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Report

Dynamic Simulations

Deepwater Horizon Incident

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Dynamic Simulations
Deepwater Horizon Incident

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ABSTRACT:

This report summarizes the modeling and dynamic simulations performed in response to the blowout occurring on well MC252 #1 the 20th of April 2010. The work has been done in the Horizon Incident Investigation Team that was established right after the incident.

Simulations were performed using OLGA-WELL-KILL[1], a software developed for well control applications. Fluid characterization and properties are generated by using PVTsim[2] (from Calsep).

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KEY WORDS:

Dynamic Simulations, Well Control

[1] Powered by OLGA from SPT-Group
[2] From Calsep

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Summary

This report summarizes the dynamic simulations and evaluations performed in response to the Deepwater Horizon blowout that occurred 20th of April 2010. The incident occurred during a negative test performed to check the integrity of the well barriers (cement, float, casing and seal assembly).

The evaluations and findings made during this work (to the date of this report) are based on witness statements, printouts from the SDL fast data set and cement unit log in addition to the well MC252's design, reservoir properties and reservoir fluid composition. A detailed dynamic OLGA-WELL-KILL network model has been build, used and found as a valuable tool to analyze and understand the transients occurring in the wellbore right before the explosion. The model includes the casing, the tapered drillpipe, kill line, outer annulus, riser, surface piping, mud degas separator, pumps, valves and control systems. The fluids include seawater, the Form-A-Set spacer, 14 ppg mud and hydrocarbons. The start time of the simulation model has been 15:00 when the entire wellbore was filled with 14 ppg mud. Simulations have been performed following the operations for the entire period until the last data recording at 21:49.

The main reservoir in the MC252 well consists of two oil bearing sands, the Upper and the Lower M56. Both sands have a pore pressure of 12.6 ppg. The top of the Upper M56 is at 18086 ft tvd rkb and only few feet separates the upper ant the lower sands. An analysis of the specified reservoir fluid composition reveals an under-saturated oil with a bubble point at 6500 psi at reservoir temperature. The density of the oil will, above the bubble point pressure, decrease with decreasing pressure and increase with decreasing temperature.

The properties of the oil are of such a character that a potential influx will maintain the volume when migrating through the mud towards seabed. This will challenge kick detection after a kick is taken as pit gains will be limited before the kick is right below the BOP. The crew will have less time to react, and once a well control problem is apparent, a late detection can mean that gas is already inside the riser before the BOP is closed. This behavior is different from a gas kick, but still not uncommon for deepwater drilling operations. Awareness and knowledge of these mechanisms are important.

The target reservoir sands are very prolific. Based on 300 mD and 86 feet net pay, the inflow performance curve indicates a productivity index of 49 stb/d/psi for pressures above the bubble point pressure. This contributes to a fast unloading of the well if it is left open to flow in an underbalanced condition. For example will a drawdown of only 1000 psi result in an influx of 73 bpm of oil from the reservoir into the wellbore. This is equivalent to a rate of 34 stb/m at surface conditions, the oil formation volume factor is 2.14 bbl/stb.

The well's blowout potentials are calculated to get an idea of the maximum flowrate. The worst case blowout rate to surface is calculated to be 68 000 stb/d assuming flow through the casing shoe and 47 000 stb/d assuming flow through the outer annulus.

The release rates to seabed are somewhat lower. The blowout potential through the drillpipe to seabed is 40 000 stb/d without any restrictions and fully exposed reservoir.

The well's shut-in pressure is calculated to be 6800 psi if the well is shut-in at surface using the IBOP, and 8250 psi if it is shut-in at seabed using the BOP. Both pressures are above the bubble point pressure, and no gas will be present after a long shut-in period and equilibrium is obtained.

Changes in witness statements have challenged the job of determining the conditions in the wellbore prior to and during the period where influx from the reservoir was taken. Due to a poor volume control on the rig during the negative test and the spacer displacement, these statements were important inputs to the Investigation Team. During the bleed downs, the pressure at down hole conditions dropped below the pore pressure, and initially, a gain of 60 - 85 bbl was believed to be taken. Simulations were performed assuming influx in the outer annulus due to a failed seal assembly, and through the casing shoe.

Later it become evident that the riser was filled up with 50-60 bbls during this period due to a leaking annular preventer and hence no, or only a small influx was taken during these bleed downs. This information changed the premises quite a lot with respect to the evaluations and flow path determinations. First of all, the new information indicates barrier integrity during the bleed down, since the conditions were underbalanced during these operations. The equivalent down hole pressure inside the casing was 11.5 ppg at this time with zero pressure on the drillpipe and influx would be taken if the reservoir was open to flow. The pressure in the outer annulus was 12.0 ppg, also at underbalanced conditions.

The constant shut-in pressure of 1400 psi measured on the drillpipe between 18:35 and 20:00 is not possible to explain based on a pore pressure of 12.6 ppg, observations and witness statements. With only mud in the wellbore and seawater in the drillpipe, the shut-in pressure should be 1030 psi if communication to the reservoir was through the casing shoe, and only 600 psi if communication was through the seal assembly. The pressure difference cannot be explained by an influx through the shoe as this requires a volume much higher than the logged and reported as gains. A sand pressurized at 13.0 ppg will however match the observed 1400 psi shut-in if the reservoir pressure is communicated through the shoe. If the pressure is communicated from a 13.0 ppg sand through the outer annulus, the resulting shut-in pressure is still too low.

During the spacer displacement, the drillpipe pressure was reading 1000 psi and increasing after the pumps were shut down for the sheen test at 21:08. This pressure increase was most likely caused by an influx. At this time, 1300 bbl of water had been pumped and both the drillpipe and the annulus (between the drillpipe and the casing) were fully displaced to water. At this point in time, the pressure at the formation is underbalanced only if the communication is through the casing shoe. A kick of more than 25 bbl is required from a 13.0 ppg pressurized sand in order to become underbalanced in the outer annulus at this time.

Based on the simulations, evidence and evaluations performed it is believed that the initial flow path was through a leaking casing shoe and up inside the casing. Further it is believed that when the pumps were shut in at 21:30, the crew was trying to close the BOP, most likely one of the annular preventers. This was obviously not sealing 100 % and the flow continued. At 21:36:25 it is believed that the drillpipe was opened and bled down to the cement unit until 21:38:05. The leak in the BOP continued until 21:47, where a dramatic pressure response is observed on the drillpipe. This response can be explained by finally establishing a 100% seal at the BOP. It is believed that one of the pipe rams was closed at this time.

The last pressure recording on the drillpipe is 5730 psi. According to the simulations, this pressure corresponds to a shut-in pressure with only hydrocarbons in the wellbore. Further, it is believed that this pressure is above the design pressure of the surface equipment and the ECD set points of the pumps were probably reached with that consequence that the blowout continued through the drillpipe to surface. The volume of the drillpipe is 207 bbls, initially filled with water and some hydrocarbons from the short bleed down, and this will be unloaded in 2 minutes according to the simulations. After closing the BOP, the riser will still flow and unload due to the presence of hydrocarbons above the BOP. The blowout rate through the drillpipe to surface is estimated to 28 000 stb/d. This will also be the blowout rate to seabed.

1. Background Information and Input Data

1.1 General

On April 20th 2010, a fire and explosion occurred onboard the Deepwater Horizon rig while it was working on the HPHT well MC252 #1 offshore Louisiana. The rig had cemented the casing and complications occurred during and after performing a negative test (standard procedure to test the cement job). Explosions occurred with subsequent fire and uncontrolled flow of hydrocarbons and a total loss of well control. The rig sank April 22nd.

An investigation team was established immediately to evaluate the causes of the accident. Add wellflow was asked to contribute to the engineering support team with dynamic analysis, simulations and evaluations, and this report summarizes the work performed.

1.2 Well location

The well is located on the Macondo prospect situated on Mississippi Canyon block 252 (MC 252), offshore Louisiana, Gulf of Mexico, 52 miles southeast of the Louisiana port of Venice.

Figure 1.1: Field location

1.3 Water Depth

The water depth at the spud location is 4992 ft MSL.

1.4 Drilling Rig

The Deepwater Horizon was a dynamic positioned semi-submersible drilling unit capable of operating in harsh environments and water depths up to 8 000 ft using 18 ¾" 15 000 psi BOP and 21" OD (19 ½" ID) marine riser. The air gap (rkb – MSL) is 75 ft.

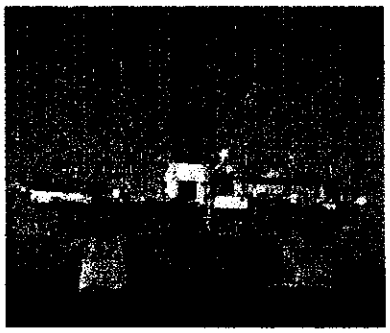


Figure 1.2: Deepwater Horizon

1.5 Reservoir fluid

The reservoir fluid is an under-saturated oil with a GOR of 2824 scf/stb. The fluid composition is shown in Table 1.1. Some key fluid parameters are shown in Table 1.2 and the phase envelope is shown in Figure 1.3.

Table 1.1: Reservoir fluid composition

Component	Mole frac	mole wt.	liq. dens
N2	0.624	28.01	
CO2	0.974	44.01	
C1	65.918	16.04	
C2	6.374	30.07	
C3	4.439	44.1	
iC4	0.92	58.12	
nC4	2.083	58.12	
iC5	0.845	72.15	
nC5	1.024	72.15	
C6	1.341	86.18	0.664
C7	1.934	93.26	0.7081
C8	2.092	107.8	0.8675
C9	1.536	120.54	0.852
C10	1.285	134.22	0.7569
C11-13	2.542	159.97	0.9395
C14-19	2.904	222.64	0.9074
C20-28	1.758	321.86	0.9296
C29+	1.407	604.5	0.8165

Table 1.2: Key fluid data

Property	Value
Gas Oil Ratio	2824 scf/stb
Bubble point @ 273 °F	6500 psi
Bubble point @ 40 °F	4400 psi
Oil formation volume factor, Bo	2.14 Rb³/stb
Oil density at standard conditions	7.09 ppg
Oil density at standard conditions	35 °API
Oil density at reservoir conditions	5.17 ppg
Gas density at standard conditions	0.059 lb/ft³

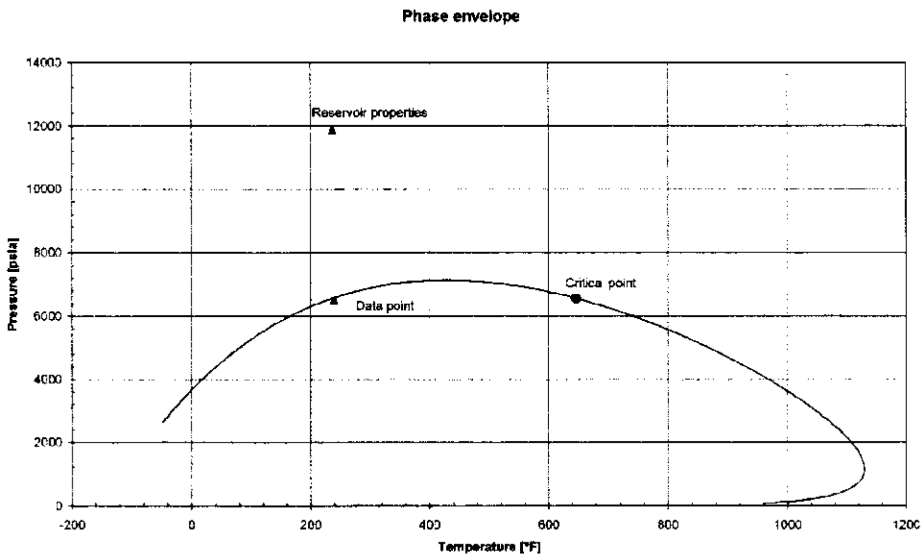


Figure 1.3: Phase envelope

1.6 Mud data

The dynamic simulations reproduce the trends shown by the data logs. For operations involving flow of the Form-A-Set spacer, the pressure drop in the system was higher than what was estimated by the model. A non-Newtonian Bingham viscosity model was but could still not reproduce the viscous behavior of the Form-A-Set. This effect was compensated by introducing additional pressure drop at the outlet of the wellbore. Rheology tests performed using a viscometer after the incident showed off scale readings and indicated very high viscosity and this is believed to be casing this discrepancy. Figure 1.1 shows the numbers used for the Form-A-Set and for the 14 ppg synthetic oil based mud.

Table 1.3: Rheology data for synthetic oil based mud and Form-a-set spacer

	SOBM	Form-a-Set
Density, ppg	**14**	**16**
Plastic viscosity, cP	28	324
Yield Point, lbf/100 ft²	14	34
10 sec gel, lbf/100 ft²	14	31
10 min gel, lbf/100 ft²	23	38

1.7 Reservoir data

The target reservoir sands consist of two main pay zones, M56 upper and M56 lower. The combined net pay is 86 ft with an average permeability of 300 mD and MDT samples indicate a pore pressure of 12.6 ppg.

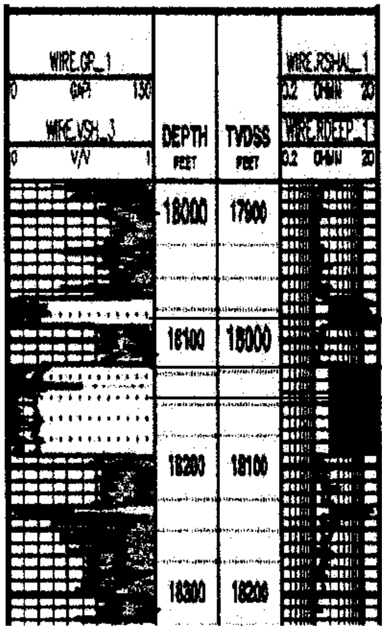
Table 1.4 lists some key information while Figure 1.4 shows a geological column and lists depths and pressures for the reservoir sands.

Table 1.4: Top sands

		Net	Pay	Por	Sw	Perm ar	Perm geo
	TOPS_SAND_LOGS FORMATION_1	S_SAND_L I_NET_SAN	S_SAND_L I_PAY_SAN	S_SAND_L S_POR_PA	S_SAND_L G_SW_PAY	S_SAND_L RM_ARITH	S_SAND_L ERM_GEO
17000.0000	Above_Upper_Lobe	3.00000	1.00000	23.45833	22.52296	155.707	18.1521
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
18225.0000	Below_Lower_Lobe	5.50000	5.50000	22.23788	19.84553	2046.812	403.5124

	S_SAND_BOTH_L FORMATION_1	AND_BOT I_NET_SAN	AND_BOT I_PAY_SAN	AND_BOT S_POR_PA	AND_BOT G_SW_PAY	AND_BOT RM_ARITH	AND_BOT ERM_GEO
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Only 2 main lobes



Depth (ft MD)	Pressure (psi)	Temperature (°F)	GOR (scf/stb)	API (°)
18086	11841	234	3017	34.9
18124	11850	236	2920	34.7
18142	11856	236	2845	35

Figure 1.4: Reservoir zones

1.8 Pore and fracture pressure profile

The pore and fracture pressure profiles are shown in Figure 1.5 and Figure 1.6.

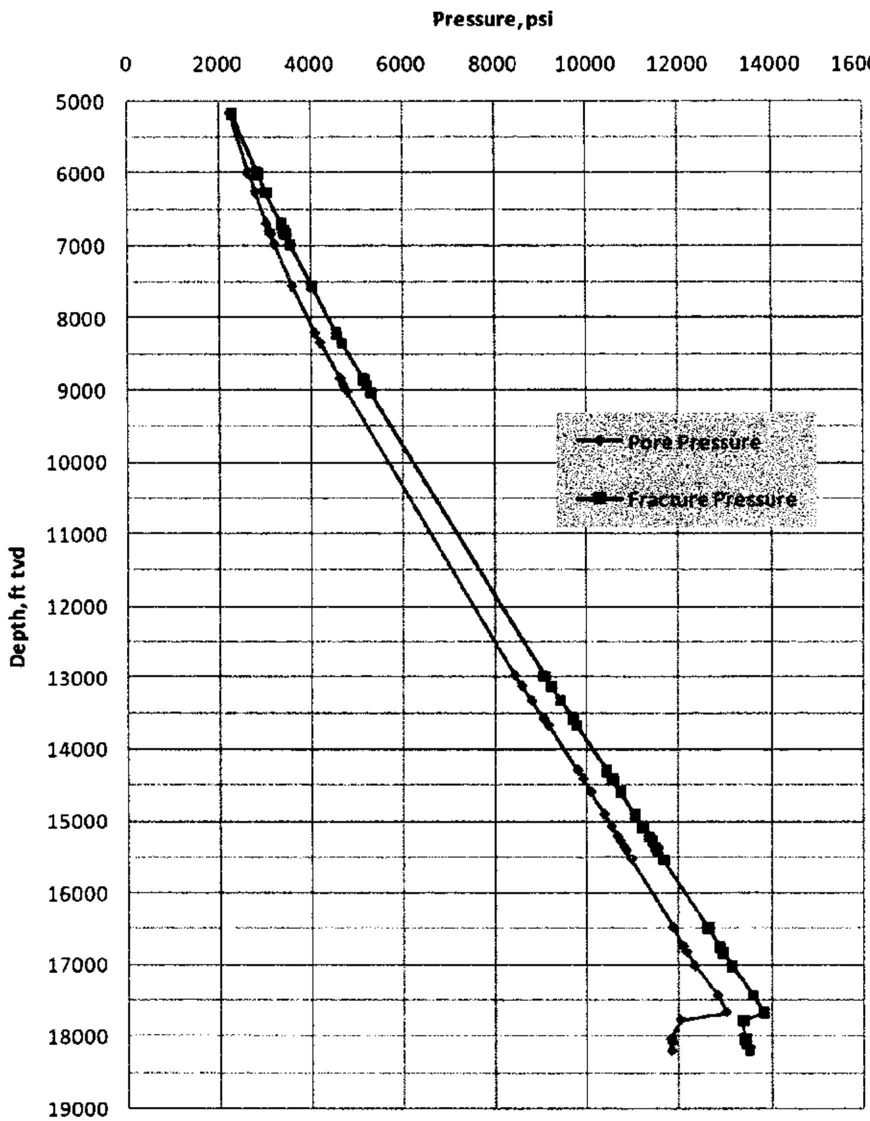


Figure 1.5: Pore and fracture pressure profile

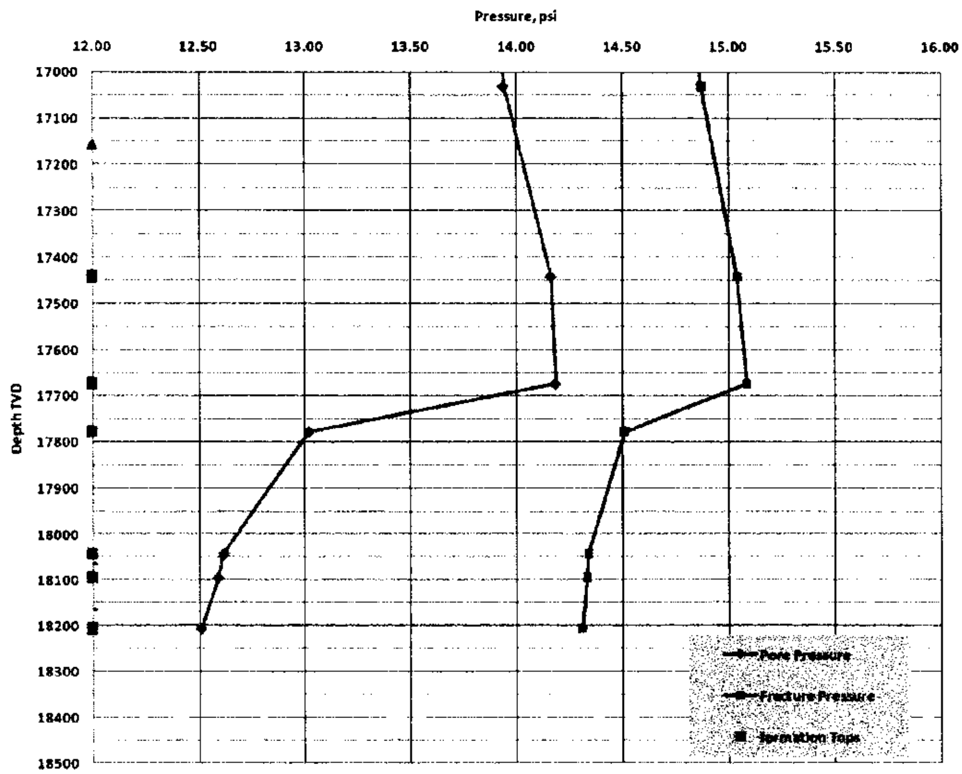


Figure 1.6: Pore and fracture pressure, EMW

1.9 Temperature profile

The temperature profile is shown in Figure 1.7.

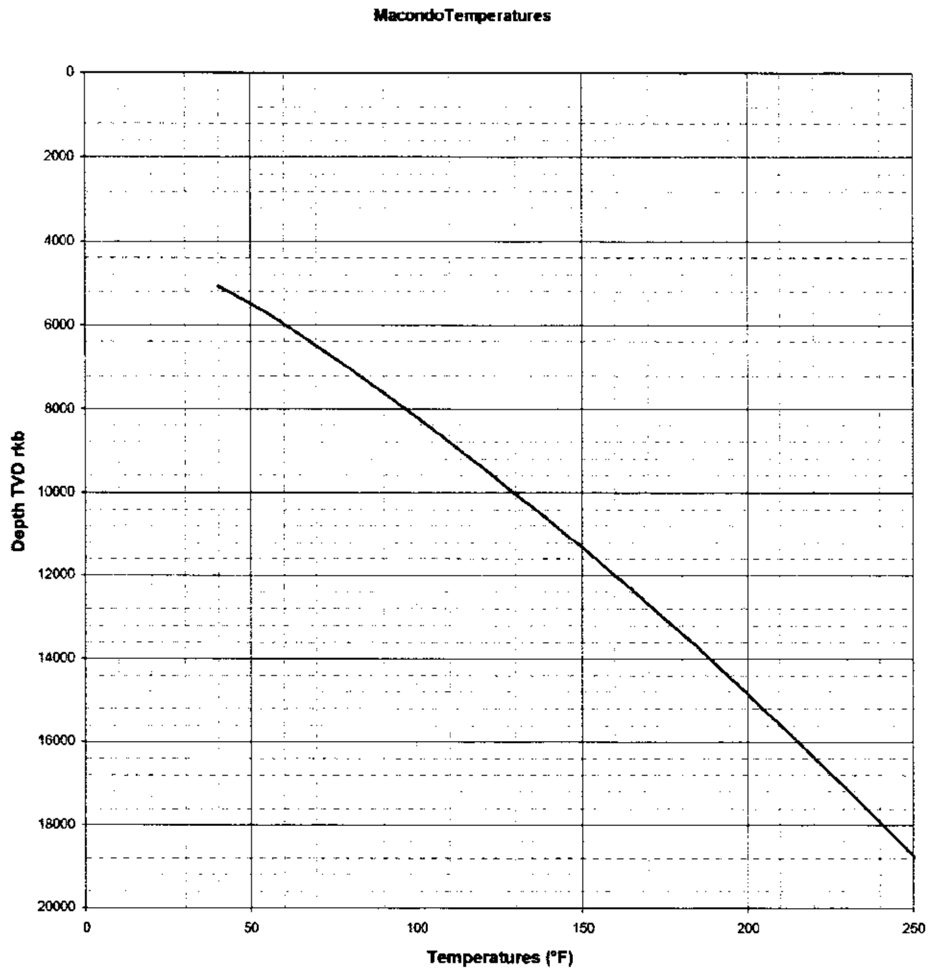


Figure 1.7: Temperature profile

1.10 Well configuration and casing design

The pipe dimensions are listed in the following tables. The total volume inside the casing up to seabed is 746 bbl. The volume in the outer annulus 1180 bbl. The volume in the annulus between the riser and the drillpipe is 1640 bbl. The volume inside the drillpipe is 207 bbl. Figure 1.8 shows a schematic of the well with depths at scale while Figure 1.9 shows the wellbore capacities.

Table 1.5: Outer casing strings

	Weight lb/ft	OD in	ID in	Top ft	Bottom ft	Length ft	Capacity bbl/ft
Choke/Kill		3.0625	1.5	0	5067	5067	0.002186
Riser		21	19.5	0	5001	5001	0.369390
BOP			18.75	5001	5054	53	0.341522
Wellhead			18.5	5054	5057	3	0.332475
22" Casing		22	18.375	5057	5227	170	0.327998
16 " Casing	97	16	14.85	5227	11153	5926	0.214224
13 ⅜" Liner	88.2	13.375	12.375	11153	12803	1650	0.148767
11 ⅞" Liner	71.8	11.875	10.711	12803	14759	1956	0.111449
9 ⅞" Liner	62.8	9.875	8.625	14759	17157	2398	0.072266
Open Hole			9.875	17157	18130	973	0.094731
Rat Hole			8.5	18130	18360	230	0.070187

Table 1.6: Inner casing strings (cemented)

	Weight lb/ft	OD in	ID in	Top ft	Bottom ft	Length ft	Capacity bbl/ft
7" x 9 ⅞" Tapered Csg	62.8	9.875	8.625	5067	12484	7417	0.072266
7" x 9 ⅞" Tapered Csg	32	7	6.094	12484	18303	5819	0.036076

Table 1.7: Drillpipe dimensions

	Weight lb/ft	OD in	ID in	Top ft	Bottom ft	Length ft	Capacity bbl/ft
6 ⅝" DP	32	6.625	5.426	0	4177	4177	0.028601
5 ½" DP	21.9	5.5	4.78	4177	7567	3390	0.022196
3 ½" DP	9.3	3.5	2.992	7567	8367	800	0.008696

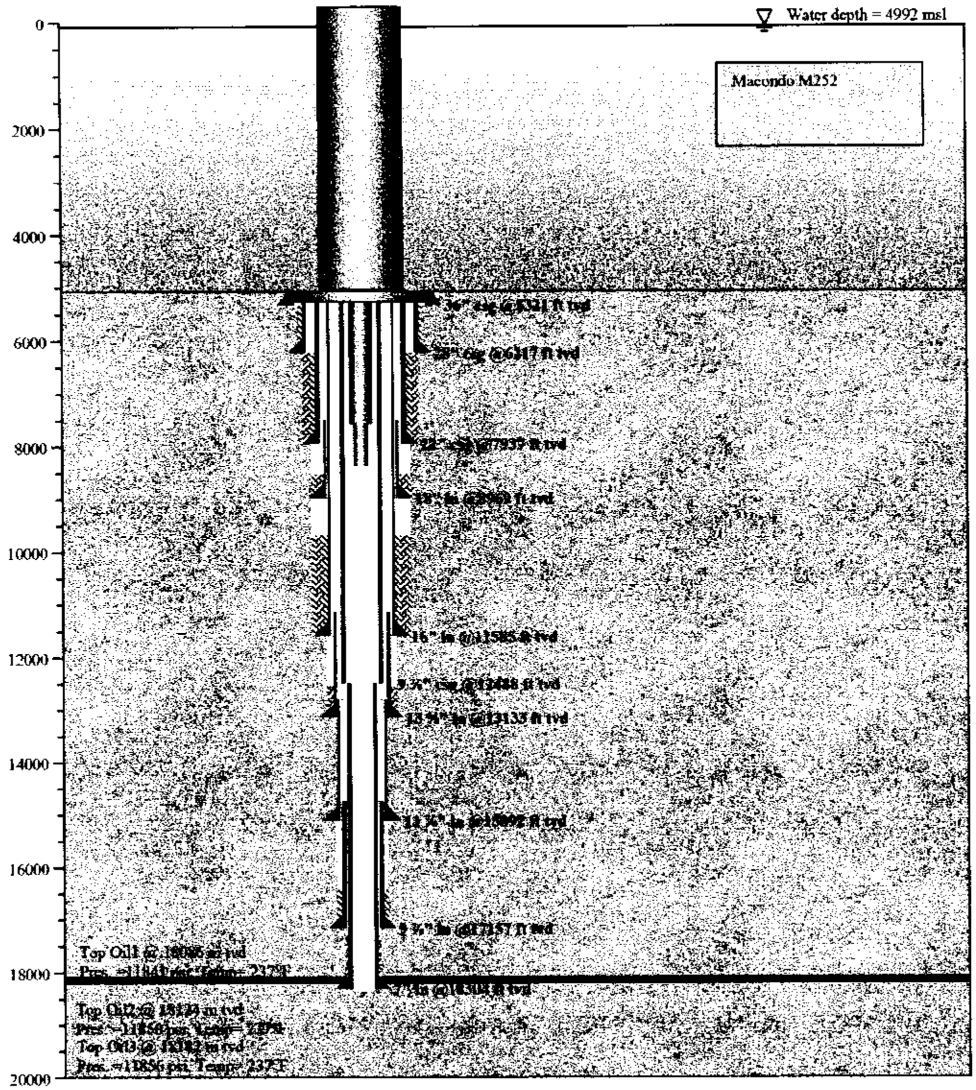


Figure 1.8: Well schematic, tvd to scale

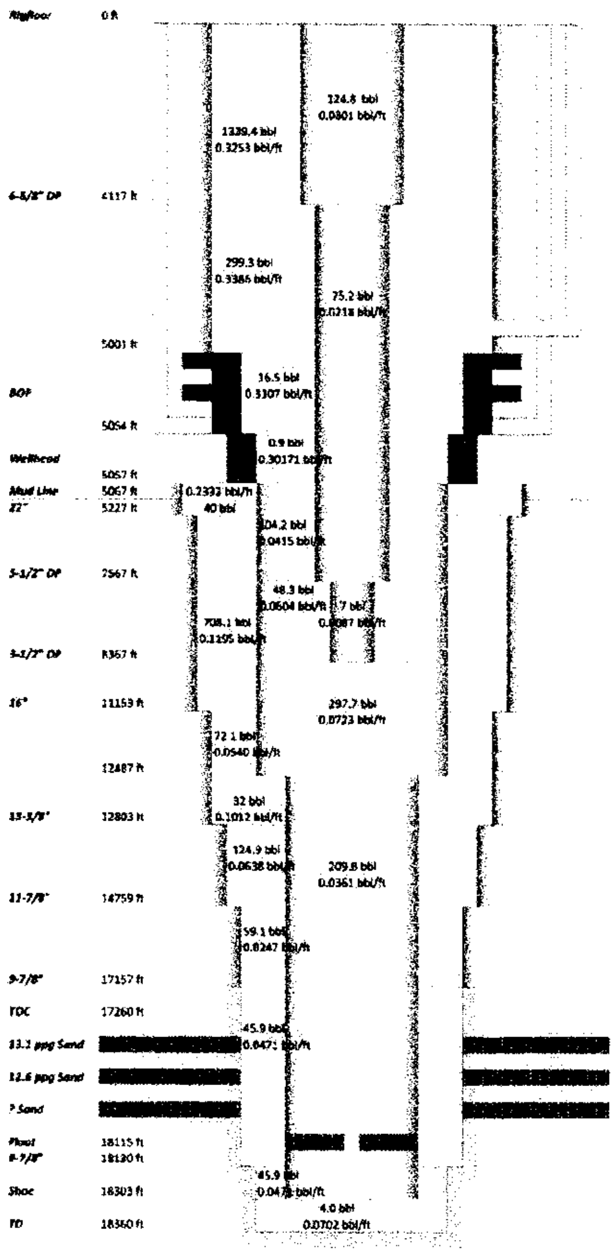


Figure 1.9: Well schematic with capacities

2. Events leading up the well control incident

The well was drilled to TD at 18350 ft tvd and the 7 x 9 ⅞" production casing was run and cemented. It took nine attempts to convert the float equipment before it opened and the cementing could start. 14 ppg mud was in the wellbore.

After cementing, the 9 ⅞" seal assembly was set and tested to 6500 psi followed by a casing test to 2500 psi. It took 6.7 bbls to pressurize the casing from 0 to 2500 psi.

A tapered drillpipe (6 ⅝" – 5 ½" – 3 ½") was run to 8367 ft before the negative test. The boost, choke and kill lines were displaced to seawater. A batch of 454 bbl of 16 ppg Form-a-set spacer was pumped followed by 352 bbl of seawater. The plan was to pump the spacer above the annular but incorrect volume was pumped and hence, the spacer was left across the BOP. The pressure on the drillpipe was 2400 psi after the water was pumped. The annular preventer was then closed.

The pressure was bled down from 2400 psi to 1200 psi through the drillpipe and high bleed back volumes were observed. The bleed down was continued, but the pressure did not decrease below 250 psi, and the well was subsequently shut in. Witness statements vary with respect to bleed back volumes. The pressure increased to 1250 psi during a period of 7 minutes. According to witness statements, the riser was filled up with 50 – 60 bbl.

Another attempt to bleed down was performed, and the pressure dropped to zero. Additional volumes were recovered from the well, but it is unknown how much.

The pressure gradually increased to 1400 psi over a 30 minutes period before it stabilized. At 20:02, the pumps were started to displace the spacer with seawater. The pumps were shut down for a sheen test at 21:08 and the test indicated that the fluids could be dumped overboard. The pressure then builds on the drillpipe and it is suspected that the annular preventer is closed and that the flow is routed on diverters through the gas buster. The mud was raining down from derrick, most likely due to an overfilled gas buster and vent line. The back pressure was building up. The flow was observed coming from the vent line up the derrick – estimated 4 minutes before the explosion. Approximately 21:48, the first explosion occurred and lights went almost simultaneously. Approximately one minute later, the second explosion occurred.

The following plots show the stand pipe pressure recorded from 16:00 till the explosions occurred.

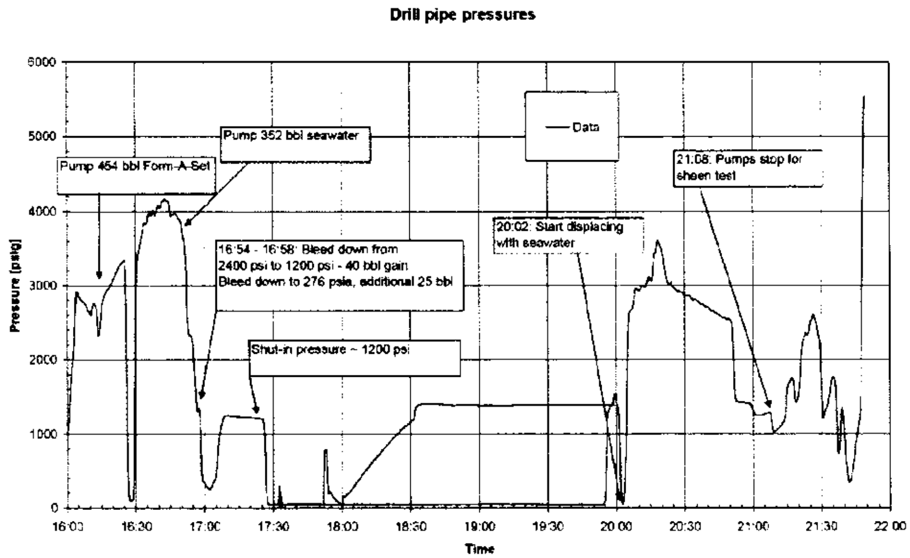


Figure 2.1: Recorded drillpipe pressures from 16:00 to 21:49

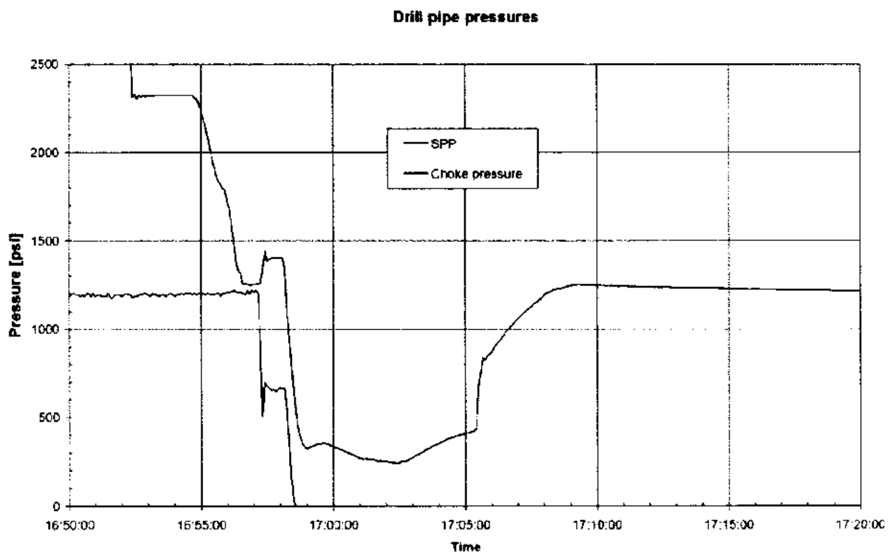


Figure 2.2: Drillpipe pressures from 16:50 to 17:20

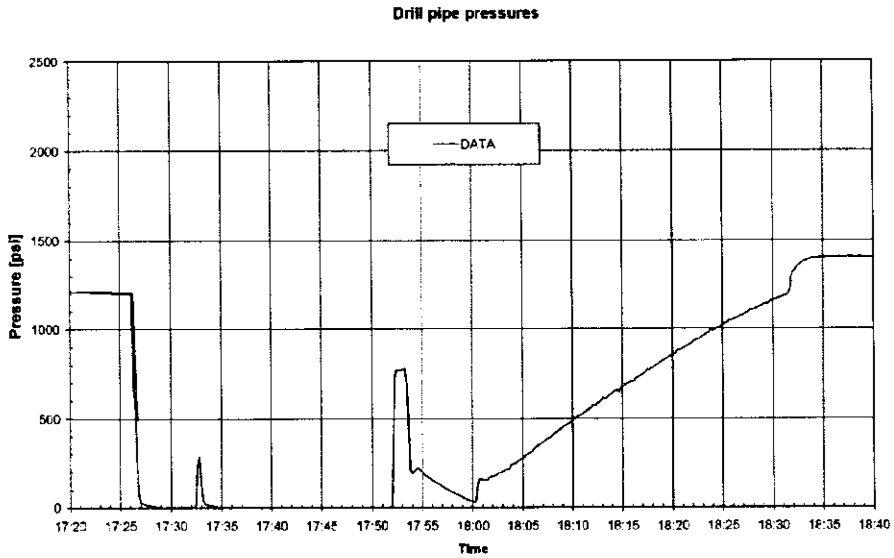


Figure 2.3: Drillpipe pressures from 17:20 to 18:40

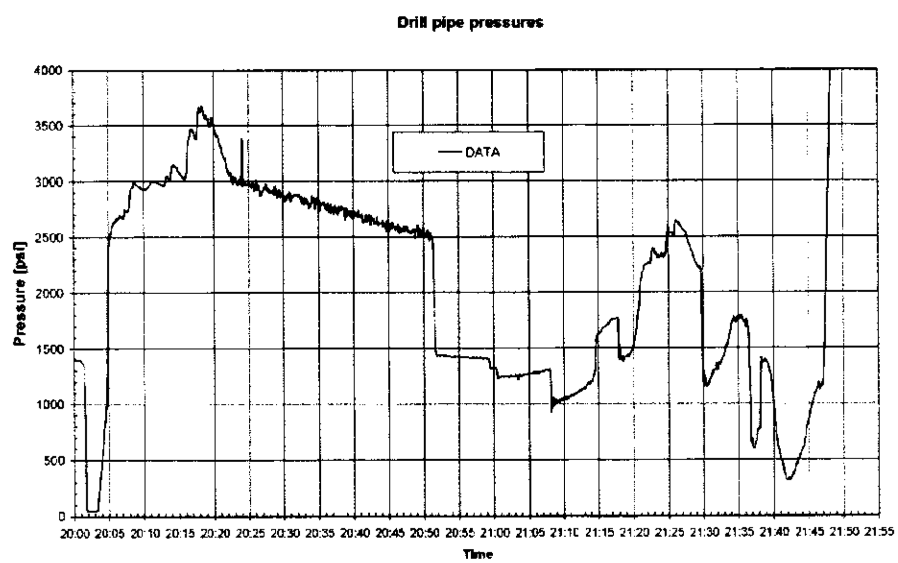


Figure 2.4: Drillpipe pressures from 20:00 to 21:49

3. Results

3.1 Oil density with pressure and temperature

The reservoir fluid is an under-saturated oil with a bubble point at 6500 psi at reservoir temperature. The density of the oil phase will decrease with decreasing pressure (see Figure 3.1) and increase with decreasing temperature (see Figure 3.2). These two effects will almost balance each other when an oil kick is taken and slowly migrates towards surface through the mud. The resulting volume expansion is almost zero, see Figure 3.3.

This density behavior will challenge kick detection after a kick is taken as pit gains will be limited before the kick is right below the BOP. The crew will have less time to react, and once a well control problem is confirmed, a late detection can mean that gas is already inside the riser before the BOP is closed. This behavior is different from a gas kick, but still not uncommon for deepwater drilling operations. Awareness and knowledge of these mechanisms are important.

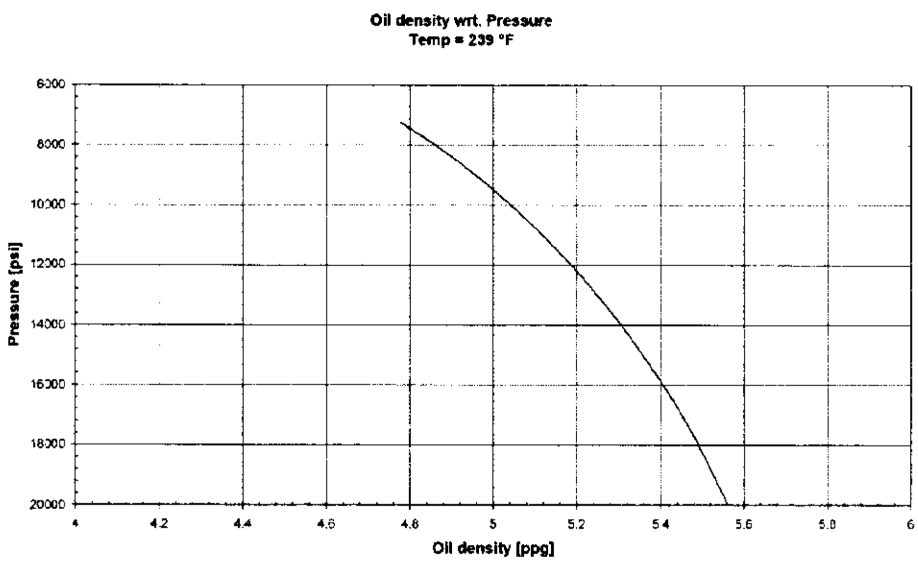


Figure 3.1: Oil density versus pressure, temperature = 239 °F

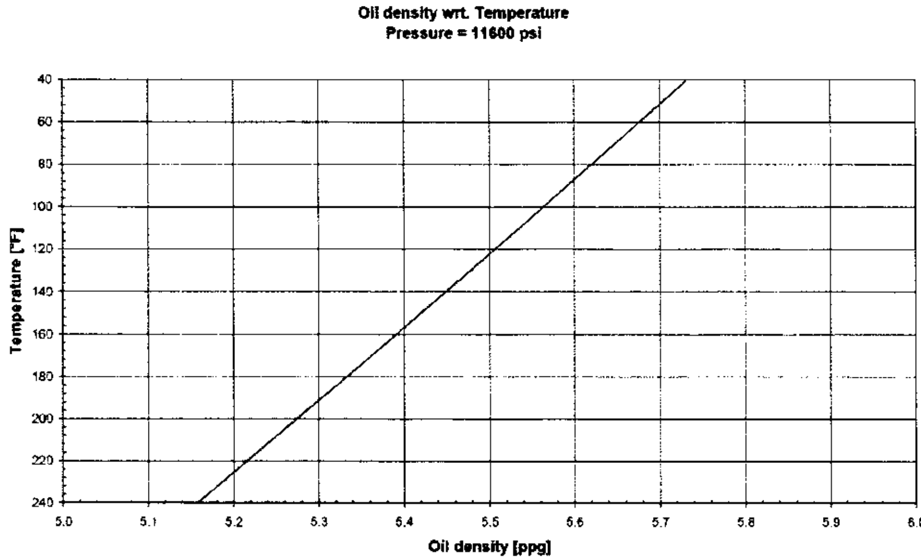


Figure 3.2: Oil density versus temperature, pressure = 11 600 psia

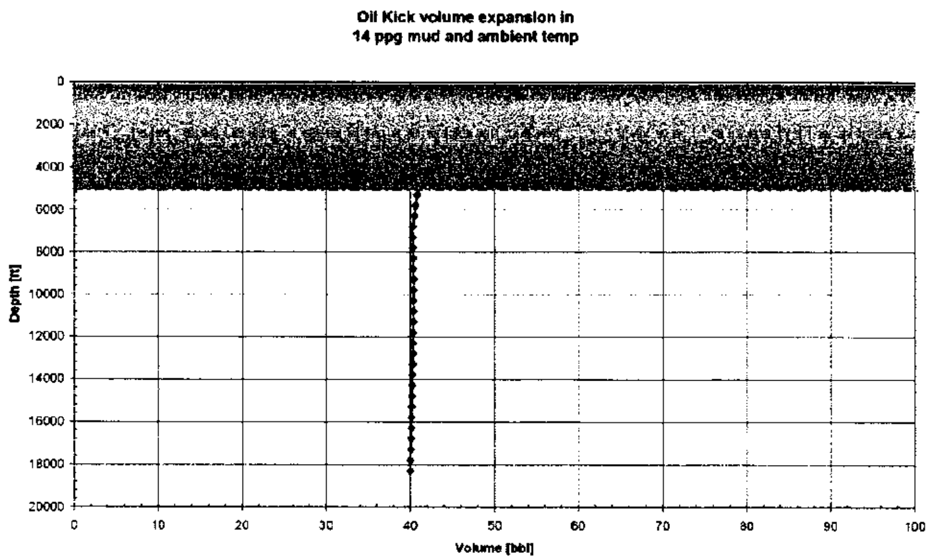


Figure 3.3: Volume expansion for a 40 bbl oil kick migrating to surface through 14 ppg mud.

3.2 Inflow performance

The 12.6 ppg pressured oil sands have an estimated average permeability of 300 mD over 86 ft of net pay. This will together with the fluid properties result in a productivity index of 49 stb/d/psi from reservoir pressure down to the bubble point pressure at 6500 psi. For pressures below the bubble point, gas will flash out of solution, and turbulent skin effects will limit the flow potential. Figure 3.4 shows the resulting IPR based on 4 ft reservoir exposure and 86 ft reservoir exposure. As can be seen, the reservoir is very prolific.

Due to the high oil formation volume factor (shrinkage factor) of 2.14 Rbbl/Stb, the volumetric inflow rate at reservoir conditions is more than twice as high as those reported at standard conditions. Figure 3.5 shows the inflow performance at reservoir conditions (in-situ conditions).

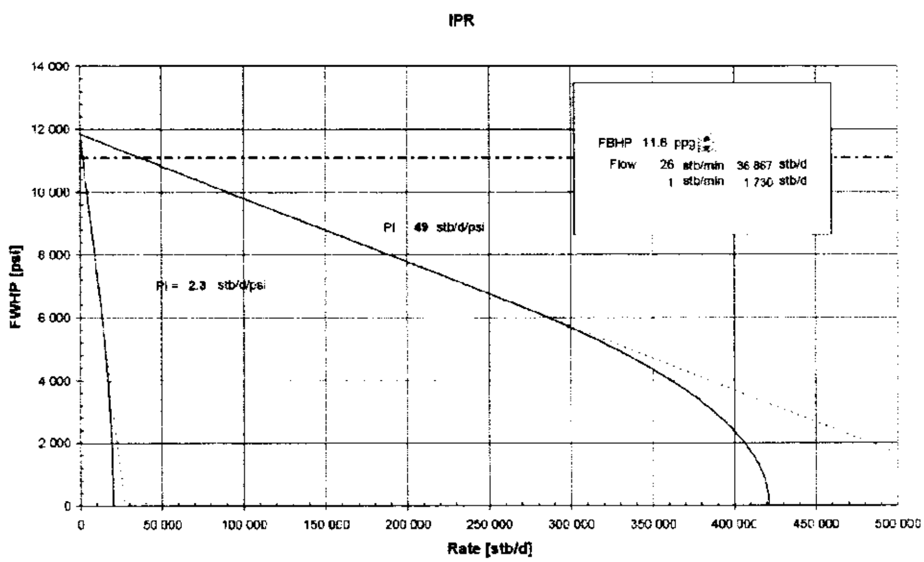


Figure 3.4: Inflow performance curves based on 4 ft and 86 ft of 300 mD sand

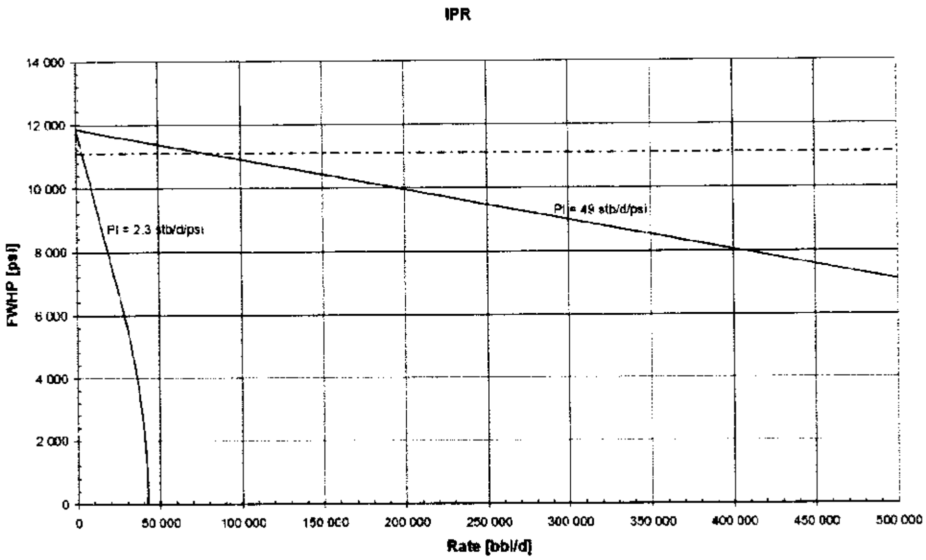


Figure 3.5: In-situ IPR curves based on 4 ft and 86 ft of 300 mD sand

3.3 Compressibility of the 14 ppg mud

Two observations are made with respect to the compressibility of the 14 ppg mud. The first was during the attempts to convert the float on April 19th between 14:30 and 17:30. It took nine attempts before the float was opened, and pressures and volumes were recorded, see Table 3.1.

Table 3.1: Float conversion attempts

Attempt No	Total volume [bbl]	From [psi]	To [psi]	Volume [bbl]	Comp. [1/psi]
#4	886	0	2000	6.7	3.78E-06
#5	886	0	2000	6.6	3.72E-06
#7	886	0	2250	7.3	3.66E-06
#8	886	0	2500	7.8	3.52E-06
Average					**3.67E-06**

In addition to these attempts, a casing pressure test was performed April 20th between 11:06 and 11:17.

Table 3.2: Casing pressure test

Test	Total volume [bbl]	From [psi]	To [psi]	Volume [bbl]	Comp. [1/psi]
Casing	758	234	2617	6.1	3.13E-06

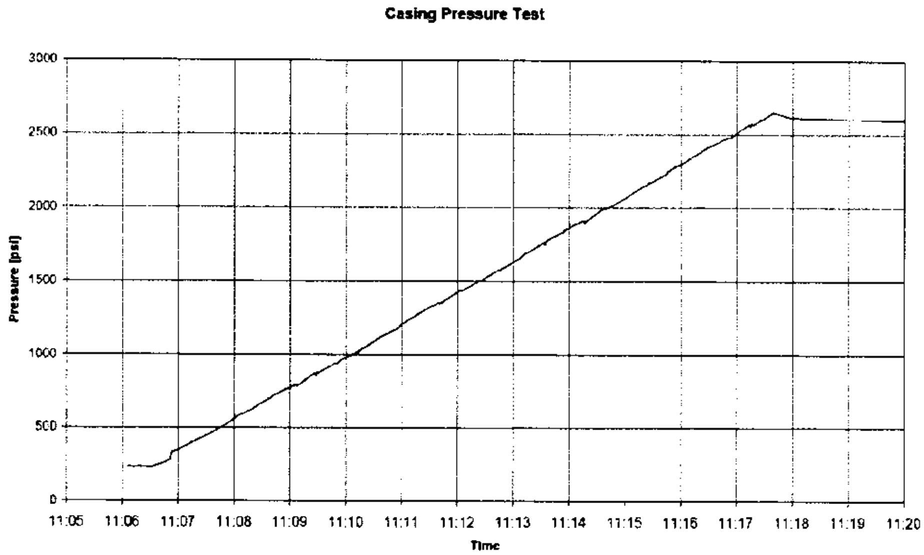


Figure 3.6: Casing pressure test from 234 psi to 2617 psi (6.0 bbl)

The compressibility is a measure of how much volume is required to pressurize a certain volume of the fluid a certain amount of psi.

$$k = \frac{\partial V}{V \cdot \partial P}$$

The outer annulus measures approximately 1100 bbl, and by using the average number from the float conversion attempts (3.67E-06), approximately 10 bbl will be expected to be bled back from this volume when decreasing the pressure form 2400 to 250 psi.

The reported gains during this bleed down were higher than what could be expected due to the compressibility of the mud.

3.4 Blowout potentials

The blowout potential for different scenarios are listed in Table 3.3, all based on comingled flow from the 12.6 ppg oil reservoirs with an average permeability of 300 mD over the 86 feet pay zone. It is assumed that the flow is exiting through both the riser and through the drillpipe without any restrictions.

The highest flow potential is through the casing. The outer annulus has some narrow sections (between the 9 ⅞" casing and the 7" casing) and the will thus create more frictional forces and higher pressure drop.

Table 3.4 and Table 3.5 show the flow distribution between the drillpipe and the annulus for the casing scenario. In addition, the total flow potential based on a blocked drillpipe and flow in annulus only, is included.

Simulations were also performed for the blowouts to seabed with restrictions in the BOP. By including a restriction resulting in a flowing wellhead pressure of 3800 psi, the flow potential decrease by approximately 10 %. From 61 000 stb/d to 54 000 stb/d inside the casing using 86 ft pay zone and assuming flow through the casing shoe. By using a wellhead pressure of 3000 psi, the flow rate reduces to 58 000 stb/d. See Figure 3.9.

Table 3.3: Blowout potential versus flow path, net pay and exit point

Flow path	**Outer annulus [stb/d]**		**Casing [stb/d]**	
Exit point	**Surface**	**Seabed**	**Surface**	**Seabed**
4 ft net pay	17 500	14 000	18 000	15 000
86 ft net pay	47 000	43 000	68 000	67 000

Table 3.4: Distribution of flow for casing scenario to surface

Flow path	**Casing [stb/d]**				
Exit point	**In drillpipe**	**In annulus**	**Total**	**Only Ann.**	**Only DP**
4 ft net pay	4 500	13 500	18 000	18 000	15 000
86 ft net pay	21 000	47 000	68 000	61 000	36 000

Table 3.5: Distribution of flow for casing scenario to seabed

Flow path	**Casing [stb/d]**				
Exit point	**In drillpipe**	**In annulus**	**Total**	**Only Ann.**	**Only DP**
4 ft net pay	3 800	11 200	15 000	15 000	13 500
86 ft net pay	19 500	47 500	67 000	61 000	40 000

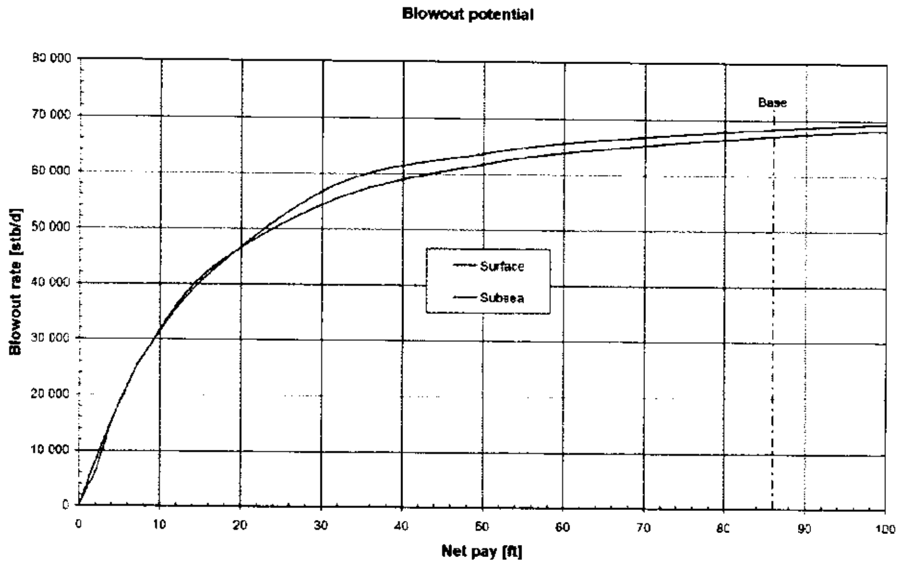


Figure 3.7: Blowout potential with flow from shoe through drillpipe and annulus

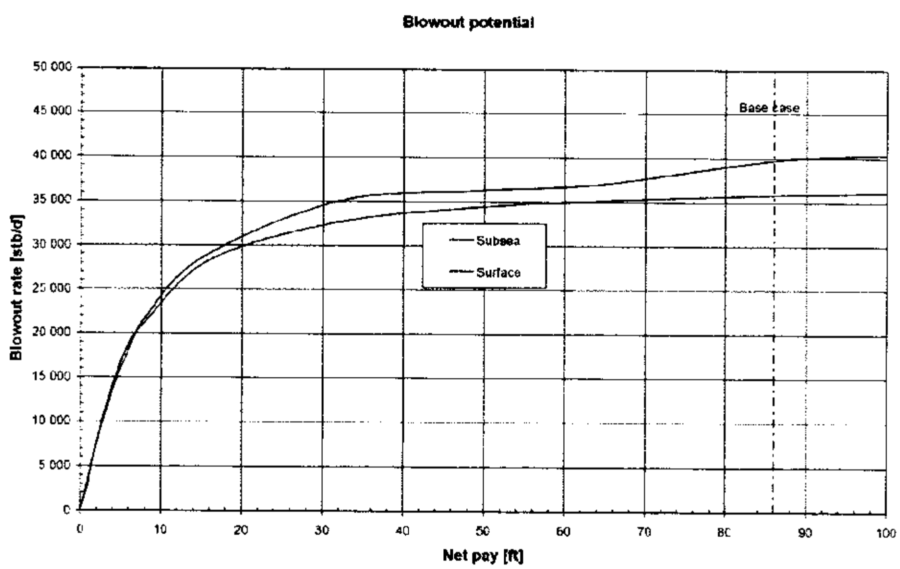


Figure 3.8: Blowout potential with flow from shoe through drillpipe only

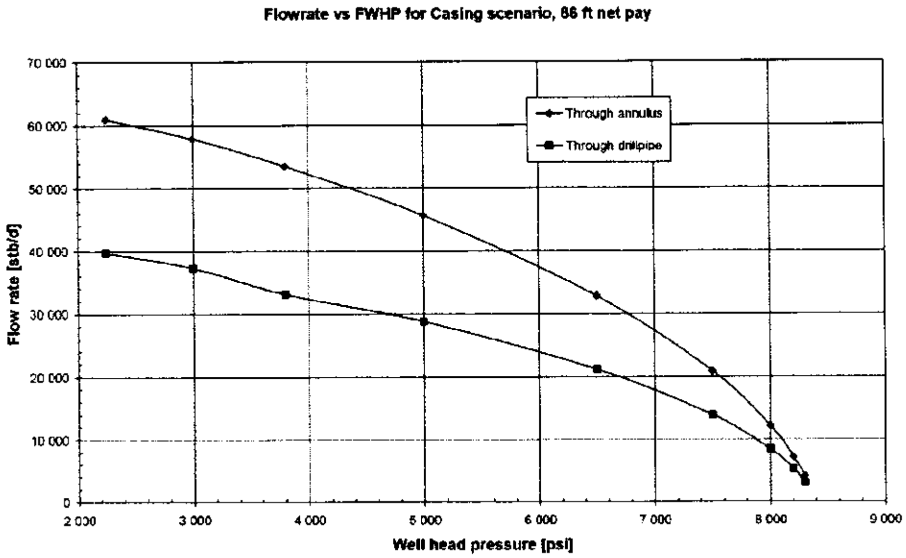


Figure 3.9: Blowout potential through casing shoe versus FWHP

3.5 Shut-in pressures with hydrocarbons in the wellbore

The calculated settle out shut-in pressures are 6800 psi when a hydrocarbon filled well is shut-in at surface and 8250 psi when shut-in at the BOP.

Depending on the flowrate and temperature profile in the well prior to the shut-in, the simulations indicate that the peak pressures can be slightly higher than the reported settle out pressures. Examples of a subsea shut-in are shown in Figure 3.10. For a potential shut-in at surface (IBOP) the pressure buildups will be slower due to more gas in the wellbore.

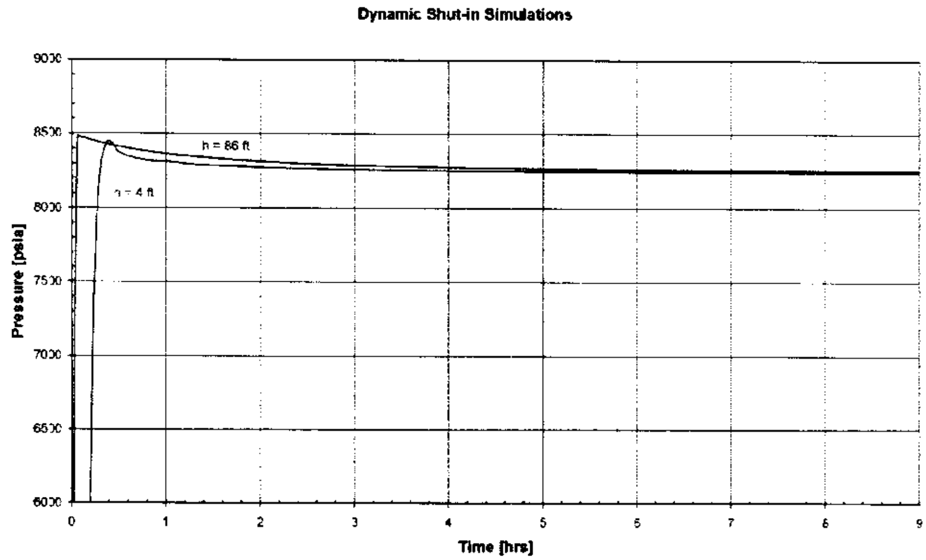


Figure 3.10: Examples of dynamic shut-in pressures, shut-in at seabed

3.6 Initial simulation with flow through casing and full reservoir exposure

The initial simulations were based on the initial observations of an 85 bbl gain and full reservoir exposure. These simulations revealed that the general trends are in line with the observations. The unloading of the wellbore is occurring quite fast, and simulations how that this can take less than one hour. However, there are a couple of discrepancies. First, the shut-in pressures do not match with the data log. According to the simulations, the shut-in pressure at 17:20 is 200 psi lower than the reported.

The second discrepancy is when the oil and gas are surfacing. Based on the full reservoir exposure, the trends show a fair match until about 21:00. At this point in time the simulations predict that hydrocarbons will reach surface at approximately 21:15 and this is too early compared to the observations.

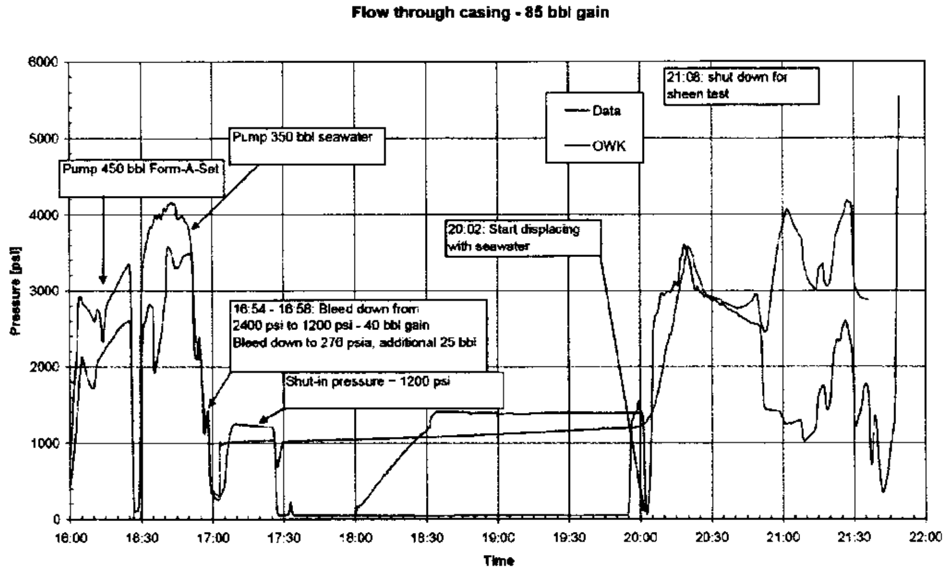


Figure 3.11: Simulated versus logged pressure for casing scenario, initial run

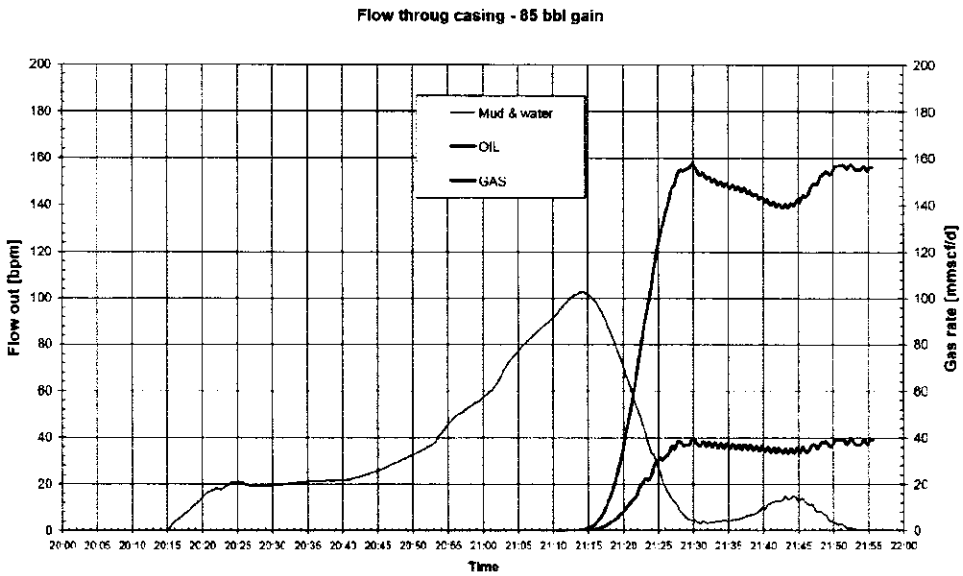


Figure 3.12: Simulated flow rates at surface for casing scenario, initial run

3.7 Initial simulation with flow through outer annulus

The same initial simulation was performed assuming that the flow path is in the outer annulus. Again, 85 bbl gain was used together with 86 feet of pay sand and 12.6 ppg reservoir pressure. For this scenario, the calculated shut-in pressures are higher than the observations. At the very end of the unloading sequence, this scenario shows a better match with the observations compared to the casing scenario. As the outer annulus will be exposed to higher pressures during the circulation job than the casing, the unloading is slower.

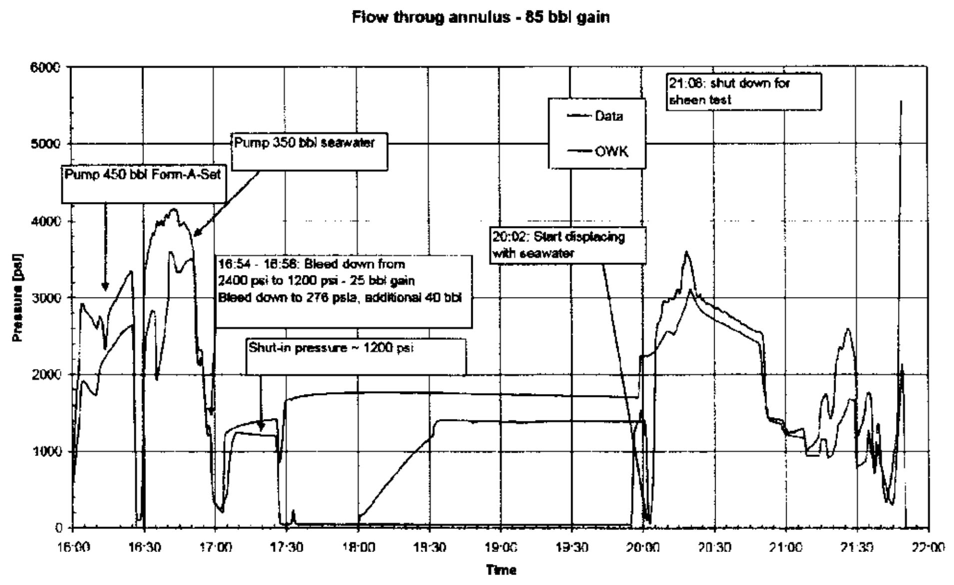


Figure 3.13: Simulated versus logged pressure for outer annulus scenario, initial run

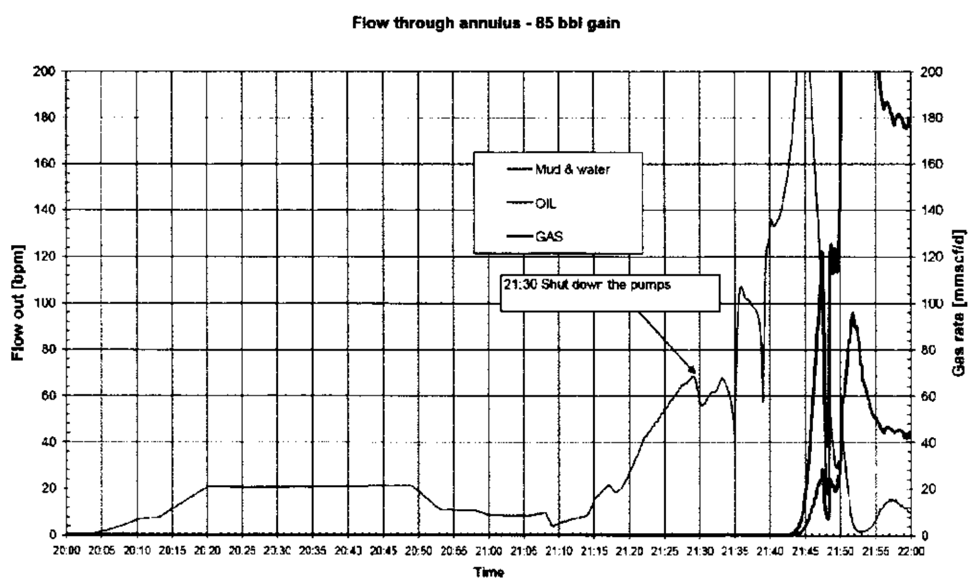


Figure 3.14: Rates at surface for outer annulus scenario, initial run

3.8 Shut-in pressure considerations

Two shut-in conditions exist and these can be used to estimate the downhole conditions and size of a potential kick by static considerations. However, due to uncertainties with respect to several fluids, mixing zones etc. these calculations have to be based on assumptions. Between 17:10 and 17:25, the pressure reads 1200 psi. From 18:34 to 19:57, the pressure reads 1400 psi.

The initial interpretations of the bleed-downs through the drillpipe suggested an 85 bbl gain caused by an influx from the reservoir. This would force mud or water up in the drillpipe and volume calculations can determine the mud water/level in the drillpipe.

Based on the 12.6 ppg pore pressure, there is a significant difference between the kick volume required to create these shut-in pressures. It will take 190 bbl inside the casing to end up with 1200 psi shut-in drillpipe pressure whilst it will only take 25 bbl in the outer annulus. This is observed from the initial simulation runs where the inside casing scenario ended up with a shut-in pressure of 1000 psi based on a 85 bbl kick see Figure 3.11.

For the outer annulus scenario, simulations showed a shut-in pressure of 1400 psi based on an 85 bbl kick, compared to the recorded 1200 psi, see Figure 3.13. Unknown conditions down hole also challenges these calculations as the capacity in around the inflow zones depend on the quality and quantity of cement.

The difference in shut-in pressures for the two flow path scenarios is caused by the different fluids present in the two paths. For the casing scenario, there is initially water in the drillpipe to 8367 ft, and 14 ppg mud from this point to TD. For the outer annulus, there is 14 ppg mud from the bottom and up to the seal assembly at mudline, 16 ppg spacer and water in the annulus, and water in the drillpipe, see Figure 3.15.

If it is assumed that no influx was taken during the negative test, the resulting drillpipe shut-in pressure should be 1030 psi based on a 12.6 ppg sand. To reach 1400 psi, the pore pressure should be 13 ppg, see Figure 3.17.

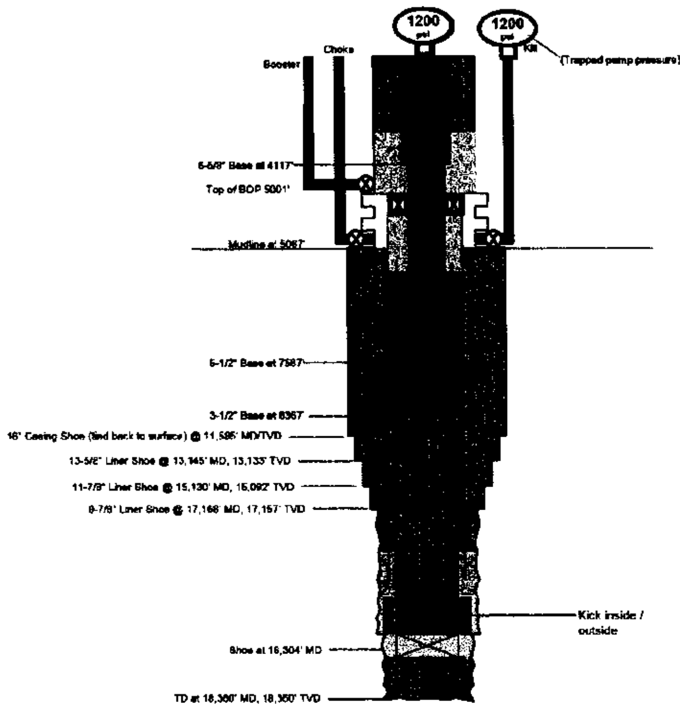


Figure 3.15: Kick and shut-in pressures

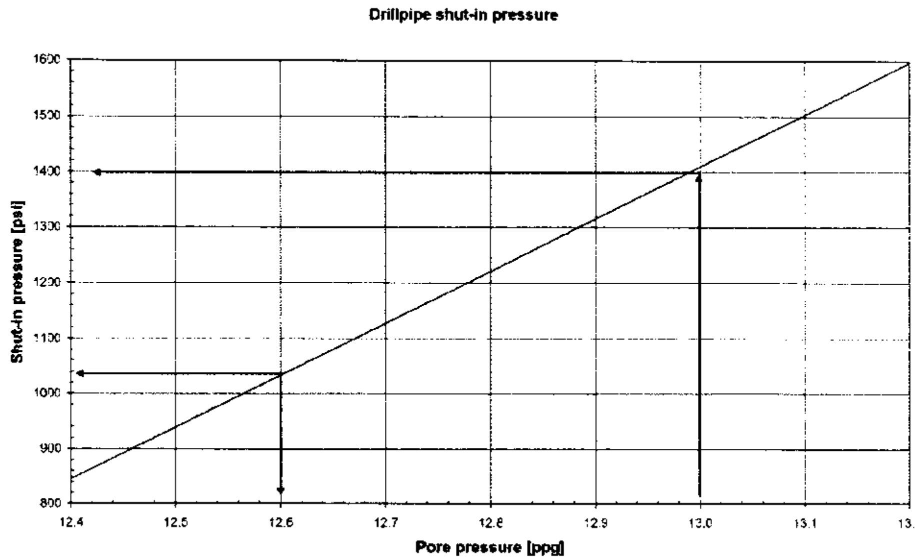


Figure 3.16: Shut-in pressures with no hydrocarbons and water in drillpipe

3.9 Flow inside casing based on 13 ppg sand and 4 ft net exposure

The shut-in pressure based on a 12.6 ppg pressurized sand was too low based on the reported 85 bbl gain, and a new simulation was performed assuming that a 13 ppg sand was exposed to the wellbore. This sand has however only 4 ft of net pay and the oil and gas rates will therefore be lower and it is expected that the hydrocarbons will surface later than what was simulated using the 86 ft of the 12.6 ppg scenario.

For this simulation, the estimated gain based on the simulations was approximately 60 bbl. The calculated shut-in pressure after the 2400 – 250 psi bleed down was above the observed pressure of 1200 psi, but showed a good match with the 1400 psi shut-in pressure. The estimated unloading sequence was in relative good agreement with the observations.

Remark:
Mud is displaced up inside the drillpipe and influx is required to match the 1400 psi pressure compared to the simulations assuming leaking annular preventer.

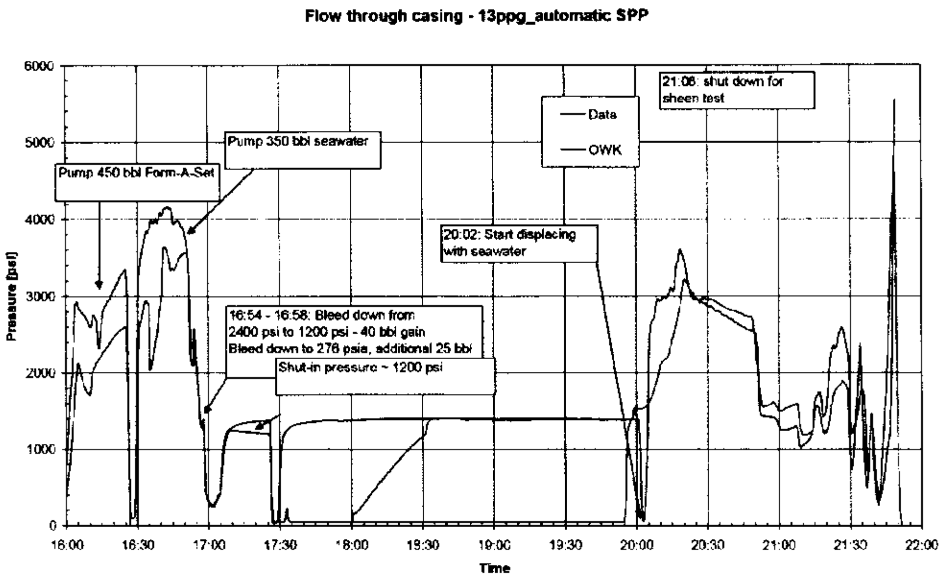


Figure 3.17: Stand pipe pressures casing scenario, 13 ppg pore pressure

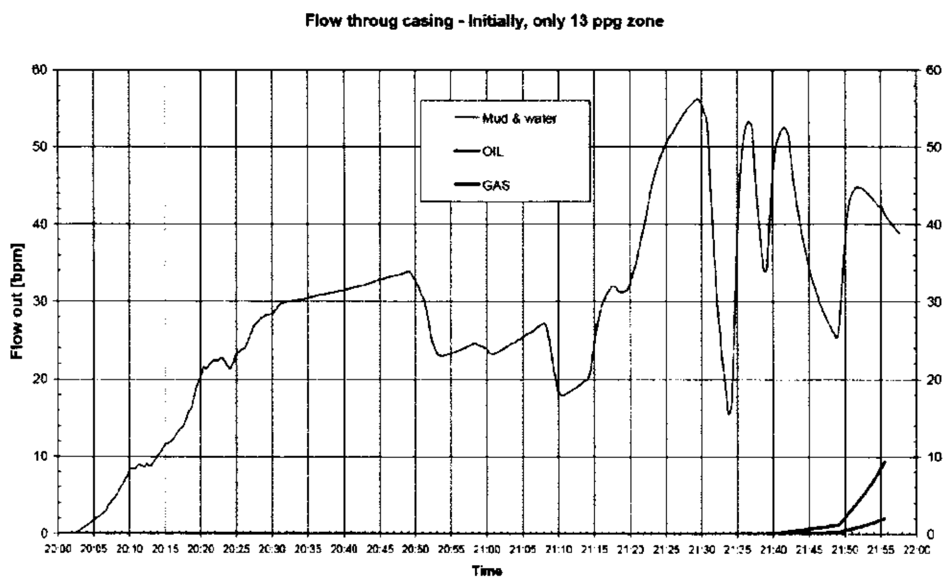


Figure 3.18: Rates at surface for casing scenario, 13 ppg pore pressure

3.10 Simulations based on a leaking annular and no influx before circulation

From witness statements, the gains reported initially was most likely caused by a leaking annular as it was reported that the riser was filled up with approximately 50 bbl between 17:12 and 17:22. If no influx was taken during this initial bleed down from 2400 psi to 250 psi, it must be assumed that the cement was holding the formation fluids back at this time, as the conditions down hole is underbalanced during this operation.

Simulations were based on no influx taken before the circulation job starting at 20:02. When the circulation is started, the pump pressure and the bottom hole pressure will increase. At 21:08, the pumps are stopped for a sheen test, and the stand pipe pressure is 1000 psi, but increasing. At this point in time, 1200 bbl of water has been pumped, and both the drillpipe and the annulus between drillpipe and 9 ⅞" casing up to the seabed is be filled with water. The pump rate has ranged between 500 and 1250 gpm and this is sufficient to obtain an effective transportation of the fluids in this annulus (between drillpipe and 9 ⅞"). This annulus is thus fully displaced to seawater at this point in time. Hence, the pressure at the formation in the outer annulus is 13.6 ppg, and no influx can be taken. Inside the casing, however, the pressure is lower, and influx can be taken.

Simulations were performed assuming that no influx was taken prior to this period, and the well was fully filled with water, spacer and mud before the circulation operation starting at 20:00. The flow path of potential hydrocarbons is inside the casing from the casing shoe.

The simulations show a fairly good match with the recorded stand pipe pressure during the circulation job, until the pumps are shut down at 21:30. From this point in time the simulations predicts a decreasing stand pipe pressure in contrast to the recordings showing several pressure peaks. The decrease in pressure is caused by lighter fluid in the annulus as mud and water is being replaced by hydrocarbons.

The following figures show plots of various variables, flow rates and pressures during the unloading sequence. The simulations are based on a constant influx of 300 mD and 15 m net pay. The casing is open to flow at surface.

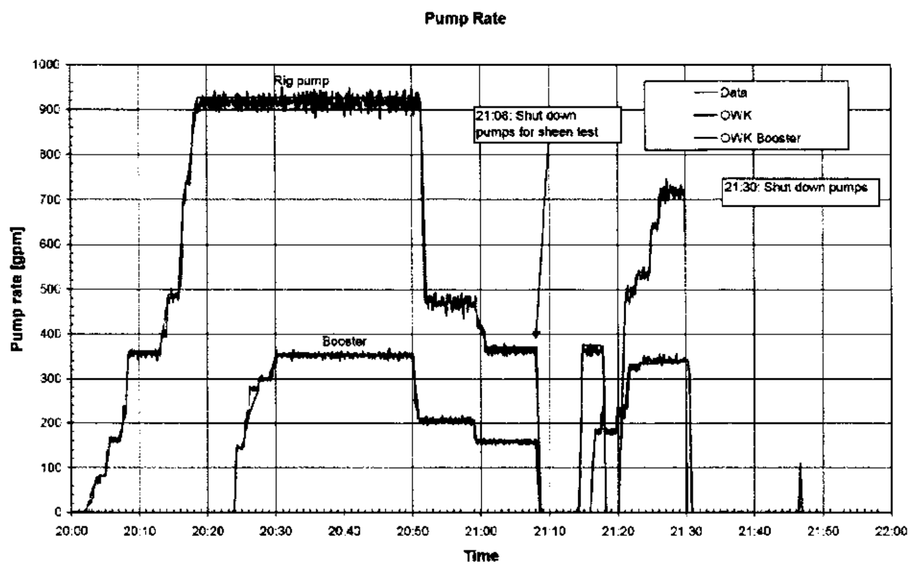


Figure 3.19: Pump schedule, 20:00 – 21:30, from data log and input to model

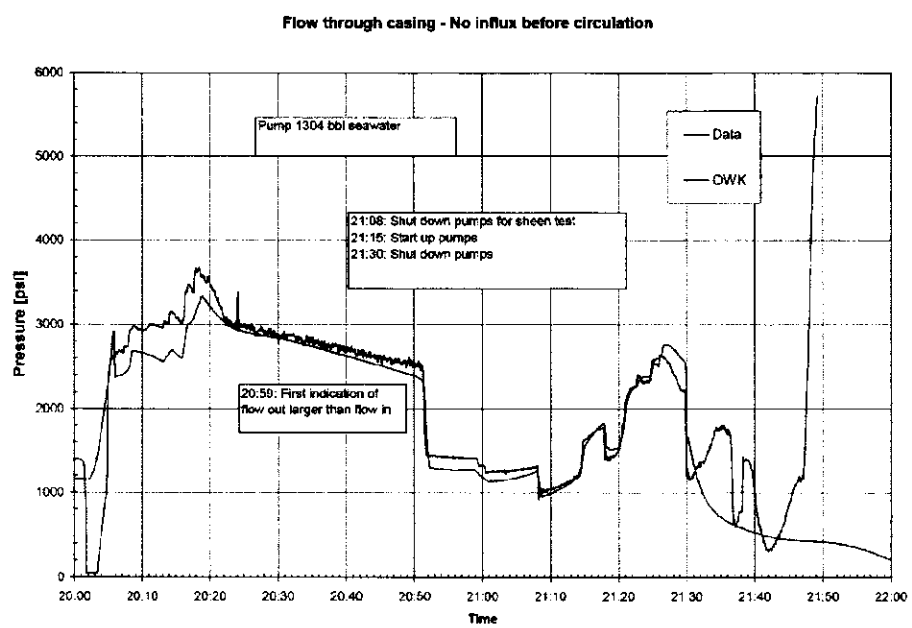


Figure 3.20: Stand pipe pressure, casing scenario, no pressure buildups

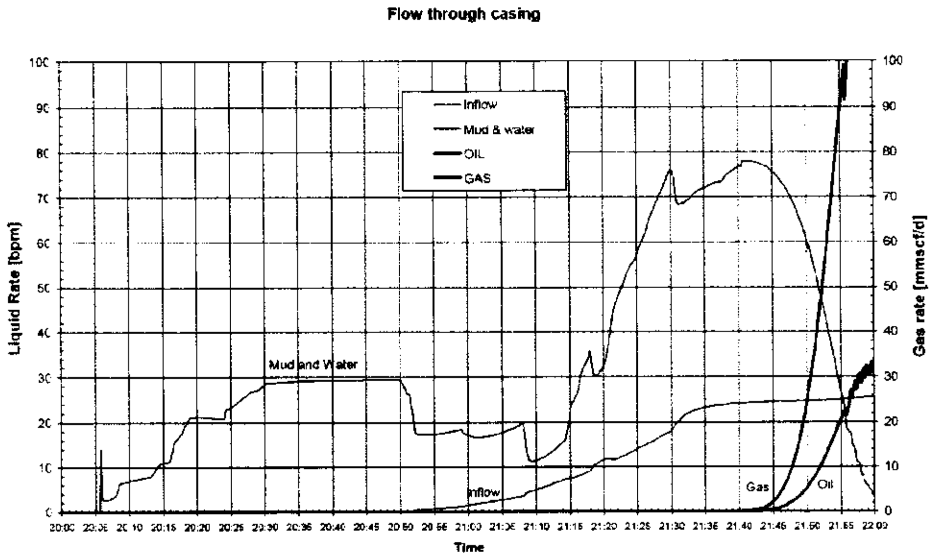


Figure 3.21:Flow rates, casing scenario

3.11 Pressure drop in surface lines

In order to investigate whether the surface piping can create enough backpressure on the system to blow the diverter, several simulations were performed for a 500 ft horizontal line. The liquid flow capacity is high for the larger dimensions (see Figure 3.22), but as soon as gas is flowing together with the liquid, high frictional pressure drop can be observed.

The vent line from the gas buster is 245 ft high, and this will create a hydrostatic head of 180 psi based on the 14 ppg mud. A burst disk is installed to protect the gas separator, and is supposed to pop open at 60 psi. The flow will then be routed through a 6" line overboard with the vent line still open.

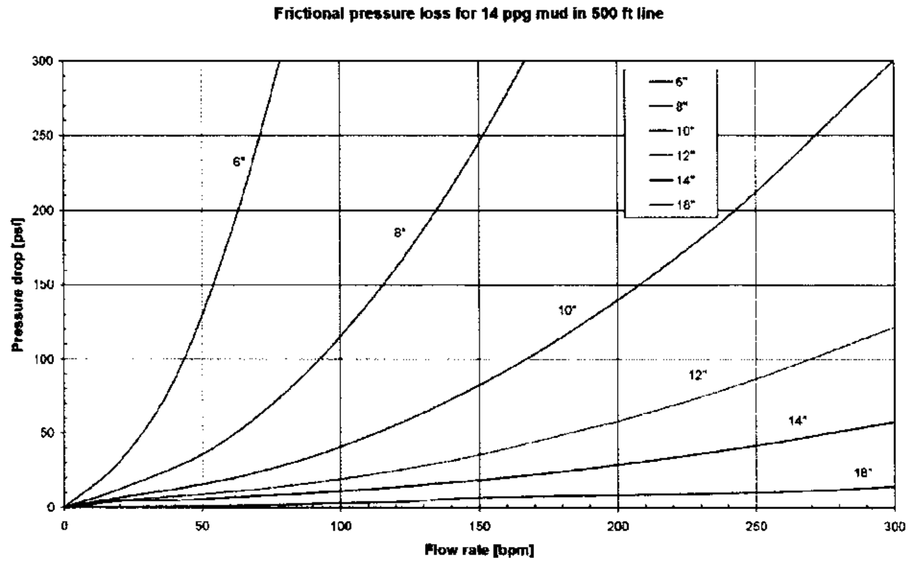


Figure 3.22: Frictional pressure loss in 500 ft pipe with 14 ppg mud

3.12 Pressure drop across leaking annular

Simulations were performed to investigate the pressure drop that would occur in a situation with mud flow through a leaking annular between the riser and the 5 ½" drillpipe. The total flow area of a fully open annular is 252 in², and Figure 3.24 shows the pressure drop versus opening for two fixed flow rates of 14 ppg mud. As can bee seen from the figure, only minor pressure drops occur before the annular preventer is more than in a 97 % closed position.

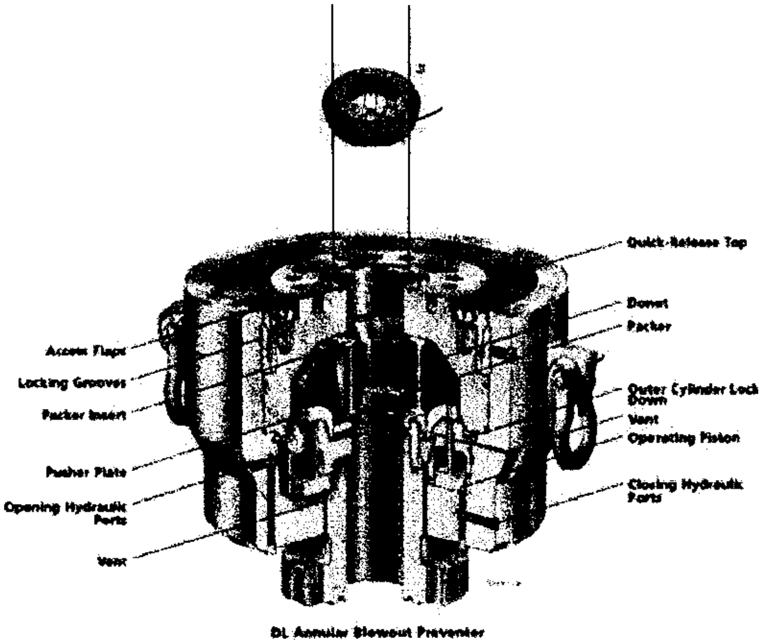


Figure 3.23: Annular preventer

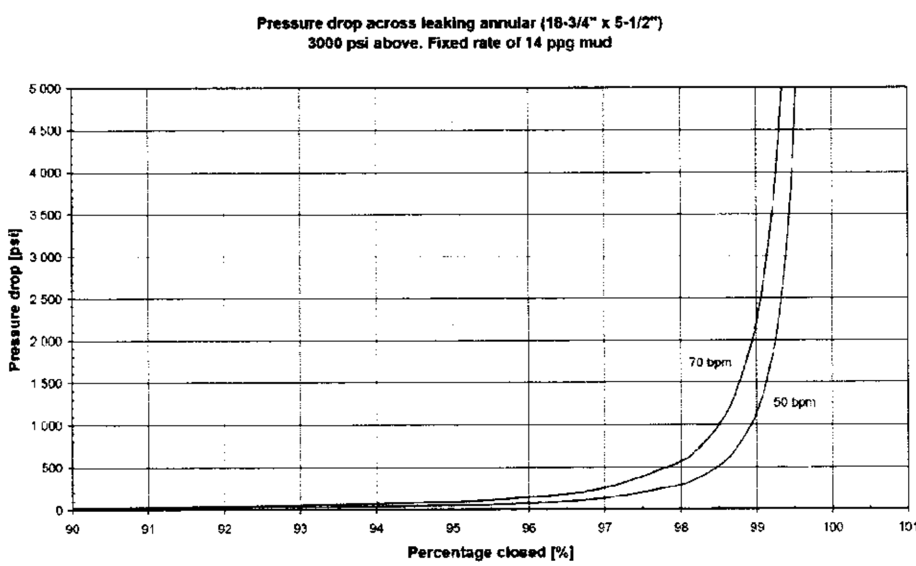


Figure 3.24: Pressure drop across leaking annular

3.13 Sensitivities with respect to potential events after 21:30

The actual pressure readings show fluctuations in pressure between 21:30 and 21:50. These fluctuations are believed to be caused by restrictions in the flow path (partly sealing annular preventers) and/or additional back pressure caused by surface piping and equipment. They cannot be explained by the transient effects such as inflow, changes in wellbore fluids, flashing, flow regime, swapping etc.

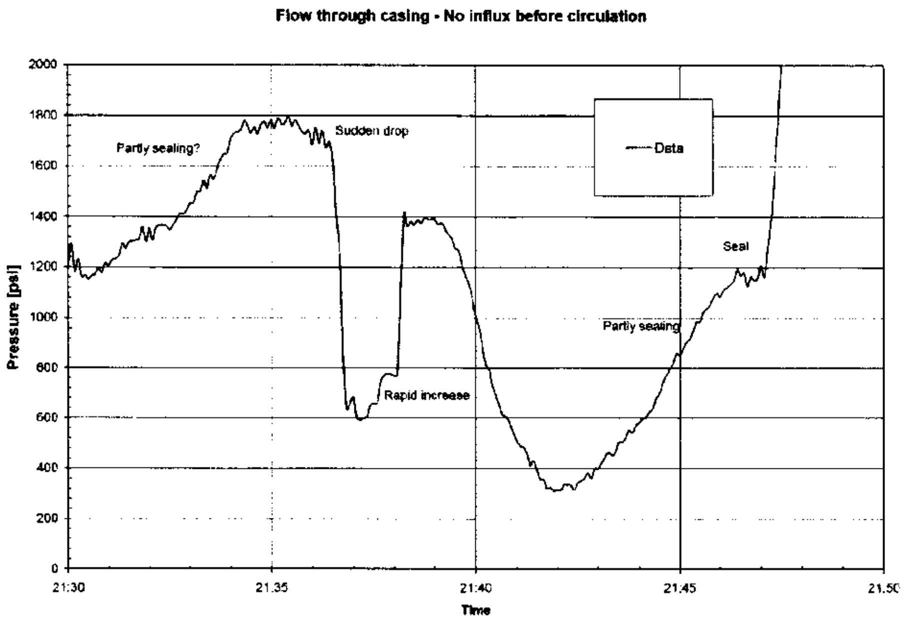


Table 3.6: Pressure fluctuations the last minutes before explosion

A simulation was run where the well was shut in at surface at 21:30. The pressure response indicates a quicker pressure buildup than shown by the data, see Figure 3.25.

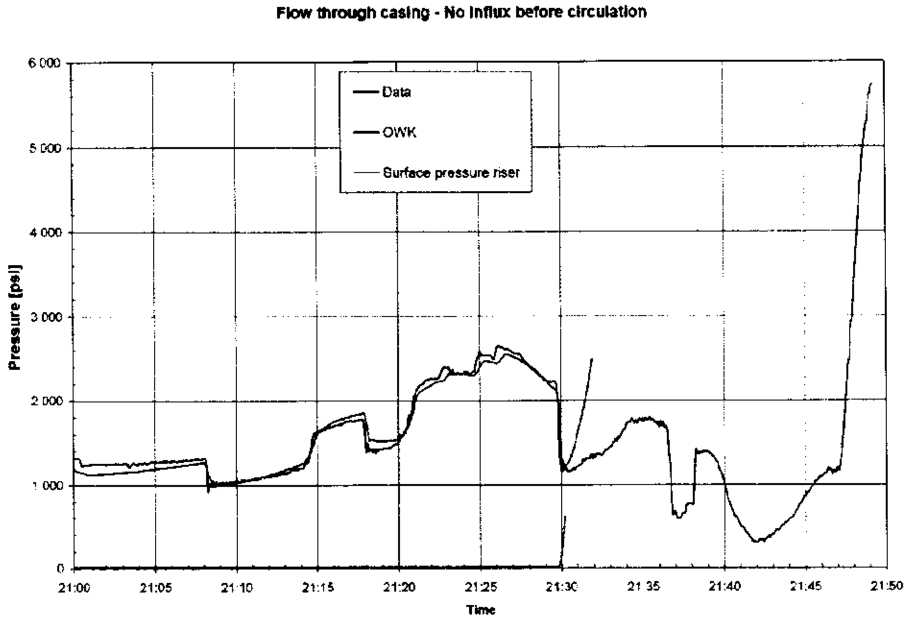


Figure 3.25: Pressure response for a sudden shut-in at surface (no flow)

The first pressure build-up after 21:30 cannot be reproduced by closing in the well 100 %. Another simulation was performed where it is assumed that the annular is leaking. In addition to a leaking annular, the sudden drop and buildup occurring between 21:36 and 21:37 match very well with the assumption of a short bleed off to the cement unit. This sudden drop and build-up cannot be explained by a closing opening annular, as gas is already in the system and will dampen the pressure response on the drillpipe side.

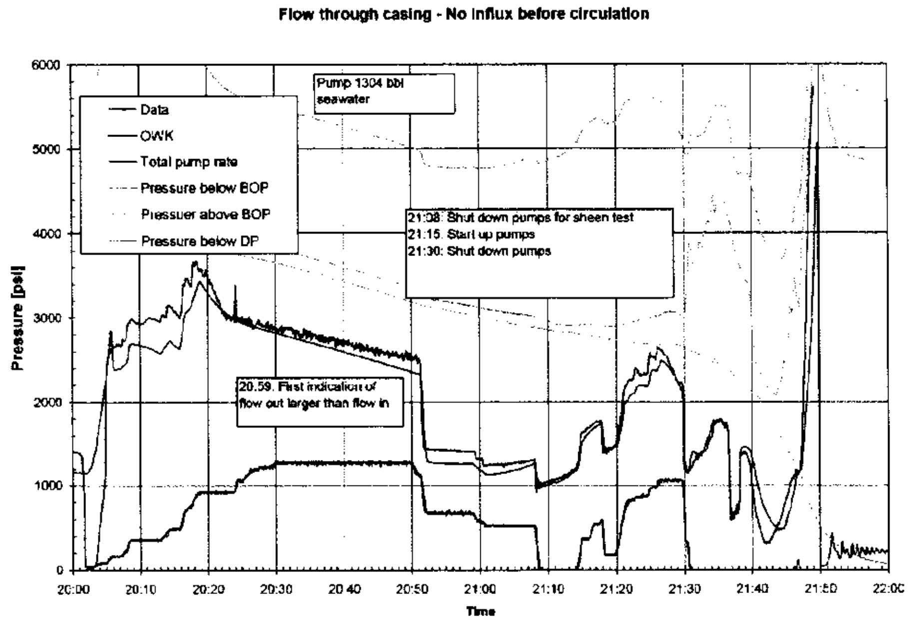


Figure 3.26: Simulations of circulation with flow through shoe, pressure buildups

3.14 Flow through annulus based on leaking annular and no influx before circ

As stated in the previous section, it is not possible to get an influx from the outer annulus right after the sheen test if no kick was taken before 20:00. Figure 3.27 shows a linear static pressure profile in the well with 1000 psi drillpipe pressure, seawater in drillpipe, seawater in annulus up to the seal assembly and 14 ppg mud down to the top of a potential influx. In order to balance a 13 ppg sand at 17800 ft based on this condition, the top of the hydrocarbon influx should be at 16700 ft, see Figure 3.27. This requires a 25 bbl kick assuming that the top of the cement is at 17450 ft, with only smaller channels below to the 13 ppg sand.

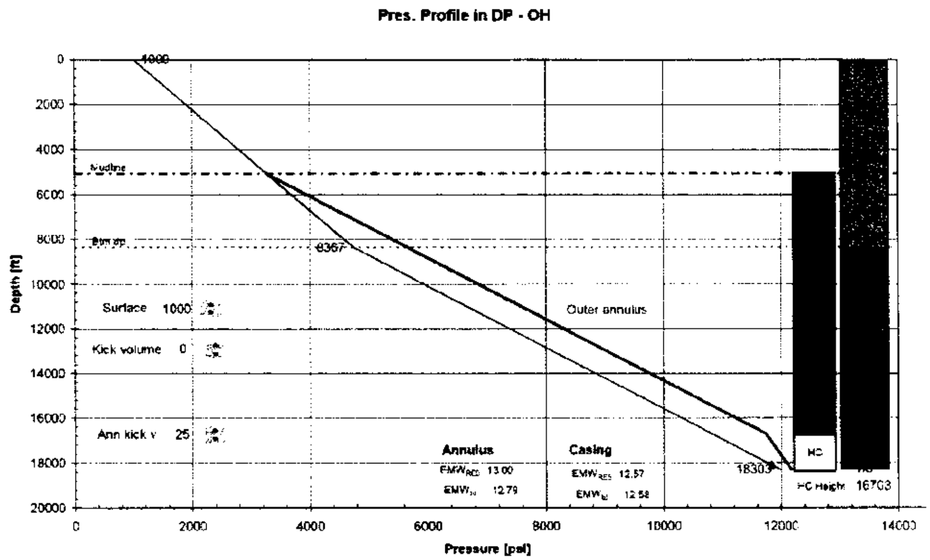


Figure 3.27: Pressure profile in outer annulus to balance 13 ppg sand

A. Appendix A

For the dynamic simulations, OLGA-WELL-KILL, (powered by OLGA from SPT Group) was applied. The simulator is tailor-made for well kill simulations and has been used in a number of on-site applications for blowout and well control. The development started in 1989 (during an underground blowout in the North Sea) based on the OLGA pipeline simulator. The model is a fully dynamic simulator that is capable of handling three different fluid phases simultaneously. The model is capable of handling non-Newtonian fluids; i.e. the viscosity is depending on the shear-rate. The OWK simulator handles a number of different flow configurations, e.g. annular flow, flow through bit nozzles, valves, pipe joints etc. See www.addenergy.no for more information.

The base core Olga code was presented in 1991 [ref. 14]. The original version of the OLGA-WELL-KILL model is described in a paper from 1996 [ref. 10]. Application of the model have been presented in a number of papers [ref. 1, 2, 4, 8, 11, 12 and 13].

Reservoir fluid characterization and property generation was performed by PVTsim. This is the market leading fluid characterization and simulation software. See www.calsep.com for more info.

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