	10.91	13.31	4881.24	5105.88	5183.88	4846.228
Surface Casing	7500	2500	10	10.43	14.37	3900	4067.7	4197.7	3979.101
Conductor Casing	6000	1000	10	10.43				52	49.23093
	5000	Jetted In							

The calculations of pressure in table 24 further verifies that the BOP on the Transocean rig will be able to handle these pressures, since the BOP rams has a capacity to handle up to 15,000 psi. Some of the other safety measures on the Transocean 706 are the dual variable bore rams which will to shut in flow by closing the BOP valves and ensure a long lasting seal, since when the BOP valves are closed, it will activate the packers and the rubber inserts will be displaced inward to close the packer around the pipe, sealing any flow of fluid (Transocean, 2017).

Figure 18: BOP and Low Marine Riser



The next aspect of design is the pressure test that is applied to the formation at the casing shoe during drilling. The test is performed after the casing strings are placed to make sure that maximum pressures are applied without formation damage.

The Shoe Test pressure is calculated by the difference between frac pressure and hydrostatic pressure and at each casing string:

$$Shoe\ Test\ Pressure\ =\ Pfrac - Psurf \qquad \text{Eq. 43}$$

Table 25: Shoe Test Pressure

Casing String No.	TVD (ft)	MW (PPG)	Frac MW (ppg)	Hydrostatic P (psi)	Frac Pressure (psi)	Shoe Test Pressure(psi)	MW Shoe Test (psi)
Production Liner	18000	13	13.68	12168	12804.48	636.48	0.03536
Casing String 4	15500	12.36	13	9962.16	10478	515.84	0.03328
Casing String 3	13000	11.55	12.36	7807.8	8355.36	547.56	0.04212
Casing String 2	10500	10.91	11.55	5956.86	6306.3	349.44	0.03328
Casing Liner 1	9000	10.43	10.91	4881.24	5105.88	224.64	0.02496
Surface Casing	7500	10	10.43	3900	4067.7	167.7	0.02236

Cost Estimates

Estimating costs for an oil and gas facility like the one reviewed in this project is often difficult since many the cost for equipment fluctuate due to market instability. The cost estimate show in table 26 for the well is done using Dr. Bommer's values for the cost per item for everything used in the drilling process.

Table 26: Cost Estimates

AFE				
PGE 430				
Class Project Well				
Item	Price Unit	Unit Price	Number of Units	Price Estimate - $
Transocean 706	$/day	$290,000.00	95	$27,550,000.00
Water Base Mud	$/Bbl	$50.00	553.69	$27,684.50
SOBM	$/Bbl	$650.00	1500.62	$975,403.00
Conductor Casing	$/ft	$3.00	331,390	$994,170.00

Surface Casing	$/ft	$3.00	742,150	$2,226,450.00
Int Csg 1	$/ft	$3.00	204000	$612,000.00
Int Csg 2	$/ft	$3.00	144000	$432,000.00
Int Csg 3	$/ft	$3.00	231250	$693,750.00
Int Csg 4	$/ft	$3.00	157000	$471,000.00
Int Csg 5	$/ft	$3.00	0	$0.00
Production Casing	$/ft	$3.00	240000	$720,000.00
Surface Cmt	$/sack	$35.00	2340	$81,900.00
IC 1 Cmt	$/sack	$35.00	462	$16,170.00
IC 2 Cmt	$/sack	$35.00	304	$10,640.00
IC 3 Cmt	$/sack	$35.00	410	$14,350.00
IC 4 Cmt	$/sack	$35.00	632	$22,120.00
IC 5 Cmt	$/sack	$35.00		$0.00
PL Cmt	$/sack	$35.00	1128	$39,480.00
Surface Bit	$/In Diameter	$600.00	24	$14,400.00
IC 1 Bit	$/In Diameter	$600.00	18	$10,800.00
IC 2 Bit	$/In Diameter	$600.00	16	$9,600.00
IC 3 Bit	$/In Diameter	$600.00	13.625	$8,175.00
IC 4 Bit	$/In Diameter	$600.00	8.875	$5,325.00
IC 5 Bit	$/In Diameter	$600.00	0	$0.00
PL Bit	$/In Diameter	$5,000.00	7	$35,000.00
Directional Services Standby	$/Day	$5,000.00	90	$450,000.00
Directional Services In Use	$/Day	$10,000.00	10	$100,000.00
Well Evaluation Services	Estimated	$500,000.00	1	$500,000.00
Miscl Services	Estimated	$500,000.00	1	$500,000.00
Rig Fuel	$/gal	$1.85	1175394.24	$2,174,479.34
Contingencies at 20% of Subtotal				7,738,979.37
Total AFE Estimate				**46,433,876.21**

The rig fuel was estimated using the engine horsepower of the rig which is 3640 kW and the equation 44.

$$P_e = \frac{w_f \rho_f}{60} H \frac{779}{33,000}$$

$P_e =$ input horsepower to the engine from the fuel (hp)

$w_f =$ fuel consumption at given speed and load $\left(\text{gallons/hour}\right)$

$\rho_f =$ density of the fuel $\left(\text{lb}_\text{m}\text{/gallon}\right)$

$H =$ fuel heat content $\left(\text{BTU/lb}_\text{m}\right)$

$779 = \frac{\text{ft-lb}_\text{f}}{\text{BTU}}$

$33,000 = \frac{\text{ft-lb}_\text{f}}{\text{min-hp}}$

Eq. 44

After taking into consideration costs for drilling mud, the bit types, casing string, the rig cost, the fuel and various other services the total AFE estimate is approximately $46,433,876.21. These numbers again can change if one were to encounter problems while drilling which might delay the process and add more operational costs.

Conclusion

Drilling in an unconsolidated sandstone formation in Gulf of Mexico can be quiet challenging, therefore some of the key aspects of drilling plan that were discussed such as the well plan, rig selection, mud window, the pipe program, cement program as well the BHA and BOP. Based on the mud frac weight and pore mud weight, 7 casing strings were established, and from the pressures the setting depths of the casing strings were determined. Using collapse pressure, burst pressure and tensile load equations, the grade of casing type, the mud program, cement program, and bit program were established. Finally the AFE cost estimate for the entire drilling program is $46,433,876.21.

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