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-THEME-

EVALUATION OF MPD APPLICATION IN BAHAR EL HAMMAR FIELD

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DEDICATION

We are very thankful to ALLAH that he enabled us to finish this work after years of education;

We want to dedicate our work in the first place, to our dear parents for their sacrifices, patients and encouragement, during the whole period of studies;

We also dedicate this work to our brothers and sisters, friends and all family and who contributed from near or far.

ABSTRACT

ملخص: اغلب عمليات الحفر ظاهر ان يتم تخصيص مبالغ مالية من اجل مشاكل الحفر المتعلقة بالتصاق خيط الحفر، ضياع دورة سائل الحفر ،الرفسة و الزيادة المفرطة في تكلفة سائل الحفر. من اجل تقليل نسبة الوقت غير المنتج الحاصل بسبب هذه الانواع من المشاكل، الهدف هو التحكم في الاحتكاكات الحلقية خاصة في المناطق اين يكون الضغط المسامي و ضغط التكسير للطبقات متقاربين جدا و هو ما يسمى بنافذة الحفر الضيقة. اذا استطعنا حل هذه المشاكل فان الميزانية المخصصة لحفر هذه الابار ستنخفض و منه سيمكن الصناعة ان تكون قادرة على حفر هذه الابار التي كانت سابقا غير محفورة و غير اقتصادية. الحفر بالتحكم في الضغط هو تكنولوجيا جديدة تمكننا من تجاوز هذا النوع من مشاكل الحفر و ذلك من خلال التحكم في الاحتكاكات الحلقية. نحاول في هذه المذكرة تقييم تطبيق الحفر بالتحكم في الضغط كتجربة جديدة في الجزائر وهل هي قادرة على تجنب التحديات استنادا على نتائج دراسة اقتصادية وتقنية .

الكلمات المفتاحية : الحفر بالتحكم في الضغط،نافذة الحفر الضيقة،الوقت غير المنتج،الرفسة،ضياع سائل الحفر

Abstract: In the most of the drilling operations it is obvious that a considerable amount of money is spent for drilling related problems; including stuck pipe, lost circulation, kicks and excessive mud cost. In order to decrease the percentage of non productive time (NPT) caused by these kind of problems, the aim is to control annular frictional pressure losses especially in the fields where pore pressure and fracture pressure gradient is too close which is called narrow drilling window. If we can solve these problems, the budget spent for drilling the wells will fall, therefore enabling the industry to be able to drill wells that were previously uneconomical and undrillable. Managed Pressure Drilling (MPD) is a new technology that allows us to overcome these kinds of drilling problems by controlling the annular frictional pressure losses. We try in this thesis to evaluate of application of Managed Pressure Drilling as a new experience in Algeria and if it can be able to avoid the challenges according to results of economic and technical study .

Key words : managed pressure drilling, narrow drilling window, non productive time, kick, lost

Résumé: Dans la majorité des opérations de forage il est évident que une quantité considérable d'argent dépensé pour problèmes durant forage ; coincement de la garniture perte de circulation venues et prix excessive de la boue. Afin de diminuer le pourcentage de temps non productif causé par ces problèmes. L'objectif c'est le contrôle des pertes de charges annulaires spécialement pour champs où la pression des pores et fracturation sont très proches qui s'appelle la fenêtre courte de forage. Si on peut résoudre ces problèmes, le budget dépensé pour le forage des puits sera tombé, par conséquent permettre a l'industrie pour forer ces puits qui étaient auparavant non économique et non forables. Forage par pression gérée est une technologie qui nous permettre de vaincre ces types de problèmes par le contrôle des pertes de charges annulaires. On essaie dans cette thèse de évaluer l 'application de forage par pression gérée comme nouvelle expérience en Algérie et si elle peut capable d éviter les défis selon des résultats d une étude économique et technique .

Les mots clés : forage par pression gérée, étroite de forage, NPT, venues, perte de circulation

SUMMAREY

SUMMAREY

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Nomenclature

ΔD:drilled depth (m)

AFP: Annular Friction Pressure (psi)

APL: Annular pressure losses (psi)

BHP: Bottom Hole pressure (psi)

ECD: Equivalent circulating density (sg)

EMW: Equivalent Mud Weight (sg)

ID: Inside Diameter (in)

KMW: Kill Mud Weight (sg)

MD: Measured depth (m)

MW: Mud weight (lb/gal)

MW: Mud weight (sg)

NPT: Non Productive Time (hrs)

OD: Outside diameter (in)

P_{db}: price of drilling bit(kda)

P_{dr}: price of rent drilling rig(kda)

P_m: price of drilled meter (kda/m)

ROP: Rate of penetration (rpm)

SBP: Surface back pressure (psi)

T_d ,T_t: drilling ,tripping time(hours)

TD: Total depth (ft)

TVD: True vertical depth (m)

WOB: weight on bit (t)

ADA: Air drilling association

BH: Bahar el Hammar

BHA: Bottom hole assembly

BOP: Blowout preventer

NOMENCLATURE

CBHP: Constant Bottom Hole Pressure

DC: Drill collar

DDV: Downhole Deployment Valve

DGD: Dual Gradient Drilling

DMK: Dalle Mekratta

DP: Drill Pipe

DST: Drill stem test

GEA: Grès el Atchane

GEG: Grès El Goléa

GOS: Grès d'oued Saret

HPU : Hydraulic power unit

HWDP: Heavy weight drill pipe

IADC: The international Association of Drilling Contactor

ICU : Intelligent control unit

LCM: Lost circulation material

LLT: Lower Limit Test

LWD: lethologie while drilling

MAASP: Maximum Allowable Annulus Surface Pressure

MPD: Managed pressure drilling

NBS: Near bit stabilisator

NRV: Non-return valves

OBM: Oil based mud

PMCD: Pressurized Mud Cap Drilling

POOH: Pull out of the hole

QZH: Quartzite el Hamra

RCD: Rotating control device

RFC: Return Flow Control

RFCD: Return Flow Control Drilling

RIH: Run in hole

SDC: Short drill collar

SDV: Shutdown valve

SH: SONATRACH

TDS: Top Drive System

UBD: Under balance drilling

ULT: Upper Limit Test

WTF: WEATHERFORD

Introduction

Drilling operations have always been challenging, wells are getting deeper, temperature and pressures are getting higher, geological difficulties like narrow drilling window and depleted reservoirs. The industry is starting to focus on more remote and complex reservoirs. Many problems occurred such as kicks, losses and sticking while drill this wells conventionally. Proper procedures for remedial actions are essential to keep drilling risks and problems controlled and minimized. Managed Pressure Drilling (MPD) is a drilling process that enables accurate control of the wellbore pressure faster than conventional methods. Pressure variations can thereby be reduced, influx and losses handled at an early stage thus reducing the subsequent challenges, and wellbore stability can be improved. MPD allows drilling into narrow pressure margins in a safer and more cost-effective manner while mitigating drilling hazards and reducing Non-Productive Time (NPT). It can be used for specific purposes such as drilling into depleted reservoirs and narrow drilling window. MPD is a drilling technique that helps make the otherwise un-drillable wells become drillable.

The objective of this work to see if this technology able to reduce the non-productive time which it caused by different major problems (losses, kicks) in Bahr lhammar field and how this technology help minimizing help power intensity of risks so we could win the drilling time and limit the wasting of money.

This thesis consists of three parts: the first part talking about the description of Bahar al Hammar field and study of the conventional drilling application in this field. In the second one, the study of managed pressure drilling applied in Bahar al Hammar is performed. The evaluation technico-economic and comparison between the two drilling techniques are detailed in the third part.

CHAPTER I:

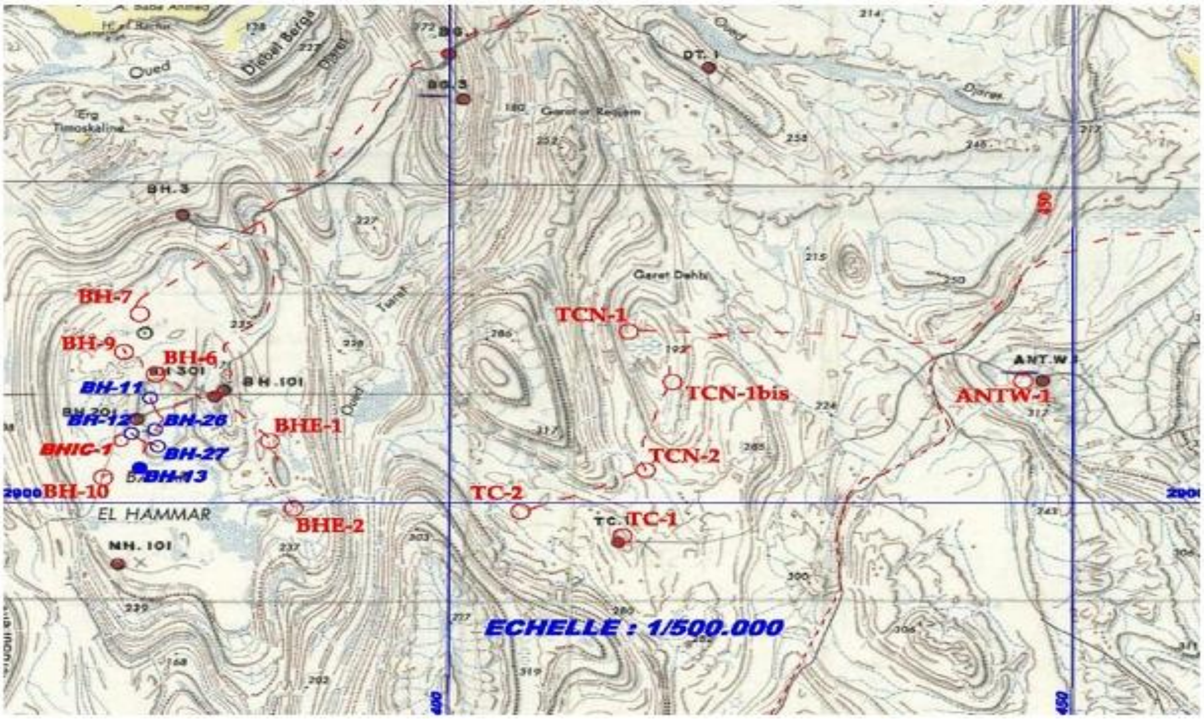
STUDY OF CONVENTIONAL DRILLING IN BAHAR EL HAMMAR FIELD

Bahar el Hammar is one of the most important fields in Algeria. The purpose of drilling in this field is achieving the target with the minimum incidents and low Non Productive Time. Unfortunately drilling Bahar El Hammar field is very difficult especially the reservoir section where it has been faced several types of problems such as kicks, losses and well control situations.

Consequently, four (4) conventional wells (see table I.1 and Fig. I.1) have been selected between 2016 and 2017 in order to study in details all the difficulties faced while drilling the reservoir. And look for the most efficient approach to reduce these problems.

Table I.1: Selected wells and coordinates.[1]

Name of wells	Rig	Spud date	Coordinates	
			X	Y
BHE-2	TP 183	11/05/2016	388267.85	2898751.67
BH -13	ENF 06	30/07/2016	375995.801	2902801.011
BH -26	TP 204	01/09/2016	377227.589	2906643.349
BH -27	ENF 06	25/01/2017	377450.100	2904961.741



FigI.1: Wells distribution map [2]

I.1. Presentation of Bahar el Hammar Field

I.1.1. Generality of the field

The structure of Bahar El Hammar is a vast anticline of slightly steering north-east south-west whose summit part represents a closed structure or outcrops the lower Devonian to the east the Carboniferous.

The main theme of the block is the Combro-Ordovician, sandstone or quartzitic reservoirs that are progressively enriched with sandstone towards the south. The entire Cambro-Ordovician series can reach 400 to 500 m thick. The matrix characteristics of the reservoirs are very poor with porosities of 2 to 7% and tight reservoir matrix permeabilities of 10-3 to 10-4mD.

Average reservoir characteristics are enhanced by intense cracking / fracturing, which yields reasonably good productivity wells. [2]

Fig.I.2:Location of Bahar el Hammar Field [3]

Bahar el Hammar is a gas field in Algeria. It is located in the province Tamanrasset , in the central part of the Algerian desert, 1 200 km south of the capital Algiers, as illustrated in figI.2Bahar el Hammar is 145 m above sea level. Its geographical coordinates are as follows:

Latitude in degrees, minutes, and seconds: **26° 12' 00" N**

Longitude in degrees, minutes, and seconds: **1° 47' 00" E.** [4]

I.1.2.Petrophysical characteristics of the reservoir

The different reservoirs existing in the region of Bahar El Hammar are the ordovicien and the cambrien which are subdivided as follows:

- Ordovicien contains: (Sandstone, Clay, and Quartzitic Sandstone) formation top ±1970m.
  - DMK (Dalle de Mekratta)

- GEG (Grès El Goléa)
- GOS (Grès d'oued Saret)
- QZH (Quartzite d'el Hamra)
- GEA (Grès el Atchane)

❖ Cambrien contains : (Sandstone) formation top ±2200 m.

- Cambrien.

❖ Infra-camberien: "Série Pourprée'' the series is shale-prone , and quartzified sandstones formation top ±2560 m. [2]

The table I.2 describe some petro-physical characteristics of Bahar El Hammar field like Porosity and Water saturation.

Table I.2**:** The average characteristics of the field wells. [2]

Stratigraphy		**Porosity(ϕ)%**			**Water saturation (Sw)%**		
		Min	**Mil**	**Max**	**Min**	**Mil**	**Max**
Ordovician	DMK/GEG	0.90	2.50	4.25	23.7	30.40	41.00
	GOS	1.00	2.60	3.70	18.00	31.10	5.20
	AAT	0.80	5.55	6.40	12.20	17.20	100.0
	QZH	0.70	3.64	4.30	7.20	23.90	47.00
	GEA	2.90	3.94	4.80	14.50	28.70	52.10
Cambrian	CAMB	1.10	2.76	4.80	31.10	42.90	51.10

The principal objectives of drilling this reservoir are to reach the subdivisions (layers): GEG, GOS and Quartzite El Hamra. While, the secondary objectives are to reach Cambrien and Infra-cambrien layers. [2]

I.1.3.Offset wells

Table I.3 presents a general idea about pore pressure, depth reference and equivalent mud weight of different offset wells (the wells that have been drilled in this field). These parameters help to make the appropriate drilling mud to avoid any hazardous (kicks, losses sticking…) while drilling. [2]

Table I.3: Pressure analysis of offset wells. [2]

Well Name	**Reservoir Formation**	**Pore Pressure Kg/cm^2**	**Depth Reference (m)**	**Equivalent MW (sg)**
BH-1	Emsian	85	777	1.09
	Upper Ordovician (GOS)	172	1886	0.91
	Lower Ordovician (HQ)	200	2130	0.94
BH-3	Emsian	46	428	1.07

Well name	Reservoir Formation	Pore Pressure Kg/cm^2	Depth Reference (m)	Equivalent MW (sg)
BH-3	Siegenian	57	528	1.08
	Upper Ordovician (GOS)	138	1395	0.99
	Lower Ordovician (HQ)	141	1605	0.88
BH-301	Upper Ordovician (HQ)	143	1530	0.93
BH-4	Emsian	66	622	1.06
	Siegenian	76	702	1.08
	Upper Ordovician (HQ)	150	1600	0.94
BH-26	Ordovician (DMK&GOS)	145.39	1294	1.07
BH-13	Ordovician (DMK&GOS)	144.4	1364	1.06

I.1.4.Reservoir drilling program

I.1.4.1.Hole section 8"1/2 x 7" Liner

This section 8 ½ ‘’ has been drilled using oil based mud as drilling fluid with a density ranging between 1.00 and 1.03sg, 10-15 lb / 100 ft^2 of yield value and 90/10 oil water ratio as mentioned in the table I.4.

For more details about characteristics of BHA, drilling bit and casing see Appendix B

Table I.4: The parameters of the drilling mud of 8"1/2 hole section [1]

Density sg	FV Sec/qt	Yield Value lb / 100 ft2	HPHT Filtrat.	NaCl %	PV Cp	OWR	Pom CC	Elect. Stability Volt
1.00-1.03	35-40	10-15	4	26	ALAP	90/10	2.5 – 2	800-100

I.1.4.2. Hole section 6" x 4 1/2" Liner

Same mud as previous section was used. Mud weight and filtrate are key parameters to get good hole stability. Mud weight start with 1.00 SG and can reach 1.03 SG at the end of the section if necessary. The characteristics of BHA, drilling bit, casing described in Appendix C. [1]

Table I.5: The parameters of the drilling mud of 6" hole section. [1]

Density SG	FV Sec/qt	Yield Value lb / 100 ft2	HPHT Filtrat.	NaCl %	PV Cp	OWR	Pom CC	Elect. Stability Volt
1.00-1.03	30-35	8-12	4	26	ALAP	95/05	2.5 – 3	1000-1900

I.2 Analysis of Wells problems for phases 8 ½" and 6"

I.2.1.Study of the Produced Problems

I.2.1.1.Losses:

Lost circulation means loss of drilling fluid into the formation. Lost circulation always causes non productive time (NPT) that includes the cost of rig time and all the services that support the drilling operation.

The origin of this incident is formation problems (geological problems). In this case of reservoir formations major of lost point face to a sandstone formation 100%, or a certain percentage in a narrow drilling window, where the pore pressure and fracture pressure are close.

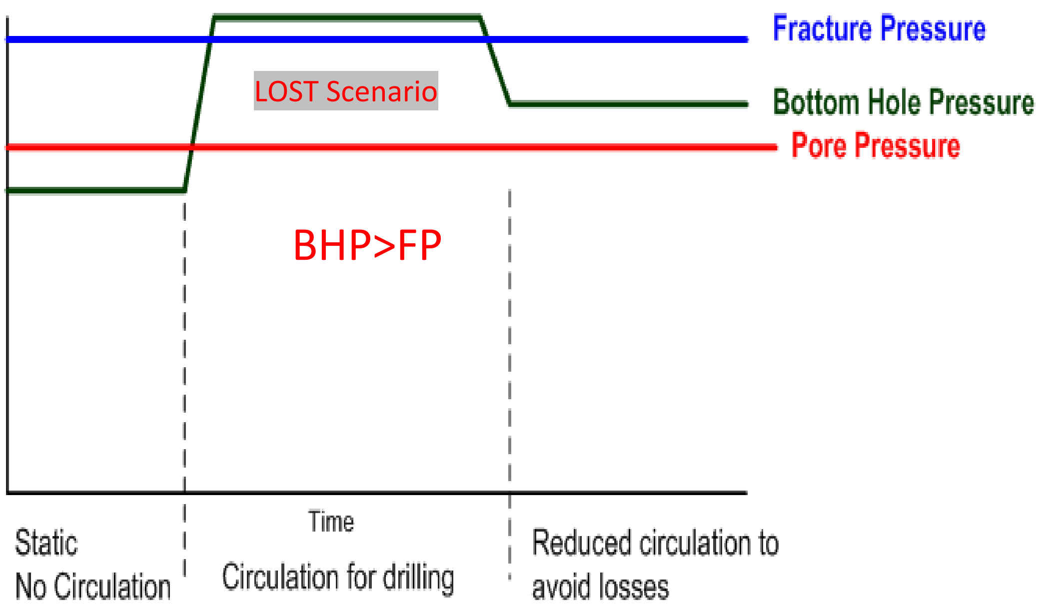


Fig I.3: Drilling window. [5]

Sandstone is considered to have greater lost potential, because sandstone has high permeability and porosity, yet another factor affecting lost severity is the "differential pressure" involved. Differential pressure is the difference between the formation pressure and the mud hydrostatic pressure. If the BHP is much greater than the formation pressure, a large negative differential pressure exists. If this negative differential pressure is coupled with high permeability and high porosity, severe losses may occur. Lost circulation in these wells not cured only by mud displacement (decrease mud density), also cured by pump Lost Circulation Material (LCM) Plug.

We can say that the main origin of problem is the narrow drilling window, which can't make us condition the drilling mud density, for that Mud Weight will greater than pore pressure ,then the lost of circulation may occur.

I.2.1.2.Well control operation

Kick tolerance is an important concept that can be applied both in drilling operations and in casing program design. For the wells currently drilled, more multifaceted planning and execution are required. Application of kick tolerance concept is especially helpful. Considering kick tolerance made drilling execution safer and more economical by reducing the probability to have an incident. It is crucial to keep an eye on the kick tolerance in real time, by updating the calculation every time there is a variation of parameters, which influence its value. In deepwater, choke and kill line friction is an important factor, particularly when the threshold between mud density and casing shoe fracture gradient is really narrow.

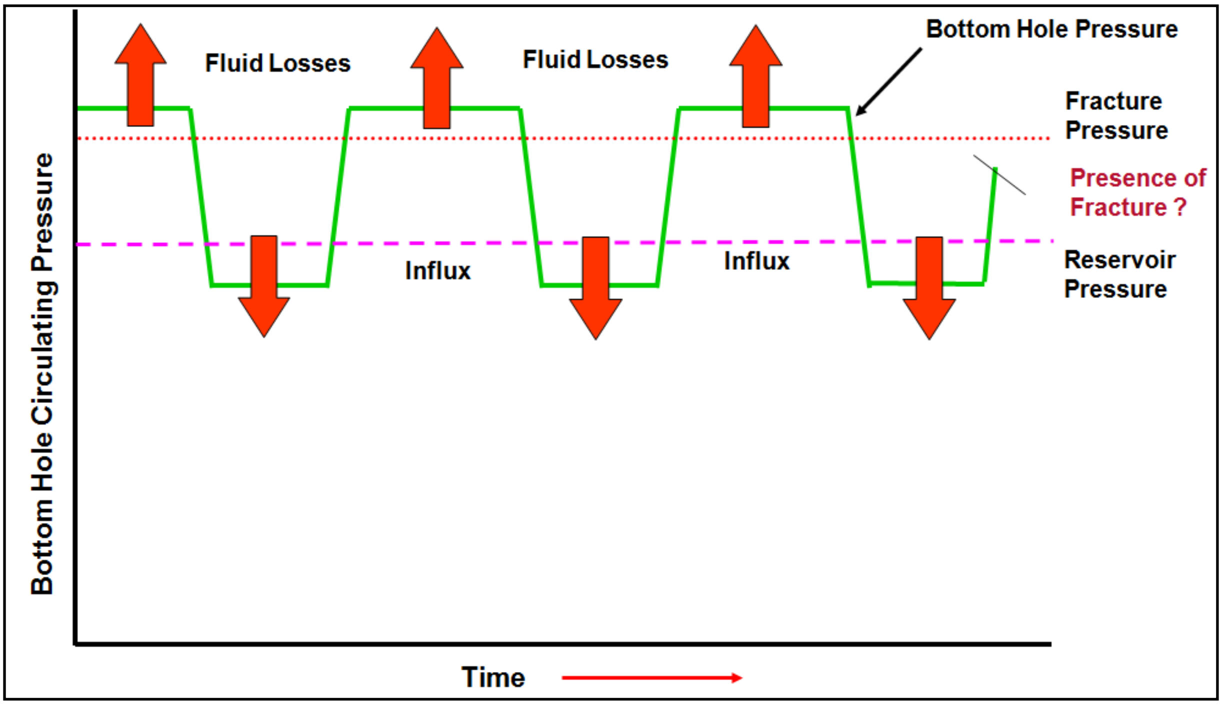


Fig I.4: Kick Occurrences due to Narrow Drilling Window. [6]

Fig I.4 illustrates that taking kick is faced while stopping the pumps to make connection in conventional wells which have narrow drilling window. Dynamically overbalance system turns statically underbalance which allows kicks to the well. Disadvantages of conventional drilling while dealing with kicks by emphasizing that annular pressures can not be adequately monitored in an open vessel unless and until the well is shut in. Well control incidents during conventional drilling are predicated on increased flow, where precious time is often wasted pulling the inner bushings to “check for flow”. In that, time the influx volume becomes larger. The larger the influx volume becomes, the more difficult it is to manage the kick. Correspondingly, during conventional drilling operations it is required to cease the drilling and shutting in the well. While the influx volume is being circulated out of the wellbore and the drilling fluid is more adequately weighted to compensate for the increased bottom hole pressure, the hole is not being drilled and casing is not being run. The non-productive time is mounting, exposing time sensitive formations to drilling fluids, that will cause other problems leading to increased nonproductive time. The effects of non-productive time are iterative and costly. [6]

I.2.1.3 Wait & Down hole failures

The problem of faulty equipment such as service equipment, coring equipment, contractor equipment, Top Drive System (TDS), Draw Works ,DST, logging, BOP, drill string and pump failures are very repetitive, especially the latter are considered to be one of the major problems during the drilling of the $8^{1/2}$ “and 6 ‘’ phases.

Origins of problem are:

-Misuse of equipment

-Poor quality of material.

-No maintenance.

I.2.2.Descriptions of Conventional Wells Problems in the $8^{½}$“and 6“hole section

The following table I.6 represent the different problems faced during the reservoir drilling($8^{½}$ ”and 6”).Their location, description, duration of all consequences (in hours) and solutions provided to solve them in site, in BH-13 well. As well as, the secondary problems are estimated by the total number of 462 hours which divided on waiting of DST equipments and crew, coring, rig repair, circulation, logging and casing/liner accessories.

Table I.6: statistical study of the problems for 8 ½ “and 6“of the well BH13. [7]

MAIN PROBLEMS				
Phase	**Problem**	**Cause /Description**	**NPT (hrs)**	**Solution**
8,5’’	Kick	-Kick detected at 1369m 8.5’’ hole in Top Ordovician (DalleMekrata,100% sandstone),drilling parameters (WOB=6-7 t, ROT=40-50 rpm, Q=1600 lpm, Pr=1000 psi,ECD=1.07sg), this kick caused by a swabbing phenomenon	22,5	Evacuation by driller’s method, changing density from 1,25 to 1,9
6’’	Total Losses	Total mud losses followed by kick occurred at 1586 m for 6″ Argile de Tiferouine Ordovician 90% shale and 10% sandstone (WOB=10-13 t, ROT=50-60 rpm; Q=1300 lpm, Pr=800-850 psi, MW=1.09 sg)	136	the losses were cured by pumping LCM Plug no returnobserved, the mud level in the well decrease causes a kick ,in this case the well on well control operation for pump LCM to eliminate losses and circulate to evacuate gain, 5.5 days to control the situation and 146 m^3 total of mud losses

Phase	Problem	Cause /Description	NPT (hrs)	Solution
6’’	Kick	-Kick(Gas Flow) of 8 m^3 detected at 1641m 6’’ hole in Hamra Quartzite 100% sandstone,Ordovician, with drilling parameter (WOB=5-7 t, ROT=40-60 rpm, Q=700 lpm, Pr=450 psi,MW=0.95sg),	40 (with lost NPT)	Increasing mud weight from 1.06sg to 1.09sg (well control operation)
6’’	Well Control	Displacing mud density 1.06sg by 1.09sg To eliminate another kick index	29,5	Well control operation Shut in well: Pa =147psi, Pt=150 psi. Bleed of 100psi 15psi, Pt=65psi. Bleed of 65psi (Pa =00psi, Pt=00 psi). Circulation
6”	Partial Losses	Partial mud losses of 6m3/h occurred at 1588 m for 6″ Argile de Tiferouine Ordovician 50% sandstone and 50% shale,(WOB=4-8 t, ROT=40-60 rpm, Q=600 lpm, Pr=450 psi,MW=1.11 sg)	16	the losses were cured with setting LCM plug,14m^3total mud losses
6’’	Well Control	Flowing well gain 08m^3	550	Driller’s method (set LCM plug at balance and displace it)
6”	Partial Losses	Partial mud losses of 5m3/h occurred at 1603 m for 6″ Hamra Quartzit Ordovician 90% sandstone and 10% shale,(WOB=2-4 t, ROT=80-100 rpm, Q=500 lpm, Pr=500 psi,MW=0.97 sg),	242	Shut in well as procedure Pump Through annular and drill pipe HI-VIS , LCM and SPACER

FigI.5 shows the distribution of NPT problems of the well BH 13 for the phases 8.5" and 6" of the Bahar el Hammar field. As it can be seen from, the well control operation has the large margin of NPT by 580 hrs (24 days) which represents 40% of total NPT. Also, lost circulation has a considerable value of 394 hrs (16 days), i.e., 27% of total drilling NPT.

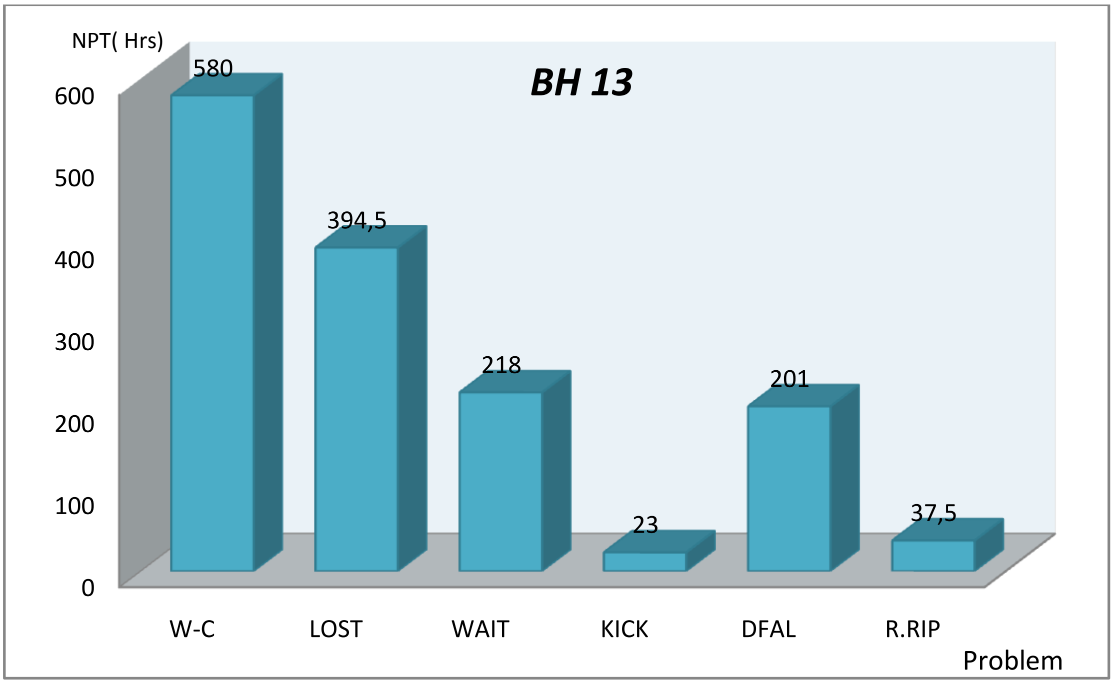


Fig I.5: The NPT Problems of the well BH 13

TableI.7 below describes the different problems that have been confirmed in reservoir phases (8 ½" and 6") in BH26 well with their locations, lost time (NPT) and practical solutions that have been applied. While the secondary problems occurred take a large value of 580 hours (24 days) distributed in: waiting for logging equipments and crew, rig repair, surface failure and human factor.

Table I.7**:** Statistical study of the problems for 8½ "and 6" of the well BH 26. [7]

MAIN PROBLEMS				
Phase	**Problem**	**Cause/Description**	**NPT (hrs)**	**Remedial job**
6''	Well control	-Kick detected at 1462m 6'' hole (Hamra Quartzite 100% sandstone, Ordovician), drilling	243.75	Circulate to homogenized mud -Run degazer-Decrease flow from 1500 To 1200 l/min

Phase	Problem	Cause/Description	NPT (hrs)	Remedial job
		parameters (WOB=10-12 t, ROT=50-90 rpm, Q=1500 lpm, Pr=9600 psi, MW=1.50sg), 7hrs to control the situation		
6’’	Lost	Partial loss of 4 m3 at 1477 m in 6’’ hole (HamraQuartzit ,Ordovician),drilling parameters applied WOB=5-7 t ,ROT= 30-60 rpm, Q=800 lpm Pr=900 psi,MW used 1.04 sg,	95,5	cured losses by decrease MW to 1.03 sg from SV/SH request and Flow rate to 600 lpm followed by Set 1.5m3 LCM at Balance C=280k g/m3 (CACO3 + BAROFIBRE SF)
6’’	Lost	- Partial losses = 3.6 m3/h at 1677m in 6’’ hole (HamraQuartzit ,Ordovician),different parameters WOB=5-7 t ,ROT= 40-60 rpm, Q=500 lpm Pr=550 psi,MW used 1.03 sg,	150.75	losses cured by: Set 1m3 LCM at balance C=280kg/ m3 (CACO3 + barofibre SF),Pooh s tring to top of LCM, decreased Mud weight from d=1.03sg To d=1.02sg, No losses, RIH string to bottom and resume drilling .this losses followed by kick while running in the hole
6’’	Well control	kick detected at 1477m in 6’’ hole(Hamra Quartzite 100% sandstone ,Ordovician),while RIH kick occurred after lost situation ,Get Kick @1411m while runnin g in hole *Pt = 320psi Pa = 850psi	391.25	it was initially processed by circulation through POORBOY Degasser with 30 spm,13days of continuous well control operations ended by failure, this’s what led to abandon the well by setting Cement Plug

FigI.6 shows the distribution of NPT problems of the well BH 26 for the 8.5” and 6” phases in the Bahar el Hammar Field. It is noticed that, this well has the same cause of NPT like the pervious well estimated by the by 635 hrs (26,4 days), which represents 43.13% of total NPT. Also, Wait has a considerable value of 543.5hrs (22.63 days), by 36.92% total NPT of the drilling operation time. Lost circulation gets a part of 247.25 hrs (10, 34 days), whether 16% of total well NPT. Rig Repair, surface failures, kick and human factor took a small value of NPT between 16 and 5 hours.

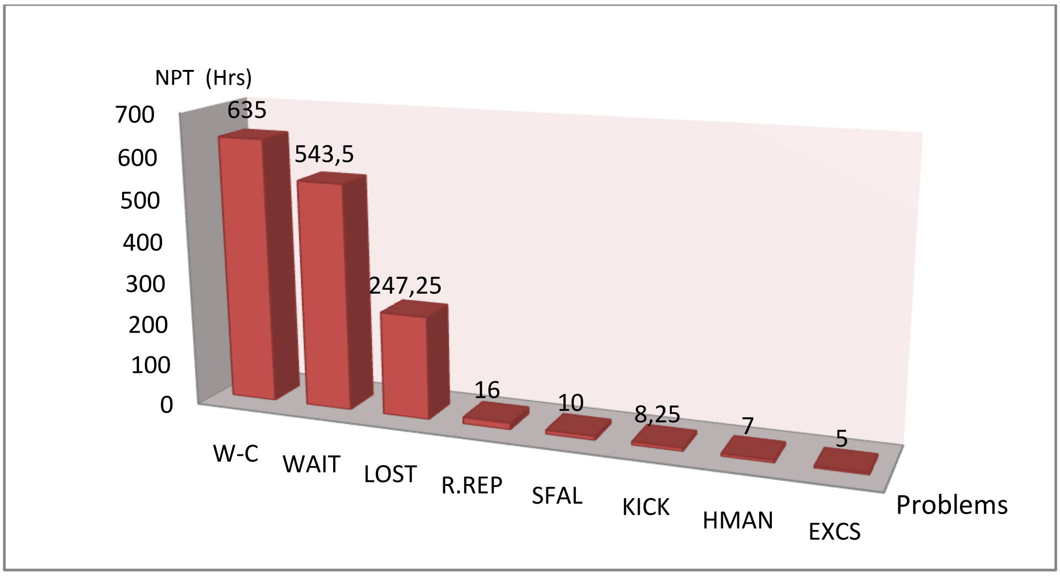


Fig I.6: The NPT Problems of the BH 26 well

After analyzing NPT of BH-13 and BH26 the drilling challenges which may occur while drilling in 8½” and 6” holes mainly the loss/kick scenario, back ground gas and uncertainty in pore and fracture pressure in the target formations, which leaded to well control situations. The main challenge is to tune the ECD while drilling to be at balance and avoiding losses which followed by gas kicks as the reservoir formations are fractured which created narrow window to drill (Because of all the problems mentioned above, have a great deal of NPT). The well control situation in BH-13 started from the drilling of the 8 1/2" section due to the kick/Losses scenario at ATA formation, the window was between 1, 00 sg to 1, 09 sg. The drilling with issue and Kick/Losses continue to the 6" hole section drilling at Hamra Quartzite formation where the window decreased to 0, 95 Sg – 0, 97 sg and the drilling stopped at 1641 m MD.

I.3.Evaluation of conventional drilling

In the conventional drilling of Bahar el Hammar field “overbalance drilling” all problems events in reservoir hole section (8-1/2″ and 6″) have a high percentage NPT such as lost circulation, kick, down hole failure so all of this problems base on Mud Weight and drilling parameters and the characteristic of drilling fluid generates a large differential pressure across the Ordovician formation which contains different problems. Otherwise, there is a high probability for kick or fluid loss, especially when the margins between the pore and fracture gradients is unknown or not exactly estimated; large or narrow window, as shown in fig I.7.

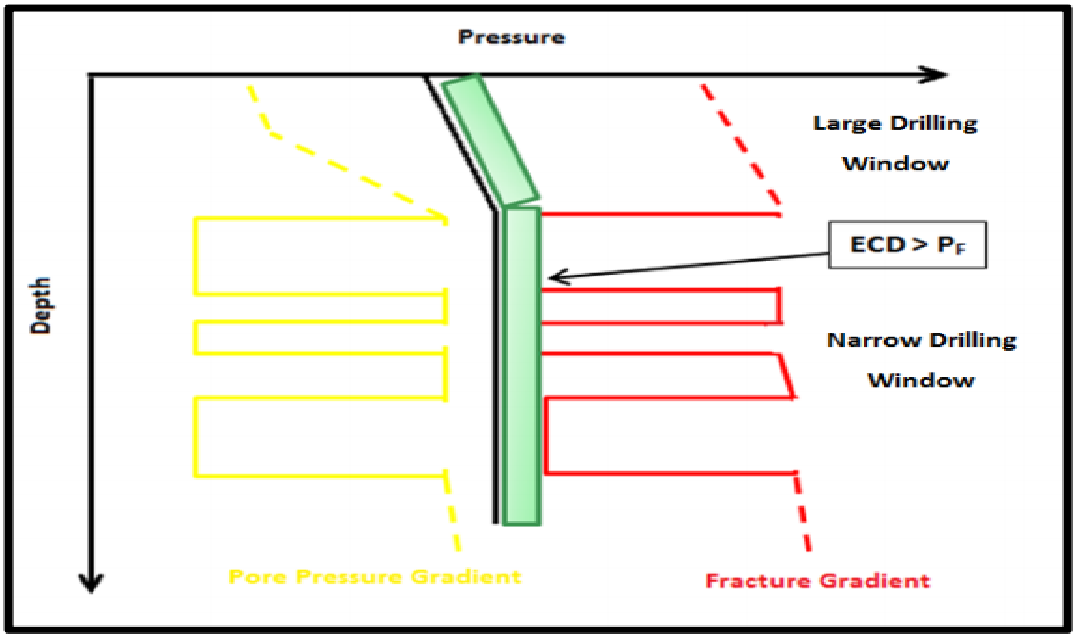


Fig I.7: Large and narrow window.[5]

What has made difficult, there are geological uncertainty represented by poor data offset wells and difference between layers depth (depleted formations). In this case of all problems; we have to look for another approach to solve these problems and override the obstacles which can be compatible with this case among the proposed solutions to drill (8-1/2″ and 6″) hole section, like:

-Under Balanced Drilling

-Managed Pressure Drilling

-Integrated Mud

MPD was selected as more efficient and economically feasible choice over UBD since wellbore instability is an issue, and SONATRACH company has chosen this technique by virtue of its previous experience and proved its effectiveness in other fields (NEZLA,EL HAMRA and GARET EL GOUFEL). For Integrated mud it still under trial in Algeria.

I.4. MPD or UBD

MPD is used primarily to resolve drilling hazard problems, although some reservoir benefits can be achieved. MPD offers a reduction in the degree of overbalance and thus the impact of drilling fluid on virgin formation usually will decrease. While UBD can address the same issues (except wellbore instability) and can gain reservoir advantage like minimized formation damage and early production recovery while drilling. In may not necessary to solve the drilling problems. Furthermore, equipment for both UBD and MPD operation are similar, though there are variations depending on the design parameters of the project. In some instances, the same equipment setup is necessary for both UBD and MPD methods. The distinguishing difference is that for an MPD setup, fluid influx is not expected during drilling.

In this study, MPD was selected as more efficient and economically feasible choice over UBD since wellbore instability is an issue, and MPD is meant preclude influx from the formation during operation. [8]

Chapter II:

Study of MPD application in Bahar el Hammar

Introduction

In the wells already drilled by the conventional drilling method we have encountered many problems which have led to a considerable loss of time (high Non-Productive Time), especially in terms of the loss of circulation and kicks which make impossible to complete the realization of drilling operation (goal is not achieved).

We have presented a solution of these problems using the Managed Pressure Drilling (MPD) technology, and we will study the possibility of application of this technique, its efficiency, and its role of treatment of such problems. According to the results of using MPD technology it can be concluded that if the reservoir is reached more safely and with reduced NPT and costs compared to conventional drilling.

II.1.MDP theoretical study

II.1.1.Why using MPD

Managed pressure Drilling become a very good option to be used on challenging wells, with narrow margin between pore and fracture pressures (see Fig. II.1), reducing the lost time and increasing the chance to complete these wells successfully.

MPD reduces risk and increases safety of drilling operations. Which is an engineering and scientific way to overcome the current Complexities, Extended Reach, difficulties of Multilateral wells [9].

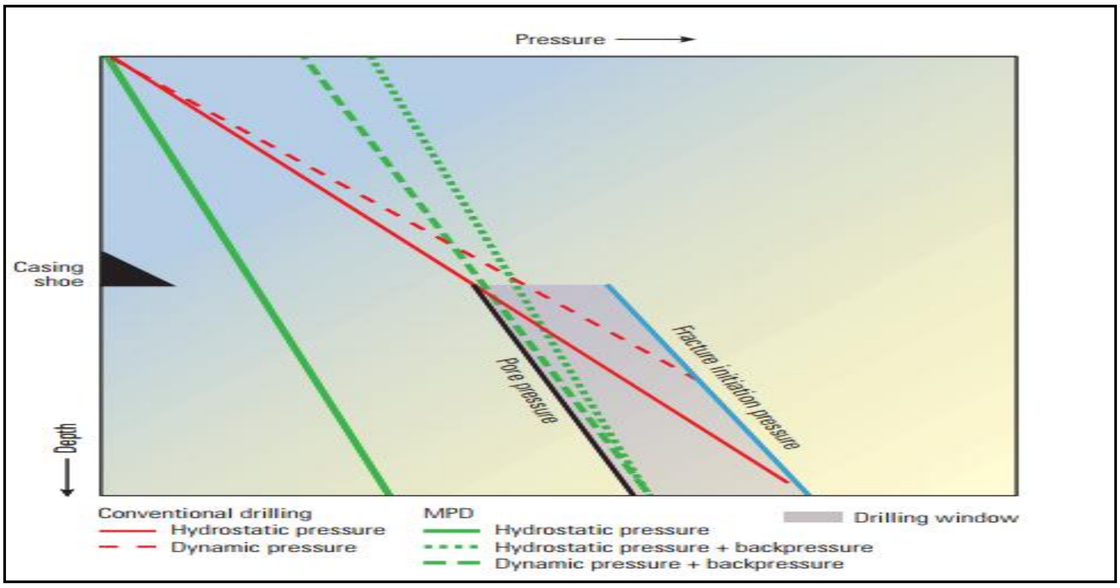


Fig II.1 : Pressures between Conventional and MPD drilling window [8]

II.1.2.Definition of MPD

The international Association of Drilling Contactor (IADC) defines managed pressure drilling or MPD as “an adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore. The objectives are to ascertain the downhole pressure environment limits and to manage the annular hydraulic pressure accordingly. MPD is intended to avoid continuous influx of formation fluids to the surface. Any influx incidental to the operation will be safely contained using an appropriate process [5].

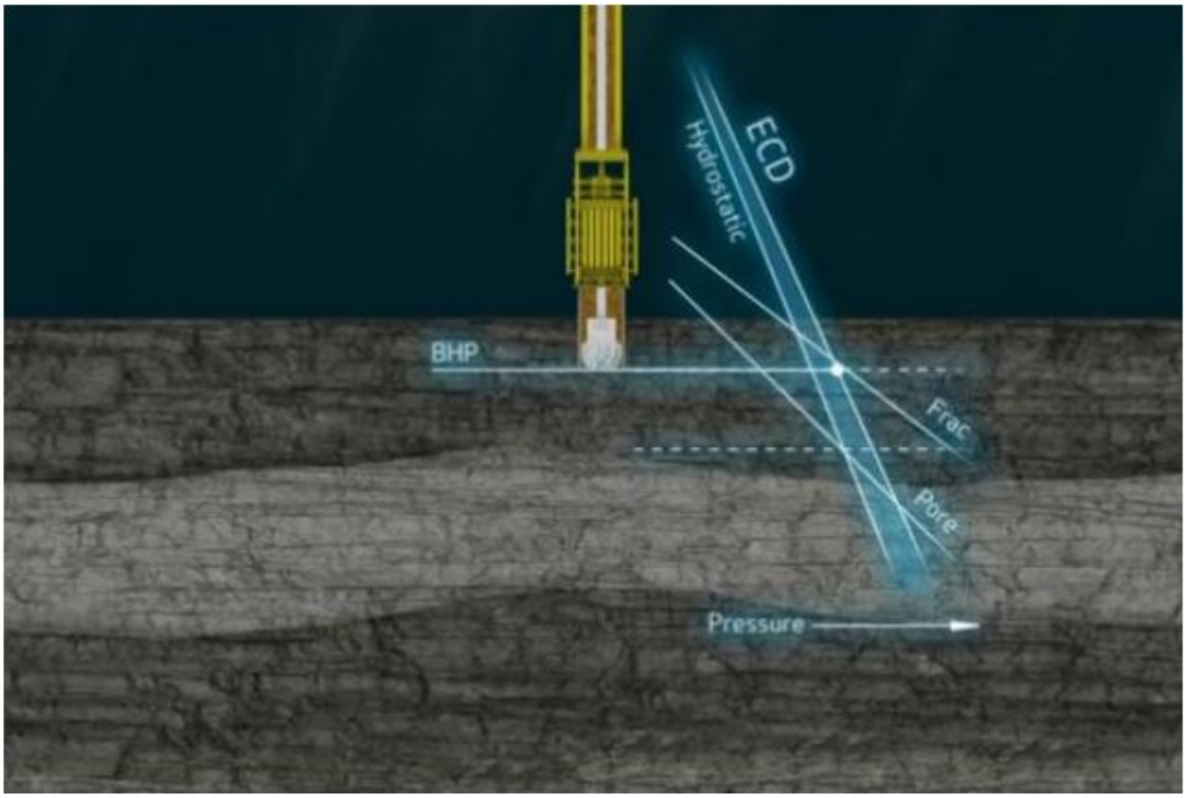


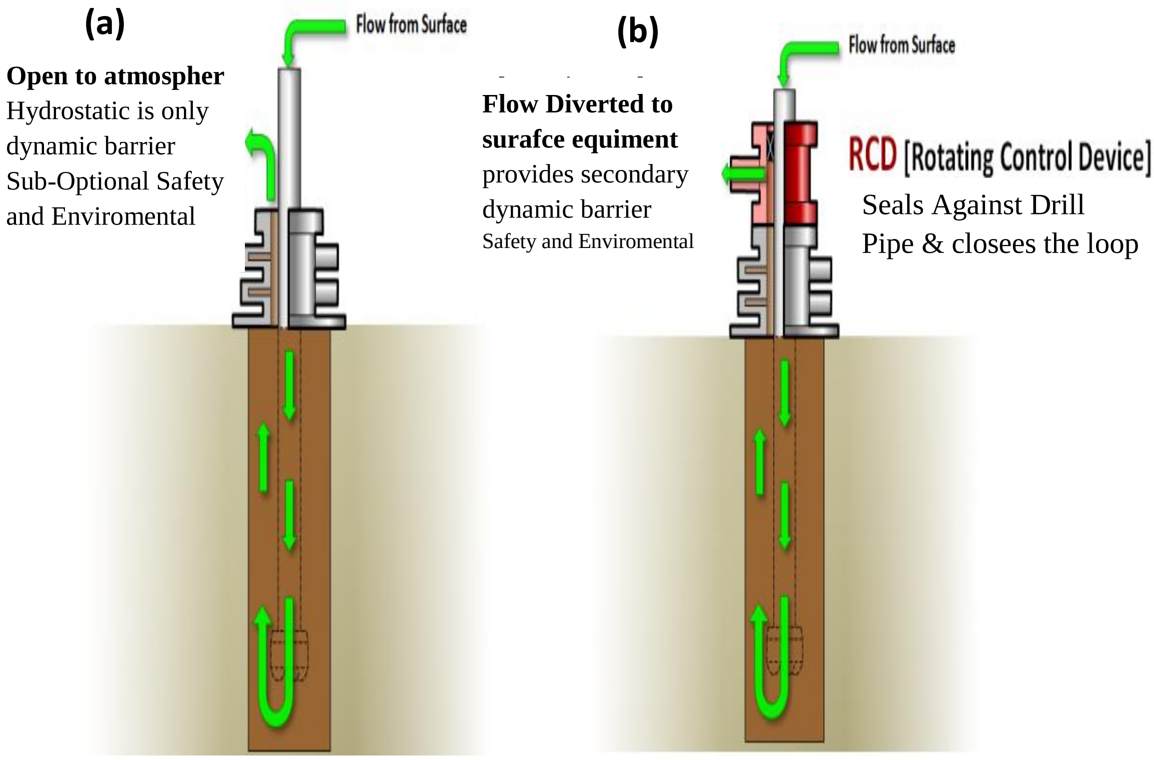
Fig.II.2: MPD technology [10].

For a well open to atmosphere (conventional drilling, see fig II.3 (a)) the BHP can be estimated as in Eq. (II.1):

$$BHP = MW + friction \qquad (II.1)$$

For a closed loop system, like for MPD and UBD (see fig II.3 (b)), the return-flow is diverted to surface equipment. The BHP can then be estimated as in Eq. (II.2):

$$BHP = MW + friction + backpressure \qquad (II.2)$$



FigII.3 (a):The conventional circulation loop: return open to atmosphere [8]

FigII.3 (b):Closed loop circulation :the MPD and UBD approach flow [8]

II.1.3.Proactive and Reactive MPD Classification

Depending upon the stage where MPD is chosen to be used, all MPD activities can be broadly classified as Proactive MPD or Reactive MPD. [9]

II.1.3.1.Proactive MPD All MPD activities where the use of MPD is considered beforehand are proactive MPD activities. The IADC definition of proactive MPD is, “Using MPD methods and/or equipment to actively control the pressure profile throughout the exposed wellbore” (IADC 2008a). [9]

II.1.3.2.Reactive MPD Reactive MPD projects are not always last minute decisions. The scale and nature of a few small projects is such that, either MPD might not be required to finish them, or there is little economic loss in stopping in the middle of the project and rigging up for reactive MPD. For such projects, the additional hassle of getting proactive MPD in place is futile. The IADC definition of reactive MPD is, “Using MPD methods and/or equipment as a contingency to mitigate drilling problems as they arise” (IADC 2008a). [9]

II.1.4.How Managed Pressure Drilling Works?

The basic technique in MPD is to be able to manipulate the BHP and the pressure profile as needed. In conventional drilling, the BHP can be calculated by summing the mud weight hydrostatic head and the annular friction pressure (AFP). The AFP is the friction pressure that results from the circulation of the mud while drilling. ECD is defined as the Equivalent Circulating Density of the BHP. It is basically the BHP while circulating converted into the units of mud weight. During a connection, the pumps turn off and the fluid stops circulating, thus eliminating the annular friction pressure. The starting and stopping of pumps can greatly affect the pressure profile, causing the pressure to fluctuate out of the pressure-gradient window and thus leading to drilling problems. [9]

A conventional drilling system is open to the atmosphere so that the returns gravity flows away from the rig floor. The only way to adjust BHP while drilling is by the pumping rate. MPD uses a closed and pressurisable mud system. With a closed system the equation for the BHP (Eq. II.1) can be varied to include backpressure, see Eq. II.2. BHP now can be found by summing the mud hydrostatic and the AFP with the amount of backpressure being applied. Adjusting backpressure while drilling can quickly change the BHP. [9]

The basic configuration for MPD is to have a Rotating Control Device (RCD) and a choke.

The RCD diverts the pressurized mud returns from the annulus to the choke manifold. A seal assembly with the RCD enables the mud returns system to remain closed and pressurized and enables the rig to drill ahead. The choke with the pressurized mud return system allows the driller to apply backpressure to the wellbore. If the pressure starts to climb above the fracture pressure of the formation, the driller can open the choke to reduce backpressure and bring the pressure down. If the driller needs to increase the pressure throughout the well, closing the choke will increase backpressure. This technique is mainly used during connections when the pumps are turned off then on. When the pumps are turned off, the choke is closed to apply backpressure to replace the lost AFP. As the pumps are turned on and the AFP increases, the choke can be opened to decrease backpressure. This helps keep pressure profile to remain inside the pressure window throughout the well (see fig II.4). [9]

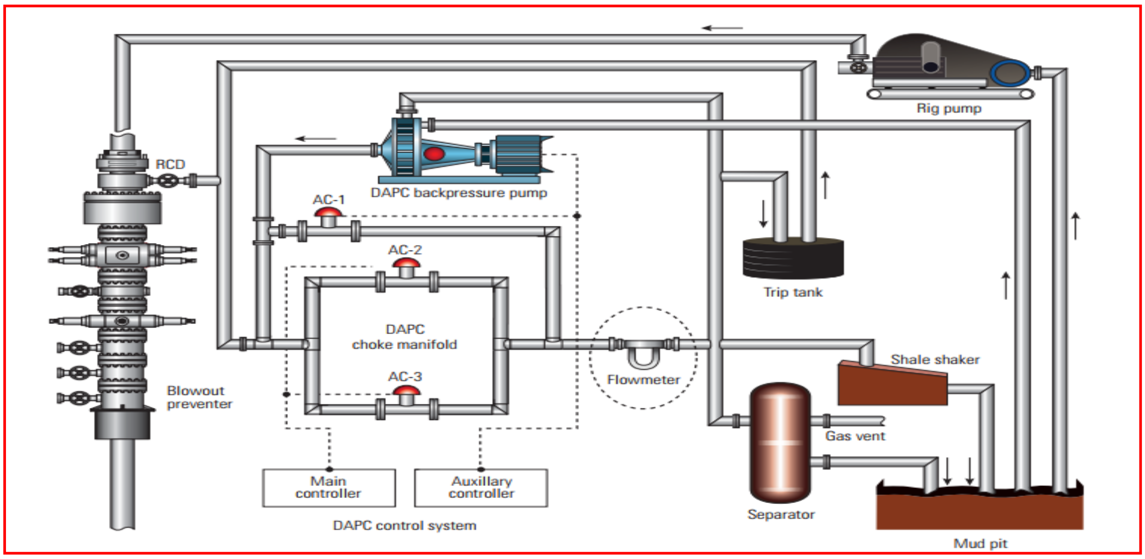


Fig II.4: MPD flow diagram. [8]

In Fig II.5, the pressure profile shows that, in static conditions, the pressure will fall below the pore pressure and that, while circulating, the pressure will exceed the fracture pressure.

By adjusting the mud weight and using backpressure, a driller would be able to keep the pressure inside the pressure window. The driller can decrease mud weight so that the pressure stays below the fracture pressure while circulating. Applying back pressure while not circulating could keep the pressure above the pore pressure of the formation. By adjusting the drilling plan, a driller would be able to successfully drill a well that has tight pressure margins. [11]

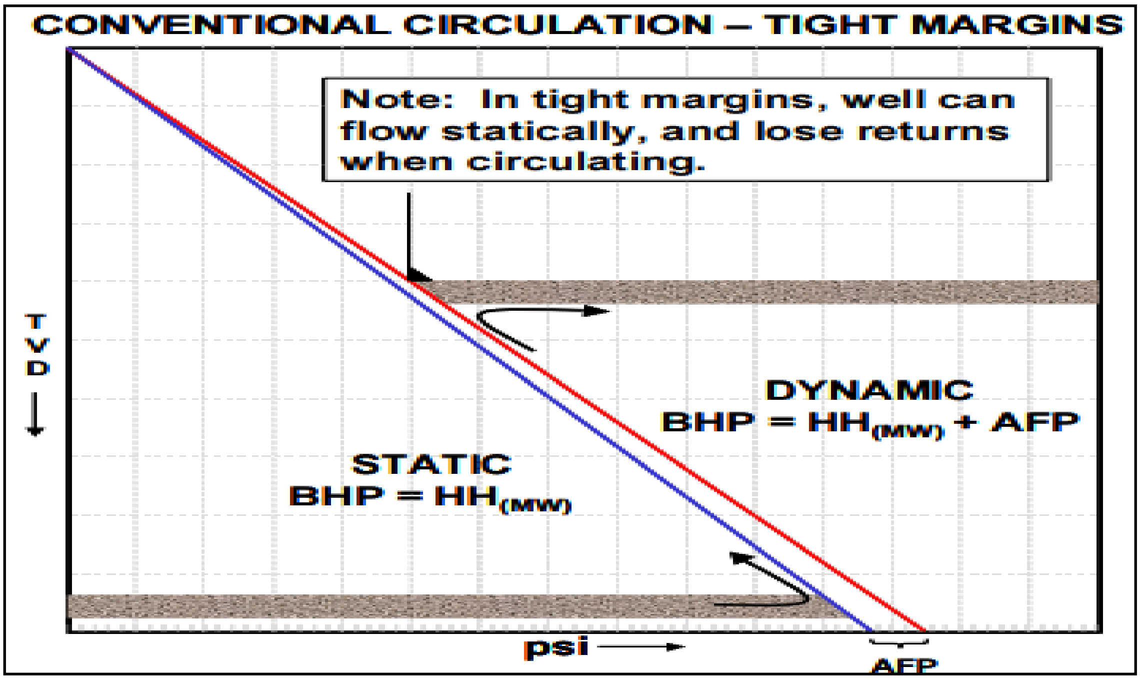


Fig II.5: Pressure gradient window for tight margins [11]

II.1.5.Different Methods of MPD

There are several methods of MPD; each method can be used depending on the region (the field) characteristics. The commonly used method is CBHP, namely in Algeria.[9]

II.1.5.1.Constant Bottom Hole Pressure (CBHP)

Constant Bottom Hole Pressure (CBHP) is a MPD method whereas the annular pressure is kept close to constant at a given depth. The method is based on maintaining control of the annular back pressure and has been successfully applied in several depleted reservoirs. The objective for this method is to eliminate cycles of kicks/losses that are common in deep wells where fracture gradient are close to the pore pressure. The typical application for this technique is for cases where there are high uncertainties on the pressure limits, a narrow mud weight window with kicks/losses and high associated NPT, which are fractured reservoirs. More specific, the BHP are bounded by the pore pressure and wellbore stability at one side and differential sticking, lost circulation and fracture pressure at the other side. A continuous circulating system (CCS) is used to maintain constant BHP. For a closed system the mud flows through a choke manifold designed to control the backpressure and maintain constant BHP. The choke manifold increases the backpressure to compensate for frictional pressure losses when the mud pumps are turned off by using the MPD pump.This method has been used in most of wells in Algeria.

II.1.5.2.Pressurized Mud Cap Drilling (PMCD)

Pressurized Mud Cap Drilling (PMCD) is a drilling technique to mitigate extreme fluid losses commonly found in highly depleted and naturally fractured formations and associated NPT. Mud cap drilling is employed when normal techniques have difficulties to maintain circulation. To prevent and control kicks and lost circulation while drilling in fractured or layered formations, drilling fluid together with water and cuttings are pumped into the wellbore and drill pipe (DP).PMCD is referred to as drilling without returns to the surface, and maintaining a full annular fluid column above a formation whereas fluids and cuttings are injected. When fractures are encountered and drilling fluid is lost, the annulus is closed using the RCD. Sacrificial fluid (light weight, seawater) is then pumped down the DP and a fluid cap is injected into. The fluid cap is balanced by the formation pressure and managing the surface pressure as the well is shut in, i.e. fluid cannot return up through the annulus. By pumping water or brine down the DP, drilling can be continued.

II.1.5.3.Dual Gradient Drilling (DGD)

Dual Gradient Drilling is an MPD technique that employs two different annulus fluid gradients to find a close match to the natural pressure regime; one above the seabed, another beneath. This concept is the most applicable technology for deepwater drilling due to the heavy mud column in the marine riser. The objective is to reduce formation damage and the related fluid losses when drilling deep formations with low fracture gradients (eliminating mud density changes)

II.1.5.4.Return Flow Control Drilling (RFCD) or HSE Method

Return through Flow Control (RFC) Drilling is a MPD method that reduces risks from drilling fluid, hazardous gases and well control incidents to the personnel and the environment. The objective of this method is to focus on HSE primarily.This method is specifically designed to enable drilling high- pressure, complex wells at reduced operational costs.

II.1.6.MPD Equipment Requirement

The recommended equipment and their specifications to perform the MPD-CBHP operations are included and described in the following section. [11]

II.1.6.1.MPD-CBHP Process Flow Diagram:

The process flow diagrams shown in the Fig II.6 is recommended for the planned MPD-CBHP operations (the red colored equipment is the basic for the MPD-CBHP operation and the blue colored equipment is the additional required to perform the flow and Build up test), since it is already tied-in to the wellbore annulus. The pump rate can be monitored via stroke counter or a flow meter. However, it is recommended to use the system currently available on the rig, typically a stroke counter for reliability. [11]

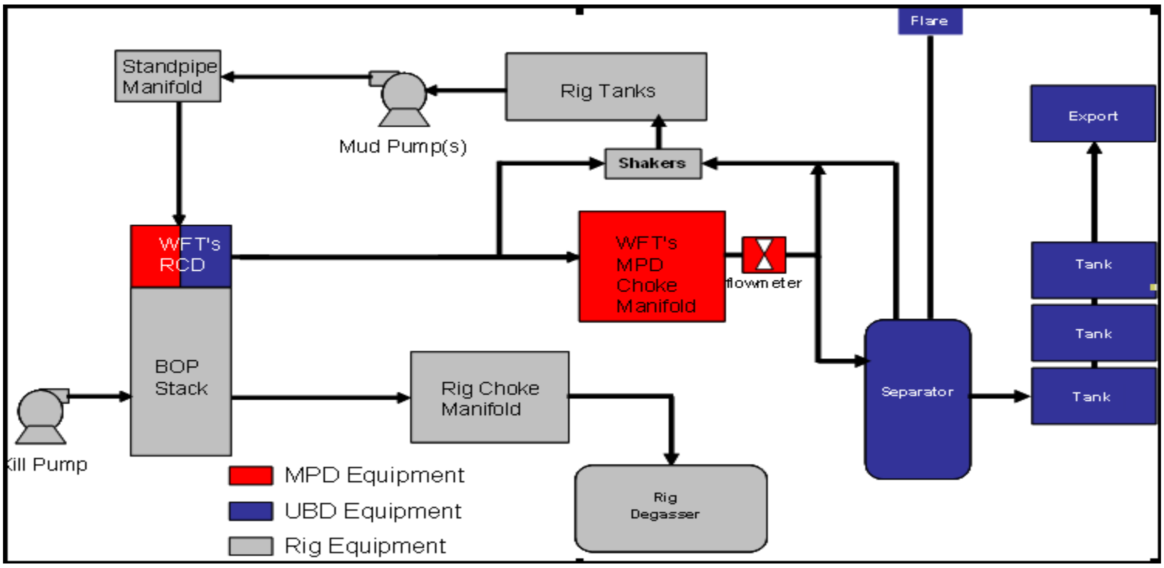


Fig II.6: Preliminary Process Flow Diagram [11]

A Piping and Instrumentation Diagram will also be developed when preparing the drilling program to highlight all the flow lines, valves, flow meters and sensors associated with this project.

II.1.6.2.Rotating Control Device (RCD):

The main function of the RCD is to divert the upstream flow from the wellbore to the choke manifold while still maintaining an effective seal between the drill string and the hole. The rotating control diverter (RCD) provides the rotating seal between the annulus and atmosphere during MPD operations. In additional to the Dynamic and Static pressure rating for each RCD model, the geometric limitations of the RCD devices related withthe selection and availability of the drill pipe will determine the appropriate RCD to be used in the MPD operation. The rotating control diverter is usually bolted on top of the annular preventer.Rotating control device technology is based on applying an advanced compound sealing rubber against the drill string or Kelly surface, which provides an effective, seal but still allows the vertical movement of the drill pipe. The sealing sleeve is located within a secondary housing that allows unrestricted rotation of the drill pipe while still maintaining the seal. Rotating control diverters are available in several models depending on the pressure that they can hold. The rotating control diverter specifications include a static (no rotation) and dynamic (rotating/ reciprocating) pressures. The choice of RCD is based on the reservoir pressure of the specified formation [8]. The characteristics and specifications of WTF 7100 RCD are chosen to be described here as example, as shown in Table II.1 and fig II.6.

Table II.1: Rotating Control Device Specifications [11]

Rotating control device	**Specifications**
Rotating working **pressure**	2500 psi
Static pressure	5000 psi
Maximum operation RPM	100 RPM
Operating Temperature	-20°F to 250°F
Bottom flange	11” - 13 5/8” - 5000

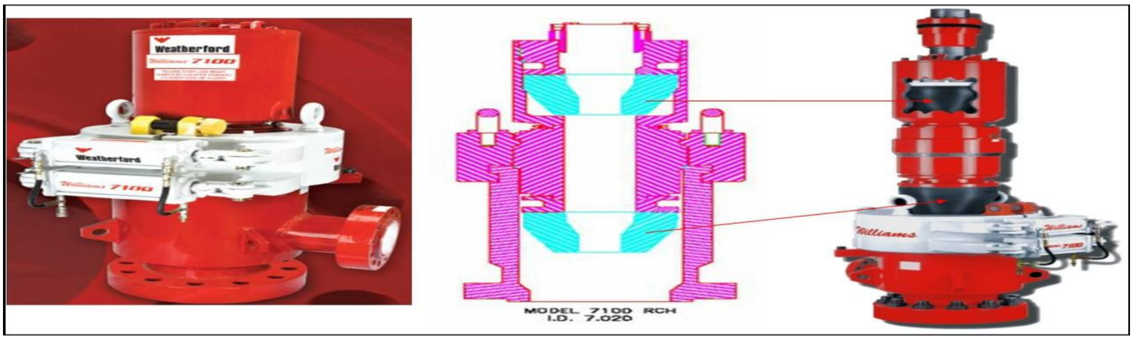


Fig II.7: RCD WFT Model 7100 [11]

II.1.6.3.ChokeManifold:

The MPD choke manifold is a critical component among the MPD equipment. It creates the variable flow restriction that controls the wellhead pressure which in turn maintains a relatively constant bottom hole pressure in both static and dynamic conditions. The proposed choke manifold is a semi-automated choke rated for 5000 psi; it is illustrated in fig II.8. [11]

Fig II.8:Control Cabin MPD Choke-Semi Automated [11]

The semi-automated choke regulates the annular backpressure to the values set by the MPD choke operator in order to maintain a constant BHP and compensate friction losses when changes in the dynamic flow conditions are required (connections, tripping pipe, etc...) as shown in Fig II.9 .

Fig II.9: Semi-Automated Choke [5]

II.1.6.4.Non Return Valves (NRV's):

Non-return valves (NRV's) are required to prevent back flow from bottom through the drill string. Positioning at least two NRV's in the BHA allows for safe tripping, fulfilling the two barriers policy inside the drill string. Like shown in fig II.10 [11]

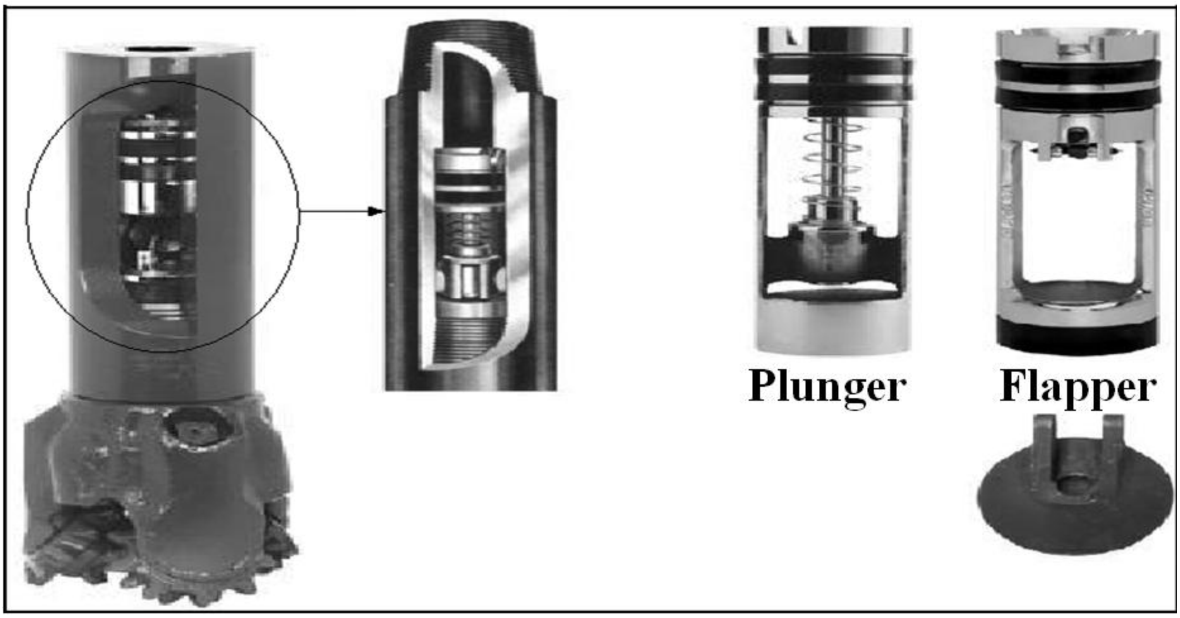


Fig II.10: Non-Return Valves [11]

II.1.6.5.Downhole Deployment Valve

The Downhole Deployment Valve (DDV, see fig II.11) system is a surface controllable downhole valve system that is run as an integral part of the well's casing string that increases safety and eliminates snubbing from the drilling operation. For this specific application, it is recommended to locate the DDV valve as integral part of the 7" casing. [11]

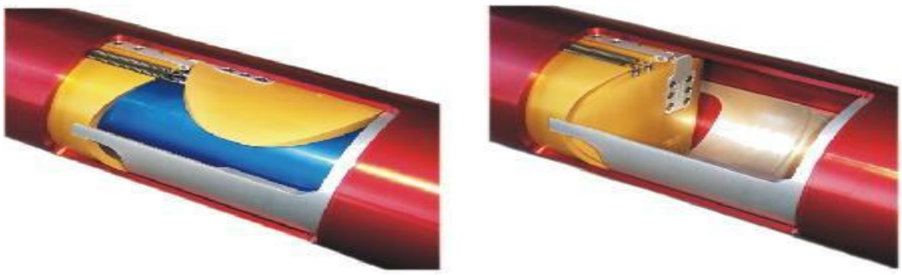


Fig II.11: Downhole Deployment Valve [11]

The DDV is used whenever the drill string is retrieved from the well or deployed into the well while surface pressure exists. When it is necessary to pull the drill string out of the hole, the drill string is stripped out through the sealing elements until the bit is above the valve. The valve is then closed, pressure above the valve is bled off and the drill string can be safely removed. The drill string trip back into the well will be carried out until the bit is just above the DDV; and then the DDV is reopened, and the drill string is finally run to the bottom to continue drilling operation. [8]

The DDV system consists of a flapper valve casing deployed downhole tool that is controlled from surface through a Control Line which is run inside of the annular space between casing strings. The Control Line incorporates 2 x ¼" diameter continuous length of tubing on either side of a 5/16" braided wire rope. The wire rope contains a mono conductor line to transmit operational data from the valve. Operation of the valve is accomplished through the application of pressure to either of the control lines, for opening or closing respectively. To open the valve, pressure is applied to one of the two control lines. To close the valve, pressure is applied to the other line [8]. The characteristics and specifications of WTF Downhole Deployment Valve are chosen to be described here as example, as shown in Table II.2.

Table II.2: WTF Downhole Deployment Valve (DDV) – Specifications [11]

Size	**7'' - 32 lb/ft**
OD	8.50 in
ID	6.276 in
Length	120 in
Max. p accross valve	5000 psi
Max.temperature	300 deg f

For MPD operations where a tight margin between the static/dynamic pressure exerted by the drilling fluid and the pore/fracture pressure exists, the DDV helps to avoid the pressure fluctuations while tripping pipe in the hole (surge/swab) and to kill the well during every drill string pulling out operation. Thus, production interest formations will suffer less reservoir damage. [11]

II.1.6.6.Data Acquisition:

In order to maintain a high level of pressure control, an accurate real-time knowledge of the variables that affect the ECD is required. Standard methods of kick and loss detection and conventional rig data recording alone are simply not sufficient for this degree of control. A data acquisition system that has electronic pit level, standpipe pressure (psi), wellhead pressure (psi) and pump speed (lpm) is highly recommended. Rig measured depth (m), torque lb/ft),Choke Temperature (Celsius), Choke Temperature(Celsius),Bottom hole pressure (psi), RPM and other additional sensors are also beneficial.[8]

A data acquisition display monitor will be placed in locations where the monitoring of the MPD-CBHP/UBD parameters is essential. This includes a panel situated next to thechoke operator; moreover, the data can be displayed in real-time in all of the locations where rig data monitors are located such as rig floor and rig manager’s office.

The Data Acquisition will be stored and displayed by its system continuously during the MPD-CBHP. [8]

II.1.6.7.Mass Flow Measuring System (Flow Meter-Coriolis)

Coriolis meter for MPD applications, see fig II.12,is generally installed downstream of the choke manifold. Field experience showed that the use of Ultrasonic Flow Meter as a Non-Intrusive meter, has been disturbed by the high level of background noise and also by unknown elements regarding pipe properties (cuttings deposits, etc). Due to the high accuracy and immunity from external forces and the facility of installation, Coriolis meter is a reliable tool to take the flow measurements. The Coriolis measuring principle operates independently of the physical fluid properties, such as viscosity and density.[11]

Fig II.12: Flow Meter – Coriolis Flow Measurement [11]

II.1.6.8.Hydraulic Actuating Shutdown Valve

The hydraulic actuator valve is designed to shut-off the drilling well fluids from the downstream MPD equipment or shale shaker in the event of an emergency situation; it's also designed to smoothly switch over between drilling conventional to the shale shaker to the MPD system and vice versa. The 5 1/8" 5K shutdown valve (SDV, see Fig II.13) is a gate type valve and is fitted with a hydraulic/spring actuator that is designed to hydraulically hold the valve open. In an emergency, the hydraulic pressure is released and the valve will close automatically by the actuator spring action. The system is an air-operated control unit (air supplied by the rig) to feed the hydraulic pump with separate hydraulic output to operate this valve.[11]

Fig II.13: Shutdown Valve[11]

II.1.6.9.MPD Auxiliary Pump

Annular Injection pump (triplex pump, Fig II.14) rated at 2500psi is used to provide the continuous flow required to maintain the annular pressure constant during connection.The characteristics of 3 ½" Plunger TWS 600S Auxiliary Pump are presented in the table II.3.

Fig II.14MPD auxiliary pump [11]

It is required that the pump provides the sufficient flow (around 568-757 lpm) to be able to maintain the SBP up to 1350 psi which is the highest expected at the 6" hole section. This pump will be lined up to the inlet of MPD manifold to maintain the surface back pressure (SBP) required during the drilling, connection and tripping operation.[11]

II.1.6.10.MPD Mud Gas Separator

The degasser is presented in Fig II.15, its use is optional in MPD operation. It is designed to handle the initial flow from the well, which can be slug flow, high gas rates, and high cuttings rates. With 80 psi design pressure rating the separator can manage rates expected with a fluid retention time of at least two minutes and still remain with the allowed weight requirements.

Well effluent enters the degasser via wrap around inlet device, known as the "Snail". The Snail is designed to aid liquid separation by reducing the velocity of the incoming fluid and increasing the average liquid drop size. There are two liquid legs from the degasser, upper and lower.[11]

Fig II.15: Mud Gas Separator [11]

II.1.6.11.Microflux^{TM} Control System

The Microflux^{TM} System uses the Coriolis mass flow meters and the principle of Mass Balance to measure and compare the volume and density injected into the well and returned from the well to identify downhole events[11]. The components of Microflux^{TM} System, see fig II. 16, are as follows:

- Coriolis Mass flow meter
- Precision quartz pressure sensors
- Hydraulic power unit (HPU)
- Intelligent control unit (ICU)

Fig II.16: Microflux^{TM} Control System. [11]

II.1.7.Advantage of MPD drilling

Drilling in MPD was introduced in the last few years, and essentially to overcome certain problems encountered in drilling. The remarkable results obtained allowed its rapid expansion in the oil world.[11]

The main advantages of the MPD are represented in the following points:

- ✓ **Reduction in circulation losses during drilling**

In oil drilling, the drilling fluid plays an important role in controlling the drilling conditions. This fluid contains many products to add physical and chemical characteristics adapted to the drilling conditions. The choice of drilling fluid acts directly on the operation cost, and therefore any loss of fluid is a challenge to the cost price increase.

In conventional drilling the loss of circulation is frequent because the bottom pressure is higher than that of the reservoir. As known, the fluid always takes the easiest way. It will have circulation losses and these losses are often in the fractured zones, low pressure areas and high permeability zones. But in MPD, the bottom pressure is always equal to that of reservoir which means no losses and no kicks. [11]

- ✓ **Increased rate of penetration**

Among the advantages of MPD, the increase in penetration speed (ROP). This later is related to bit selection, speed of rotation, weight on bit and good bottom cleaning of the well. All the parameters can be controlled except for the good cleaning of the bottom of the well. In the conventional drilling the hydrostatic pressure exerted by the mud obstructs the evacuation of the cuttings. at the same time the cake settles on the walls of the hole causing the fall of bit cutters which directly affects the bit advancement. Whereas, in the drilling in MPD the hydrostatic pressure is equivalent to that of reservoir, and there is almost no cake formation, which allows the quick removal of the cuttings.[11]

- ✓ **Increasing bit lifespan**

The increase in the lifetime of the bit depends on several parameters, such as, weight on the bit, the work performed by the bit, the rotational speed, the bottom temperature and the quality of lubrication.

In Overbalance, a considerable amount of heat is produced by the temperature gradient and by the friction of the bit with the formation. The drilling fluid conveys heat away from these friction locations by convection. It should be noted that the solids in the drilling fluid contribute to creating additional frictional heat in addition to that produced by the bit. But, with MPD drilling the friction force will be less when using the method of injecting the mud within the annular space. The mud acts as a lubricant, so the oil-based mud is a good lubricant.[11]

- ✓ **Minimize pressure differential stuck pipe**

The pipe sticking is the most frequent causes of the most serious instrumentation operations. Generally, the differential pressure occurs in the permeable zones (limestone, sandstone).The drill string sticks with the formation wall due to the pressure difference between the formation pressure and the hydrostatic pressure of the mud. Also, the cake column forms a joint that prevents pressure equalization. But, with MPD the pressure difference is lower than that in the case of conventional drilling, so there is no cake deposition.[11]

- ✓ **Reduce formations damage (reservoir):**

In overbalance drilling, the formation is always exposed to the drilling fluids that penetrate into the pores causing the internal and external cake formation, the external cake can be eliminated by scraping but the internal cake cannot be eliminated. Reservoir damage is not only due to the cake but also to other phenomena, such as physicochemical clogging due to the presence of the clay of the type of sméctiteor illite which causes swelling. Also, organic clogging which is due to the precipitation of the organic constituents of the mud when it comes into contact with the rock. With managed pressure drilling using the mud contains the calcite no cake formation is occurred. Consequently, the formation damage decreases because of the reduction of hydrostatic pressure and the solid in the drilling mud volume.[11]

- ✓ **Simple drilling fluid program :**

Drilling fluids used in conventional drilling consist of many chemical additives, which are added to the fluids to control the density, viscosity of the fluid in the formations, and the addition of clogging agents in the case of partial losses.

The manufacturing systems of these fluids as well as the chemicals used are very expensive. On the other hand, significant savings can be made with MPD, using other fluids such as oil-based mud of density between 1.10: 1.15SG.

The drilling fluids used in MPD are very simple to be treated0. The fluid losses are avoided which reduces the cost of the operation.[11]

- ✓ **Instant evaluation of the reservoir during drilling**

During drilling in MPD reservoir characteristics, such as fracturing pressure, and pore pressure can be identified. Thanks to the use of MPD, it is also possible to identify the fracturing pressure of the formation and the flow types. In the case of conventional drilling, the choice of the drilling fluids takes into consideration the following parameters: the mud salinity, the depth of filtrate invasion and the pressure rupture caused by the fluid to ensure that, geological information on the surface of the soil is properly assessed, which requires a lot of time, resources and above all money. [11]

II.1.8. Disadvantages of MPD

Like all the techniques used, the MPD technique has disadvantages among them:

Limitations related to directional drilling equipment:

Directional drilling equipment may have limitations in MPD drilling. Hydraulically operated tools can not be used in wells of MPD and if a gasified system is used the MWD pulse systems may not work. Some engines and other directional equipment may be prone to failure due to the rubber components becoming impregnated with the gas used.

The torque of higher torques in MPD wells can also prevent certain trajectories to be drilled into MPD. The very high torque is caused by the reduced buoyancy combined with the lack of cake filter on the walls. [11]

II.1.9.Drilling window

The pressure window is the area between the pore pressure and the fracture pressure. The goal when drilling a well is to keep the pressure inside this pressure window. In a static well, the pressure is determined by the hydrostatic pressure of the mud. When the well is static, the pressure in the well is less than the pore pressure, a kick will happen; i.e., hydrocarbons flow into the well.

Before the restart of drilling, the kick has to be circulated out. After a connection, the pumps restart, the BHP (Bottom Hole Pressure) increases and the pressure goes above the fracture-pressure, resulting in lost circulation, or fluid flowing into the formation. The goal of managed pressure drilling is to walk the line of the pressure gradients. Managing the pressure and remaining inside this pressure gradient window (see fig II. 17) can avoid many drilling problems. [9]

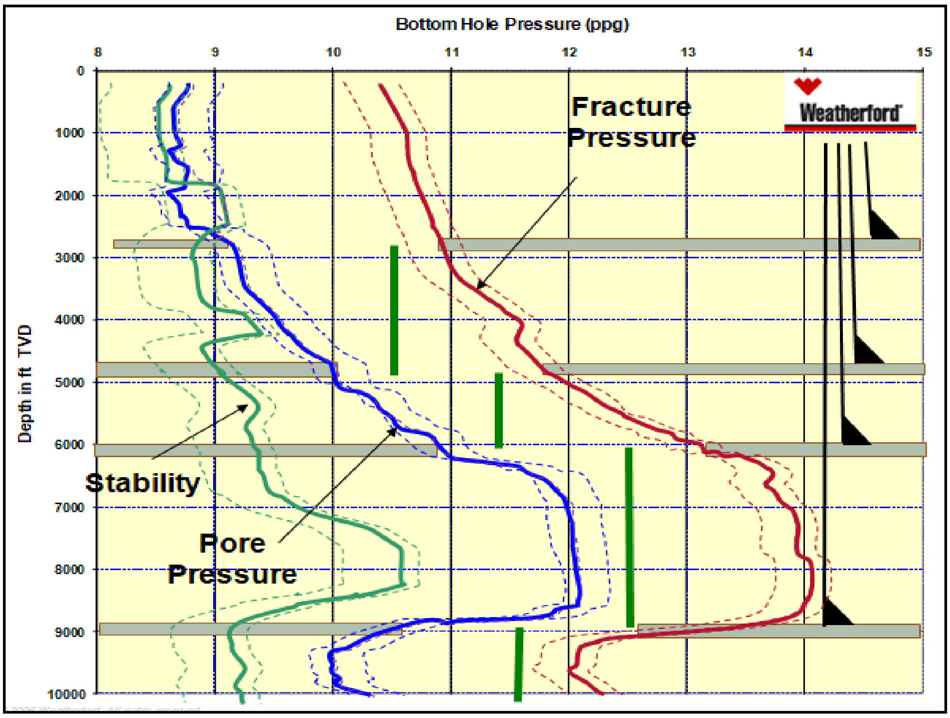


Fig II.17: Graph of drilling margin [5]

II.1.10.The Effect of the equivalent circulating density

The pressure exerted on the formation while circulation is the equivalent circulation density (ECD) and it is the sum of the entire annular pressure losses of the hole sections added to the hydrostatic pressure generated by drilling fluid. The ECD is influenced by mud weight, frictional pressure loss in the annulus, cutting loading and rheological properties of the mud. The ECD should be carefully managed while drilling through reservoirs with a tight drilling window between the pore and fracture pressures. In this case the ECD may exceed the fracture pressure and result in lost circulation. Where explain in Eq.II.3 :

$$ECD = MW + \left(\frac{APL}{0{,}052} * TVD\right) \qquad (Eq.II.3)$$

MW : Mud weight (lb/gal).

APL : Annular pressure losses (psi).

TVD : True vertical depth (ft). [11]

II.1.11.Well Control Strategy – MPD Well Control Matrix

The proper application of MPD techniques requires the surface pressure to be maintained within the Safe Working Pressure ratings. If the MPD equipment is compromised in service and is not able to safely handle the returning well fluids, then the rig’s well control equipment must be engaged to allow for continued dynamic annular pressure control conditions. [5]

The IADC (International Association of Drilling Contractors) defines the Well Control Matrix, represented in Table II.4; as an interface to MPD operations, establishing the actions required to be taken following a deviation from the original plan that presents an imminent hazard. Well Control events may occur when the returning flow parameters enter into the RED shaded areas of the Matrix, or when the failure of any part of the MPD equipment either presents an imminent hazard to the personnel, environment, and equipment or prevents the continuation of safe MPD. [5]

Manageable wellhead pressures must be determined to ensure continuous and safe drilling operations. The Well Control Matrix defines the well control interface between MPD Operations and Conventional Well Control, then, limitations for MPD regarding well control issues are defined in this matrix. A risk based approach to the design of the flow control matrix is required and must be based on:

- Pressure rating on the flow control equipment: RCD, MPD choke manifold and primary flow line. The maximum allowable casing pressure is the limiting factor in this case due to the narrow window between the pore pressure facture pressure.
- MPD casing design limits Maximum Allowable Annulus Surface Pressure MAASP as a function of the planned mud density. Maximum operating well head pressures on the “X” axis are defined as follows (see Table II.3):

Green light: The choke pressure based on the designed drilling pump rate and the calculated ECD.

Yellow light: The choke pressure at which the ECD is at the fracture pressure.

Orange light: Any change in pump rates or choke pressure will result in exceeding fracture pressure.

Red light: Is a well control event. [5]

Table II.3: MPD Well Control Matrix [5]

MPD Well Control Matrix		Surface Pressure Indicator			
		At Planned Drilling Back-pressure (200 psi)	At Planned Connection Back-pressure (750 psi)	> Planned Back-pressure & < Back-pressure Limit (>200 psi & <890 psi)	≥ Back-pressure Limit (890 psi - 1.55 SG LOT)
Influx Indicator (Pit Gain)	No Influx	Continue Drilling	Continue Drilling	Increase pump rate, mud weight, or both AND reduce surface pressure to planned or contingency levels	Pick up, shut in BOP, evaluate next action
	Normal Operating Limit - 70% Kick Tol (560 L)	Increase back pressure, pump rate, mud weight, or a combination of all 3. Continue Drilling	Increase back pressure, pump rate, mud weight, or a combination of all 3. Continue Drilling	Increase pump rate, mud weight, or both AND reduce surface pressure to planned or contingency levels	Pick up, shut in BOP, evaluate next action
	< Planned Limit Max. Kick Tol. (780 L)	Stop Drilling. Increase back pressure, pump rate, mud weight or a combination of all 3, circulate out any influx prior to resuming operations	Stop Drilling. Increase back pressure, pump rate, mud weight or a combination of all 3, circulate out any influx prior to resuming operations	Pick up, shut in BOP, evaluate next action	Pick up, shut in BOP, evaluate next action
	≥ Planned Limit (> 780 L)	Investigate problem. Pick up, shut in BOP, evaluate next action	Investigate problem. Pick up, shut in BOP, evaluate next action	Pick up, shut in BOP, evaluate next action	Pick up, shut in BOP, evaluate next action

II.2. Study of MPD Wells in Bahar El Hamar field

Three wells, BH11, BH25, BH37 (see Table II.4 and Fig II.18) have been selected in 2018 in order to study in details all the difficulties faced while drilling the reservoir with managed pressure drilling technique (MPD) in BH field. We look for the most efficient approach to reduce these problems.

Table II.4: Selected wells and coordinates [13]

Name of wells	Rig	Spud date	Coordinates	
			X	Y
BH-11	TP158	09/2018	376 852.437	2 909 811.093
BH-25	ENF-06	14/04/2018	377572.82	2907844.63
BH-37	ENF-06	20/05/2018	379824.560	2910508.283

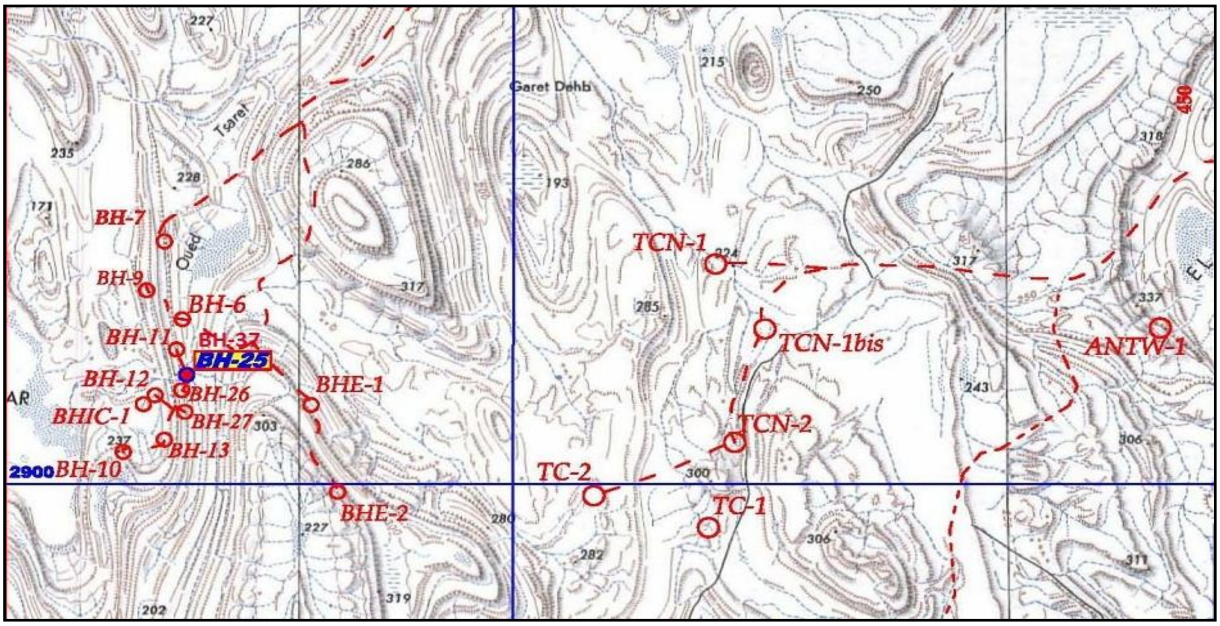


Fig II.18: MPD wells distribution.[13]

II.2.1 Well Plan

The well plan for BH-37 (as shown in Fig II.19) designed by SONATRACH engineers based on important data (formation lithology, well bore stability, formation pressure profiles, hole-section length, diameter, production zone intervals), in order to drill the targeted TD safely and without any damage of formation or reservoir.(see Fig II.19) [14]

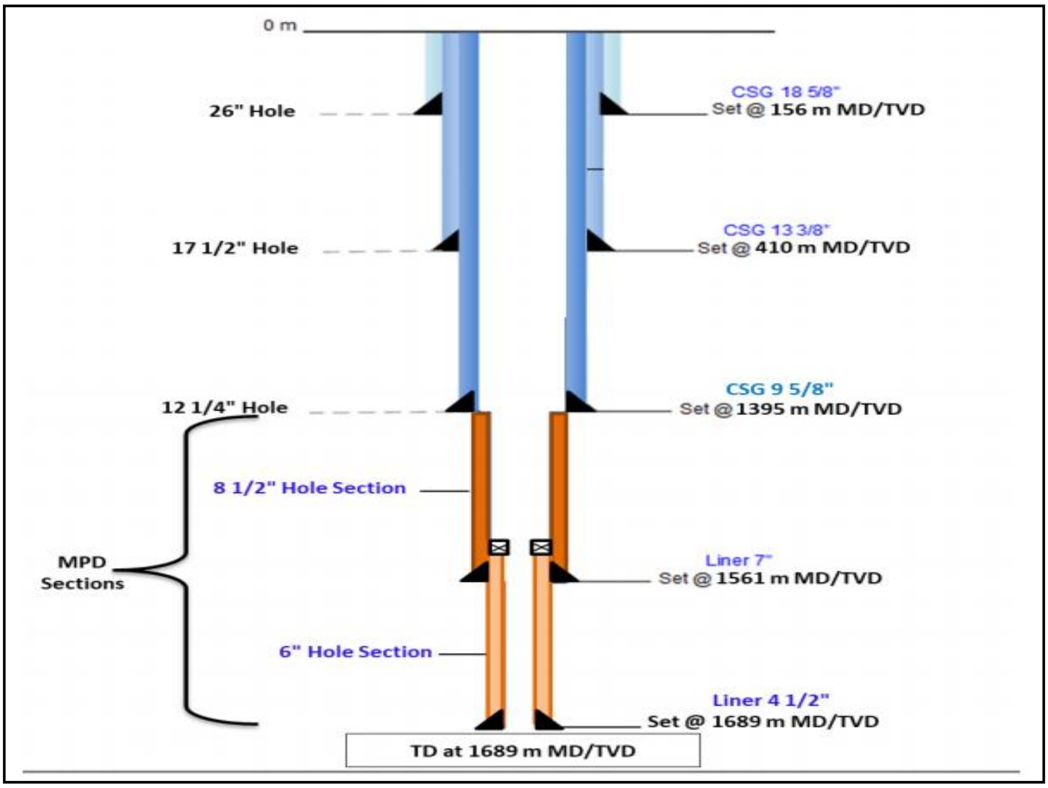


Fig II.19: BH37 well plan[14]

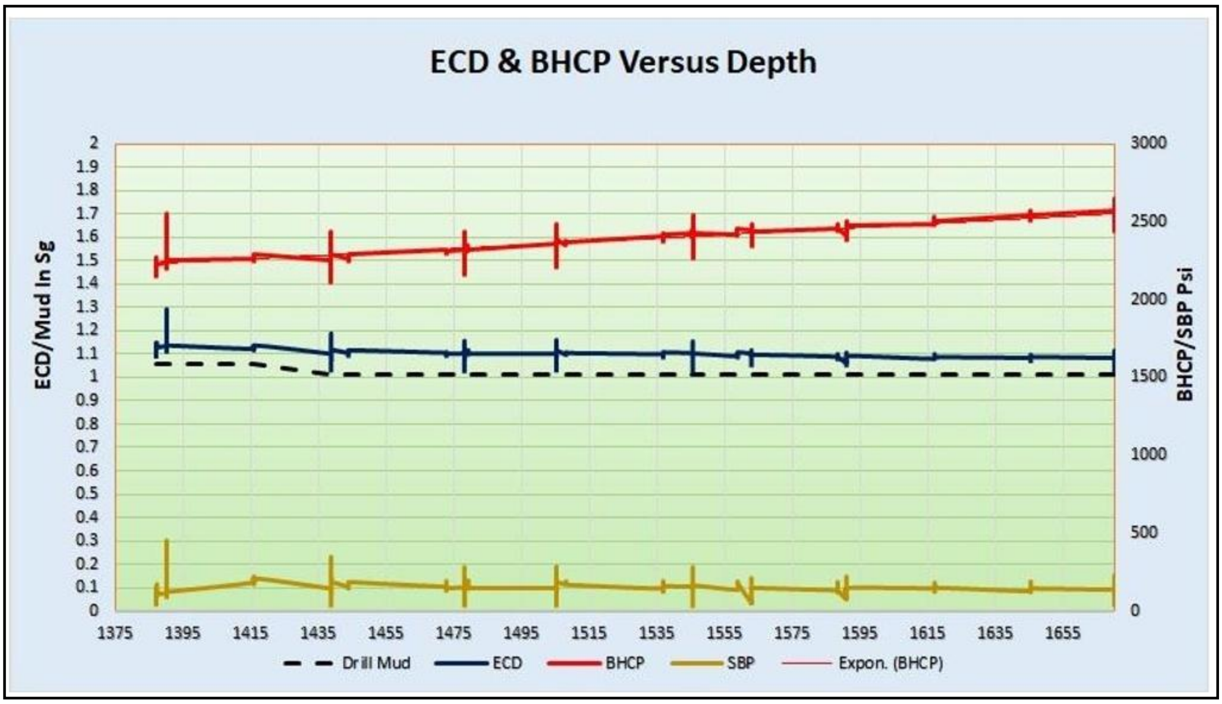


Fig II.20: BH-37 well 8 1/2" phase Pressure Profile. [14]

II.2.2. ROP and WOB characterization

A total of 308.75 hrs were required to drill the 8.5’’ section which equates to 13 days this was however spread over between 14th October and 11th November. The section was drilled with 3-bit with 6 trips.

During this time 299 m of open hole section was drilled penetrating for (Dall M’kratta, Grés d’el golea, Grés d’oued saret, Argile de tiferouine, Quartzites d’el hamra, Grés d’el atchane and Comberien).

First bit was used to drill out the cement and few meters of new formation 73m at an average 0.85 m/h of ROP to perform the first upper and lower limit test which achieved at 1.30 sg for the upper test and 1.07 Sg for lower test, the third bit was made which drilled 125m with 1.73 m/h of ROP. The average ROP achieved was around 0.97 m/h. Fig II.21 is a plot of ROP & WOB vs Depth showed below illustrates the ROP and WOB achieved while drilling 299 m of all the 8.5’’ section. [14]

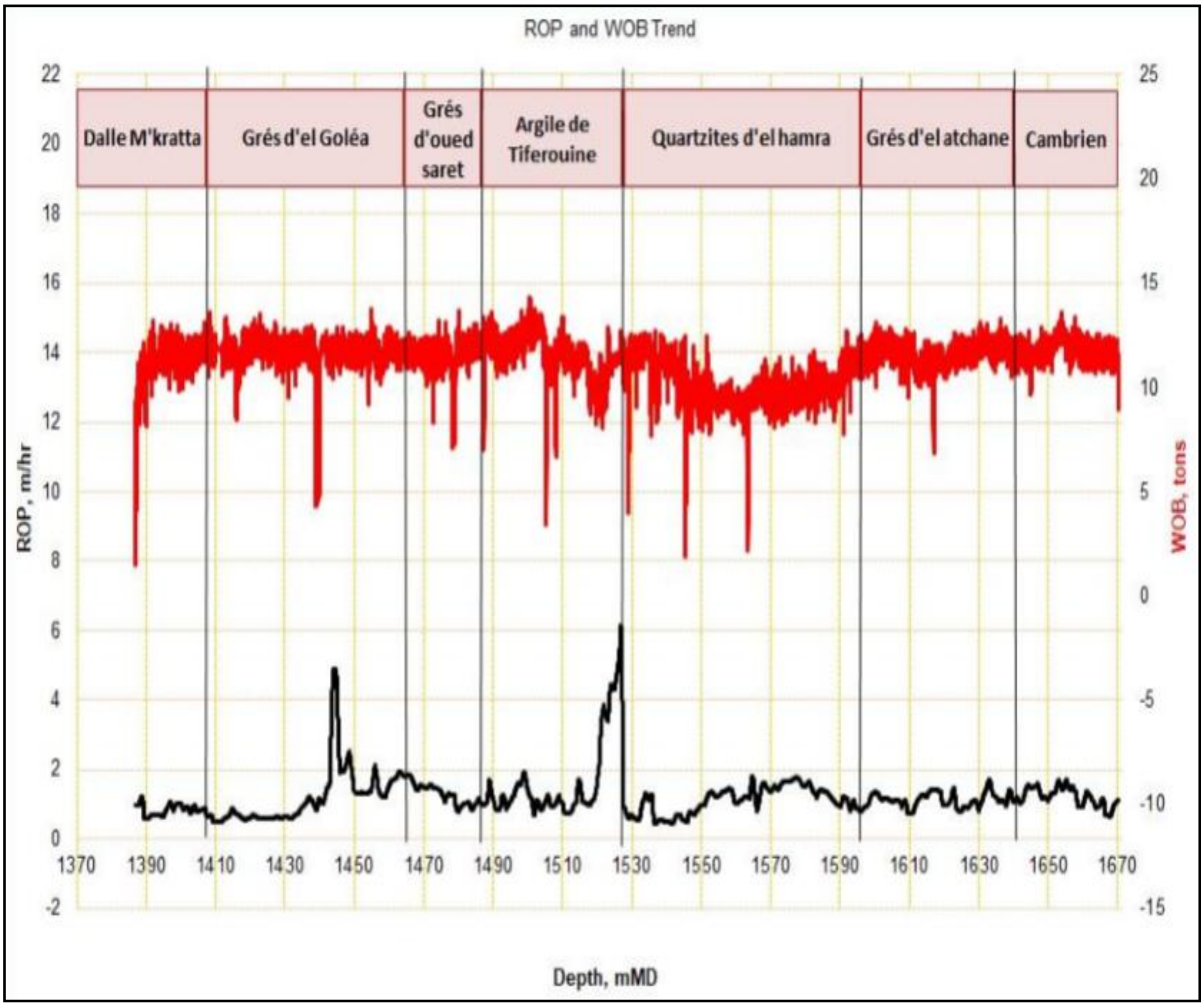


Fig II.21: BH-37 ROP & WOB vs. Measured Depth 8 1/2" Section. [14]

II.2.3. Bit Records

The table II.7 contains details of three BAKER HUGHES bits used to drill the 8 1/2" section of BH37 well.

The first bit used to drill out 16 m of cement and 35 m of the new formation. It drilled the cement and continued drilling to 1438 m MD, at that depth a decision taken to change the drill bit after 96 hrs of work.

After pooh to surface and change the bit by new hybrid drill bit, RIH back to bottom with LWD and resume the 8.5'' hole section drilling from 1438 m to 1545 m MD, a total of 107 m was drilled in 46 hrs by the second bit before the decision to change the drill bit in aim to L/D the LWD tools after confirmation of QZH top. The third BAKER HUGHES drill bit of BH-37 used to drill 125 m of 8 1/2" hole section from 1545 m to TD at 1670 m in 107,4 hrs. [14]

Table II.5: 8 1/2" Bit Record. [14]

BHA	Bit No/ReRun(U)	Bit Run	Bit Size	Bit Manufacture	Bit Type	Bit S/N	Bit TFA (in^2)	Bit Depth In MD/TVD (m)	Bit Depth Out MD/TVD (m)
1	10/N	1	8.5’’	BAKER HUGHES	GX-44GDXDH1	5274650	0.589	1387	1438
2	11/U	4	8.5’’	BAKER HUGHES	KM524X	5281108	0.785	1438	1545
3	12/N	2	8.5’’	BAKER HUGHES	VM-44CDVHX2	5277699	0.589	1545	1670

II.3. Descriptions of MPD Wells Problems

Table below represent the occurred problems in 8 $^{1/2}$“and 6“ with it description and it solution of BH25 well.

Table II.6: Analysis of problems for 8 1/2 “and 6“of the well BH25. [15]

Phase	Problem	Causes/Description	Consq (hrs)	Solutions
Lost8"	Partial losses	-at 1410 m observed mud losses -at 1410 m with a maximum rate of 200 l/min (overall losses was 3 m3) -at1414 m observed seepage losses since midnight with an average rate of 300 l/hrs. (total losses in 7 hrs was 2m3).	17,5	Pump LCM plug
Kick	Gas flow	-at1 178,0 drill out cement Meduim to Hard, while connection bubble observed at bell nipple	57,5	-Shut in the well as per SH procedure -flow check - Steady level & bubble observed at bell nipple- -circulation through poor boy to evacuate gas

Phase	Problem	Causes/Description	Consq (hrs)	Solutions
Excess	Logg/rup	-logging and rig up equipments	8	
Wait	Logging,casing ,completion, order ,MPDequipment	-Waiting on logging unit -waiting on casing 7" p110 n-vam 32# -waiting on completion equipment -repair on WFD MPD choke(hydraulicmotor blocked) -Observed Leak in cooling system of bearing (cooling fluid contaminated with mud).	256,75	

Fig II.22 shows the distribution of NPT problems of the well BH25 for the phase 8.5” and 6” of the BAHAR AL HAMMAR field. Wait have the large margin of NPT by 256.75 hrs (10 days) by 76% of total NPT. Kick also have a considerable value of 17% of total NPT beyond57.5 hrs (2 days).While Losses get a part of 17.5 hrs through 5% of total NPT of the well. Casing/Liner Excess get also a minimal part of 8 hrs away 2% of total NPT.

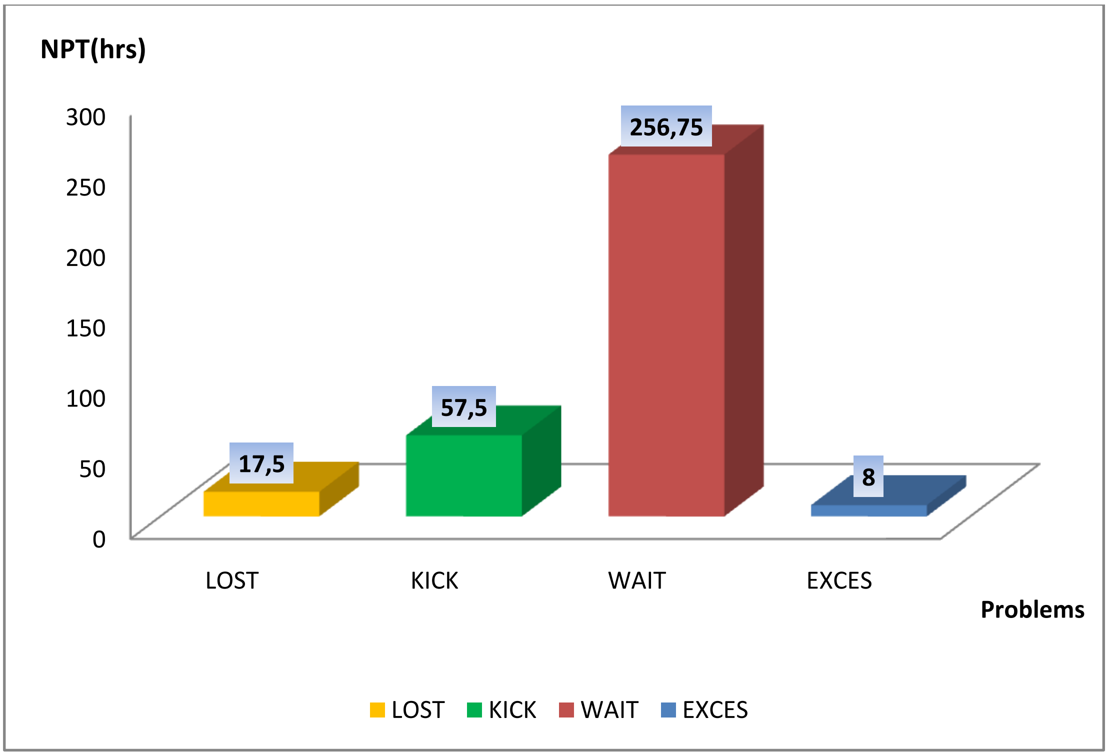


Fig II.22: The NPT Problems of the well BH 25.

Table II.11represent the description problems in 8 1/2"and 6"with it solution of BH37 well.

Table II.7 : Analysis of problems for 8 1/2 "and 6"of the well BH37. [15]

phase	Problem	Causes/description	Cons q (hrs)	Solutions
Lost	Partial losses	-at1562 m closed bop,circulate bottom up lost 5m3/h EMW=1.07sg,dynamic hold pressure lost 2.2m3/h EMW=1.05sg, -detected seepage losses w/ 300 - 470l/h while drilling from 1557m to 1559m -at 1670 m partial loss: 1.9 m3/hr. Upper & lower limit test at 1670 m detect partial mud losses 800 litters/h.	91,5	-Set at balance 4,3 m3 LCM PLUG d = 1.02 sg -set at balance 5 m3 LCM PLUG d=1,06 sg (200 kg/m3) -set at balance 7m3 LCM PLUG concentration (140kg/m3)
Misc	Gain	-Detected gain: 30l with ADA coriolis, check level mud tank -stable-	8,5	-ADA increase ECD gradually f/1.10sg to 1,14sg.
Wcon	Kick	-Flow check - unsteady level & bubble observed at bell nipple-	2,5	Circulation * increase density to 1.10sg * max tg=0.38%
Dprb	Remedial	-Wash down to bottom	124,75	-Cement plug job -squeeze operation -infectivity test
Wait	Logging, fix(ADA), completion	-Waiting on SLB logging equipments&crew. -Repair on ADA RCD bearing. -Wait on completion equipments	126	

Fig II.23: shows the distribution of NPT problems of the well BH 37 for the phases 8.5” and 6” of BAHAR EL HAMMAR Field. It can be seen that Wait have the largest part of NPT by 126 hrs (5 days), so it represent 35.68% of the total NPT. Remedial also has a considerable value of 124.75 hrs (5. days), whether 35.31% of total NPT. Whereas, lost circulation NPT occupy 26% of total NPT which represents 91.5 hrs (3 days). Miscellaneous & Well control operations have small margin about 2% and 1 % respectively of this NPT.

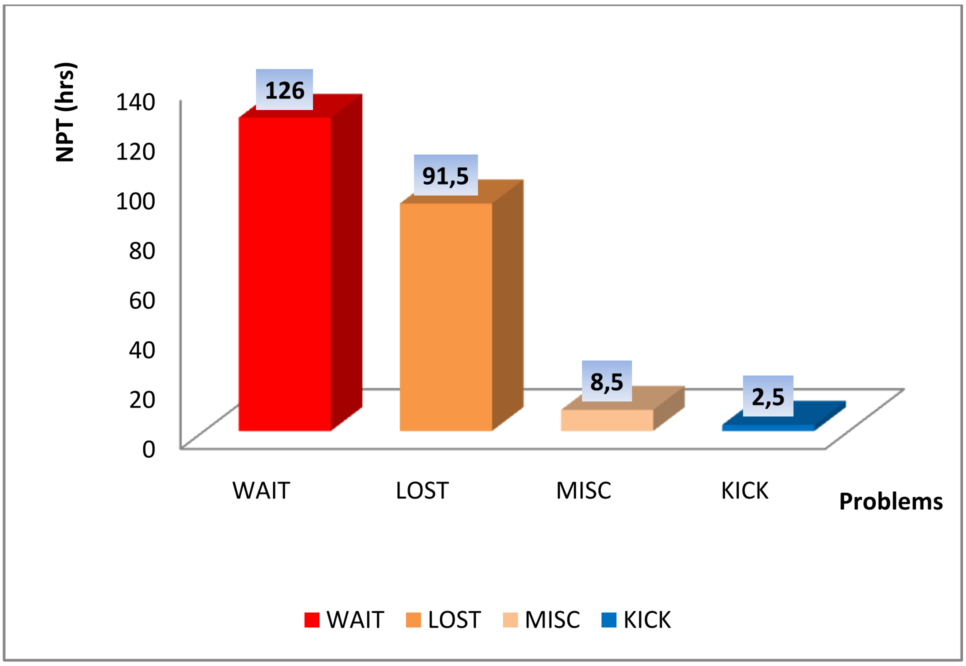


Fig II.23: The NPT Problems of the well BH 37.

II.4.Study of the problems produced

II.4.1Lost Circulation

- the wells drilled by MPD technology are characterized by partial losses between 1400 m-1600 m (Hamra Quartzite and Grés El Atchane) nearly at all in average rate of 300 l/hrs with mud density 0.95 sg
- Losses in this wells get in total : 170 hours (BH25= 17.5 hrs, BH37 =91.5 hrs, BH11= 61.75 hrs, see figII. 24).

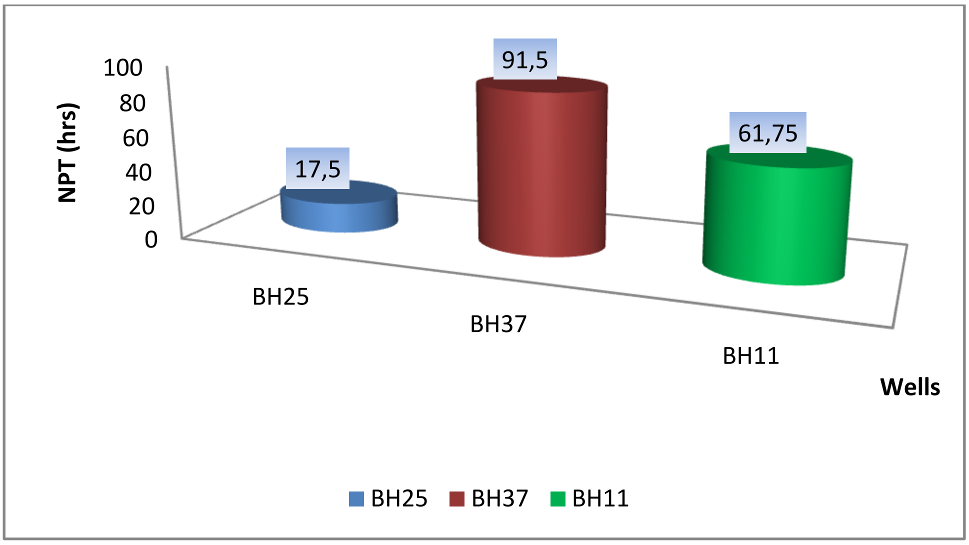


Fig II.24: Losses NPT in MDP wells

- Major of losses problems happened in this wells caused by Upper & Lower tests.
- Partial losses in this case cured by pumping LCM Plug (after drilling into 1562m MD a partial loss of 0.45m3/h is recorded).The decision made, is to decrease ECD to 1.05sg and to pull out the drill string to the casing shoe allowing us to pump 4.5m3 of LCM.
- Remedies and Solutions of losses problems were fast and efficient
- Losses by using this technique are very low (3m^3 case BH37), because using drilling window as a limited area between pore and fracture pressure. For that causes of losses were known and expected (fractured formation, cracked formation, tender formation, unconsolidated formation…etc) according to the table II. 8.

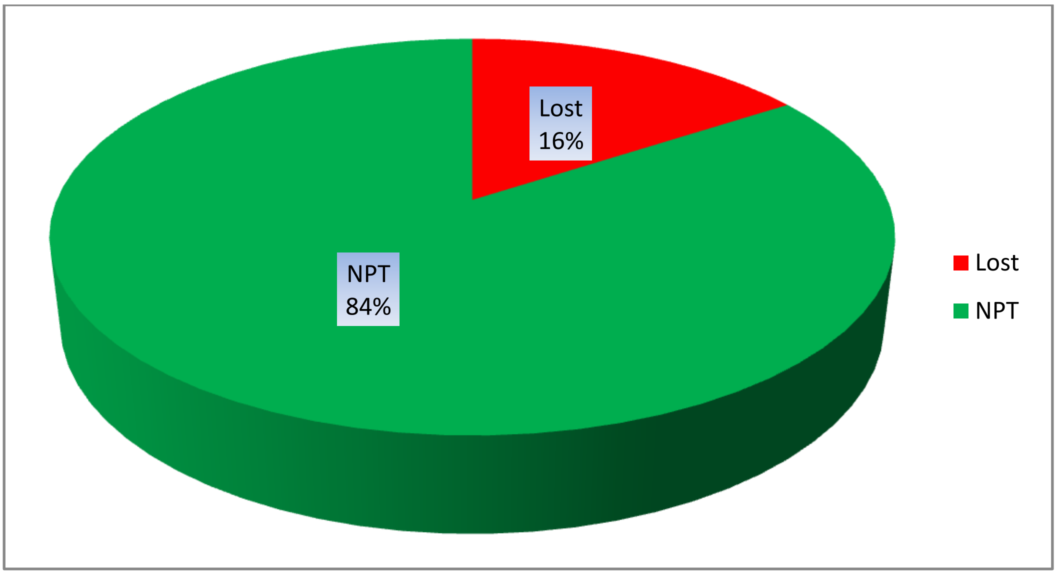
Table II.8: Bottom Hole Pressure Profile BH37. [16]

Formation	Date	Depth(m)	Upper test (sg)	Lower test (sg)	Time (min)	Gain (L)	Losses (L)
DMK	15/10/2018	1390	1.30	1.07	5	N/A	N/A
GOG	19/10/2018	1439	1.17	1.02	5	35	23
GOS	22/10/2018	1478	1.14	1.02	5	23	35
ATT	26/10/2018	1505	1.14	1.02	5	30	20
HQ	03/11/2018	1545	1.13	1.02	5	40	10
Cambrian	11/11/2018	1670	1.11	1.02	5	25	125

- To react with losses problems in this case is very easy and simple by using SBP, this technique eliminate displacement of mud to increase mud density if losses happened.
- The results of MPD drilled wells prove that there are no total losses happening while drilling 8$^{1/2}$ "and 6'' phases. This indicates the effectiveness of this technique and its approval.

- The geological complications are sometimes impeded success of lost interventions
- According to drilling reports by using this technique there are no difficulties to react with Losses.
- An average of 6 upper and lower test was performed during the operation in order to identify the real window and enhance the drilling ECD in target of enhancing drilling performance and avoiding any gain/losses while drilling.

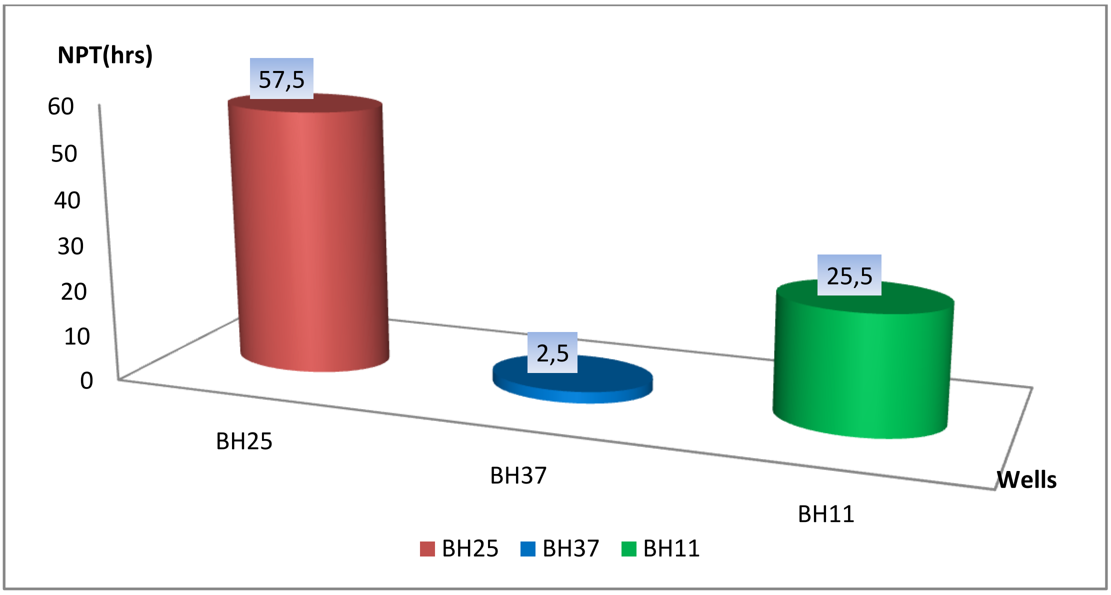
FigII.21 illustrates the total non productive time due to lost during the drilling operations of all wells considered. Which represent 16% of NPT.



FigII.25: Lost and NPT relation

II.4.2.Kicks

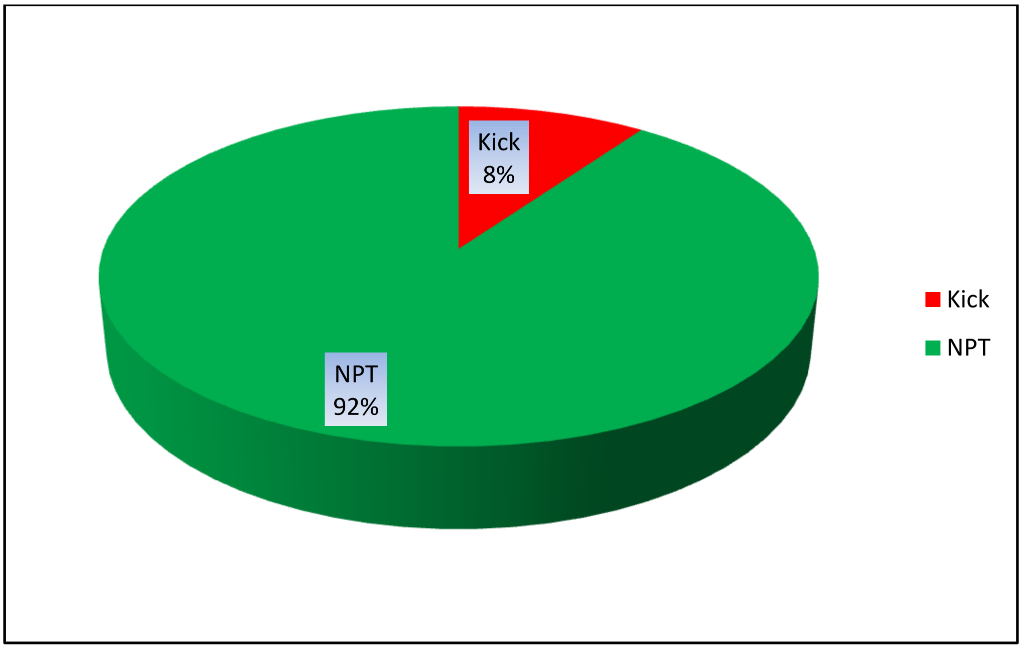
- Total NPT problems of kicks in this wells get 85.5 hours (3.56 days), BH 25= 57.5 hrs, BH 37 =2.5 hrs, BH 11= 25.5 hrs (see fig II.22)
- Reservoir of MPD drilled wells contains gas which are Ordovician, Cambrian, and Infra-Cambrian.
- Kicks detected at 1178 m , 1480m and 1597 m above DMK ATF and GEA respectively .



FigII.26: Distribution of kick between MPD wells

- Kicks occurred when Bottom hole pressure which adjusted by surface back pressure is less than pore pressure of the formations contain gas, see Eq. (II.2).
- Major of kicks scenarios occurred in this wells were caused by Upper & Lower tests(After limit test and run back to bottom hole, after mud displacement a gain was detected in ADA MPD system so back pressure increased gradually to 250 Psi in order to stop the gain as in case of BH37).
- A light OBM 1.06 Sg was used, it was changed to 1.02Sg at 1412m and to 1.01 Sg at 1439m with 1400-1600 Lpmflow rate and applying a backpressure results of 1.13 Sg and 1.10 Sg ECD when reached 1439m in depth while Drilling.
- Kicks in this MPD wells cured by increasing mud density ECD rapidly and displacement gain and evacuate it via MPD equipments (RCD , choke).
- Another state of kicks happening when drilling new hole section (kick detected while drill out cement (Case BH37), that what causes by using ECD less than pore pressure in front of permeable formations contain gas.
- Reaction with kicks scenario while using MPD technique was fast and easy (2,5 hrs for kick evacuation).

FigII.23 illustrates the total non productive time due to kicks during the drilling operations of all wells considered.



FigII.27: Kick and NPT relation

Conclusions

The use of MPD in the El Bahar El Hammara field was positive:

-Drill 8’’ ½ and 6’’hole sections to the planned depth 1700 m MD throughout the Ordovician:(DMK: DaledeMekrata/GEG: Gedinnian sandstone /GOS: sandstone of Serrat /QZH: Quarzitic of El-Hammra/Cambrian: Sandstone).

- Lost circulation and kicks has been reduced to a minimum.

- The development of the drilling window (pore & fracture window) specific to the reservoir instantaneous evaluation through the Lower & Upper tests.

-BH-37, BH11 and BH25 8.5’’and 6’’ Hole sections were drilled from the 9 5/8” casing shoe with MPD technology which is lower than the initial planned depth TD, However the main target was drilled in DMK-GEG-GOS-ATF-QZH-GEA-CAMB which represent a good reservoirs layers.

- No critical well control incident was experienced while drilling this sections. And all stripping in and stripping out operations were performed at lower speeds to ensure no influx would be swabbed in.

-Maintain the bottom hole pressure within MPD window limits (Pore pressure/fracture pressure) during the drilling operation.

-Reduce NPT associated with Loss/gain events, Mud weight increase/decrease, cement plugs, long circulations in circulating out kicks, stuck pipes/wellbore stability, hard reaming/back reaming, additional trips (due to cement plugs & curing losses).

Chapter III:

Technical and economic evaluation between conventional and MPD

Introduction

In this chapter, we will represent an evaluation study of both technologies: Conventional drilling and MPD applied in reservoir phase of Bahar El Hammar field. The both technical and economic aspects are explained by referring to the different problems produced and their consequences such as NPT and the Costs involved. Also, make a technical assessment of these problems and explain their various causes.

The study remains unfinished if we don’t talk about the impact of this lost time on the economic and strategic level of the company.

III.1. Recapitulation of Conventional wells drilled studied:

The table below (Table III.1) resumes the main problems with its NPT (hours) of two conventional wells. As we can see from this table the NPT of different problems (well control, lost circulation and wait) for conventional drilling wells get a high values. And these values cannot be disregarded compared to the overall drilling time.

Table III.1: NPT (Hours) of main problems of conventional wells.

NPT’s problems	BH 13	BH 26
Well control (hrs)	580	635
Lost circulation (hrs)	394	247.25
Wait (hrs)	218	543

Fig III.1 represents the total drilling time and non productive time during drilling operation of BH-13, BH26, BHE-2, BH27 wells. As it shown the figure we notice that NPT occupies almost half of total drilling time except BH-26 and BH-27 well where it represents more than half the total time.

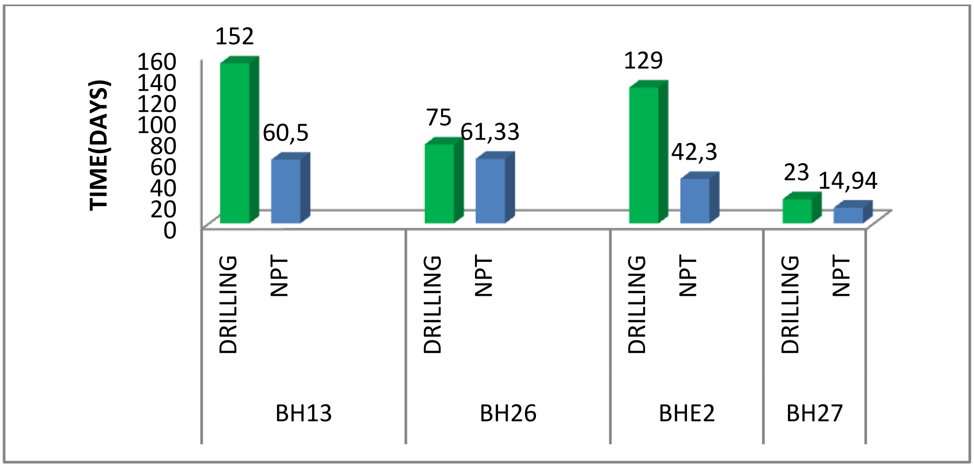


Fig III.1: Comparison between Total drilling time and NPT

Fig III.2 describes the percentage of NPT and Total drilling time for the four conventional wells studied. From this Fig III.2, the percentage shows that NPT represents 45% of the total drilling time. Also, it can be seen that the NPT occupies almost the half of total drilling time. These results must be considerable and noticeable.

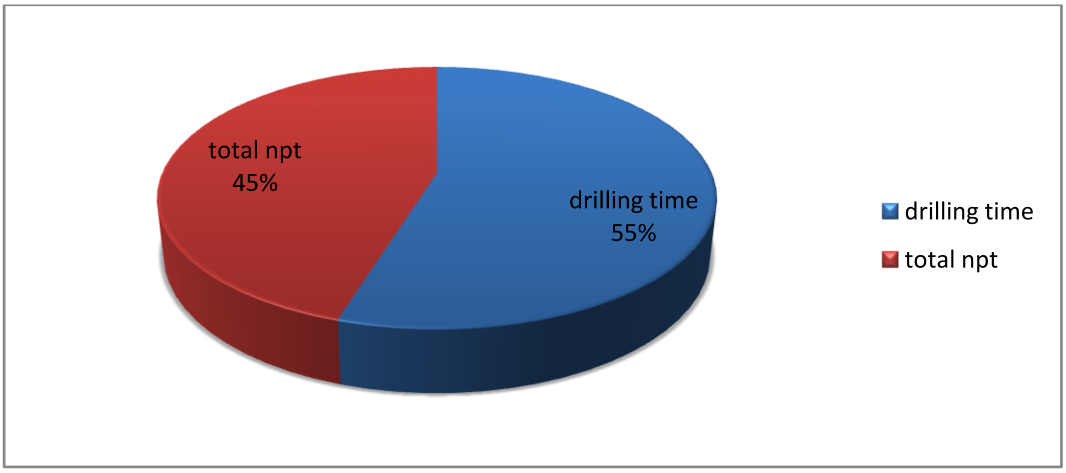


Fig III.2: Total Drilling and NPT Time distribution

Table III.2 contains the planned and the real time of selected conventional wells. As it mentioned in this table the real time is greater than the planned time due to loss & kick scenarios and their frequency and intensity.

Table III.2: Planned and Real Time Drilling of 8,5 " and 6" phases

Wells	Planned time (days)	Real time (days)
BH-13	64,6	152
BH-26	64,6	75
BHE-2	64,6	129
BH-27	64,6	23

NB:

-For BH-27 well, the real time is less than the planned time due to the drilling of this well is stopped.

-The target of all conventional wells (BH-13,BH-26,BH-27,BHE-2) are not achieved many causes we will talk about it.

III.2. Recapitulation of MPD wells studied:

The Narrow Pressure Window of the reservoir (8 ½" and 6" holes) in Bahar el Hammar field is very difficult to drill. So MPD can help and drill these formations safely, quickly and saving time and money.

So in this zone all problems such as "lost circulation, kicks" were solved with less NPT and less cost.

The table.III.3) shows the NPT of well control, lost circulation and wait problems in each well BH25, BH37, BH11. The one can say that, these values are acceptable compared to conventional wells. While Wait NPT's gets a high values compared to those of lost and well control. Wait NPT's depends on SONATRACH decisions and orders, as well as, the complacency and delay of human element in the execution of tasks. Furthermore, the Wait NPT's doesn't count as a technique on the MPD.

Table.III.3: Hours of major NPT of MPD wells problems

NPT's problems	**BH 25**	**BH 37**	**BH 11**
Well control	57,5 hrs	2,5 hrs	25,5 hrs
Lost circulation	17,5 hrs	91,5 hrs	61,75 hrs
Wait	256 hrs	126 hrs	187,5

Fig III.3 represents the drilling total time with NPT of BH25 and BH37. The NPT's occupies almost one third of total drilling time. This is considered like an achievement counts to MPD team compared to that recorded in conventional wells drilling.

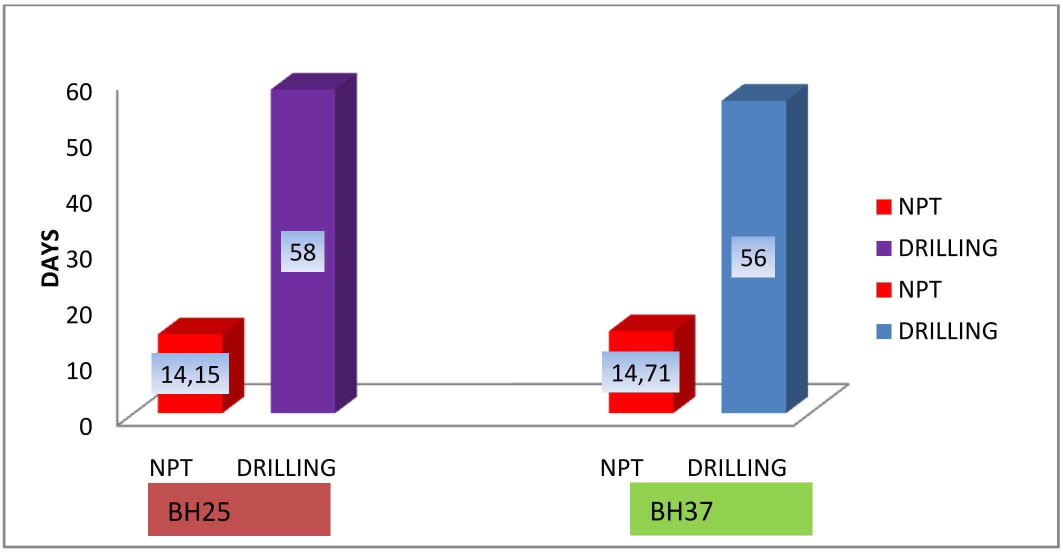


Fig III.3: Difference between Total drilling and NPT time

Fig III.4 appears a pie chart which defines a relation of non productive time and drilling time percentage to total drilling time for all MPD selected wells. We see that NPT resulting from MPD wells decreased. Where NPT value of 25% was recorded after we have been scored 45% of conventional wells drilling. This decrease considered like an achievement calculated to the MPD.

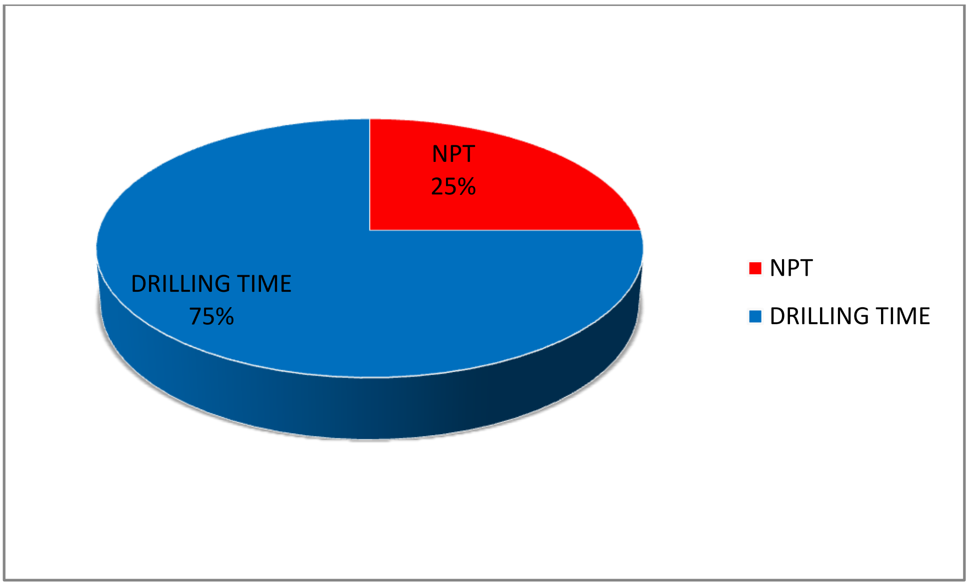


Fig III. 4: Breakdown time between Drilling and NPT

Table III.4 contains the planned and real time of MPD selected wells. It explains that real time (for realization of well) is less than planned time (which was set up as an estimate dury for drilling wells). and as it mentioned the real time doesn't reach planned time, including to the pervious result of conventional wells . Note that the time difference is clear and is evidence of the effectiveness of this technology and its significant role in reducing the total length of drilling well, thus winning time and money.

Table III.4: Planned and Real Time Drilling from phase 8,5 " [5]

Wells	**Planned time (days)**	**Real time (days)**
BH-25	78,56	58
BH-37	74,23	56

III.3. Comparison between conventional and MPD

We make a comparison which based on the establishment of major problems occurred and its total time between drilling and NPT's.

Fig III.5 represents total time results of Well control and lost circulation problems for conventional and MPD drilled wells, this column chart represented in hours. We notice that the difference of NPT (hours) recorded between the two drilling techniques is clear and remarkable. For Conventional wells, Well control represents a high value of 1215,5 hrs (50,6 days) and Losses by a considerable value of 642,75hrs (27 days). While, in the other side we recorded a little duration, much less than the first. Represented by 2,5 days for Well control and 4,5 days for lost circulation. From our study, most of the problems in the various wells are due to a variety of reasons:

-High probability for kick or fluid loss, especially when the margins between the pore and fracture gradients is unknown or not exactly estimated.

-Geological uncertainty (fractured and depleted formations).

-Losses in Hamra Quartzite and in micro-fractured Cambrian formations.

-Swab kick while tripping out

-Influx while drilling from Hamra Quartzite / Cambrian Reservoirs.

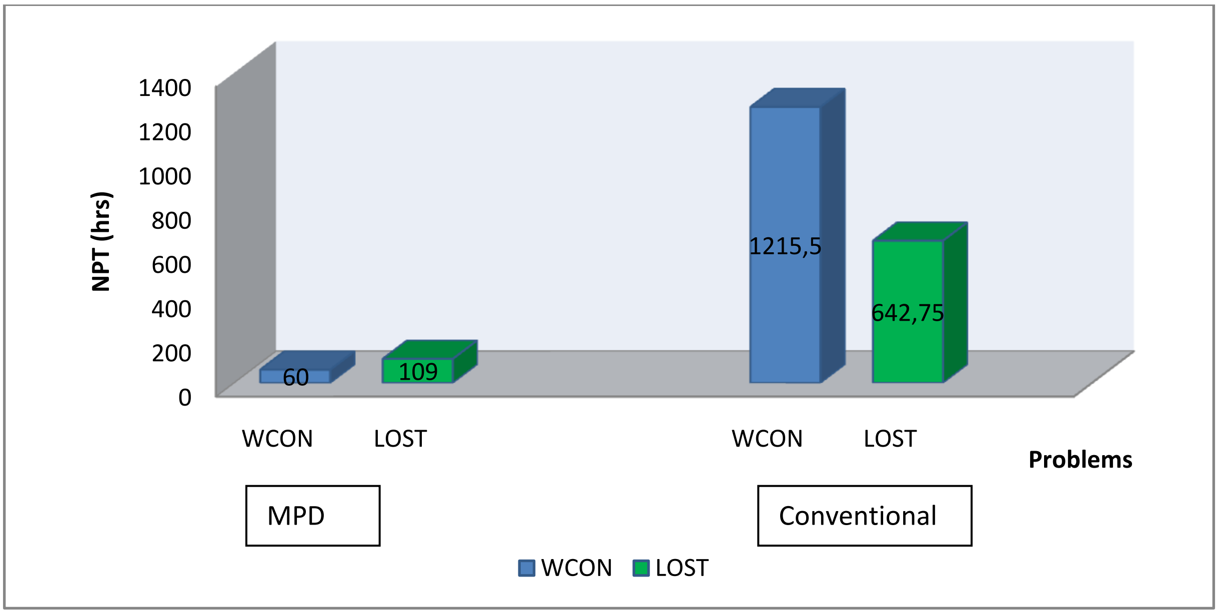


Fig III.5: Well control and Lost result between MPD and Conventional drilling

Fig.III.6 shows the consumed time for Conventional and MPD drilling techniques. What describes a large difference between them. The NPT's appeared in conventional wells were equivalents or a lesser amount of total drilling time. But NPT conducted by MPD drilling wells is much less than that of conventional drilling. These results can be described by the benefit of MPD and its efficiency for these types of problems (lost and kicks).

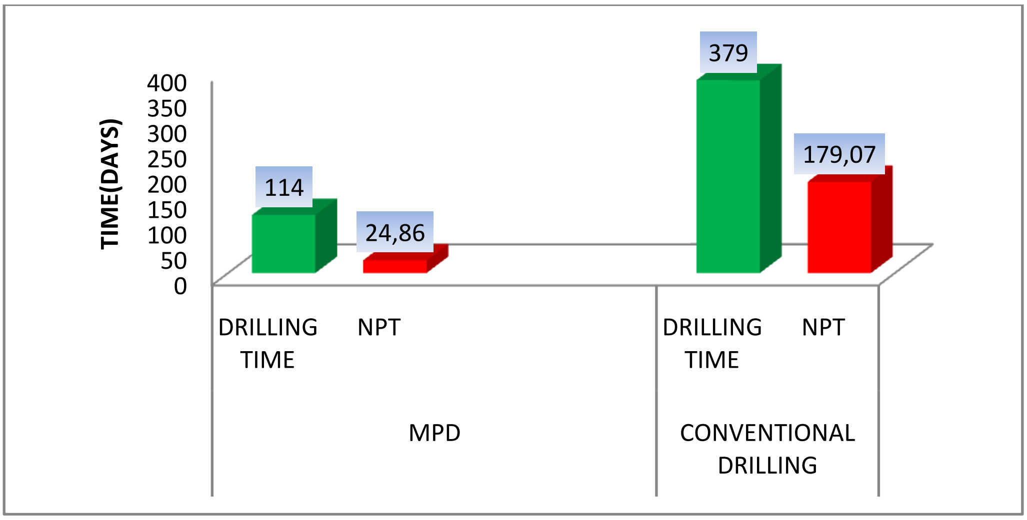


Fig.III.6: Conventional and MPD Progress

Table III.5 illustrates the selected wells in our study with its drilling technique progress used in El Bahar Hammar field.

Table III.5: Drilling costs and drilling progress

Wells	Drilling technology	Drilling time from 8,5" to 6''(day)	NPT's (day)	Cost of drilling 8,5'' and 6"(kDA)	Cost of drilled meter (kDA / m)	Average of drilled meter (Kda/m)
BH-13	Conventional	152	60.5	689776	2520	1890
BH-26	Conventional	75	61.33	319913	1750	
BHE-2	Conventional	129	42 ,3	759874	1400	
BH-25	MPD	58	14,15	427571	1730	1358
BH-37	MPD	56	14.71	372402	1245	
BH-11	MPD	52	12	301208	1100	

The cost price per meter drilled as the following:

$$P_m = (P_{dr}(T_d+T_t)+P_{db})/\Delta D$$

P_m: price of drilled meter (kda/m)

P_{dr}: price of rent drilling rig(kda)

T_d ,T_t: drilling ,tripping time(hours)

P_{db}: price of drilling bit(kda)

ΔD:drilled depth (m)

The results represent a large difference between the two drilling technologies according to the time and cost.

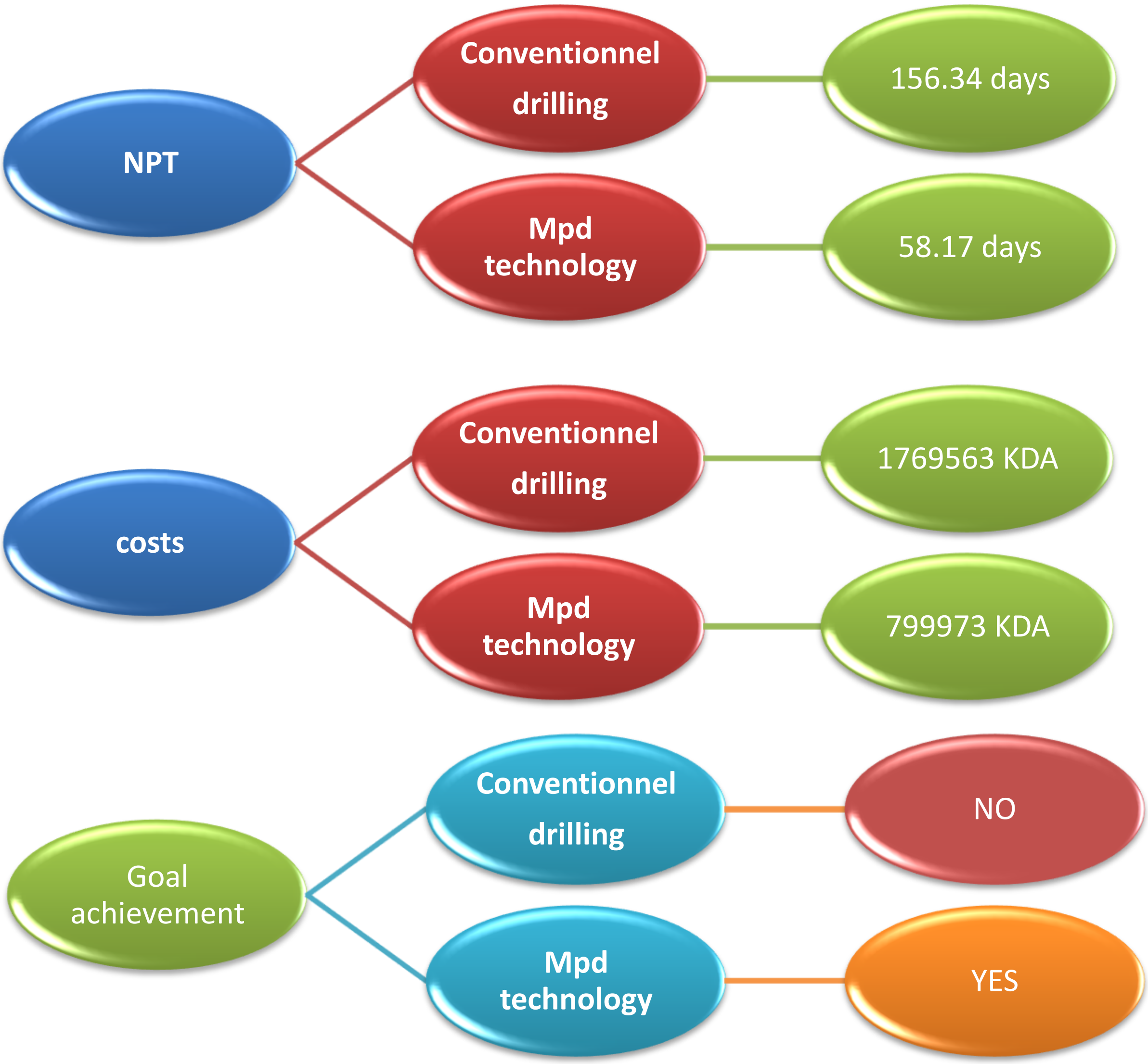


Fig.III.7: Organizational chart of main points and objectives for the both of techniques

Conclusion

After comparing the two techniques conventional and MPD, we can say that MPD is more positive and effective according the results and progress. Decrease of 20% of NPT’s in MPD wells drilled makes this technique an important advantages comparing to conventional drilling technique. Costs and NPT’s are two of the main indicators to evaluate success of drilling operations.

GENERAL Conclusion

Conclusions

In this thesis a study of managed pressure drilling (MPD) in Bahar El Hammar field is carried out. The core results are as follow:

- The primordial problem is that we cannot drill these wells (target not achieved) with conventional technique.
- The problems occurred during conventional drilling of the four wells in Bahar El Hammar field were hard to solve and to avoid them, such as kicks and lost circulation which result a large amount of non productive time.
- The main problems found in the conventional drilled wells studied are caused by the narrow drilling window (pore and fracture pressure are close). Taking in consideration the presence of many difficulties such as geological uncertainty and Missing a reliable geomechanical model in this region.
- The planned objectives of the wells drilled with MPD technique (8'' ½ and 6''hole sections) are reached.
- The application of the MDP technique in Bahar El Hammar field has efficiently reduced the amount of risks encountered in drilling the 8,5'' and 6" sections with the compliance of the operational objectives regarding safety, environment and performance.
- MPD is a drilling technique that helps to mitigate several drilling hazards, thereby reducing the associated NPT resulting in operational cost savings. However, this is only the result if a good candidate selection has been performed.
- No critical well control incidents were recorded during drilling these sections using MPD technique.
- MPD uses tools similar to those used in underbalanced drilling. This could mean a smoother transition for companies to begin using MPD technology.
- Many variations (methods) of MPD are available, but more research is necessary to determine which variation is best to be used in specific drilling situations.
- A large difference of NPT between MPD and conventional drilling techniques, which explains the effectiveness of this technique and its role in avoiding most dangerous problems.
- MPD is a technology that is continuously being developed, a technology with an exponential growth within the industry. Its usage is growing, due to its good features.

Recommendations and Suggestions

- It is highly recommended to use this technique (MPD) in other fields where a narrow mud window makes it difficult to drill.
- Many wells were already drilled which enabled us to acquire the required know-how for such application.
- It’s more positive to use MPD in exploration to help the extraction of the geological data.
- There are several classifications of MPD. However, the classification scheme of ‘Variations and Methods’, helps in better understanding of all the available MPD categories and sub-categories.

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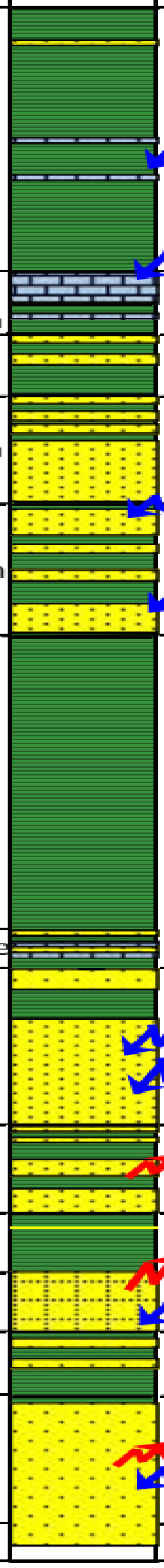
APPENDIX A

BH13 VERTICAL WELL

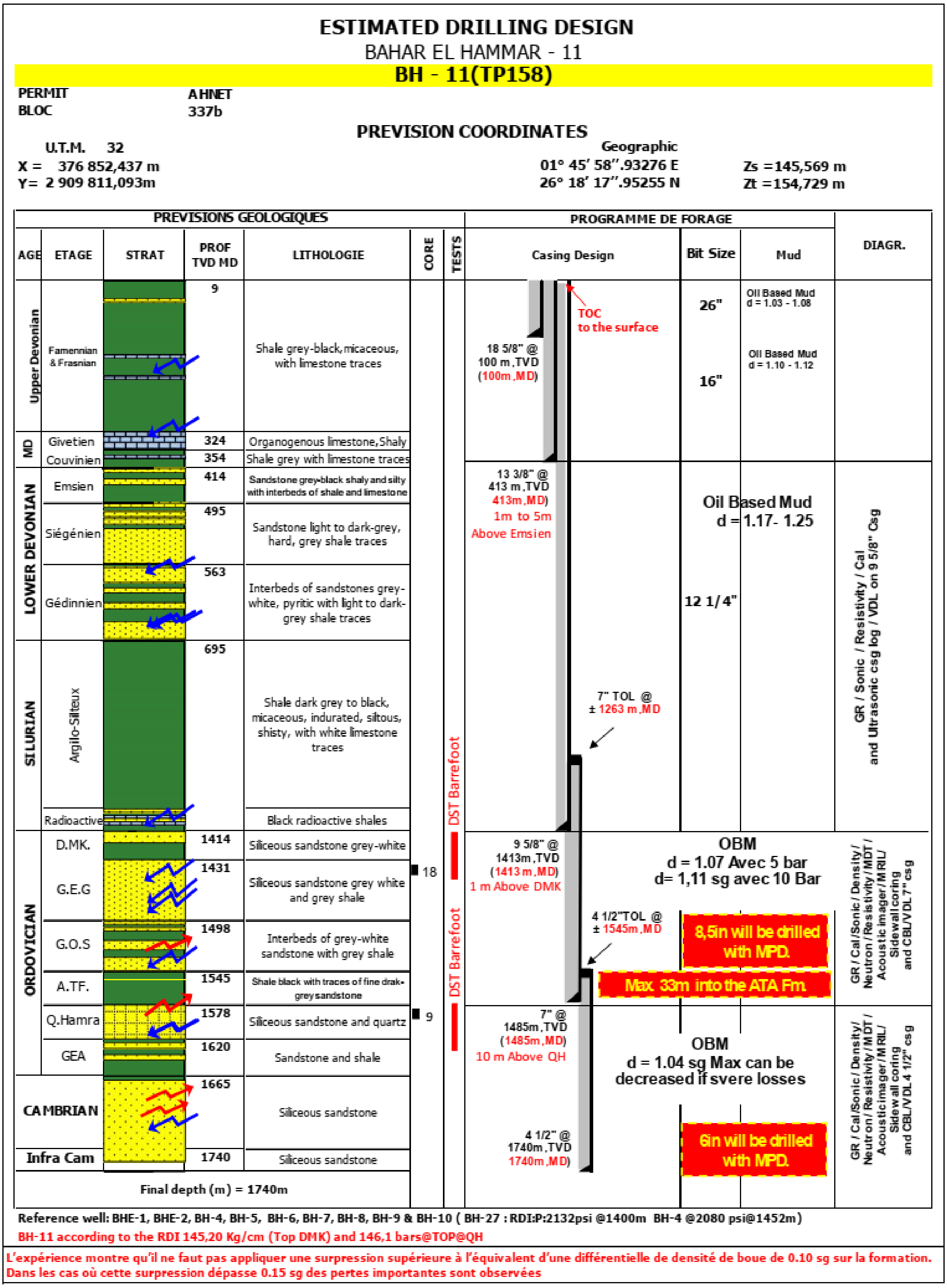
Sonatrach	Location	Algeria	Objectives	Ordovician Cambrian reservoir	Coordinates (UTM): 375 995.8 m E / 2 902 801.01 m N	Wellhead equipment	Subsurface equipment
Drilling Programme	Well Name	BH13	Well Cost Estimate	//	Coordinates (Local): 26° 14' 29.85'' N / 01° 45' 30.47'' E	13 3/8" x 20 3/4" 3K	
	Field	IN SALAH	Days on well	67,78days (TD); total completion operation 25,00days; well total including rig move 154,78days	Elevation GL:149,302, RTE 158,44m:	20 3/4" 3K x 13 5/8" 5K	
Rig: ENF06	Type	VERTICAL WELL			Actual RTE: 7,7m	13 5/8" 5K x 11"5k	



AGE	ETAGE	PROF TVD
Upper Devonian	Famennian & Frasnian	0
MD	Givetien	580
MD	Couvinien	
LOWER DEVONIAN	Emsien	675
LOWER DEVONIAN	Siégénien	765
LOWER DEVONIAN	Gédinnien	825
SILURIAN	Argilo-Silteux	950
SILURIAN	Radioactive	
ORDOVICIAN	D.MK.	1594
ORDOVICIAN	G.E.G	
ORDOVICIAN	G.O.S	1677
ORDOVICIAN	A.TF.	1734
ORDOVICIAN	Q.Hamra	1791
ORDOVICIAN	GEA	
CAMBRIAN		1831
Infra Cam		

Bit Size (inch)	Well (Risks, potential Hazrds Decision Pts and Contingencies)	CASING Size (inch)	CASING Weight (lb/ft)	CASING Grade/ coupling	CASING Shoe Depth (m)	CEMENT	DRILLING FLUIDS MUD	EVALUATION Survey and logs	PRESSURE TESTS (psi)
26" L115J / 223326 / 115 (RR)	Possible losses throughout. Max mud wt. out 1.08sg. Control drlg parameters & ROP<10 m/hr. 15-24T, 110-160 RPM, 2800-3300 lpm Sticky clays and bit balling. tight spoot while POOH, (TD 40m intoAnhydritique)	2 cent + 2 SCollar per joint for first 2 joints 1 cent + 1 SCollar on joints 3 & 4 1 cent + 1 SCollar per 4 joints for remaining joints to surface 1 cent + 1 SCollar for the last joint 5m from surface				to be confirmed w/lab tests	(OBM) Mud weight in=1,03sg Mud weight out <1,08sg YP: 26-30 LGS< 5% High bentonite loaded spud mud. Prep 24 hrs in advance	TOTCO on bit trips & TD	21 ¼" Annular: 300/1000psi Choke/Kill Lines: 300/1000psi Choke Manifold: 300/1000psi CHH 20"3/4: 375psi
	100	18 5/8	87,5	J-55 / BTC	100				
16" MKS69DG / 8710-A / M421 (RR)	Rotary Parameters: 15-24T, 2800-3300 lpm Caving and Shales instability Frasnian shales Shallow gas in Frasnian: minimum MW will be 1.10 SG Partial losses while drilling throughout the Frasnian/Givetian limestones	13"3/8 PDC drillable float equipment 2 cent + 2 SCollar per joint for first 2 joints 1 cent + 1 SCollar per 3 joints for remaining joints in open hole 1 Rigid cent + 1 SCollar per 4 joints 200m into 18-5/8" casing 1 Rigid cent + 1 SCollar for the last 2 joints at surface				to be confirmed w/lab tests	OBM MW: 1.10 sg PV: ALAP YP: 15-20 HTHP: <8 OWR 70/30-85/15 ES: 500 LGS< 5% Monitor YP and Shakers for excess hole erosion	TOTCO on bit trips & TD GR / Sonic / CAL and CBL / VDL 13 3/8" Csg	Casing N80 3000psi 13 5/8" rams 300/3000 psi Mud Cross & Choke 300/3000 psi chock manifold 300/3000psi CHS 20"3/4 x13"5/8 1350psi 13 5/8" annular 300/2500 psi
	674	13 3/8"	68#	N80 / BTC	674				
12-1/4" EHP44HP / YD7775 / 447 GF20BOAVPD / MY9381 / 517 RR	Rotary Parameters: 15-24T, 100-160 RPM, 2800-3300 lpm High Pressure zone with potential for High Fluid influx tight hole & stuck pipe	9 5/8" PDC drillable float equipment 2 cent + 2 SCollar per joint for first 2 joints 1 cent + 1 SCollar per 3 joints for remaining joints in open hole 1 rigid cent + 1 SCollar per 4 joints 200m into 13-3/8" casing 1 rigid cent + 1 SCollar for the last 2 joints at surface				to be confirmed w/lab tests	OBM MW: 2,04sg before LD2 PV: ALAP YP: 14-20 HTHP: <18 OWR 85/15-90/10 ES: 800 LGS< 5%	TOTCO on bit trips & TD GR / Sonic / Resistivity / Cal and Ultrasonic csg log / VDL on 9 5/8" C	SBT 1,00sg- 13-3/8" 13 5/8" rams 300/3000 psi Mud Cross & Choke 300/3000 psi chock manifold 300/3000psi CHS 20"3/4 x13"5/8 3000psi 13 5/8" annular 300/2500 psi
	1593	9.5/8"	47	P110 / BTC	1593				
8-1/2" KGR50BEPX / SCC073 / M842	Rotary Parameters: 5-15t, 1400-1800 lpm 60-150 Rotary Possible Losses kick due to the high pressure zone monitoring well very carefully	7" PDC drillable float equipment 2 Sprirel Glider+ 2 SCollar per joint for first 3 joints 1 Sprirel Glider + 2 SCollar per joint for next 10 joints 1 Sprirel Glider+ 1 SCollar per 3 jts remaining joints in open hole 1 Sprirel Glider cent + 1 SCollar per 4 joints in liner overlap				to be confirmed w/lab tests	Non Damaging OBM MW: 1,00 sg PV: ALAP YP: 10/15 HTHP: 4 OWR 90/10 ES: 800-1000 LGS< 5%	GR / Cal /Sonic / Density / Neutron / Resistivity / MDT / Acoustic imager / MRIL/ Sidew all coring and CBL/VDL 7" cs	FIT 1,00 sg 13 5/8" rams 300/3000 psi Mud Cross & Choke 300/5000 psi chock manifold 300/3000psi CHS 20"3/4 x13"5/8 1350psi 13 5/8" annular 300/2500 psi
	1781	7"	29#	P110 / N.VAM	1781				
6" HHCS112 / 7215354 / M843	Possible Risks : difficulties to drill the section to due to uncertainties of pore and fracture pressures	2 Sprirel Glider+ 2 SCollar per joint for first 3 joints 1 Sprirel Glider+ 1 SCollar per 3 jts remaining joints in open hole 1 Sprirel Glider cent + 1 SCollar per 4 joints in liner overlap				to be confirmed w/lab tests	Non Damaging OBM MW: 1,00 sg PV: ALAP YP: 8/12 HTHP: 4 OWR 90/10 ES: 1000-1900 LGS< 3%	GR / Cal /Sonic / Density / Neutron / Resistivity / MDT / Acoustic imager / MRIL/ Sidew all coring and CBL/VDL 4 1/2" csg	13 5/8" rams 300/5000 psi Mud Cross & Choke 300/3000 psi chock manifold 300/3000psi CHS 20"3/4 x13"5/8 1350psi 13 5/8" annular 300/2500 psi
	TD = 2131	4-1/2"	13,5#	N80/N.VAM	2131				

Appendix B



ESTIMATED DRILLING DESIGN
BAHAR EL HAMMAR - 11
BH - 11(TP158)
PERMIT AHNET
BLOC 337b
PREVISION COORDINATES
U.T.M. 32
X = 376 852,437 m
Y= 2 909 811,093m
Geographic
01° 45' 58''.93276 E
26° 18' 17''.95255 N
Zs =145,569 m
Zt =154,729 m
PREVISIONS GEOLOGIQUES
PROGRAMME DE FORAGE
AGE
ETAGE
STRAT
PROF TVD MD
LITHOLOGIE
CORE
TESTS
Casing Design
Bit Size
Mud
DIAGR.
Upper Devonian
Famennian & Frasnian
9
Shale grey-black, micaceous, with limestone traces
MD
Givetien
324
Organogenous limestone, Shaly
Couvinien
354
Shale grey with limestone traces
LOWER DEVONIAN
Emsien
414
Sandstone grey-black shaly and silty with interbeds of shale and limestone
Siégénien
495
Sandstone light to dark-grey, hard, grey shale traces
Gédinnien
563
Interbeds of sandstones grey-white, pyritic with light to dark-grey shale traces
SILURIAN
Argilo-Silteux
695
Shale dark grey to black, micaceous, indurated, siltous, shisty, with white limestone traces
Radioactive
Black radioactive shales
ORDOVICIAN
D.MK.
1414
Siliceous sandstone grey-white
G.E.G
1431
Siliceous sandstone grey white and grey shale
G.O.S
1498
Interbeds of grey-white sandstone with grey shale
A.TF.
1545
Shale black with traces of fine drak-grey sandstone
Q.Hamra
1578
Siliceous sandstone and quartz
GEA
1620
Sandstone and shale
CAMBRIAN
1665
Siliceous sandstone
Infra Cam
1740
Siliceous sandstone
Final depth (m) = 1740m
18
9
DST Barrefoot
DST Barrefoot
TOC to the surface
18 5/8" @ 100 m,TVD (100m,MD)
13 3/8" @ 413 m,TVD 413m,MD) 1m to 5m Above Emsien
7" TOL @ ± 1263 m,MD
9 5/8" @ 1413m,TVD (1413 m,MD) 1 m Above DMK
4 1/2"TOL @ ± 1545m,MD
7" @ 1485m,TVD (1485m,MD) 10 m Above QH
4 1/2" @ 1740m,TVD 1740m,MD)
26"
16"
12 1/4"
Oil Based Mud d = 1.03 - 1.08
Oil Based Mud d = 1.10 - 1.12
Oil Based Mud d = 1.17- 1.25
OBM d = 1.07 Avec 5 bar d= 1,11 sg avec 10 Bar
8,5in will be drilled with MPD.
Max 33m into the ATA Fm.
OBM d = 1.04 sg Max can be decreased if svere losses
6in will be drilled with MPD.
GR / Sonic / Resistivity / Cal and Ultrasonic csg log / VDL on 9 5/8" Csg
GR / Cal/Sonic / Density/ Neutron / Resistivity / MDT / Acoustic imager / MRIL/ Sidewall coring and CBL/VDL 7" csg
GR / Cal/Sonic / Density/ Neutron / Resistivity / MDT / Acoustic imager / MRIL/ Sidewall coring and CBL/VDL 4 1/2" csg
Reference well: BHE-1, BHE-2, BH-4, BH-5, BH-6, BH-7, BH-8, BH-9 & BH-10 (BH-27 : RDI:P:2132psi @1400m BH-4 @2080 psi@1452m)
BH-11 according to the RDI 145,20 Kg/cm (Top DMK) and 146,1 bars@TOP@QH
L'expérience montre qu'il ne faut pas appliquer une surpression supérieure à l'équivalent d'une différentielle de densité de boue de 0.10 sg sur la formation. Dans les cas où cette surpression dépasse 0.15 sg des pertes importantes sont observées

Appendix C

ESTIMATED DRILLING DESIGN

BAHAR EL HAMMAR - 26

BH - 26

PERMIT AHNET
BLOC 337b

PREVISION COORDINATES

U.T.M.	Geographic	
X = 377 227.598 m	01° 46' 13''.54554 E	Zs = 142.894 m
Y= 2 906 643.358 m	26° 16' 35''.11537 N	Zt =151.06 m

PREVISIONS GEOLOGIQUES

AGE	ETAGE	PROF TVD	LITHOLOGIE	CORE	TESTS
Upper Devonian	Famennian & Frasnian	0	Shale grey-black, micaceous, with limestone traces		
MD	Givetien	580	Organogenous limestone, Shaly		
MD	Couvinien		Shale grey with limestone traces		
LOWER DEVONIAN	Emsien	675	Sandstone grey-black shaly and silty with interbeds of shale and limestone		
LOWER DEVONIAN	Siégénien	765	Sandstone light to dark-grey, hard, grey shale traces		
LOWER DEVONIAN	Gédinnien	825	Interbeds of sandstones grey-white, pyritic with light to dark-grey shale traces		
SILURIAN	Argilo-Silteux	950	Shale dark grey to black, micaceous, indurated, siltous, shisty, with white limestone traces		
SILURIAN	Radioactive		Black radioactive shales	18	DST Barrefoot
ORDOVICIAN	D.MK.	1594	Siliceous sandstone grey-white		
ORDOVICIAN	G.E.G		Siliceous sandstone grey white and grey shale	9	
ORDOVICIAN	G.O.S	1677	Interbeds of grey-white sandstone with grey shale	9	DST Barrefoot
ORDOVICIAN	A.TF.	1734	Shale black with traces of fine drak-grey sandstone		
ORDOVICIAN	Q.Hamra	1791	Siliceous sandstone and quartz	9	
ORDOVICIAN	GEA		Sandstone and shale		
CAMBRIAN		1831	Siliceous sandstone	9	
Infra Cam			Siliceous sandstone		

Final depth (m) = 2131m

PROGRAMME DE FORAGE

Casing Design	Bit Size	Mud	DIAGR.
18 5/8" @ 100 m,TVD (100m,MD); TOC 250m above 13 3/8" shoe	26"; 16"	Oil Based Mud d = 1.03 - 1.08; Oil Based Mud d = 1.10 - 1.15	GR / Sonic / CAL and CBL / VDL 13 3/8" Csg
13 3/8" @ 674 m,TVD (674 m,MD); 7" TOL @ ± 1 443 m,MD	12 1/4"	Oil Based Mud d = 1.17- 1.31; Increase the MW to 1,25 at the top of Silurian	GR / Sonic / Resistivity / Cal and Ultrasonic csg log / VDL on 9 5/8" Csg
9 5/8" @ 1 593 m,TVD (1 593 m,MD); 4 1/2"TOL @ ± 1 734m,MD	8 1/2"	OBM emulsified Mud d = 1.00- 1.03	GR / Cal/Sonic / Density / Neutron / Resistivity / MDT / Acoustic imager / MRIL / Sidewall coring and CBL/VDL 7" csg
7" @ 1 781m,TVD (1 781 m,MD); 4 1/2" @ 2 131 m,TVD (2 131 m,MD)	6"	OBM emulsified Mud d = 1.00- 1.03	GR / Cal/Sonic / Density / Neutron / Resistivity / MDT / Acoustic imager / MRIL / Sidewall coring and CBL/VDL 4 1/2" csg

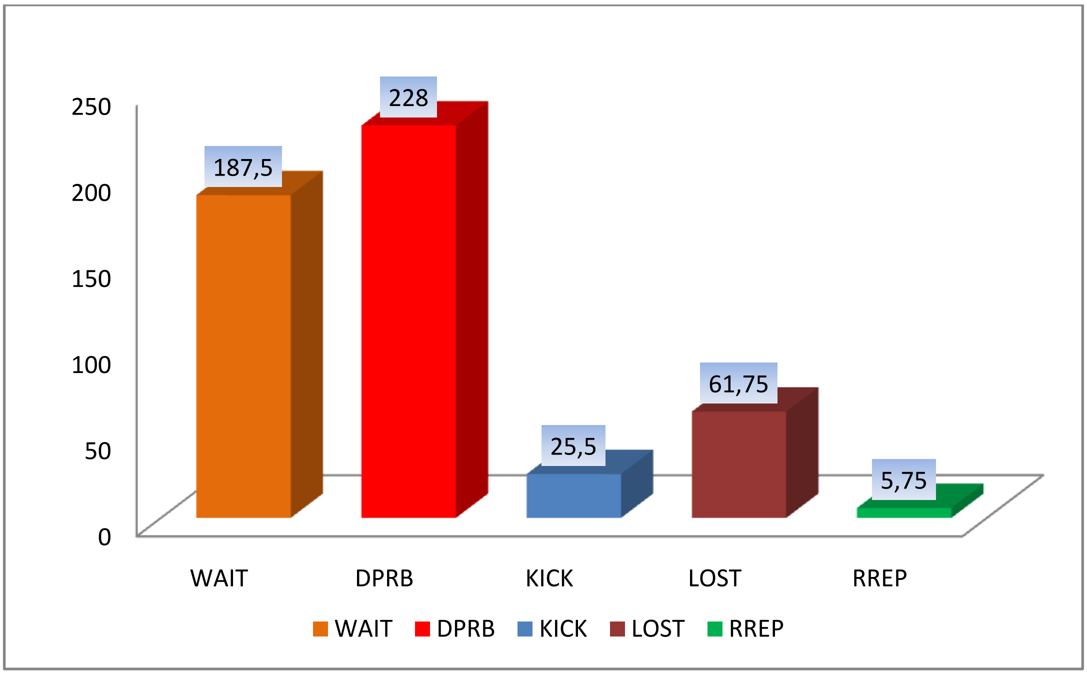
Reference well: BHE-1, BHE-2, BH-4, BH-5, BH-6, BH-7, BH-8, BH-9, BH-10 & BH-13

Formation Depth = TVDSS(m) + MSL + RT

Appendix D

BH-25 Management Plan for MPD															
	Interval		Modeling Depth	Formations	PP	FG	MPD MW	Target ECD (sg)		Applied SBP (psi)		Pump Rate	Ann. Vel	CTR	DDV
	(m MD)		(m MD/TVD)		(sg)	(sg)	(sg)	Shoe	At TD	Drilling	Connect	(lpm)	(m/min)	(Fract)	Y/N
8½ Hole Section Scenario 1	From	1284	1284	DMK, GEG,	1.08	1.15	0.95	1.13	1.11	250	330	1600	64.1	0.962	No
	To	1486	1486	GOS, ATF,									64.1	0.962	
8½ Hole Section Scenario 2	From	1284	1284	DMK, GEG,	1.13	1.19	1	1.18	1.16	250	330	1600	64.1	0.962	No
	To	1486	1486	GOS, ATF,									64.1	0.962	
6" Hole Section Scenario 1	From	1486	1486	Q.Hamra, GEA, Cambrian	0.93	1.01	0.85	1.005	1.001	150	330	900	73.2	0.9	Yes
	To	1660	1660										73.2	0.9	
6" Hole Section Scenario 2	From	1486	1486	Q.Hamra, GEA, Cambrian	0.95	1.05	0.9	1.033	1.032	100	283	900	73.2	0.9	Yes
	To	1660	1660										73.2	0.9	

Appendix E



BH 11 MPD . NPT result