OPTIMIZATION OF DRILLING HYDRAULICS IN VERTICAL HOLES

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7139

Dissertation submitted in partial fulfillment of
the requirements for the
Bachelor of Engineering (Hons)
(Mechanical Engineering)

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CERTIFICATION OF APPROVAL

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A project dissertation submitted to the
Mechanical Engineering Programme
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In partial fulfillment of the requirement for the
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Approved by,

....

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CERTIFICATION OF ORIGINALITY

This is to certify that the writer is responsible for the work submitted in this project, that the original work is his own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

Richard Lado Longwa Milla

ABSTRACT

This report gives the account on the dissertation of the final year project report title "Optimization of Drilling Hydraulics in Vertical Hole" assigned to the student as one of the courses requirement by the Universiti Teknologi PETRONAS before his graduation. The final year project given for period of two semesters starting from January of the first semester and ends December of the second semester 2008. Immediately following the continuation of the FYP 1 on this project, the student carries on to do study on the project. In the following dissertation report, it reports on the work that has been accomplished.

The necessary conditions for attaining optimal bottom hole cleaning below a drill bit is usually approximated via the optimization of two design criteria: Hydraulic Impact force and Bit Hydraulic horsepower. The process involves running a circulating pressure test at the rig site, while keeping the rotary speed and weight-on-bit constant. The test involves varying the mud pump speed and recording the pump pressure and circulating rate at each speed.

This paper describes a proven technique that maximizes either the hydraulic impact force or the hydraulic power of the fluid hitting the bottom of the hole. The objective is to determine nozzle sizes and flow rate to deliver maximum Hydraulic Horse power (HHP) or Jet Impact Force (JIF) within specified operating constraints.

In this paper, the introductory part in chapter one talked about the background, problem statement, Objective and the scope of study. Second chapter covers the literature review on the study and chapter three the methodology used. Chapter four discusses on the finding of the study, chapter five discusses the results and final chapter six gives the conclusion and the recommendation.

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CHAPTER ONE.

1.0 INTRODUCTION

The theory of hydraulic optimization of drilling with conventional (incompressible) drilling fluids is well known and has been widely practiced in the industry. Classical theory of hydraulics optimization for maximum drilling rate calls for either the use of empirical correlations (such as Fullerton charts, or Amoco curves) or the use of optimization theory to maximize some arbitrary objective functions such as maximum bit hydraulic horsepower or jet impact force.

As stated by Swanson et al. "drilling hydraulics optimization, similar to many other engineering optimization problems, involves the manipulation of several independent variables to obtain a maximum (or minimum) one or more of the dependent variables within boundaries imposed by cost, safety and the physical properties of the system under analysis".

Optimization of drilling hydraulics requires calculation of frictional pressure losses in the system and calculation of the minimum fluid velocity to carry the cuttings in the annulus. Determining the optimum back pressure and gas/liquid injection rates for effective cuttings transport while achieving maximum drilling rate are some of the major techniques in use under trail. Finding satisfactory answers to all of these problems have been a challenge for engineers with using incompressible drilling fluids.

1.1 Background

Drilling costs are a significant portion of exploration and production budgets. For this reason, the use of complex mathematical models to optimize drilling operations began in the early 1950s, at roughly the same time as the introduction of the first commercially available digital computer. Twenty years of development and field testing resulted in the release of sophisticated drilling optimization programs to the oil industry in 1971. Despite being tied to large mainframe computers, by 1979 computer optimization of drilling operations was being used by hundreds of companies to significantly reduce drilling costs. The development of inexpensive, yet powerful, microcomputers allows drilling optimization programs to be placed directly into the hands of drilling personnel anywhere in the world. This possibility promises to further reduce drilling costs in a dramatic way.

Today, well bores reach further, largely with almost the same equipment that has been in used for decades, improper selection or design of drilling hydraulics equipment, could also lead to large pressure drop along the fluid circulation system; it becomes even more important to efficiently utilize available hydraulic energy. Innovative down hole tools which currently consume more and more hydraulic energy, leaves less hydraulic energy for removing cuttings from beneath the drill bit. This energy consumption can be recognized at the maximum hydraulic power or force made available at the bit.

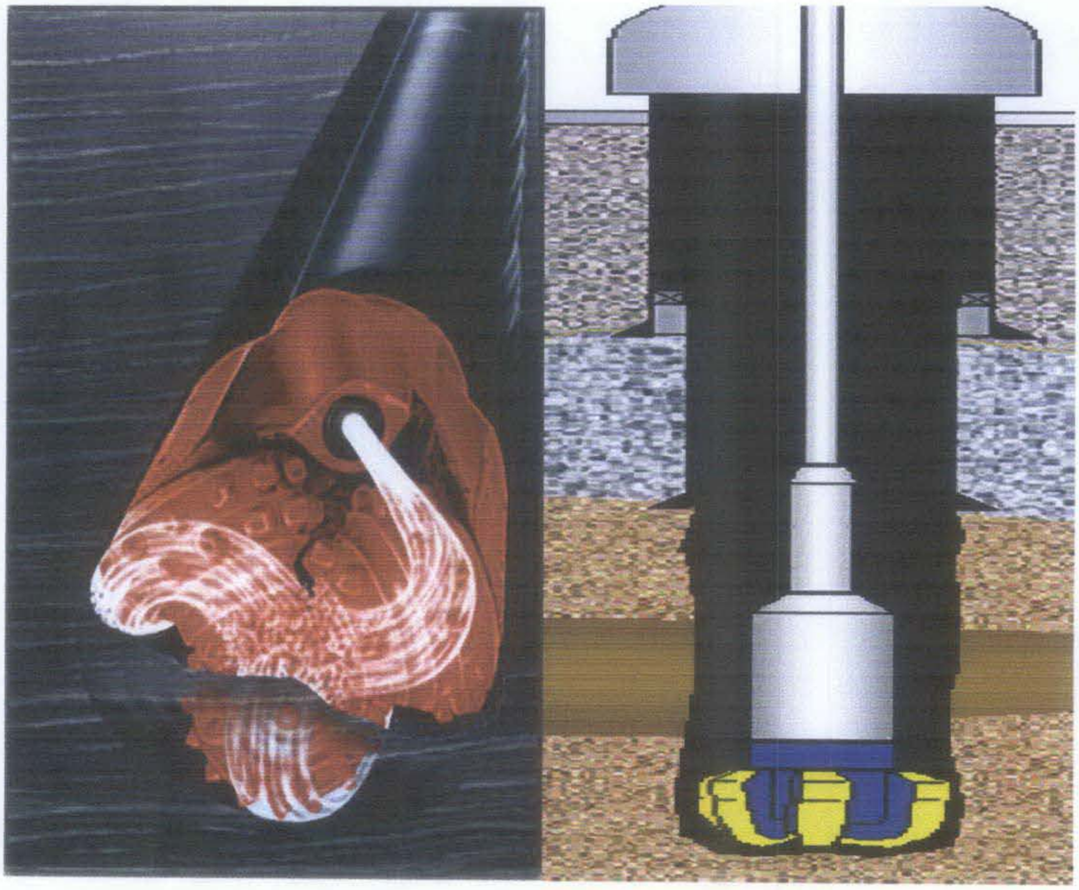

Figure 1.1: *HHP & JIF at the bit and the bottom hole assembly parameter.*

1.2 Problem Statement

Last year 2007, period from July to December in the field of Palouge back in Sudan hydraulic optimization program was initiated to all the wells under drilling. The objective was to optimize the hydraulic program to give sufficient hole cleaning and hence greater rate of penetration which in turn results to faster drilling and low cost. The program involved the analysis of frictional pressure losses in the system and the minimum fluid velocity to carry the cuttings in the annulus while taking into consideration the different formation types encountered throughout the drilling operation. The analysis and the optimization of these pressure losses are generally referred to as optimising the hydraulic power of the system.

Failure to optimize the hydraulic power to remove the cuttings, results to the drill string becoming stuck and theoretical optimization becoming fruitless. Another problem if the drill cuttings are not removed from the bit face, the bit wastes valuable effort in grinding them instead of making new hole and there will occur bit body balling in soft formation. This results in a significant reduction in penetration rate.

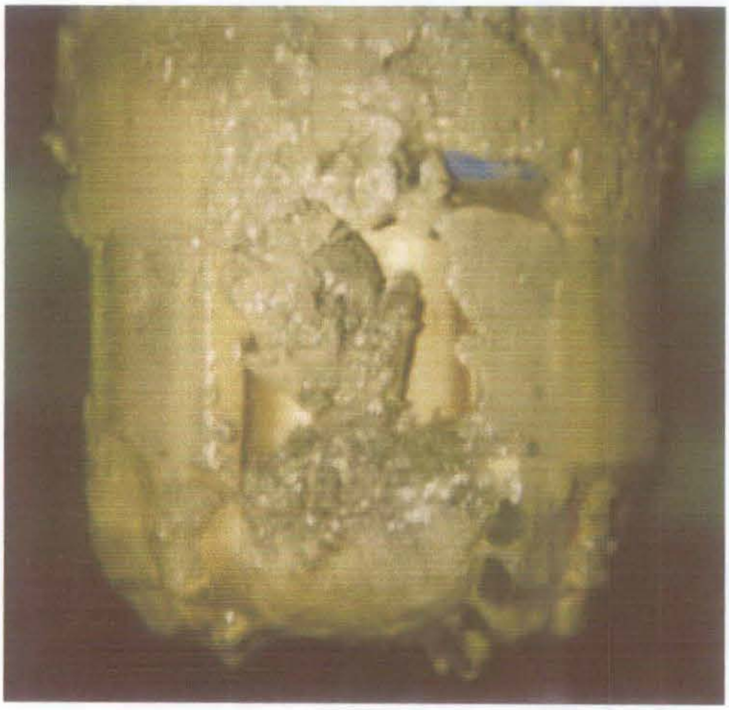

Figure 1.2: *Bit body balling.*

To ensure that the cuttings are removed from the annulus, the annulus velocity must never be allowed to fall below a certain minimum value. This minimum annulus velocity depends on the mud and cutting properties for any particular well (usually between 100 to 200 ft/min). Improper mud properties and poor circulation flow rate mostly result to insufficient cutting transfer to the surface. This usually happens due to poor application of hydraulic program resulting to high drilling cost.

1.3 Objectives

This project is intended to:

- To determine nozzle sizes and flow rate to deliver maximum Hydraulic Horse power (HHP) or Jet Impact Force (JIF) within specified operating constraints.

1.4 Scope of Study

To realize a safe, efficient and cost-effective drilling operation, drilling hydraulics, also known as rig hydraulics, play an important role. To achieve the objective, the hydraulics must be designed in such a way that the annular flow rate never falls below a pre-determined minimum value for lifting cuttings and the maximum pressure drop occurs across the bit. The pressure drops across the bit depends strong on the areas of the bit nozzle and the circulation flow rate, some careful designing is considered in satisfying both objectives. The operation constraint may include;

1. Maximum Standpipe Pressure
2. Minimum and Maximum Flow Rate
3. Maximum Pump Horsepower
4. Mud Weight
5. MWD and Motor Considerations
6. Fixed Flow Rate
7. Fixed nozzle Total Flow Area (TFA).

The scope for this study covers main aspects that make up optimum rig hydraulics i.e. Hydraulic Horse power (HHP) or Jet Impact Force (JIF) on the bit and nozzle size selection. The HHP approach assumes that the best method for cleaning the hole is to concentrate as much fluid energy as possible at the bit and the JIF approach assumes that the most effective method is to maximise the force with which the fluid hits the bottom of the hole.

CHAPTER TWO.

2.0 LITERATURE REVIEW

Once in the field of Palouge back in Sudan hydraulic optimization program was initiated to all the wells under drilling. The objective was to optimize the hydraulic program to give sufficient hole cleaning and hence greater rate of penetration which in turn results to faster drilling and low cost. The program involved the analysis of frictional pressure losses in the system and the minimum fluid velocity to carry the cuttings in the annulus while taking into consideration the different formation types encountered throughout the drilling operation. The analysis and the optimization of these pressure losses are generally referred to as optimising the hydraulic power of the system.

Another aspect for considerations is the analysis of solids transport by incompressible fluids, which still requires much effort. The role of liquid and gas phases on the transport is not clearly defined. Basically, it is assumed that in down-hole conditions gas volume fractions are small and transport is governed by the liquid phase. In the shallow portions of the well, gas velocities are high enough to contribute to cuttings transport.

Substantial research has been carried out over many years with regard to the principles of hydraulic optimization in vertical and horizontal wells. These studies have been carried out both at research centers and in the field and significant documentation on the concepts of hydraulic optimization available within the industry.

2.1 Drilling Hydraulics and Cuttings Transport

Many personnel at the rig have an impact on how well will drilling hydraulic be optimized to enhance hole cleaning. The drilling supervisor, the tool pusher, the mud engineer, the directional driller, the logging engineer, etc are all in one way or other involved and in performing their own particular functions, there is an overlap which can influence on the success of the well being optimized and better cleaned. More significance is that if one person takes actions in an adverse direction, much can be lost. The effectiveness of optimizing drilling hydraulic to improve hole cutting removal in vertical wells is greatly enhanced when personnel work as a team. For some operators, even their research personnel become an extension of the drilling team. Furthermore, the operation can be broken down into the drilling aspect, the hole cleaning aspect and the data gathering aspect. At times, there has to be some compromise between what can safely be achieved. There may be some cases where geology and reservoir engineering can't always be so demanding in what data gathering equipment, they request to be incorporated into the bottom hole tools.

The use of drilling fluids basically associated to the desire and need of having a low pressure profile inside the well. However, each drilling scenario demands the maintenance of the pressure profile inside an optimum range during the operations for optimum drilling hydraulics. The achievement of this goal can be accomplished by the availability of:

1. A reliable and simple system for designing the drilling hydraulics program, involving the prediction of the equivalent circulating density for the drilling fluid, which may contain a non-Newtonian liquid, gas, oil and solid particles and;
2. A suitable set of operational procedures for keeping the bottom hole pressure within the desirable range during connections, tripping or any other operations where the circulation is interrupted. During these periods, the drilling fluid system is not in equilibrium and, thus, the pressure profile has a tendency to change gradually along the time.

The system for hydraulics design will be based on available models that, for its validation, will be compared against experimental and field data, to be gathered along the project. Field data will be collected during pre-drilling tests or during the operations, using memory or real-time pressure and temperature sensors. Experimental data will be obtained through controlled tests in a real-scale instrumented well, in flow-loops.

CHAPTER THREEE

3.0 METHODLOGY

3.1 Procedure identification.

Carry out the pressure drop analysis by studying the velocity flow rate from the pump through the surface equipment, drillstring and the annulus.

↓

Adjust the hydraulic parameter to give optimum hydraulic horsepower and the jet impact force at the bit.

↓

Set analytical model from the fundamental

↓

Fabricate the experimental Model.

↓

Conduct lab drilling simulation experiment to investigate the effect of hydraulic optimization with varying nozzle sizes and fluid flow rate.

↓

Analyze the result

↓

Give conclusion and recommendation

Figure 3.1: *Flowchart on methodology research.*

CHAPTER FOUR.

4.0 DISCUSSION ON THE STUDY

4.1 Hydrostatic Pressure inside the Wellbore

For oil well applications, the fluid may be mud, foam, mist, air or natural gas. For a complex fluid column consisting of multiple fluids, the hydrostatic pressure is given in field units by:

$$P=0.052\sum_{i=1}^{n} p_m\left(D_i - D_{i-1}\right) \qquad 4.1$$

Where:

p_m *[ppg]* ....mud weight of the i[th] fluid column.

When gas is present in the well, the hydrostatic pressure developed by the gas column is calculated with:

$$p = p_o.e^{\frac{M.(D-D_o)}{1.544.z.(T_f+460)}} \qquad 4.2$$

Where:

z [1] ....real gas deviation factor

po [psi] .... Surface pressure

D [ft] .... total depth (TVD)

Tf [F] .... bottom hole temperature of the formation

The molecular weight M of the gas is found as:

$$\mathrm{M} = \frac{80.3.z.(T+460).p_g}{p} \qquad 4.3$$

Where:

p_g *[ppg]* ....density of the gas

T [F] ....average gas density

For practical purposes, the hydrostatics due to a complex fluid column is converted to an equivalent single-fluid hydrostatic pressure. To do this, all individual hydrostatic pressures are summed up for a specific depth p_d and then converted to an equivalent mud weight p_e [ppg] that would cause the same hydrostatic pressure.

$$P_e = \frac{p_d}{0.052.D} \quad \text{......} 4.4$$

Therefore the equivalent mud weight has to be always referenced to a specific depth. As the mud is used to transport the cuttings from the bottom of the hole to the surface and penetrated formations often contain a certain amount of formation gas, the mud column at the annulus is usually mixed with solids and gas. This alters the weight of the mud at the annulus. The new average mud weight *P*m of a mixture containing mud and solids can be calculated as:

$$\overline{\rho_m} = \sum_{i=1}^{n} \rho_i . f_i \quad \text{......} 4.5$$

Where:

P_i [ppg] ... .density of component i.

f_i [1] ....volume fraction of component i.

It should be noted that only solids contents that are suspended within the mud do alter the mud weight. Settled particles do not affect the hydrostatic pressure. If gas is present in the mud column as well, the density of the gas component is a function of the depth and will decrease with decreasing pressure. In this way, the density of mud containing gas is decreasing with decreasing depth. When the gas-liquid mixture is highly pressured (e.g. deep section of the well), the variation of the gas density can be ignored.

It is essential to understand that well control and the safety of drilling operations are strongly depended on the maintenance of proper hydrostatic pressure. This pressure is needed to counterbalance the formation pressure. In case the hydrostatic pressure in the borehole is higher than the formation pressure, the situation is called "over-balanced". This prevents kicks (fluid flow from the formation into the borehole) and causes at permeable formations an intrusion of some mud (water component) into the formation. The intrusion is stopped by the built up of mud cake that seals off permeable formations.

On the other hand, the hydrostatic pressure inside the borehole must not be higher than the fracture pressure of the formations penetrated since this would fracture the formation artificially, cause loss of circulation and lead to well control problems. To obtain maximum penetration rates the hydrostatic pressure should be kept as close as practical to the formation pressure since a higher differential pressure (hydrostatic pressure - formation pressure) leads to worst cutting removal from the bottom of the well. Due to this circumstance, underbalanced drilling techniques have been developed that use air, foam or mist as drilling fluids.

4.2 Types of Fluid Flow

Since multiple aspects of drilling and completion operations require the understanding of how a fluid move through pipes, fittings and annulus, the knowledge of basic fluid flow patterns is essential. Generally, fluid movement can be described as laminar, turbulent or in transition between laminar and turbulent. It should be understood that rotation and vibrations influence the rheological properties of drilling fluids. Also the pulsing of the mud pumps cause variations in the flow rates as well as the mean flow rates. Furthermore changing solid content influences the actual mud density and it's plastic viscosity.

Fluid movement, when laminar flow is present, can be described as in layers or "laminae". Here at all times the direction of fluid particle movement is parallel to each other and along the direction of flow. In this way no mixture or interchange of fluid particles from one layer to another takes place. At turbulent flow behaviour, which develops at higher average flow velocities, secondary irregularities such as vortices and current are imposed to the flow. This causes a chaotic particle movement and thus no orderly shear between fluid layers is present.

The so called "Reynolds number" is often used to distinguish the different flow patterns. After defining the current flow pattern, different equations are applied to calculate the respective pressure drops.

For the flow through pipes, the Reynolds number is determined with:

$$Re = \frac{928.\rho_m.\bar{v}.d_i}{\mu} \quad \text{.......} 4.6$$

$$\bar{v} = \frac{q(gal/\min)}{2.448.d^2{}_i} = \frac{17.16.(bbl/\min)}{d_i^2} \quad \text{.......} 4.7$$

For the flow through annuli;

$$Re = \frac{928.\rho_m.\bar{v}.d_e}{\mu} \quad \text{.......} 4.8$$

$$\bar{v} = \frac{q(gal/\min)}{2.448.(d^2{}_2 - d_1^2)} = \frac{17.16.(bbl/\min)}{(d_2^2 - d_1^2)} \quad \text{.......} 4.9$$

$$d_e = 0816.(d_2 - d_1) \quad \text{.......} 4.10$$

where:

ρ[ppg] .... fluid density

di [in] .... inside pipe diameter

$\bar{v}$ [ft/sec] .... mean fluid velocity

μ [cp] .... fluid viscosity

de [in] .... equivalent diameter of annulus

d2 [in] .... internal diameter of outer pipe or borehole

d1 [in] .... external diameter of inner pipe

The different flow patterns are then characterised considering the Reynolds number. Normally the Reynolds number 2,320 distinguishes the laminar and turbulent flow behaviour, for drilling purposes a value of 2,000 is applied instead. Furthermore it is assumed that turbulent flow is fully developed at Reynolds numbers of 4,000 and above, thus the range of 2,000 to 4,000 is named transition flow:

$Re < 2,000$ ... .laminar flow

$2,000 < Re < 4,000$ .... transition flow

$Re > 4,000$ .... turbulent flow.

4.3 Rheological Classification of Fluids

All fluids encountered in drilling and production operations can be characterized as either "Newtonian" fluids or "Non-Newtonian" ones. Newtonian fluids, like water, gases and thin oils (high API gravity) show a direct proportional relationship between the shear stress and the shear rate assuming pressure and temperature are kept constant.

Most fluids encountered at drilling operations like drilling muds, heavy oil and gelled fracturing fluids do not show this direct relationship between shear stress and shear rate. They are characterized as Non-Newtonian fluids. To describe the behaviour of Non-Newtonian fluids, various models like the "Bingham plastic fluid model", the "Power law fluid model" and "Time-dependent fluid models" were developed where the Bingham and Power law models are called "Time-independent fluid model" as well. The time dependence mentioned here concerns the change of viscosity by the duration of shear. It is common to subdivide the time depended models into "Thixotropic fluid models" and the "Rheopectic fluid models".

It shall be understood that all the models mentioned above are based on different assumptions that are hardly valid for all drilling operations, thus they are valid to a certain extend only.

To determine the rheological properties of a particular fluid, a rotational viscometer with six standard speeds and variable speed settings is used commonly.
In field applications, out of these speeds just two are normally used (300 and 600 [rpm]) since they are sufficient to determine the required properties.

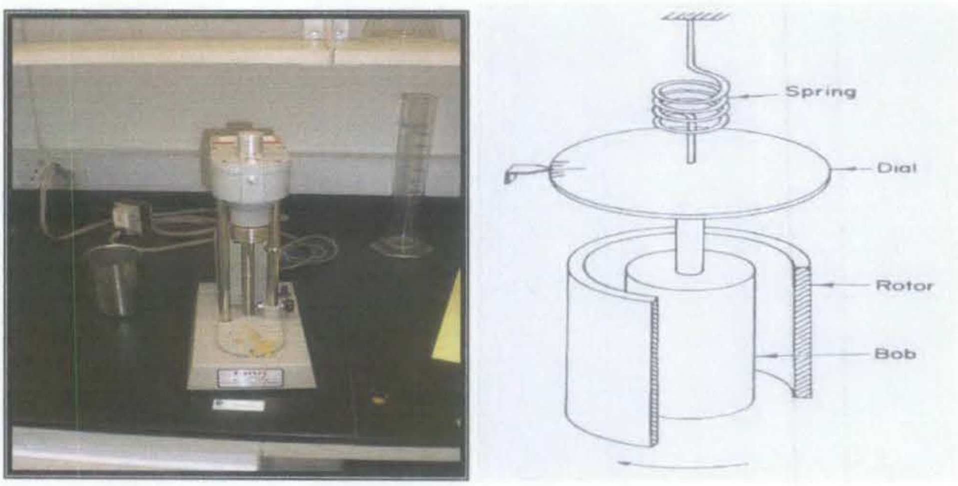

Fig 4.1; *viscometer (Source: UTP drilling Fluid lab)*

4.4 Laminar Flow in Pipes and Annuli

For drilling operations the fluid flow of mud and cement slurries are most important. When laminar flowing pattern occurs, following set of equations are used to calculate the friction pressure drop [psi], the shear rate at the pipe wall and the circulation bottom hole pressure for the different flow models:

4.5 Turbulent Flow in Pipes and Annuli

To describe the flow behaviour, friction pressure loss and shear rate at the pipe wall for laminar flow, analytic equations are applied. For turbulent fluid flow behaviour, analytic models to calculate these parameters are extremely difficult to derive. Therefore, various concepts that describe their behaviour are used in the industry.

The concept based on the dimensionless quantity called "Friction factor" is the most widely applied correlation technique. Following equations are used to determine the friction factor for fully developed turbulent flow pattern:

4.6 Pressure Drop across Surface Connections

The pressure drop in surface connections comprise of pressure drops along the standpipe, the rotary hose, swivel and Kelly. Since different rigs do use different equipment, the total pressure loss at the surface equipment can only be estimated. This is performed with equation. Another approach is to determine the equivalent length of drillpipe for each surface equipment and then use the equations presented in the last section to determine the surface pressure loss. Table 2, gives the equivalent lengths of the different equipment parts.

Table 4.1: *Groups of surface equipment*

group	E	Standpipe length & ID (ft & in.)	Rotary hose length & ID (ft & in.)	Swivel length & ID (ft & in.)	Kelly length & ID (ft & in.)
1	2.5e-4	40, 3	40, 2	4, 2	40, 2.25
2	9.6e-5	40, 3.5	55, 2.5	5, 2.5	40, 3.25
3	5.3e-5	45, 4	55, 3	5, 2.5	40, 3.25
4	4.2e-5	45, 4	55, 3	6, 3	40, 4

Table 4.2: *Equivalent drillpipe lengths for surface equipment*

No.	OD	Weight	OD	Weight	OD	Weight
	3.5	13.3	4.5	16.6	5	19.5
1		437				
2		161		761		
3				479		816
4				340		579

4.7 Pressure Drop across Bit

The pressure drop across the bit is mainly due to the change of fluid velocities in the nozzles. To increase the penetration rate, when the mud flows through the nozzles its speed is increased drastically which causes a high impact force when the mud hits the bottom of the hole. This high fluid speed on the other hand causes a relative high pressure loss. This pressure loss is very sensitive to the nozzle size. The bit pressure drop itself can be calculated using equations below.

$$(\Delta p_f)_B = \frac{q^2 . \rho_m}{12032 . C_d^2 . A_T^2} \qquad \text{4.11}$$

Where;

$$A_T = 0.32 . \frac{q}{v_n} = \frac{3.\pi}{4} . (d_n)^2 \qquad \text{4.12}$$

$$\overline{v_n} = C_d \sqrt{\frac{1238 . (\Delta p_f)_B}{\rho_m}} \qquad \text{4.13}$$

$$d_n = \sqrt{\frac{4 . A_T}{3 . \pi}} \qquad \text{4.14}$$

- A_T [in2] ....total nozzle area
- dn [1/32] ....jet nozzle size
- $\overline{v_n}$ [ft/sec] ....mean nozzle velocity
- q [gpm] ....fluid flow rate
- ρm [ppg] ....mud density
- Cd [1] ....discharge coefficient, depending on the nozzle type and size (commonly Cd = 0.95)

4.8 Initiating Circulation

All the equations to calculate the individual pressure drops presented above assume a non-thixotropic behaviour of the mud. In reality, an additional pressure drop is observed when circulation is started due to the thixotropic structures which have to be broken down. This initial phase of addition pressure drop may last for one full circulation cycle. The additional pressure drop can be estimated applying the gel strength τ_g of the drilling mud as:

For flow through pipes:

$$(\Delta p_f)_P = D.\left(\frac{\tau_g}{300.d_i}\right) \quad \text{4.15}$$

For flow through annuli:

$$(\Delta p_f)_{an} = D.\left[\frac{\tau_g}{300.(d_2 - d_1)}\right] \quad \text{4.16}$$

For flow through nozzles of a drill bit;

$$(\Delta p_{bit}) = \frac{(\rho_m)(q)^2}{12042(1.03)^2.A_T^2} \quad \text{4.17}$$

Where:

- τ_g [lbf/100 ft2] ....gel strength of the drilling mud.

4.9 Optimization of Bit Hydraulics

The penetration rate in many formations is roughly proportional to the hydraulic horsepower expended at the bit. To drill most efficiently hydraulic programs are designed for maximum bottom hole cleaning (how much bottom hole cleaning is necessary to reach maximum penetration rate) combined with maximum bottom hole cleaning based on the surface hydraulic horsepower availability. For this reason, mud rheology, hydraulics (individual pressure drops) and bit nozzle selection are the parameters to consider for drilling optimization. To optimize drilling hydraulics, different approaches can be made. The hydraulics can be designed to either optimize the nozzle velocity, the bit hydraulic horsepower or to optimize the jet impact force.

The pressure loss through the system will be related to flow rate raised to an exponent between one and two. This exponent, m (slope of the parasitic pressure loss $(\Delta p_f)_d$ vs. flow rate), is unique for every well and is characteristic of the well at the time it is determined. Put another way, this characteristic exponent will change over the life of the well and hence must be determined for each bit independently.

The total pressure drop at the circulation system is the summation of the pressure drop at the bit and the pressure drop through the rest of the circulation system.

$$p_t = p_b + p_s \qquad (4.18)$$

or

$$p_t = p_{sc} + p_d + p_b + p_a \qquad (4.19)$$

where

- p_t is the total pressure drop.
- p_b the pressure loss through the bit nozzle. This is where most of the pressure drop sould occur for efficient drilling
- p_s is the pressure loss in the system ($p_s = p_{sc} + p_d + p_a$).
- p_{sc} is the pressure loss in the surface connections (e.g. standpipe, Kelly, hose)
- p_d is the pressure loss in the drillstring (i.e. inside the drillpipe and the drillcollar)
- p_a is the pressure drop in the annulus

This relation can be seen in figure 3. (to be drawn) for changing flow rates.

Figure 4.2: *Hydraulics Optimization Circulation system.*

4.10 Limiting Conditions for Both Optimization Criteria

On a drilling rig a motor, or motors, are dedicated to providing hydraulic power to drive the mud pumps. Thus, the first limiting condition is the hydraulic power.
The second limiting condition is the maximum standpipe pressure. Before the well is run, these values can be placed on a log-log plot of pressure and flow rate.

The maximum surface pressure intersects the available hydraulic horsepower line at a flow rate called Qcrit, or Q- critical. This represents the flow rate where both the maximum stand pipe pressure and the maximum hydraulic horsepower can be used. The area to the right of Qcrit is the region where the limit conditions would be the maximum available hydraulic power, the area to the left of Qcrit is the region where the limit condition is the maximum standpipe pressure.

4.11 Measuring "n"

The optimum bit pressure drop is related to the constant "n" which is a characteristic of a particular system. It is the slope of pressure loss curve for the entire system (Pcirc), except for the drill bit, plotted on a log-log graph. The total system pressure losses, which would be equivalent to the standpipe pressure (Psurf), may also be calculated as the sum of the bit pressure loss (Pbit), and the circulating system pressure loss (Pcirc). Note that in a physical sense, in the generalized proportionality for pressure drop as a function of flowrate:

The pressure drop across the bit can be written as:

Hydraulic horsepower:

$$HHP_t = \text{input X } E_m \qquad \text{4.20}$$

Where E_m is mechanical effiency.

Jet impact force:

$$(\Delta p_f)_{B\text{-opt}} = p_{max} - (\Delta p_f)_{d\text{-opt}} = p_{max} - \frac{2}{2+m} \cdot p_{max} \qquad \text{4.21}$$

where:

m [1] ... slope of the parasitic pressure loss$(\Delta p_f)_d$ vs. flow rate

Theoretically n = 1.85 but in general it is better to determine n from field data than assuming this value.

When plotting flow rate vs. pressure on a log-log plot, the optimum design is found at the intersection between the path of optimum hydraulics and the (_pf)d line for either of the criteria mentioned above.

Having determined the optimum design, the optimum pump flow rate, optimum nozzle area and corresponding pressure losses can be calculated:

$$(A_t)_{opt} = \sqrt{\frac{(q_{opt})^2 \cdot \rho_m}{12032.C_d^2.(\Delta p_f)_{B-opt}}} \quad \text{.......} 4.22$$

$$(d_n)_{opt} = 32.\sqrt{\frac{4.(A_T)_{opt}}{3.\pi}} \quad \text{.......} 4.23$$

4.12 Hydraulic Optimization for the Power Limited Case

Hydraulic optimization is an eight-step plan for tailoring the hydraulics program to the well bore as it is being drilled. The eight steps are:

1. Calibrate rig pumps. Measure the rate of liquid level drop in the slugging tank while pumping down hole through the drill bit. Account for air in the drilling fluid to calculate the volume of liquid moved by the rig pumps.
2. Just before tripping for a new bit, circulate at several pump rates and measure accurately the standpipe pressure at each rate.
3. Calculate and subtract the bit nozzle pressure drops from the measured standpipe pressures (This gives the circulating pressure loss through the system, except for the bit nozzles.)
4. Plot the circulating pressure loss as a function of flow rates on log-log paper.
5. Draw the best straight line through the circulating pressure losses.
6. Measure the slope of the circulating pressure line with a ruler or scale.
7. Calculate the optimum pressure loss through the bit to give either the maximum hydraulic force or the maximum hydraulic power at the bit.
8. Calculate nozzle sizes for the next bit.

4.13 Hydraulic Horse Power (HHP)

The source of all hydraulic power is the pump input from the mud pumps. This hydraulic horsepower is also the product of the surface (or standpipe) pressure and the flow rate. Therefore, the total hydraulic horse power available from the pump is given by:

$$HHP_t(E_m) = \frac{P_t.Q}{1714} \quad \text{......4.24}$$

4.14 Jet Impact Force (JIF)

The purpose of the jet nozzles is to improve the cleaning action of the drilling fluid at the bottom of the hole. The optimum nozzle area leads to the respective nozzle selection. Nozzles for drilling bits are given $\frac{1}{32}$ (in) sizes thus the calculated nozzle area has to be converted into $\frac{n}{32}$ (in). Knowing n (has to be an integer and is commonly rounded down to ensure the nozzle velocity) and the amounts of nozzles to be used, the individual sizes are selected. If it is assumed that the jet stream impacts the bottom of the hole in a manner where all of the fluid momentum is transferred to the hole bottom. Since the fluid is travelling a vertical velocity V_n before striking the hole bottom and is travelling at zero vertical velocity after striking the hole bottom. The time rate of change of momentum in field unit is given by:

$$JIF = 0.000516 \times MW \times Q \times V_n \quad \text{......4.25}$$

But

$$V_n = C_d \sqrt{\frac{\Delta P_b}{8.074x10^{-4} \rho_m}} \quad \text{......4.26}$$

Equation 3 will result in observed value for nozzle velocity. The discharge coefficient may be as high as 0.98, but the recommended value is 0.95.

A rock bit has more than one nozzle, usually has the same number of nozzles as cone. When more than one nozzle is present, the pressure drop applied across all of the nozzles must be the same. If the pressure drop is the same for each nozzle, the velocities through are equal. In field unit, the velocity is given by:

$$V_n = \frac{Q}{3.117 A_t} \qquad 4.27$$

Combining equation 3 and 4 gives;

$$\Delta P_b = \frac{8.311x10^{-5} \rho Q^2}{C_d^2 A_t^2} \qquad 4.28$$

Where

P_t is the total pressure of the system (psia).

Q is the flow rate of the system (gpm).

MW is the mud meight (ppg).

V_n is the nozzle velocity (feet/sec).

Δp_b pressure drop across the bit (psia).

C_d is discharge coefficient (0.95).

ρ_m mud density (lb/ft^3).

A_t is the nozzle area (square inche).

CHAPTER FIVE

5.0 RESULTS AND DISCUSSION

Considering the following data obtained from a single specific well.

Hole Size =8-1/2",

Depth Out = 15,000 feet,

Max. Standpipe Pressure = 3000 psi

Flow Rate = 238 GPM,

Mud Weight = 14.5 ppg.

Using the Data above, the HHP = 262.438 (Eq. 25) and the corresponding JIF = 682.342 lb (Eq. 23) and nozzles sizes A_t = 0.2 square inch as shown on the graph in fig 4.

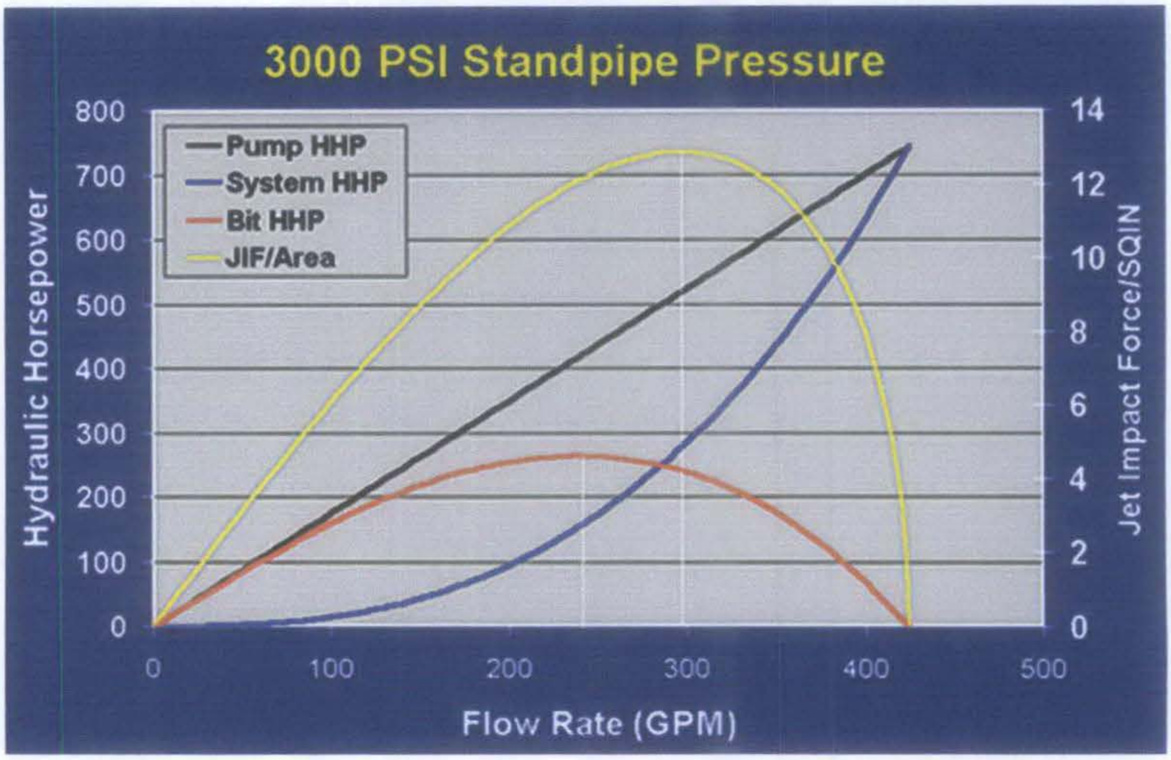

Figure 5.1: *Limited conditions.*

At Maximum JIF;

Surface Equipment Loss = 20 psi, Internal Drill String Loss = 968 psi, MWD/Motor Loss = 0, Bit Pressure Drop = 1890 psi, Annulus Loss = 122 psi, Total Loss = 3000

On a drilling rig, the mud pumps are powered by motors with a finite amount of power. Generally, the hydraulic power can be obtained by assuming a mechanical efficiency of power transfer of about 85% and a volumetric efficiency of 93% to 95%. So the mathematical relationship would be;

Optimum hydraulic horsepower is given with:

$$(hp)_{opt} = \frac{(\Delta p_f)_{B-opt} . q_{opt}}{1714} \quad \text{.......... 5.1}$$

This hydraulic horsepower is also the product of the surface (or standpipe) pressure and the flow rate.

Jet impact force

$$(F_j)_{opt} = 0.01823 . C_d . q_{opt} . \sqrt{\rho_m . (\Delta p_f)_{B-opt}} \quad \text{.......... 5.2}$$

The optimum nozzle area leads to the respective nozzle selection. Nozzles for drilling bits are given $\frac{1}{32}$ [in] sizes thus the calculated nozzle area has to be converted into $\frac{n}{32}$ [in]. Knowing n (has to be an integer and is commonly rounded down to ensure the nozzle velocity) and the amount of nozzles to use, the individual seizes are found.

The so called "specific hydraulic horsepower" is defined as hydraulic horsepower per unit borehole cross-section.

$$(hp)^{spec} = \frac{4 . hp}{\pi . d_{BH}^2} \quad \text{.......... 5.3}$$

The optimization as discussed above is performed for regular intervals (e.g. 1,000 [ft]) and is included in the drilling program. In practice, computer programs are available in the industry that performs these hydraulic optimization calculations.

5.1 Graphical Method for Optimization of Hydraulics Program.

Given that the power and the pressure limitations of the system, the geometry of the circulating system and the fluid properties are to a great extend fixed, the only control over the optimization process is to select the pump rate and the nozzle for the bit. The following method may be used to determine the optimum nozzle configuration and the pumping rates. This calculation is usually performed on the rig site with the information gathered just before pulling one bit from the hole and prior to running the next bit in the hole.

5.2 An Empirical Relationship between P and Q in Turbulent flow gives.

The empirical relationship for the pressure loss in the system

$$P_s = KQ^n \qquad \text{.......... 5.4}$$

Where k and n are constants for the system (includes wellbore geometry, mud properties etc.)

Since $HHP_b = \frac{P_t.Q}{1714} - \frac{P_sQ}{1714}$,

Substituting for P_s gives.

$$HHP_b = \frac{P_t.Q}{1714} - \frac{KQ^nQ}{1714}, \qquad HHP_b = \frac{P_t.Q}{1714} - \frac{KQ^{(n+1)}}{1714}.$$

Pressure loss at the bit when horse power at the bit is constant or differentiating with respect to Q to find the maximum HHP gives,

$$P_t = (n+1)KQ^n$$

$$P_t = (n+1)P_s \qquad \text{or} \qquad P_b = P_t - Ps\frac{n}{(n+1)}P_t$$

- To determine and draw on the log/log chart pressure vs. flow rate of the following lines.
  a) Maximum flow rate Q_{max} (i.e. critical velocity).
  b) Minimum flow rate Q_{min} (i.e. slip velocity).
  c) Maximum allowable surface pressure P_{max}.

Note:

- The critical velocity is the velocity below which the fluid in the annulus is in the lamina flow.
- The slip velocity is the velocity below which the cuttings will settle onto and form a bed on the low side wall of the wellbore.
- Recording pump-pressure (P_{surf}) for three different pump rates just before pulling the bit.
- Calculating the bit pressure for each pump rate using equation below.

$$P_{bit} = \frac{\rho Q^2}{564 A_n^2} \quad \text{.........} 5.5$$

Where;

- P_{bit} = pressure loss across the bit, (psia).
- ρ = density of mud, (psia/ft).
- Q = flow rate, (gpm).
- A_n = total nozzle flow area through the bit, (in).

- Calculating the pressure loss through the system (P_{circ}) for each flow rate.

$$P_{circ} = P_{surf} - P_{bit} \quad \text{.........} 5.6$$

- Plotting P_{circ} vs. Q on the log/log chart and drawing a line between the points.
- Measuring the slope (n) of the line and then determining the value of W from Table1 below.

- Calculating the optimum circulation system pressure loss ($P_{circ,opt}$) from.

$$P_{circ,opt} = W \times P_{max} \quad \text{.........} 5.7$$

Note; W is a factor depended on the value of the exponential "m" in the empirical equation relating flow rate to pressure loss in the circulating system.

- The intersection of $P_{circ,opt}$ with the P_{circ} line on the chart specifies the optimum flowrate (Q_{opt}).
- Calculating the optimum nozzle area.

$$\text{Nozzle area} = \frac{Q_{opt}}{23.75}\sqrt{\frac{\rho}{P_{\max} - P_{circ,opt}}} \quad \text{.........} 5.8$$

Table 5.1: *Circulating system factor.*

N	2	1.9	1.8	1.7	1.6	1.5	1.4	1.3	1.2	1.1	1
W (IF)	0.50	0.51	0.53	0.54	0.56	0.57	0.59	0.61	0.60	0.65	0.67
W(HHP)	0.33	0.34	0.36	0.37	0.38	0.40	0.42	0.43	0.45	0.48	0.50

Table 5.2: *Nozzle area and sizes.*

Nozzle size	Nozzle area (in^2)
18-18-18	0.75
18-18-17	0.72
18-17-17	0.69
17-17-17	0.67
17-17-16	0.64
17-16-16	0.61
16-16-16	0.59
16-16-15	0.57
16-15-15	0.54
15-15-15	0.52
15-15-14	0.50
15-14-14	0.47
14-14-14	0.45
14-14-13	0.43
14-13-13	0.41
13-13-13	0.39
13-13-12	0.37
13-12-12	0.35
12-12-12	0.33
12-12-11	0.31
12-11-11	0.30
11-11-11	0.28
11-11-10	0.26
11-10-10	0.25
10-10-10	0.23
10-10-9	0.22
10-9-9	0.20
9-9-9	0.19
9-9-8	0.17
9-8-8	0.16

GWDC drilling 12.25" hole section of ***Anbar 1*** at 8000 ft. The cost/ft of the bit run was found to have reached its minima and to be increasing. It was there decided to pull the bit and run another bit. Determine the nozzle configuration that will optimize the hydraulic horse power at the bit in the next bit run.

To assist in the selection of the nozzle configuration which will optimize the hydraulic horse power at the bit, the following circulation test was performed.

Table 5.3: *Pump's rate vs. equivalent surface pressure*

Pump rates (SPM)	Surface Pressure (psia)
120	3005
105	2242
90	1852
80	1363

The test was conducted with 3x14 nozzles in the bit and 6.5" liners in the pumps. All other relevant information was also compiled.

Minimum annular velocity =110ft/min.
Mud density = 10ppg.
Pump data.

Table 5.4: *Pump's type and specification*

Type	National triplex 12-P-160-T
HHP	1600
Max SPM	120
Stroke	12"
Liner size	5.75", 6.5", 7"
Volumetric efficiency (E_v).	0.95
Mechanical efficiency (E_m)	0.90

Drillstring data. Drillpipe = 5" 19.5 lb/ft.

1. Determine ;

    a) The maximum flow rate.

    b) The minimum flow rate.

    c) Maximum surface pressure.

Solution;

a) For the maximum flow rate, first calculating the maximum volume output by each liner size and therefore the maximum flow rate:

   Using equation...

$$Q = \frac{d^2 L E_v R}{98.03}$$

Where;

d = 5.75", 6.5", 7".

L = 12".

E_v = 0.95.

R = 120 spm.

Maximum pressure (P_{max}) is calculated on the basis of;

$$HHP_t \times E_m = \frac{P_t Q}{1714} \quad \textbf{\textit{(EQ. 24)}}$$

And the annulus velocity is calculated based on 5" drillpipe in 12.25" hole (± 5.1 gal/ft). From Q = VA. Hence V = Q/A. ***(EQ. 4.27)***

Hence, the result is tabulated below;

Table 5.5: *The desired annulus velocity for the operation*

D (in)	Q (gpm)	P_{max} (psia)	Ann Velocity (ft/min)
5.75"	461.384	5349.467	90.437
6.5"	589.595	4186.196	115.567
7"	683.791	3609.526	134.032

b) The minimum annular velocity will be that required to ensure that the cuttings are removed from the hole. A typical value will be 110 ft/min. The 6.5" liner will therefore be selected and the maximum flow rate will be 589.595 gpm.

c) As shown above, the maximum surface pressure (P_{max}) would be ***4186.196 psia*** at ***589.595 gpm.***

2. The pump pressures for four different pump rates were recorded prior to pulling the previous bit from the hole. There were as follows;

Table 5.6: *Pump's rates and the corresponding system pressures*

Pump rates (SPM)	System Pressure (psia)
120	3005
105	2242
90	1852
80	1363

- The bit pressure losses is calculated from

$$P_{bit} = \frac{\rho Q^2}{564 A_n^2} \quad \textit{(EQ 5.2)}$$

Where:

ρ = 0.52 psia/ft.

$A_n = 0.45\ in^2$

Resulting;

***Table 5.7:** System flow rate and the corresponding Bit pressure (0.45 in^2)*

Flow rate (GPM)	P_{bit} (psai)
589.595	1582.730
516	1212.268
443	893.525
393	703.209

- From the above results *table 5.7*, the pressure losses through the circulation system (P_{circ}) can be determined from;

  $P_{circ} = P_{sys} - P_{bit}$ ***(EQ. 5.6).***

***Table 5.8:** Flow rate, system, bit and circulation pressures*

Flow rate (gpm)	P_{sys} (psia)	P_{bit} (psia)	P_{circ} (psia)
589.595	3005	1582.730	1422.270
516	2242	1212.268	1029.732
443	1852	893.525	958.475
393	1363	703.209	659.791

3. The flow rate is plotted against the circulation pressure loss on the log-log paper as shown on the graph, and the gradient of the line measured. The gradient of this line is approximately 1.85
4. From *Table 5.1*, it can be seen that the circulation system factor W is 0.35.
5. Therefore, the optimum pressure loss at this depth and with this system is;

   $P_{circ,opt} = W \times P_{max}$ ***(EQ. 5.7).***

   $P_{circ,opt} = 0.35 \times 4186.196$

   $P_{circ,opt} =$ ***1465.169 Psia***

6. If this line is plotted on the log-log plot, the optimum flow rate can be deduced. Hence the optimum flow rate is found to be; ***600 gpm.***

7. The optimum nozzle size is selected on the basis of the following equation;

$$\text{Nozzle area} = \frac{Q_{opt}}{23.75}\sqrt{\frac{\rho}{P_{\max} - P_{circ,opt}}} \quad \textbf{\textit{(EQ. 5.8).}}$$

$$\text{Nozzle area} = \frac{600}{23.75}\sqrt{\frac{0.52}{4186.196 - 1465.169}}$$

Nozzle area = ***0.35 in.***

Hence the optimum configuration can then be from Table 2 as being 13/32", 12/32", and 12/32".

Table.5.9: *Nnozzle deviation vs. Hydraulic optimization parameters*

% Dev	HHPbit (hp)	JIF (lb)	Pbit (psi)	Psurf (psi)	Flow rate (gpm)	Nozzle vel (ft/min)	Psys (psi)	An Vel (ft/min)	HHPsys (hp)
-30	1836.719	2348.845	5339.489	-2334.49	589.595	772.0597	3005	115.5511	1148.537
-20	1406.238	2055.24	4088.046	-1083.05	589.595	675.5523	3005	115.5511	1148.537
-10	1111.102	1826.88	3230.061	-225.061	589.595	600.4909	3005	115.5511	1148.537
0	899.9922	1644.192	2616.35	388.6504	589.595	540.4418	3005	115.5511	1148.537
10	743.7952	1494.72	2162.272	842.7276	589.595	491.3107	3005	115.5511	1148.537
20	624.9946	1370.16	1816.909	1188.091	589.595	450.3682	3005	115.5511	1148.537
30	532.5398	1264.763	1548.136	1456.864	589.595	415.7245	3005	115.5511	1148.537

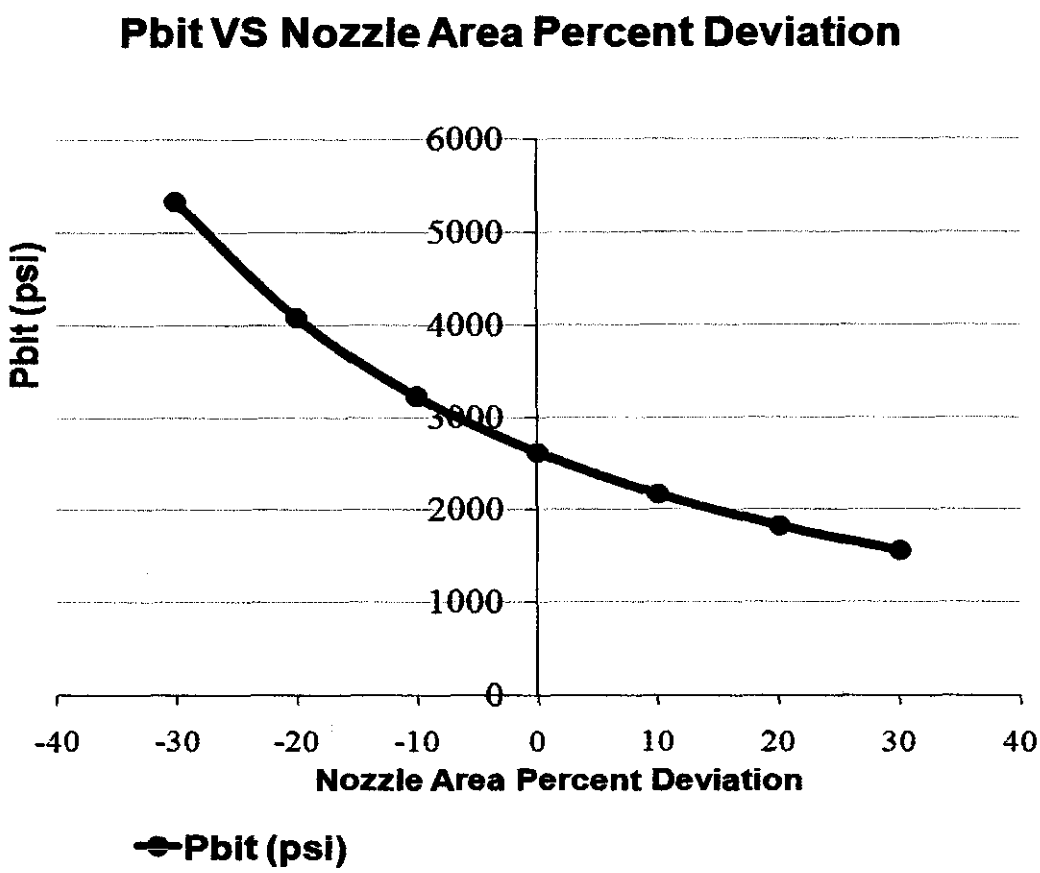

Figure 5.2: *Showing Pressure at the bit verses nozzle area percentage deviation.*

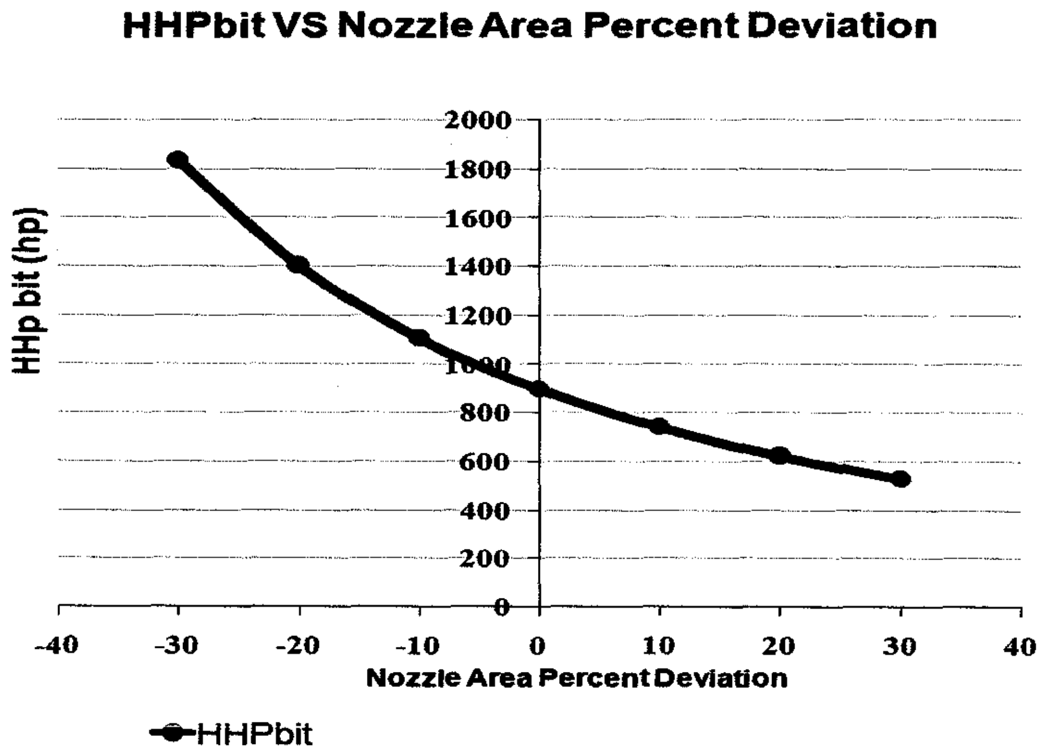

Figure5.3: *showing HHP at the bit verses the Nozzle area percentage deviation.*

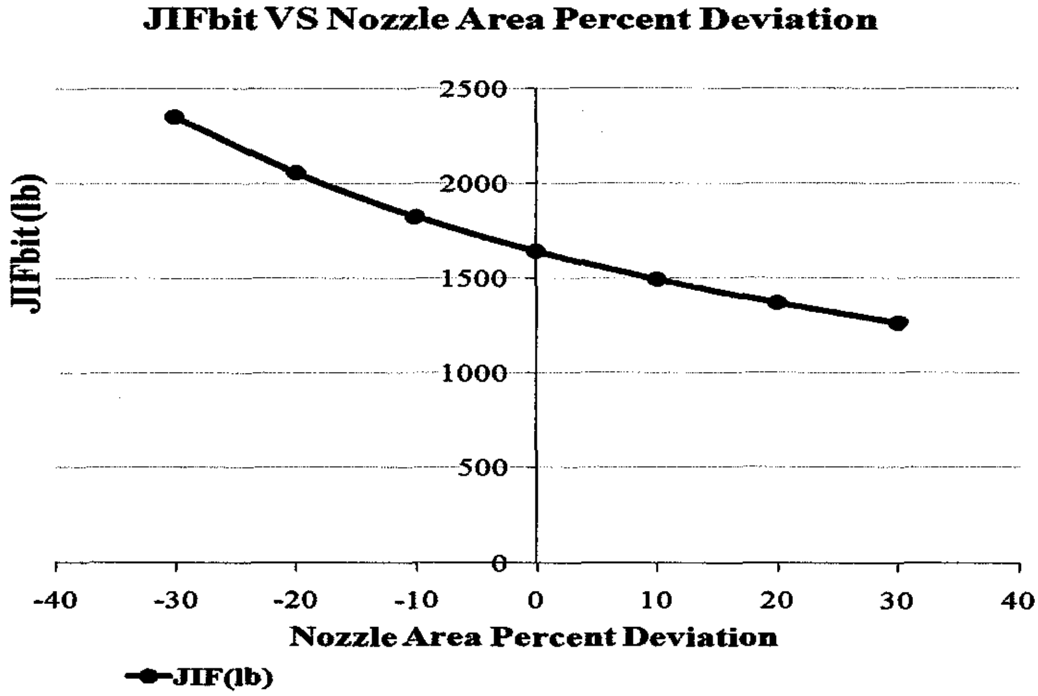

Figure 5.4: *Showing JIT at the bit verses Nozzle area percentages deviation.*

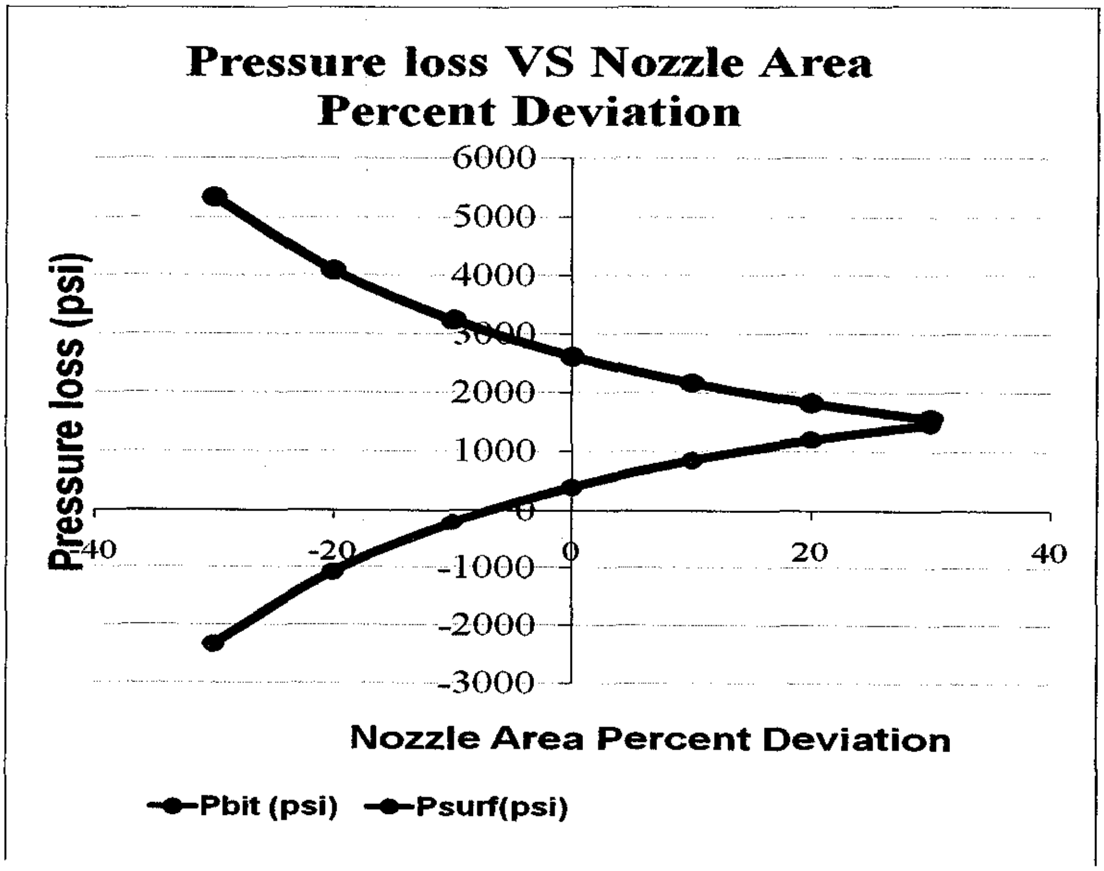

Figure 5.5: *showing the bit and the surface pressure loss verses nozzle area percenteg deviation*

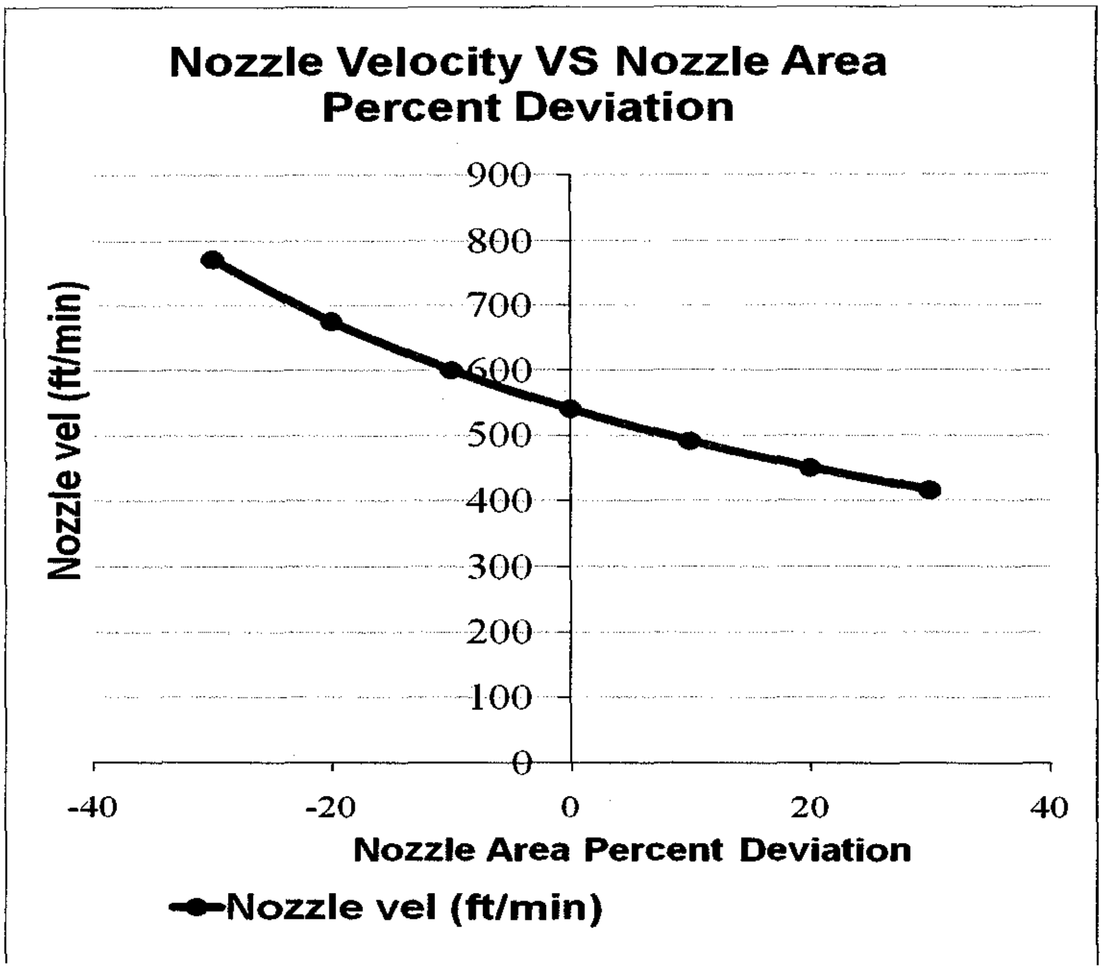

Figure 5.6: *Nozzle velocity verses nozzle area percentage deviation.*

CHAPTER SIX

6.0 CONCLUSION AND RECOMMENDATION

6.1 Conclusion

Base on the obtained results, it shows that the system flow rate, annulus velocity, system HHP and the system pressure is not very much affected by the different bit nozzle areas or sizes. But the nozzle flow velocity, HHP(bit), JIF(bit), bit pressure (Pbit) and the sacrificial pressure (pcirc) are all affected by the Nozzle area variation. The most sensitive parameter to the nozzle area variation is the bit pressure which also is the most important parameter that controls the variation of the value of HHP and the JIF for optimum hole cleaning.

6.2 Recommendation

- Flow Rate must be high enough to transport cuttings while maintaining the maximum allowable surface pressuree. Back-reaming, bit body balling and lack of chips at surface indicate cuttings transport problems.
- Flow Rate must be low enough to avoid hole erosion, equipment wear, and excessive standpipe pressure. i.e. by maintaining lamina flow in the annulus,
- High flow rates often require large or open nozzles. Bits with large junk slots, high open face volume, widely spaced teeth/inserts and numerous jets are helpful especially in a soft or medium formation.
- Maximize nozzle HHP when cutting structure or bottom hole balling is the limitation.
- Deep holes, high mud weights, water-based mud and reactive formations, cuttings packed on teeth indicate static or dynamic chip hold down problems.
- Maximum HHP obtained when nozzle pressure drop is at least 65% of standpipe pressure.
- Aggressive bit designs with widely-spaced blades and teeth are helpful.

- Maximize JIF in shallow holes where cuttings return and bit/hole balling are both potential limitations.
- Common in shallow holes with high rate of penetration (ROP) in reactive formations.
- Obtained when the pressure drop across the bit is at least 50% of the total pump pressure, 30 to 50 gpm per inch of hole diameter, 3 to 7 HHP recommended (not always possible) and 18% or less flow through centerjet (=18% of TFA).

Blank nozzles generate cross flow. Blank the nozzle pointing to the cone with fewest gauge rows inserts

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