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Sciences

Department: Drilling and Mechanics of Oilfield



MEMORY

PROFESSIONAL MASTER'S DEGREE

Field: Science and Technology

Sector: Hydrocarbons

Specialty: drilling

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Thème

**Analysis and Optimization of Suction Systems
for Drilling Mud Pumps
Case Study of the BMPT-1600-AC Pump
(Bentec GmbH)**

Publicly supported: 14/06/2026

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Academic Year : 2025/2026

Remerciements

First, we thank God who gave us the strength and courage to complete this thesis in our final year.

We extend our sincere gratitude to the members of the examination committee for accepting to evaluate this thesis.

We also express our deep appreciation to Ms. Chaiche Zineb, our supervisor, who guided us throughout the development of this work.

We are also grateful to the drilling department staff and engineers at ENAFOR/Sonatrach for providing technical documentation and field insights.

Finally, we thank our family and friends for their unwavering support and encouragement.

Dédicase

We dedicate this humble work to:

*All our family members, especially our parents
who helped us overcome many difficulties.*

*All the Ferroudj, Boudeghdegh, and Zaiem
families.*

Our brothers, sisters, and cousins.

Our professors in the Hydrocarbons Department.

All our colleagues and friends.

Abstract

The performance and reliability of mud pumps in drilling operations depend strongly on suction conditions. This study investigates suction-related problems in the BMPT-1600-AC triplex mud pump using hydraulic modeling and pressure-loss analysis. The effects of suction pipe diameter, fluid temperature, and flow rate on suction performance and cavitation risk are evaluated. The results show that insufficient charge pressure (below the recommended range of 1.2–3.5 bar) and excessive pressure losses caused by clogged strainers are the main causes of cavitation. In addition, higher fluid temperatures and flow rates reduce the available NPSH and increase cavitation risk. The study highlights the importance of maintaining adequate charge pressure and minimizing suction losses to ensure reliable pump operation. Based on these findings, practical recommendations are proposed to improve suction performance, reduce cavitation, and enhance the reliability and service life of the BMPT-1600-AC mud pump.

Keywords: Mud pump, Suction system, NPSH, Cavitation, BMPT-1600-AC.

Résumé

Les performances et la fiabilité des pompes à boue utilisées dans les opérations de forage dépendent fortement des conditions d'aspiration. Cette étude porte sur l'analyse des problèmes liés au système d'aspiration de la pompe triplex BMPT-1600-AC, à travers une modélisation hydraulique et des calculs de pertes de charge. L'influence du diamètre de la conduite d'aspiration, de la température du fluide et du débit sur les performances du système d'aspiration ainsi que sur le risque de cavitation a été évaluée. Les résultats montrent qu'une pression de gavage insuffisante, inférieure à la plage recommandée de 1,2 à 3,5 bar, ainsi que des pertes de charge excessives causées par l'encrassement des crépines, constituent les principales causes de la cavitation. En outre, l'augmentation de la température du fluide et du débit de pompage réduit le NPSH disponible et accroît le risque d'apparition de la cavitation. Cette étude met en évidence l'importance du maintien d'une pression de gavage adéquate et de la réduction des pertes de charge à l'aspiration afin d'assurer un fonctionnement fiable de la pompe. Sur la base des résultats obtenus, des recommandations pratiques sont proposées pour améliorer les performances du système d'aspiration, limiter les risques de cavitation et accroître la fiabilité ainsi que la durée de vie de la pompe à boue BMPT-1600-AC.

Mots-clés : Pompe à boue, système d'aspiration, NPSH, cavitation, modélisation hydraulique, BMPT-1600-AC.

المخلص

يعتمد أداء وكفاءة مضخات الطين المستخدمة في عمليات الحفر بشكل كبير على ظروف السحب. تهدف هذه الدراسة إلى تحليل المشكلات المرتبطة بالسحب في مضخة الطين الثلاثية المكابس BMPT-1600-AC من خلال النمذجة الهيدروليكية وتحليل فواقد الضغط، مع تقييم تأثير قطر أنبوب السحب ودرجة حرارة المائع ومعدل التدفق على أداء السحب ومخاطر حدوث التجويف (Cavitation). أظهرت النتائج أن انخفاض ضغط التغذية (Charge Pressure) إلى أقل من المجال الموصى به (1.2–3.5 بار)، إلى جانب الارتفاع المفرط في فواقد الضغط الناتجة عن انسداد المصافي (Strainers)، يمثلان السببين الرئيسيين لحدوث التجويف. كما بينت الدراسة أن ارتفاع درجة حرارة المائع وزيادة معدل التدفق يؤديان إلى انخفاض متوفر ارتفاع السحب الموجب المتاح (NPSH Available)، مما يزيد من احتمالية حدوث التجويف ويؤثر سلبًا على أداء المضخة وعمرها التشغيلي. وتؤكد النتائج أهمية المحافظة على ضغط تغذية مناسب وتقليل فواقد الضغط في خط السحب لضمان تشغيل موثوق وآمن للمضخة. وبناءً على ذلك، تم اقتراح مجموعة من التوصيات العملية لتحسين أداء السحب، والحد من ظاهرة التجويف، وتعزيز موثوقية مضخة BMPT-1600-AC وإطالة عمرها التشغيلي.

الكلمات المفتاحية: مضخة الطين، نظام السحب، التجويف، الارتفاع الصافي الموجب للسحب، النمذجة الهيدروليكية، مضخة الطين BMPT-1600-AC.

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Abbreviation	Meaning
AC	Alternating Current
AE	Acoustic Emission
BMPT	Bentec Mud Pump Triplex
CFD	Computational Fluid Dynamics
ECD	Equivalent Circulating Density
EPAct	Energy Policy Act
FFT	Fast Fourier Transform
NEMA	National Electrical Manufacturers Association
NPSH	Net Positive Suction Head
NPSHa	Net Positive Suction Head Available
NPSHr	Net Positive Suction Head Required
NPT	Non-Productive Time
VFD	Variable Frequency Drive
WOB	Weight on Bit

Symbol	Meaning	Unit
A , B ,C	Empirical constant (Antoine)	
D	Pipe diameter	m
g	Gravitational acceleration	m/s ²
H_{asp}	Geometric suction height	m
K	Local loss coefficient	
L	Pipe length	m
$NPSH_{Avail}$	Available Net Positive Suction Head	m
$NPSH_{requi}$	Required Net Positive Suction Head	m
P_A	Atmospheric pressure	Pa, bar
P_{charge}	Charging pump pressure	Pa, bar
P_V	Vapor pressure	Pa, bar, mmHg
Q	Nominal flow rate	m ³ /s, l/min, gpm
T	Fluid temperature	°C
V_m	Average fluid velocity	m/s
ΔH	Total head loss	m
ΔH_{asp}	Suction head loss	m
ΔH_r	Linear head loss	m
ΔH_s	Singular head loss	m
λ	Friction coefficient	
λ_r	Friction coefficient (linear losses)	
ρ	Fluid density	kg/m ³
$\sum K$	Sum of local loss coefficients	

The hydrocarbon industry plays a major role in the Algerian economy, and drilling operations are among the most critical stages of hydrocarbon exploration and production. These operations rely on an efficient drilling fluid circulation system, which ensures cuttings transport, drill bit cooling, pressure control, and wellbore stability.

Mud pumps are essential components of this system. They operate under severe conditions involving abrasive fluids, variable rheological properties, and high temperatures, particularly in southern Algeria. Under such conditions, suction-related problems can significantly affect pump performance and reliability.

Among these problems, cavitation is one of the most critical phenomena. It occurs when the local pressure drops below the fluid vapor pressure, leading to vapor bubble formation and collapse. Cavitation can cause performance degradation, excessive vibrations, component damage, and increased maintenance costs.

In this context, the present work focuses on the analysis of suction-related problems in triplex mud pumps used in drilling operations. The objective is to investigate the factors affecting suction performance, evaluate their influence on cavitation risk, and propose practical measures to improve pump reliability.

This work is organized into three chapters.

Chapter I presents a general overview of drilling operations and pumping systems. Chapter II presents the theoretical aspects of suction-related problems, including cavitation, NPSH, and suction pressure losses.

Chapter III presents a case study of the BMPT-1600-AC mud pump, including mathematical modeling, parametric analysis, and proposed measures for improving suction performance.

chapter I

General Overview of Drilling and Pumping Systems

I.1. Introduction:

This chapter provides a general overview of drilling and pumping systems in oil and gas operations.

It briefly presents the fundamental principles of drilling and outlines the main elements that constitute a drilling system.

The role of pumping systems is also introduced, particularly in relation to drilling fluid circulation within the wellbore.

I.2 Drilling

Drilling is a key component of the oil and gas business and is what enables exploration and extraction of hydrocarbons from beneath the earth's surface.

Achieving this requires sophisticated mechanical engineering as well as a high level of understanding of fluids and their behavior in a drilling context.

The drilling system and the pumping system are two of the more important elements of a drilling operation. The drilling system is used to drill into the earth through holes drilled in a drill bit attached to the end of rotating drill.

The pumping system is used for circulation of the drilling mud (a mixture of liquids and solids) in the well bore (Figure 1).

The characteristics of a drilling mud are many, such as: lubrication and cooling of the drill bit, removing the drilling waste (cuttings) to the surface, maintaining the stability of the hole, controlling the pressure of the earth formations [1].

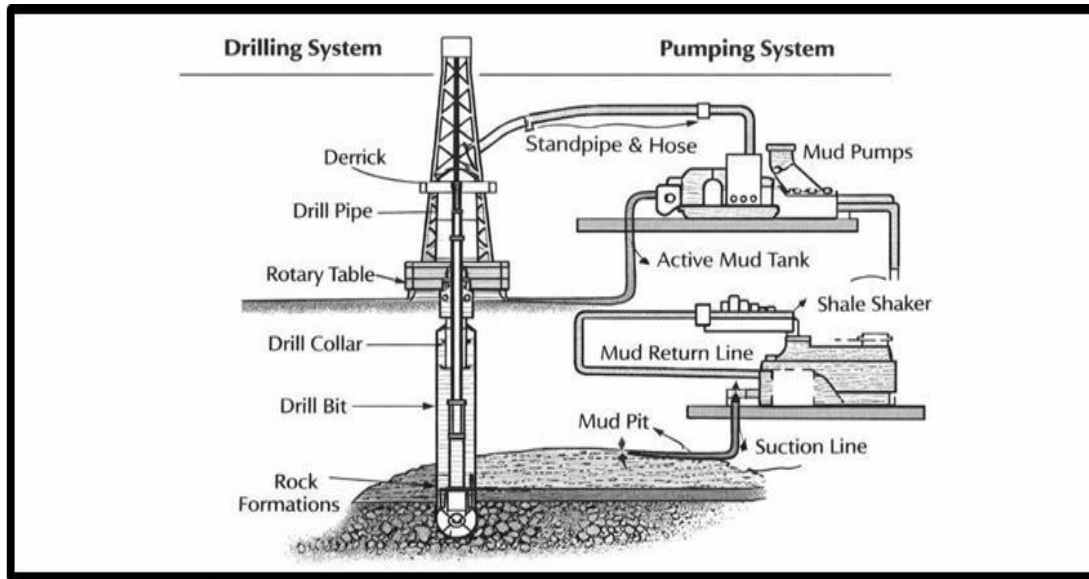


figure I.1: Schematic of drilling system with mud circulation [1]

Drilling is the set of operations that involve introducing appropriate tools into the subsurface, either for geological studies or for the extraction of fluids contained in the traversed formations. The most commonly used technique in the oil industry is rotary drilling.

There are two drilling methods:

a- Percussion drilling.

b- Rotary drilling.

In each of these methods, the operation can be performed dry or with the injection of water or mud.

Percussion drilling: has some rare applications in the case of shallow surveys in layers with very low pressures.

Rotary drilling: is the most widely used method today in oil exploration, as it allows for the best rates of penetration and, most importantly, reaching extremely great depths (the current record is around 7000 meters) [2] .

I.2.1 DRILLING PRINCIPLES

The rotary drilling principle consists of rotating a tool on which a force is applied in the direction of advancement; this process allows the creation of a hole with a radius equal to that of the tool.

The chips (cuttings) generated at the bottom of the hole due to the destruction of the rock by the tool continuously rise to the surface thanks to the circulation of the drilling fluid, which is generally a water- or oil-based bentonitic mud.

This fluid is pumped from the surface through the drill pipes and directed through the drill bit nozzles toward the cutting face.

The mud then returns through the annular space between the drill pipes and the wellbore walls, carrying the rock cuttings to the surface.

The weight on the tool (weight on bit: WOB) is achieved by gravity through the use of heavy drill pipes called drill collars.

The rotational torque is obtained either from a surface torque transmitted to the tool via a drill string or from a downhole motor above the tool controlled from the surface [2] .

I.2.2 DRILLING OBJECTIVES

The main purpose of drilling is to safely and efficiently penetrate to the desired pay zone or reservoir and to gather as much information as possible from below.

The purpose of drilling is to obtain core and samples of the rock and fluid and to gather all possible geological and petrophysical information in order to determine the characteristics of the reservoir and to evaluate its potential.

Drilling a well is also an essential part of the recovery process for oil and gas and groundwater.

Drilling a well effectively means to have well control, no blowout and to have the desired well pressure

Another important factor in drilling is to have safety, efficiency and economy. Thereby protecting human life and safeguarding equipment [2] .

I.3 DRILLING FLUID CIRCULATION IN THE BOREHOLE

The circulation path followed by the drilling mud in rotary drilling is as follows (Figure I.2):

1. The mud is mixed and stored in the settling tank.
2. A pump sends the mud into the drill pipe, which descends to the bottom of the well.
3. The mud exits from the end of the drill pipe and falls to the bottom of the well where the drill bit is drilling the rock formation.
4. The mud then follows the reverse path, rising to the surface while carrying rock fragments, called cuttings, which were removed by the drill bit.
5. The mud rises through the annular space between the drill pipe and the well walls.
6. At the surface, the mud flows through the mud return line to the vibrating screen. The vibrating screen consists of a set of vibrating metal meshes used to separate the mud from the cuttings.

The mud then drains through the screens and is returned to the settling tank.
7. A more advanced treatment is then carried out using a set of mechanical purification equipment [3] .

The circulation process of the drilling fluid through the wellbore is illustrated in Figure I.2

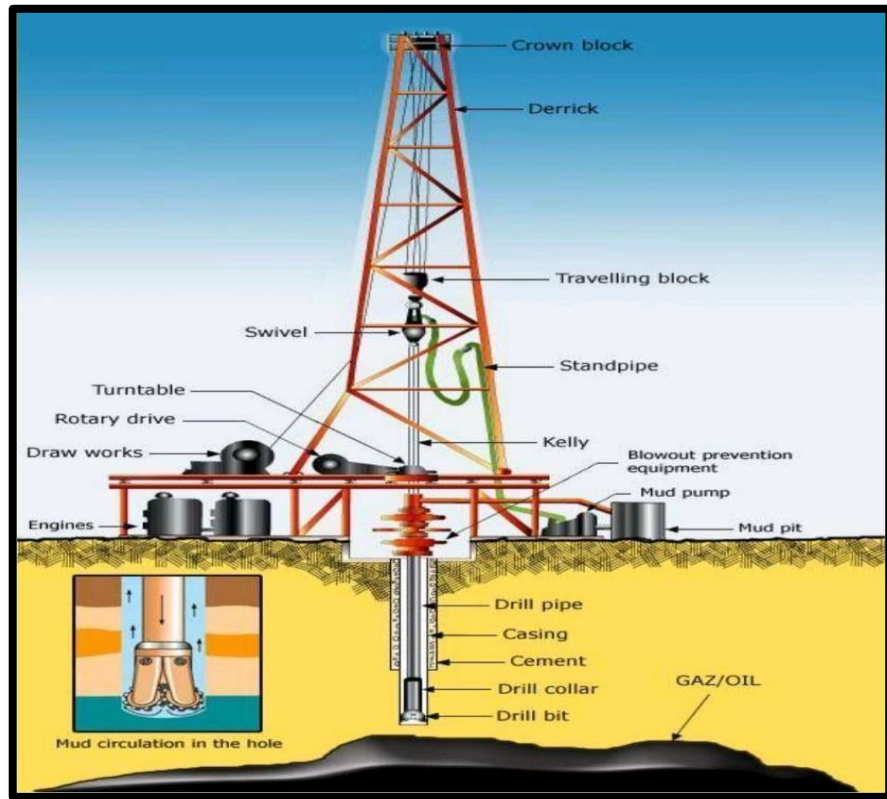


Figure.I 2: Schematic Diagram of Rotary Drilling Rig and Drilling Fluid Circulation System[3]

I.3.1 FUNCTIONS OF DRILLING MUD

Drilling mud must have properties that allow it to optimize the following functions:

- ❖ Cleaning of the well.
- ❖ Keeping the cuttings in suspension.
- ❖ Sedimentation of fine cuttings at the surface.
- ❖ Cooling and lubricating the tool.
- ❖ Supporting the wellbore walls.
- ❖ Deposition of an impermeable filter cake.
- ❖ Prevention of water, gas, or oil influxes.

- ❖ Increasing the drilling rate.
- ❖ Driving the drilling tool.
- ❖ Providing information about the well:
 - Cuttings brought to the surface by mud circulation.
 - Detection of gas or other fluids mixed with the mud.
- ❖ Contamination of the producing formations.
- ❖ Corrosion and wear of the equipment [3] .

I.3.2 Types of Drilling Mud

There are two types of drilling mud:

- **Water-Based Mud**

The starting mud varies depending on the region. Sometimes water can be used, while in other cases, high-quality mud is required at certain locations.

Surface formations may consist of unconsolidated sand and gravel.

The mud must have sufficient body to support the borehole walls in order to avoid collapse and to allow the removal of cuttings during drilling.

Sometimes, surface formations contain enough clay to form a natural mud; otherwise, bentonite or bags of clay are mixed with water before starting drilling.

- **Oil-Based Mud**

Oil-based muds are usually used during completion, coring operations, or special drilling conditions such as high temperatures, swelling clays, or stuck pipe problems.

Two types are distinguished: normal (oil-based mud) and inverse (invert emulsion mud).

Both types are very expensive and must be prepared on site [3] .

I.3.3 Circulation System

As shown in Figure I.3, the drilling mud circulation system ensures the continuous movement of drilling fluid throughout the well.

The mud is pumped from the mud tanks to the drill string, then returns to the surface carrying rock cuttings, where it is cleaned and recirculated [1] .

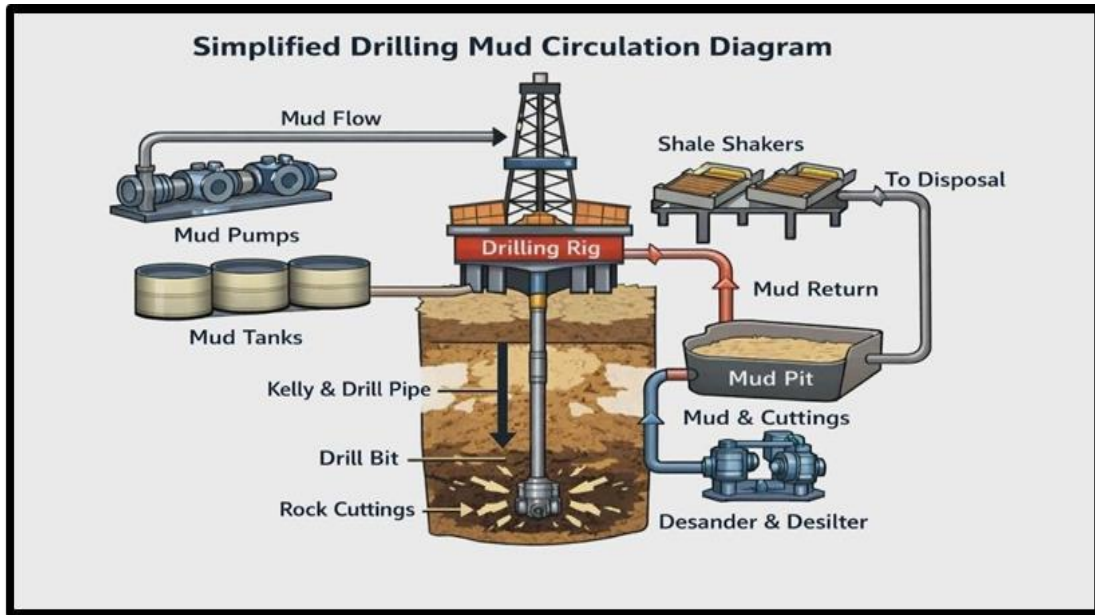


Figure I.3: Simplified Circulation System Diagram [1]

I.4 PUMPING SYSTEM

Pumps are widely used in industry for fluid transfer, cooling, lubrication, and hydraulic power systems.

They are essential in manufacturing plants, commercial buildings, and municipal services.

Pumps are mainly classified into positive displacement pumps and centrifugal pumps, depending on how they transfer energy to the fluid.

Choosing the appropriate pump type depends on system requirements, while pump reliability is crucial to ensure safe and efficient operation.

However, oversized pumps can lead to higher operating and maintenance costs, as well as increased wear on system components [4].

I.4.1. Pumping System Components

Typical pumping systems contain five basic components: pumps, prime movers, piping, valves, and end-use equipment (e.g., heat exchangers, tanks, and hydraulic equipment). [4]

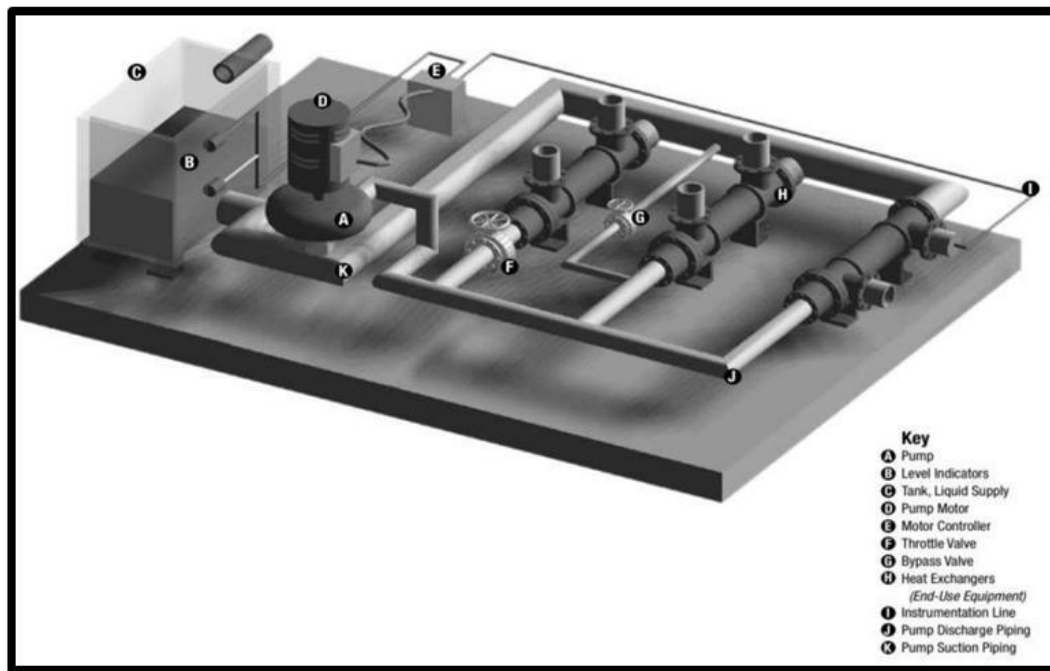


Figure. I 4: Typical Pumping System Components [4]

❖ Pump

Although pumps are available in a wide range of types, sizes, and materials, they can be broadly classified into the two categories described earlier positive displacement and centrifugal.

These categories relate to the manner in which the pumps add energy to the working fluid.

✓ Positive Displacement Pumps

Positive displacement pumps pressurize fluid with a collapsing volume action, essentially squeezing an amount of fluid equal to the displacement volume of the system with each piston stroke or shaft rotation.

✓ Centrifugal Pumps

A centrifugal pump is a rotating machine that, through a rotor equipped with properly oriented blades, increases the kinetic energy of the fluid and projects it outward toward the periphery into the volute by means of centrifugal force.

At the outlet, and with the help of a diffuser, a large part of the kinetic energy is converted into pressure energy, As illustrated in Figure I.5, the centrifugal pump consists of a motor, coupling, and pump casing working together to transfer drilling fluid efficiently.

The fluid enters through the suction flange, gains kinetic energy from the rotating impeller, and leaves the pump under pressure through the discharge flange [9] .

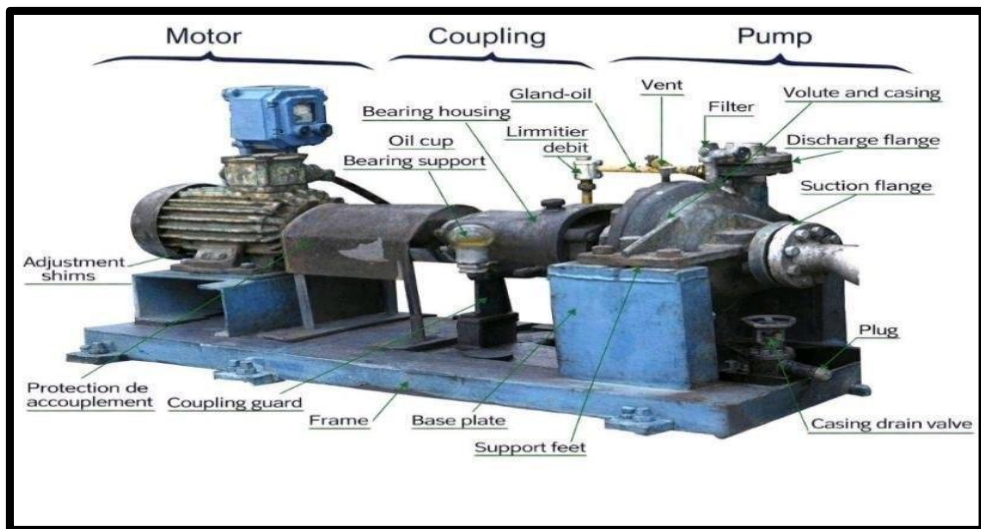


Figure. I.5: Centrifugal Pumps [9] .

❖ Prime Movers

Most pumps are powered by electric motors, especially alternating current (AC) motors, due to their high reliability and energy efficiency.

Improvements in motor efficiency, supported by standards such as EPAct and NEMA Premium, help reduce operating costs. A key

component of the pump system is the motor controller, which regulates the motor's operation. In special applications, pumps may also be driven by air systems, machine shafts, or diesel engines to ensure continuous operation during power failures.

The integration of the pump, motor, and control components within the drilling system is illustrated in figure I.6



Figure I.6: Pump and Prime Mover Assembly in an Industrial System. [4]

❖ Piping

Piping is used to contain the fluid and carry it from the pump to the point of use, The critical aspects of piping are its dimensions, material type, and cost, Since all three aspects are interrelated, pipe sizing is an iterative process.

The flow resistance at a specified flow rate decreases as the pipe diameter increases however, larger pipes are heavier, take up more floor space, and cost more than smaller pipes.

Similarly, in systems that operate at high pressures (for example, hydraulic systems), small-diameter pipes can have thinner walls than large-diameter pipes and are easier to route and install.

Small-diameter pipes restrict flow, however, and this can be especially problematic in systems with surging flow characteristics.

Smaller pipes also operate at higher liquid velocity, increasing erosion effects, wear, and friction head, Increased friction head affects the energy required for pumping.

❖ Valves

The flow in a pumping system may be controlled by valves. Some valves have distinct positions, either fully open or fully closed , while others can be used to throttle flow.

There are many different types of valves; selecting the correct valve for an application depends on several factors, such as ease of maintenance, reliability, leakage tendencies, cost, and the frequency with which the valve will be operated .

Valves can be used to isolate equipment or regulate flow. Isolation valves are designed to seal off a part of a system for operating purposes or maintenance.

Flow-regulating valves either restrict flow through a system branch (throttle valve) or allow flow around it (bypass valve).

A throttle valve controls flow by increasing or decreasing the flow resistance across it. In contrast, a bypass valve allows flow to go around a system component by increasing or decreasing the flow resistance in a bypass line.

A check valve allows fluid to move in only one direction, thus protecting equipment from being pressurized from the wrong direction and helping to keep fluids flowing in the right direction.

Check valves are used at the discharge of many pumps to prevent flow reversal when the pump is stopped.



Figure I.7: *Pumping System with Integrated Piping and Valve Network [4] .*

❖ End-Use Equipment

The essential purpose of a pumping system may be to provide cooling, to supply or drain a tank or reservoir, or to provide hydraulic power to a machine.

Therefore, the nature of the end-use equipment is a key design consideration in determining how the piping and valves should be configured.

There are many different types of end-use equipment; the fluid pressurization needs and pressure drops across this equipment vary widely.

For heat exchangers, flow is the critical performance characteristic; for hydraulic machinery, pressure is the key system need.

Pumps and pumping system components must be sized and configured according to the needs of the end-use processes [4] .

I .4.2 Pumping System in Drilling

The pumping system plays a crucial role in drilling operations by ensuring the continuous circulation of drilling fluid throughout the well.

Its main functions include transporting the drilling mud from the surface to the drill bit, cleaning the wellbore by carrying cuttings to the surface, cooling and lubricating the drilling equipment, and maintaining well pressure for safe and efficient drilling operations.

The performance and main components of the pumping system are summarized in Table I.1

Table I.1 :Technical function of pumping system in drilling engineering [6]

Function	Description
Cuttings Removal	Pumps transport rock cuttings from the borehole to the surface, keeping the wellbore clear and ensuring efficient drilling progress.
Wellbore Stability & Pressure Control	By maintaining hydrostatic pressure, the fluid counteracts formation pressures, preventing blowouts and stabilizing the borehole.
Drill Bit Cooling	Continuous circulation removes heat generated at the bit, protecting the tool and extending its life.
Heat Management in High-Temperature Wells	Centrifugal pumps circulate fluid that acts as a heat-transfer medium, regulating temperature of both equipment and the wellbore in deep, hot formations.
Mud Conditioning & Recycling	Modern systems employ closed-loop mud cleaning to remove solids and contaminants, reducing environmental impact and preserving mud properties.
Fluid Flow Regulation	Variable frequency drives (VFDs) and smart sensors enable real-time adjustments, optimizing flow rates and reducing energy consumption.

The pumping system generally consists of several main components, such as mud tanks, suction lines, pumps, discharge lines, as well as valves and control devices.

For the system to operate properly, the suction line must be correctly designed and suitable pumps must be selected to avoid hydraulic problems such as cavitation and pressure losses [9] .

Mud tank : The Mud Tank is a key part of the drilling system. It stores and conditions the drilling fluid, known as mud, during operations.

The tank receives the mud that returns from the well after picking up rock cuttings and impurities from the drilling process.

The fluid is processed through separation and cleaning stages to remove unwanted materials. After this, its properties can be adjusted by adding water or chemical additives to make it suitable for reuse.

The mud tank also maintains a steady circulation of the drilling fluid, This helps improve drilling efficiency and keeps the well stable.

- **Suction Line** :The suction line is the pipe that connects the Mud Tank to the drilling pump, It transfers the drilling fluid, or mud, from the tanks to the pump during drilling operations.
- This line is crucial to the pumping system. It ensures a steady supply of drilling fluid to keep circulation stable in the well.
- The efficiency of the suction line is vital to prevent issues like pressure drop or cavitation, which can impact how the drilling system works.
- **Mud pumps**: the mud pumps a vital piece of any drilling setup. It shuttles the drilling fluid, or "mud," from the surface down into the well and then back up again. This circulation's pretty critical for drilling to even happen.

Its main gig is pushing that drilling fluid out under serious pressure, This fluid heads down the drill string all the way to the drill bit, Once it hits the bottom, the mud flows back to the surface, dragging rock bits and other debris with it.

Drilling requires keeping the wellbore clean, the drill bit cool and lubricated, and the pressure stable. That's how you drill safely, Most mud pumps are either duplex or triplex.

Triplex pumps are way more common, though; they're just more efficient and provide a smoother flow, Each pump has two main sections: the power end, which supplies mechanical energy, and the fluid end, which actually moves the drilling fluid.

- **Discharge line:** The discharge line's a high-pressure pipe, you know? It carries the drilling fluid, or mud, from the mud pump to the rest of the circulation system on a drilling rig, Its main job is really just moving that pressurized mud around.

This mud leaves the pump, heads to the standpipe, and then flows down into the drill string. That line's gotta handle some serious pressure 'cause the fluid's pumping pretty hard, That's how they keep circulation going right inside the well.

Maintaining continuous mud flow is one of the primary functions of the discharge line, This steady flow is essential for cleaning the wellbore, cooling the drill bit, and controlling downhole pressure during drilling operations.

- **Standpipe :**Vertical pipe that carries drilling fluid from the discharge line to the top of the derrick.
- **Rotary Hose (Kelly Hose):**Flexible hose that allows the flow of drilling fluid from the standpipe to the swivel.
- **Swivel:**Allows drilling fluid to flow into the rotating drill string.
- **Drill String :** Carries drilling fluid downhole through the drill pipe

•**Drill Bit** :Drilling fluid exits through the bit jets, cools and cleans the bit, and carries cuttings to the surface.

•**Flowline** :Carries drilling fluid from the swivel to the flowline.

•**Shale Shaker / Solids Control Equipment**:Removes cuttings and solids from the drilling fluid before it returns to the mud tank.

As shown in Figure I.8, the pumping system in drilling consists of interconnected components that ensure the continuous circulation of drilling fluid from the mud tank to the wellbore and back to the surface for cleaning and reuse [5] .

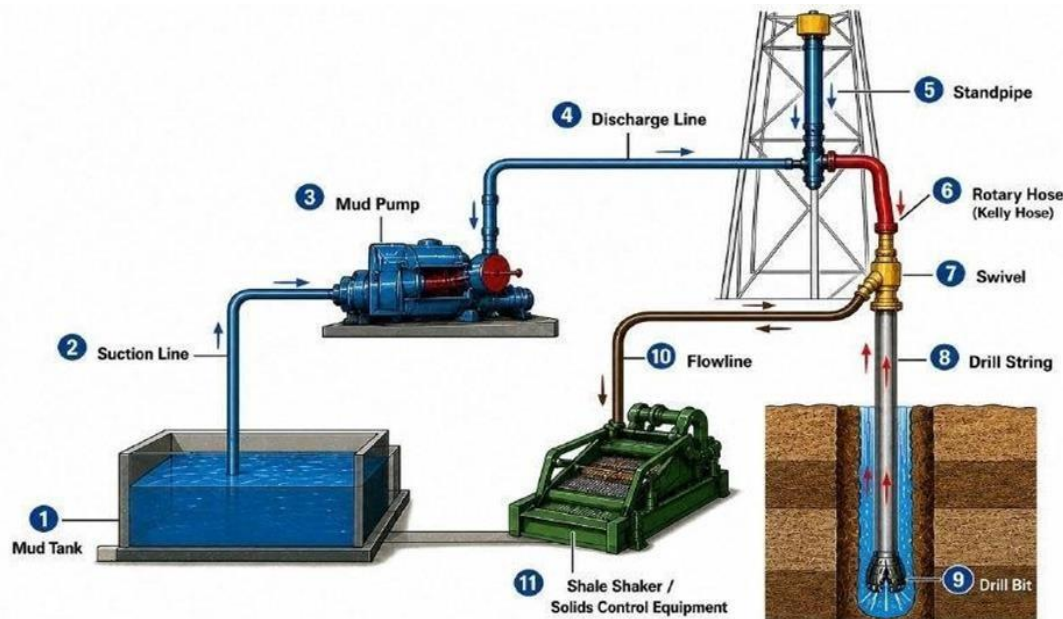


Figure I.8: Components of the Pumping System in drilling [5]

I.5 Fundamentals of Suction

The liquid is drawn into the center of the impeller through an opening called the distributor, whose role is to guide the fluid from the suction pipe to the inlet section of the impeller.

When the pump is primed (that is, filled with liquid), the velocity of the fluid entering the impeller increases, and consequently the pressure at the impeller eye decreases, thus creating suction and maintaining the priming [8] .

I .5.1 Suction line equipment

The water to be pumped arrives at the station through a pipeline, which is directly connected to the plant's suction manifold, from which the pump suction lines originate, There is no storage tank at the station [7] .

a) Suction manifold:



Figure I.9: Simple suction manifold [7]

b) Joints and elbows:

If the suction pipe is under negative pressure, the joints must eliminate any possibility of air ingress and, if necessary, the access of pollutants.

On the other hand, elbows allow changes in the direction of the pipeline.



Figure I.10: Joints and elbows [7]

C) Suction Valve:

A valve installed on the pump suction allows the pump to be isolated for maintenance or disassembly. The valves used can be either gate valves with a hydraulic stuffing box or butterfly valves.



Figure. I. 11 : Manual valve [7]

D) Suction Convergent:

To limit head losses at the pump suction, the suction pipe often has a large diameter, resulting in a flow velocity lower than the velocity at the pump flange inlet.

The pipe is then connected to the pump via a convergent section, which allows a gradual acceleration of the flow, promoting a proper distribution of velocities just upstream of the pump.

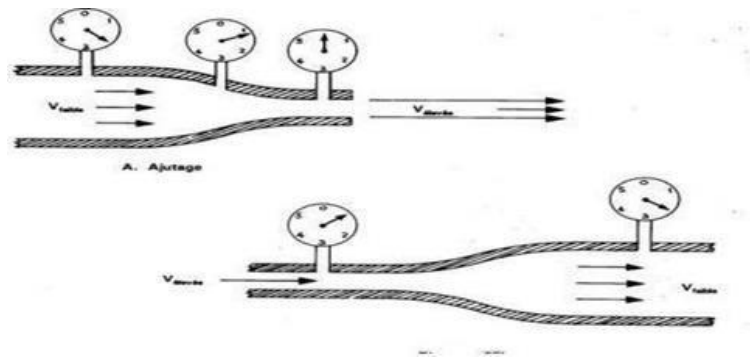


Figure. I.12: Example of a convergent [7]

E) Flow Meters:

They allow the measurement of the fluid flow.

F) Pressure Gauges:

They allow the measurement of pressure.

I .6 Conclusion

This chapter presented a general overview of drilling and pumping systems, It introduced the basic principles of drilling, the role of drilling fluid circulation, and the main functions and types of drilling mud.

In addition, the chapter discussed pumping systems, their components, operating principles, and the importance of suction conditions.

Overall, this chapter established the theoretical foundation necessary for understanding the role and operation of pumping systems in drilling applications, which will be further developed in the following chapters.

Chapter II

Analysis of Suction Problems

II.1 Introduction

The suction system is one of the most critical elements affecting the performance and reliability of pumps used in petroleum drilling operations. Since it operates at the lowest pressure region of the hydraulic circuit, it is particularly sensitive to pressure losses, air or gas ingress, and cavitation phenomena. Any deterioration in suction conditions can lead to reduced performance, increased vibration levels, and premature wear of pump components.

This chapter focuses on the hydraulic aspects of suction performance and the analysis of the main malfunctions that may affect pump operation. It begins by introducing the fundamental concepts of Net Positive Suction Head (NPSH) and cavitation, followed by a discussion of common suction-related problems such as air entrainment, gas binding, and vortex formation. The technical causes of these malfunctions and their effects on system performance are then examined.

The objective of this chapter is to provide the theoretical background necessary for understanding suction-related problems, diagnosing their root causes, and implementing appropriate corrective measures to improve the reliability and efficiency of pumping systems in drilling applications.

II.2 Fundamentals of Pump Suction Hydraulics.:

The energy path from the liquid surface to the inlet suction is described by the extended Bernoulli equation. At the suction inlet, the available pressure head is reduced by elevation change, inlet velocity, and total suction losses, while the local pressure at the impeller throat is the minimum point in the whole circuit.

That is why the transition between suction pipe and suction inlet is more critical than the pipe alone: small changes in temperature, altitude, pipe geometry, or flow rate directly reduce the suction margin and move the system toward cavitation inception.

The hydraulic energy path and its associated head components from the suction source to the pump manifold are schematically illustrated in Figure II.1 [10] .

Energy pathway from sump to pump inlet

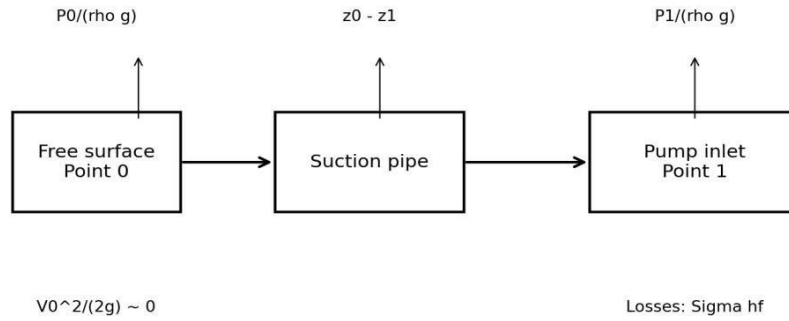


Figure II.1: Energy pathway from the free surface to the pump inlet, showing pressure head, velocity head, elevation head, and suction losses [10] .

II.3 Suction-Related phenomena and Technical Dysfunctions

II. 3.1 Net Positive Suction Head (NPSH):

Net Positive Suction Head (NPSH) is a key parameter used to assess the suction performance of pumping systems. It represents the difference between the pressure available at the pump suction inlet and the liquid vapor pressure.

An adequate NPSH margin is required to prevent cavitation and ensure reliable pump operation.

✓ Available NPSH(NPSHa)

Net Positive Suction Head Available (NPSHa) is the system-side suction margin above the fluid vapor-pressure head at the pump inlet.

It depends on installation geometry, suction lift or flooded suction, fluid temperature, atmospheric pressure, and line losses, not on the pump itself. In practice, the basic relation is

$$NPSHa = \frac{P_a - P_v}{\rho g} + h_s - \Sigma h_f \quad \text{II.1}$$

Where:

NPSHa = Net Positive Suction Head Available (m)

Pa = Absolute pressure acting on the liquid surface (Pa)

Pv = Vapor pressure of the liquid (Pa)

ρ = Liquid density (kg/m³)

g = Gravitational acceleration (9.81 m/s²)

hs = Static suction head (m)

Σhf = Total friction head losses in the suction line (m)

The most demanding case is the one that matters: maximum flow, minimum level, highest temperature, and lowest site pressure.

To better understand these dynamics, figure II.2 maps the sensitivity of individual NPSHa elements under shifting environmental and thermal conditions [11] .

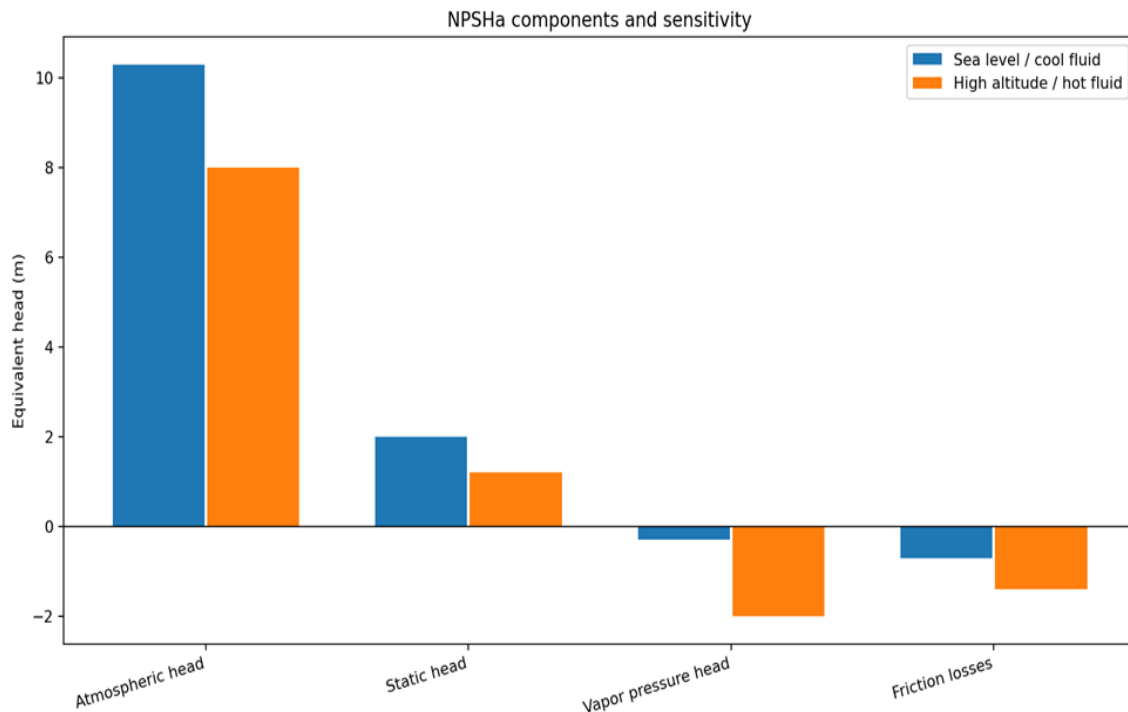


Figure II.2: Decomposition of NPSHa components under low altitude/cool and high-altitude/hot conditions [11] .

✓ **Required NPSH (NPSH_r):**

Required NPSH (NPSH_r) belongs to the pump and is fixed by manufacturer testing. By standard convention, it is the NPSH_a value at which developed head falls by 3% from the no-cavitation curve.

That 3% point is useful for standards and comparison, but it is not the first moment cavitation starts: inception happens earlier, and visible damage can already be growing Before the head curve moves, this performance breakdown is clearly captured in figure II.3, which displays the standard 3% head-drop curves alongside the earlier inception zone [12] .

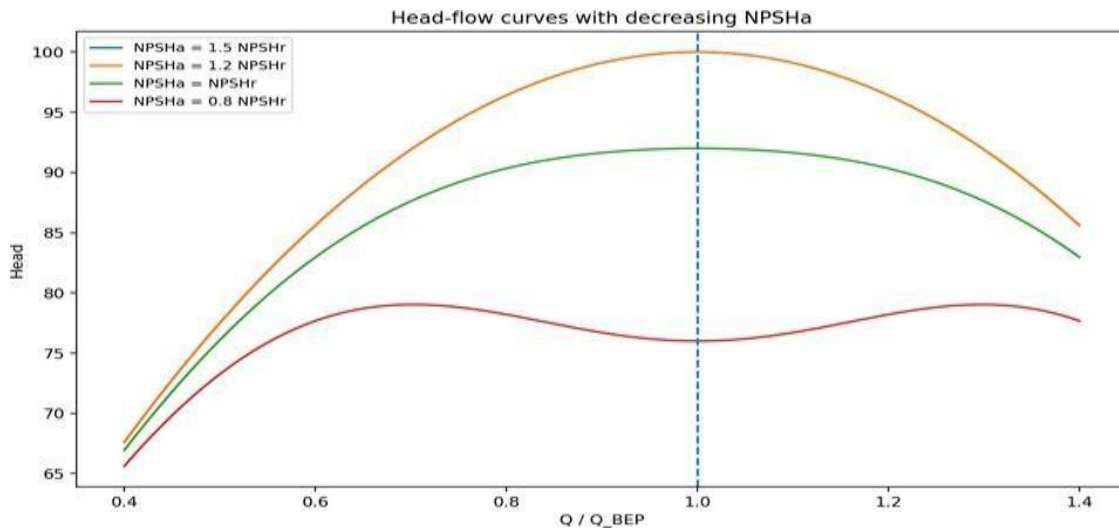


Figure II.3: Head-flow curves at decreasing NPSH_a, with the 3% head-drop definition of NPSH_r and the earlier inception zone above it [12] .

✓ NPSH Margin:

NPSH margin is not universal, for clean water service, a small margin may be acceptable, but petroleum service is more conservative because the cost of failure is much higher. Hot hydrocarbons can show some thermodynamic suppression of cavitation, while drilling muds usually need a much larger margin because viscosity, entrained gas, and friction losses push the suction system in the opposite direction [13] .

II. 3.2 Cavitation Dynamics and Classification

✓ Physics of Bubble Nucleation:

Cavitation starts at nucleation sites when local pressure falls below vapor pressure. The growth and collapse of one bubble can be represented by the Rayleigh-Plesset relation, which shows how pressure, surface tension, and viscosity control the bubble radius over time ,Near a solid wall, collapse becomes asymmetric and creates a microjet that can strike the metal surface at very high local pressure, which is why the suction face of the blade is so vulnerable.

The actual timeline of this bubble growth followed by its subsequent violent collapse is plotted behaviorally over time in Figure II.4.[14].

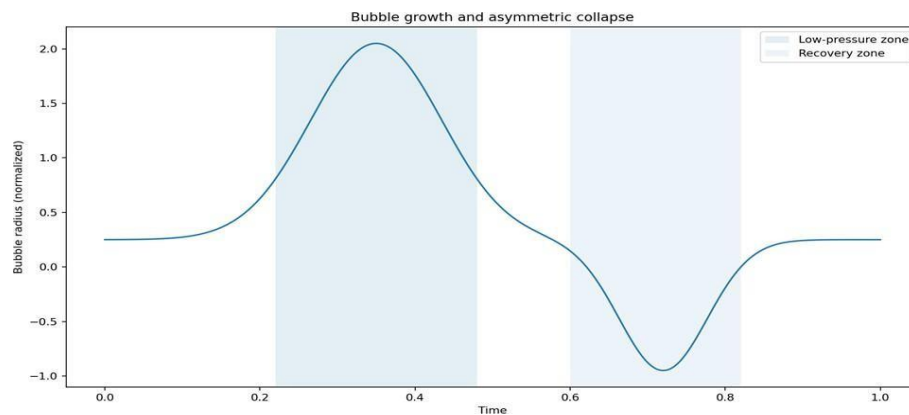


Figure II.4: Bubble growth in the low-pressure zone and asymmetric collapse near the blade surface [14] .

✓ **Classic Vaporous vs Gaseous Cavitation :**

Vaporous cavitation is a true phase change driven by pressure falling below vapor pressure, while gaseous cavitation is gas release from dissolved or entrained gases when suction pressure drops.

The acoustic signature is also different: vaporous cavitation crackles, while gas release tends to hiss, In drilling service, gas release can appear even when the NPSH calculation still looks acceptable, so the corrective action may be degassing or reducing gas entrainment rather than only increasing suction head [15] .

II. 3.3 Aeration and Fluid Discontinuity

✓ **Air Entrainment:**

Air entrainment is different from cavitation because the gas is drawn into the flow mechanically from outside the liquid rather than created by phase change.

Leaks at flanges, partly open drain valves, poor stuffing-box sealing, or misconnected vents can all ingest air under suction lift, and even a small gap can create enough air entry to break prime.

Field guidance in suction service treats small air fractions seriously, because once the inlet fluid is no longer continuous liquid, the pump loses head and priming becomes unstable.

Figure II.5 outlines the most common physical pathways and mechanical joints where this external air ingress typically occurs [16] .

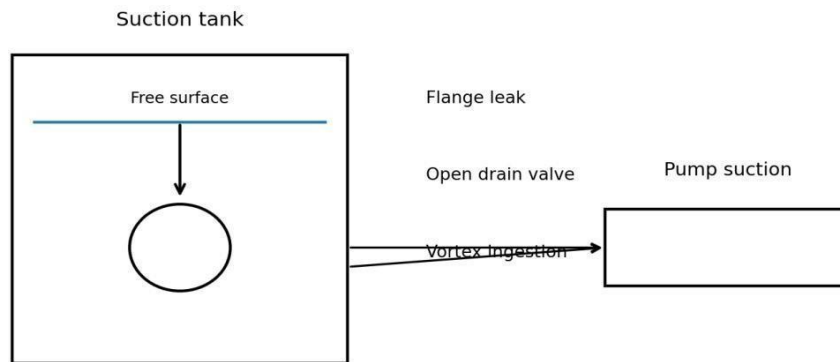


Figure II.5: Air entrainment paths through suction leaks, drain valves, vent misconnection, and free-surface vortex ingestion [16] .

✓ Gas Binding Mechanics

Gas binding is the point where the gas volume fraction becomes high enough that the suction inlet cannot build head.

The gas collects in the inlet suction, fills the passages, and forms a stable lock that blocks liquid entry, unlike cavitation, which may fluctuate. Gas binding is self-sustaining and often needs venting, re-priming, or a temporary change in backpressure before the pump can recover [16] .

II. 3.4 Vortex Formation and Swirl

✓ Surface Vortices:

Surface vortices form when the sump withdraws liquid faster than gravity can redistribute the flow.

The rotation deepens into a coherent core, and if the core reaches the inlet, atmospheric air is pulled directly into the suction stream, HI-style vortex classification separates

harmless surface motion from the severe types that destroy prime, and the usual design control is to keep the Froude number low or add anti-vortex hardware.

The progressive severity of these surface formations is classified systematically according to international standards in figure II.6. [16].

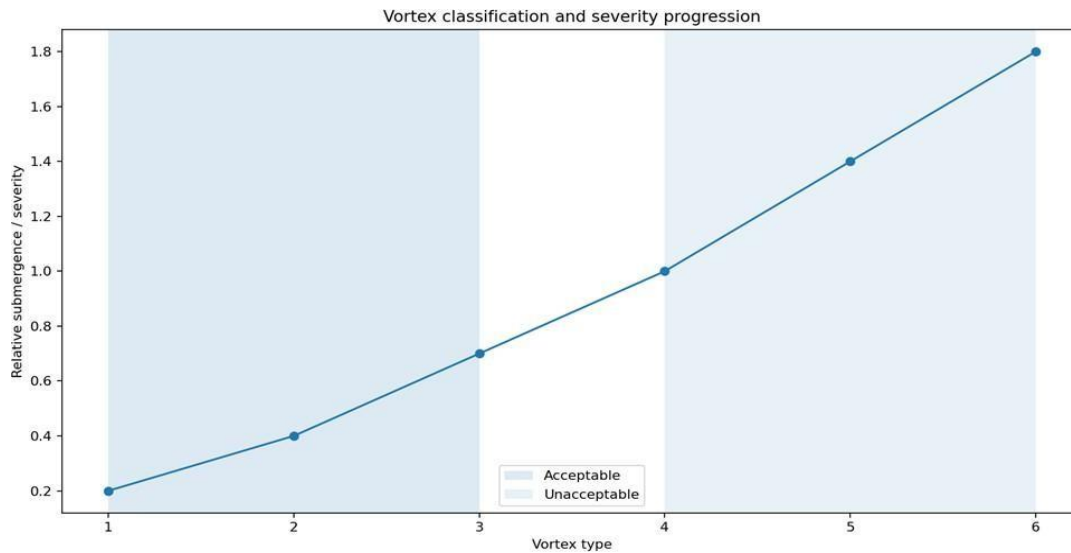


Figure II.6: Vortex severity progression from weak surface dimple to fully developed air-core ingestion [16] .

✓ Submerged Vortices:

Submerged vortices are different because they begin on the sump floor or walls and transfer swirl to the inlet before the fluid reaches the suction inlet. That pre-rotation changes the inlet velocity triangle, reduces head when the swirl is co-rotating, and can push cavitation earlier when the swirl is counter-rotating.

In practice, inlet swirl produces symptoms that look like cavitation, but the real fix is sump or intake redesign rather than simply adding suction head [9] .

Finally In addition to what has been mentioned previously, Table II.1 summarizes the main suction-related problems in drilling pumps by grouping them into distinct categories based on their physical origin and operational behavior [18]

Table II.1. *Classification of Suction Problems in Drilling Pumps [9] .*

Problem Type	Physical Basis	Field Indicator	Risk Level
Cavitation	Local $P < \text{Vapor Pressure}$ → bubble nucleation & collapse	Crackling noise; pitting on liners & valves	CRITICAL
Gas Entrainment	Free gas reduces bulk modulus; absorbs compression energy	Foamy returns; soft stroke; declining mud weight out	HIGH
Insufficient Suction Head	$\text{NPSH}_a < \text{NPSH}_r$ due to elevation, friction, or density	Incomplete fill; low flow at rated SPM	HIGH
Valve Failure	Wear, spring fatigue, seat erosion by abrasive solids	Erratic pressure; back-flow; efficiency drop	HIGH
Rheological Effects	High viscosity / gel strength → slow fill, high friction loss	Slow startup; pressure surge on first stroke; gel plugging	MEDIUM
Suction Line Blockage	Solids settling or strainer plugging → flow obstruction	Zero or very low flow at rated SPM; high suction dP	CRITICAL
Pulsation / Resonance	Acoustic amplification of cyclic suction demand	High vibration; intermittent cavitation at moderate SPM	MEDIUM

II.4 Technical Causes of Malfunctions

II. 4.1 Inadequate Hydraulic Piping Design:

✓ Suction Line Sizing:

Undersized suction piping is one of the most preventable causes of suction failure, Using Darcy-Weisbach, friction loss scales with V^2 , so a modest velocity increase can consume a large part of the suction margin.

The practical rule is simple: the suction line must be sized for low velocity and low loss, not merely for a pipe that fits the pump nozzle.

Figure II.7 charts these friction head loss trends against shifting velocities and diameters, noting the strict regulatory limits [12] .

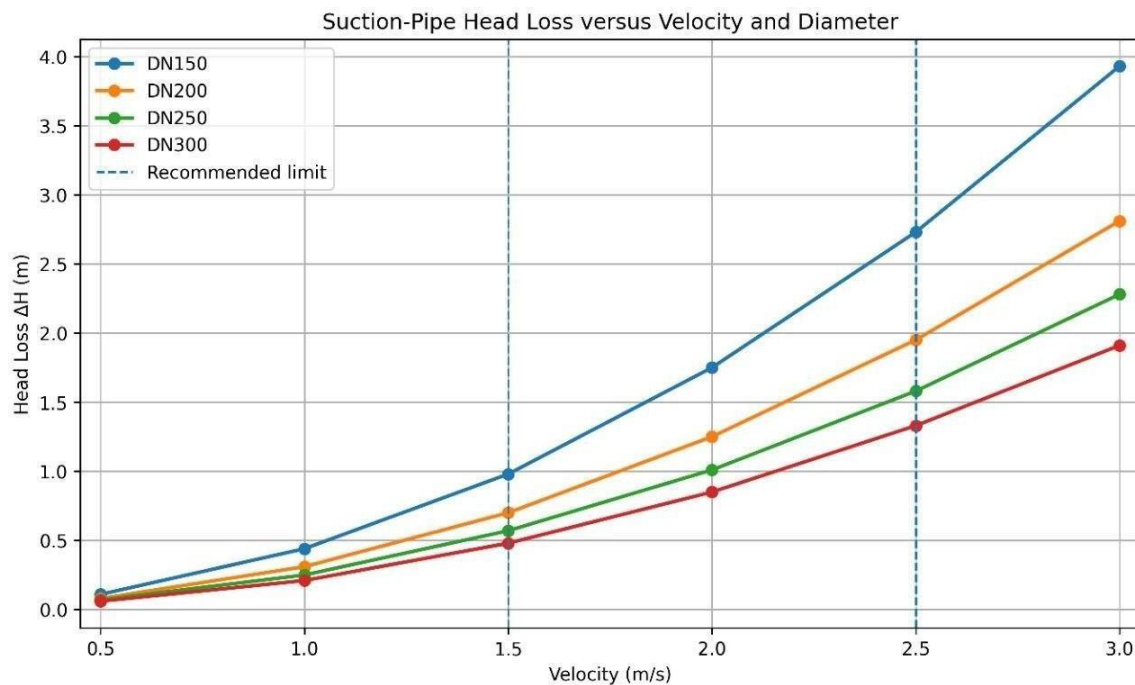


Figure II.7: Friction loss trends showing how suction velocity and pipe diameter control are available NPSH [12].

✓ Fitting Impacts

A 90-degree elbow located close to the pump inlet can distort the velocity profile, generate secondary swirl, and create a non-uniform flow distribution at the suction inlet. These disturbances increase local pressure losses and reduce the effectiveness of the suction system, even when the average suction pressure appears acceptable.

The resulting flow instability may promote localized low-pressure zones, increase the risk of cavitation, and generate vibration and noise within the pumping system.

Therefore, the geometry of the suction piping should be considered an integral part of the hydraulic design rather than a simple connection between the suction source and the pump.

To minimize these adverse effects, adequate straight-pipe lengths should be provided upstream of the suction inlet, and abrupt changes in flow direction should be avoided whenever possible [13].

✓ Eccentric Reducer Orientation:

The eccentric reducer must be installed flat-side up. That orientation keeps the top of the pipe continuous and prevents a high-point pocket where vapor or free gas can collect.

If the reducer is installed bottom-flat or replaced with a concentric reducer, the pocket can trap gas, break the liquid column, and generate intermittent suction problems even when the calculated NPSH margin looks acceptable [16] .

✓ Minimum Straight Pipe Length:

The 10D straight-pipe rule exists to let upstream disturbances decay before the fluid reaches the suction inlet. When elbows, reducers, or valves are connected directly to the nozzle, the inlet flow remains non-uniform, and the pump can lose a large part of its NPSH margin in real service compared with the factory test condition.

If space does not allow the full straight length, a flow straightener can help, but its pressure loss must be counted explicitly in the suction calculation, this velocity profile

distortion and its gradual stabilization over multiple pipe diameters are demonstrated in figure II.8. [12].

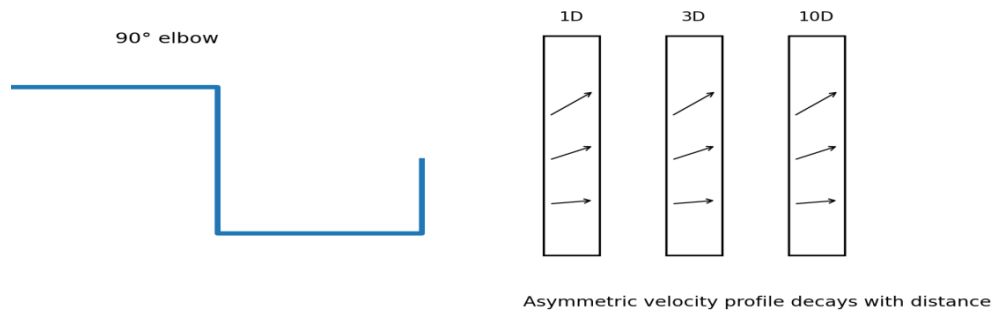


Figure II.8 Velocity-profile distortion downstream of a 90-degree elbow at increasing straight-pipe distances [12] .

II. 4.2 Operational and Environmental Drivers

✓ Tank Level Fluctuations:

In suction-lift or sump systems, liquid level directly controls the static head term of NPSHa. If the level falls during drawdown, batch withdrawal, or switchover events, the available suction head can drop below the required value even though the nominal design calculation looked safe.

The practical answer is not only alarm logic, but also proper submergence, reliable level measurement at the intake, and a trip set before the vortex or air-core condition develops. [16]

II. 4.3 Fluid Physics and Drilling Mud Properties:

✓ Temperature-Vapor Pressure Correlation:

Temperature is one of the fastest ways to lose suction margin because vapor pressure rises directly with temperature.

For water and many process fluids, the increase is large enough that a system designed for cold conditions can lose several meters of NPSHa once the fluid heats up.

That is why vapor-pressure tables or Antoine-based calculations must be revisited for the real operating temperature, not only for the design-point temperature [17] .

✓ Non-Newtonian Behavior of Drilling Muds:

Drilling mud is not a simple Newtonian liquid, Its apparent viscosity depends on shear rate, so low-speed or low-flow suction conditions can generate much higher friction loss than a fresh-water calculation would predict.

For weighted muds, the real NPSHr can be far above the published water curve, so using uncorrected freshwater data is a common source of early suction trouble [13] .

II.5 Systemic Consequences and Impact Analysis

II. 5.1 Hydraulic Performance Decay

✓ Reduction of volumetric performance

Cavitation and suction deficiencies can significantly reduce the volumetric performance of a drilling pump, When the available suction pressure becomes insufficient, the cylinders may not fill completely during the suction stroke.

As a result, the actual delivered flow rate decreases below the theoretical capacity of the pump. In severe cases, vapor cavities and entrained gas occupy part of the cylinder volume, reducing the amount of liquid transferred during each cycle.

This phenomenon leads to flow-rate fluctuations, pressure instability, and a reduction in overall pumping efficiency [10] .

✓ **Efficiency Loss**

Cavitation also results in significant energy losses within the pumping system. Part of the energy available at the suction inlet is consumed in the formation, growth, and collapse of vapor bubbles rather than being used to transport the fluid effectively.

As cavitation intensifies, volumetric efficiency decreases due to incomplete cylinder filling and unstable flow conditions. These effects are often accompanied by pressure fluctuations, increased mechanical loading, and irregular power consumption. Consequently, the pump operates less efficiently while being subjected to greater mechanical stress and thermal loading [10] .

II. 5.2 Material and Structural Degradation

✓ **Surface Erosion**

Cavitation erosion follows a progression from isolated pitting to surface roughening, then deep craters, and finally perforation in thin sections. The cause at each stage is the repeated impact of microjets on localized areas of the metal surface. Small changes in suction conditions can significantly influence the severity of erosion because the collapse pressure governs the intensity of each impact. Consequently, even moderate suction degradation can accelerate material wear and significantly reduce the service life of pump components.

Figure II.9 illustrates the typical four-stage progression of cavitation-induced material degradation on metallic surfaces [14] .

Cavitation erosion progression on the impeller suction face

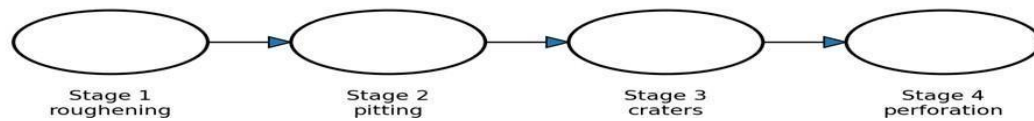


Figure II.9: Typical cavitation erosion progression from roughening to perforation on the suction face [14].

✓ Mechanical Fatigue

Bearings and seals are often secondary victims of suction instability and cavitation. Under severe cavitation conditions, vibration levels increase and pressure fluctuations become more pronounced, placing additional mechanical stress on rotating and sealing components.

These conditions can disrupt the lubrication film at sealing interfaces and accelerate the wear of bearings and seals. The visible consequences include reduced bearing life, seal leakage, increased maintenance requirements, and a significant reduction in the expected service life of the equipment [13].

II. 5.3 Acoustic and Vibrational Impacts

✓ Noise Generation:

Cavitation produces a broadband crackling sound that operators often describe as gravel or marbles in the casing. The acoustic level rises with cavitation intensity, and the spectrum helps distinguish vaporous cavitation from gas release or suction recirculation. This makes sound one of the earliest practical clues in the field, even before major performance loss appears on the test data [13].

✓ **Vibration Spectrum:**

The vibration spectrum associated with suction-related problems typically exhibits an increase in broadband vibration energy together with pronounced peaks at frequencies related to crankshaft rotation, piston motion, and pressure pulsation harmonics.

These spectral features help distinguish hydraulic disturbances from purely mechanical faults such as imbalance or misalignment. Under cavitating conditions, broadband vibration levels generally increase due to the repeated formation and collapse of vapor bubbles, while pressure fluctuations generate characteristic harmonic components in the frequency spectrum.

Figure II.10 illustrates the typical frequency-domain differences between stable operating conditions and a pump affected by suction instability [12] .

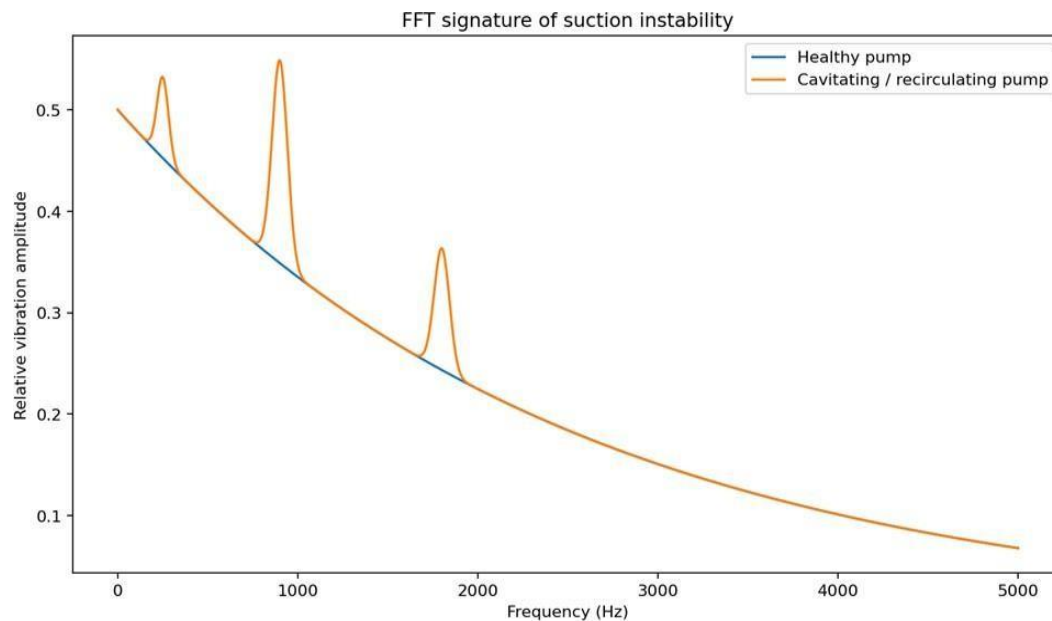


Figure II.10: *FFT signature of suction instability, with broadband energy rise and blade-passing sidebands [12].*

II. 5.4 Economic Consequences

The economic consequences of suction problems vary significantly depending on their severity, duration, and the operational stage at which they occur.

Minor suction valve failures that are detected and corrected early may result in only two to four hours of downtime and repair costs ranging from USD 5,000 to 20,000.

In contrast, severe suction failures that progress into well control incidents can generate costs exceeding USD 10 million due to well-control operations, environmental remediation, regulatory penalties, equipment damage, and potential litigation.

Figure II.11 presents the economic cost distribution associated with different suction-related failure modes on a logarithmic scale.

The figure highlights the asymmetric nature of suction-related risks: low-severity failures remain operationally manageable, whereas high-severity events may threaten the economic stability of the project or company.

This risk asymmetry justifies investment in preventive maintenance, where relatively small maintenance costs can prevent extremely expensive operational failures [18] .

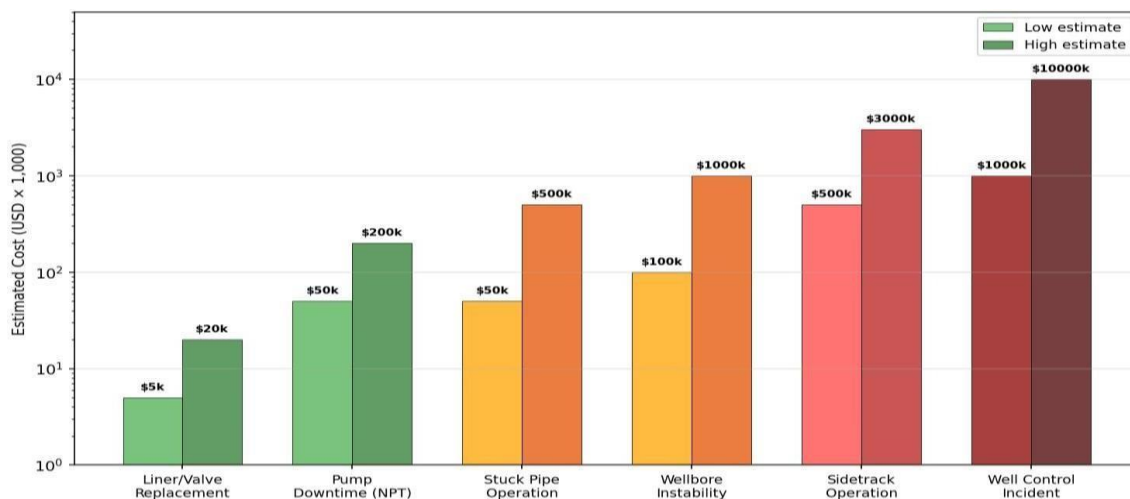


Figure II.11. Economic Cost of Suction-Related Failure Events (Logarithmic Scale, USD) [18].

Finally, Table II.2 summarizes the consequences of suction problems by integrating their short-term operational effects, long-term system impacts, and associated cost ranges.

Table II.2: Consequences of Suction Problems: Integrated Impact Matrix [18].

Consequence	Short-Term Impact	Long-Term Impact	Cost Estimate (USD)
Liner / Valve Erosion	Efficiency loss 5–20%; noise	Component replacement required	\$5,000 – \$20,000 / Event
Reduced Flow Rate	Poor hole cleaning; cuttings	Cuttings bed; stuck pipe risk	\$50,000 – \$500,000
ECD Instability	Pressure fluctuations at bit	Wellbore instability; kicks / losses	\$100,000 – \$1,000,000
Pump NPT (Downtime)	2–8 hours shutdown per event	Schedule delays; cost overrun	\$50,000 – \$200,000 / Day
Crankshaft / Bearing	Vibration increase; noise	Catastrophic mechanical failure	\$200,000 – \$800,000
Well Control Incident	Kick; shut-in; influx	Blowout risk; regulatory action	>\$10,000,000

II.6 Diagnostic

II. 6.1 Conventional Field Diagnostics

✓ **Manometric Analysis:**

The compound gauge at the suction nozzle is the first field instrument for suction assessment, A stable but unusually deep vacuum points to excess friction loss, while a fluctuating reading often points to cavitation or suction inlet disturbance.

A near-zero or positive reading during poor flow can indicate gas binding or complete loss of prime, so the gauge reading must always be interpreted together with fluid properties and pipe elevation [13] .

✓ **Performance Mapping:**

Performance mapping consists of comparing the measured operating parameters, such as flow rate, discharge pressure, power consumption, and pump speed, with the manufacturer's specifications and expected operating conditions.

When the measured values remain within the specified operating range, the hydraulic condition of the pump is generally considered satisfactory, Significant deviations may indicate cavitation, air ingress, leakage, excessive wear, or other suction-related problems.

This method provides a practical means of evaluating pump performance in the field without dismantling the equipment [9] .

II. 6.2 Advanced Monitoring Techniques

✓ **Vibration FFT Analysis:**

FFT FFT analysis transforms vibration signals from the time domain into the frequency domain, making suction-related problems easier to identify.

An increase in broadband vibration energy is often associated with cavitation, while characteristic peaks related to crankshaft rotation, piston motion, and pressure pulsation harmonics provide valuable diagnostic information.

When interpreted correctly, vibration spectra can reveal suction instability and cavitation before significant performance degradation becomes evident [13] .

✓ **Acoustic Emission (AE):**

Acoustic emission works in the ultrasonic range and can detect individual bubble-collapse events before conventional vibration thresholds are reached. That makes it valuable in the silent damage zone between inception and the 3% head-drop point.

In critical petroleum and drilling service, the value of AE is early warning: one prevented unplanned failure can justify the sensor system [12] .

II.7 Conclusion

This chapter presented the theoretical and technical background related to suction problems in petroleum and drilling pump systems.

The study highlighted the importance of suction performance in maintaining pump reliability and hydraulic stability, particularly under conditions where pressure losses may lead to cavitation, vibration, erosion, and flow disturbances.

The chapter also reviewed the main concepts associated with the energy balance, Net Positive Suction Head (NPSH), cavitation mechanisms, and suction-line hydraulic behavior.

In addition, the principal causes of suction dysfunctions and the commonly used diagnostic approaches, including field measurements and CFD analysis, were discussed.

The theoretical elements developed in this chapter provide the necessary foundation for the following chapters dedicated to the analysis and evaluation of the suction system performance under different operating conditions.

Chapter III

Suction System Analysis of the BMPT- 1600-AC Pump

III.1 Introduction

This chapter presents the application of the theoretical concepts developed in the previous chapter to the BMPT-1600-AC mud pump. The study focuses on the analysis of the suction system, which plays a critical role in maintaining adequate hydraulic conditions and preventing cavitation.

First, the main characteristics and operating conditions of the pump are presented. Subsequently, a diagnostic analysis of the suction system is carried out, followed by the mathematical modeling of the parameters governing the available NPSH and suction pressure losses. A parametric study is then conducted to evaluate the influence of key operating parameters on suction performance. Based on the obtained results, several optimization measures are proposed to improve operating conditions and reduce cavitation risk.

III.2 Case Study Description

III.2.1 General Description of the pump BMPT-1600-AC

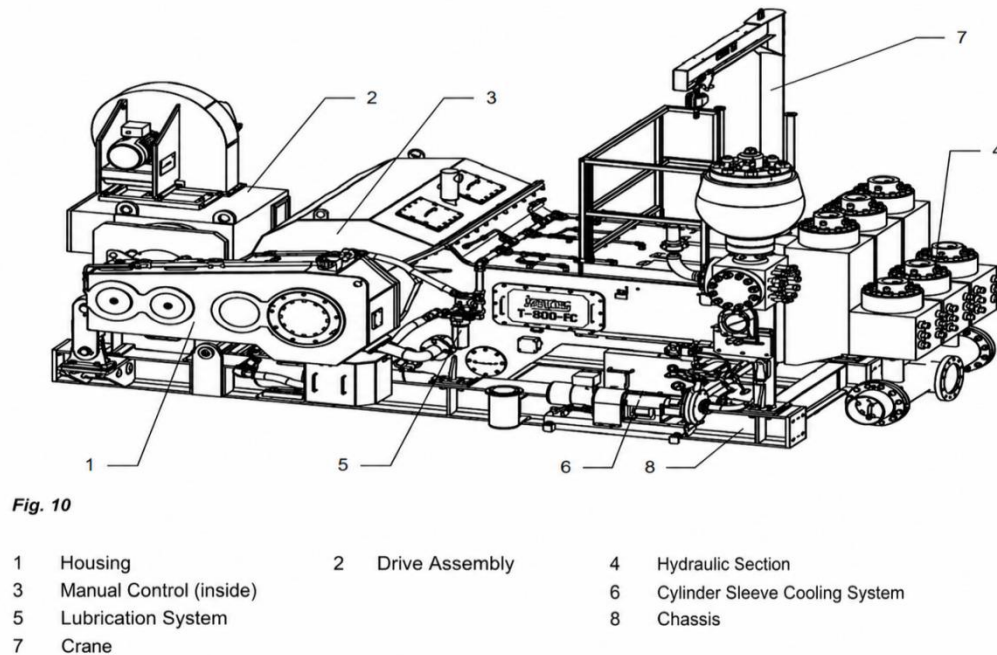
The pump under study is a triplex piston pump (three pistons). It is used on a drilling rig (project DR 534, Enafor), positive displacement piston pumps are the most commonly used for high-pressure discharge in drilling rigs. The table III.1 presents the designation and technical specifications associated with the BMPT-1600-AC R-7 1/2" × 12" mud pump.

Table III.1. Technical specifications of the BMPT-1600-AC R-7 1/2" × 12" [19] .

Designation	Signification
BMPT	Bentec Mud Pump Triplex
1600	Rated power: 1600 HP (1193 kW)
AC	Alternating Current
R	Rear mounted
7 1/2"	Maximum piston diameter
12"	Stroke length

III.2.2 Main Components of the Pump

The figure. III.1 shows an overview of the pump with the main components and their roles.

**Figure III.1.** General view of the pump BMPT-1600-AC [19].

- 1) **housing:** Steel structure containing all the components
- 2) **drive assembly:** Drive motor, hollow gearbox, clutch
- 3) **manual control:** Converts rotary motion into linear motion
- 4) **Hydraulic section:** Contains suction and discharge valves
- 5) **Lubrication system:** Gear pump, oil circuit
- 6) **Cylinder sleeve cooling system:** Clean water spray to cool the pistons
- 7) **Crane:** 1000 kg capacity for maintenance
- 8) **Chassis:** Supports the entire pump.

The hydraulic part (4) is the one that interests us for suction; the suction valves are among the most mechanically stressed components, with more than 170,000 cycles per day of operation.

III.2.3 Technical Identifications

The figure III.2 shows the pump's sign plate BMPT-1600-AC.

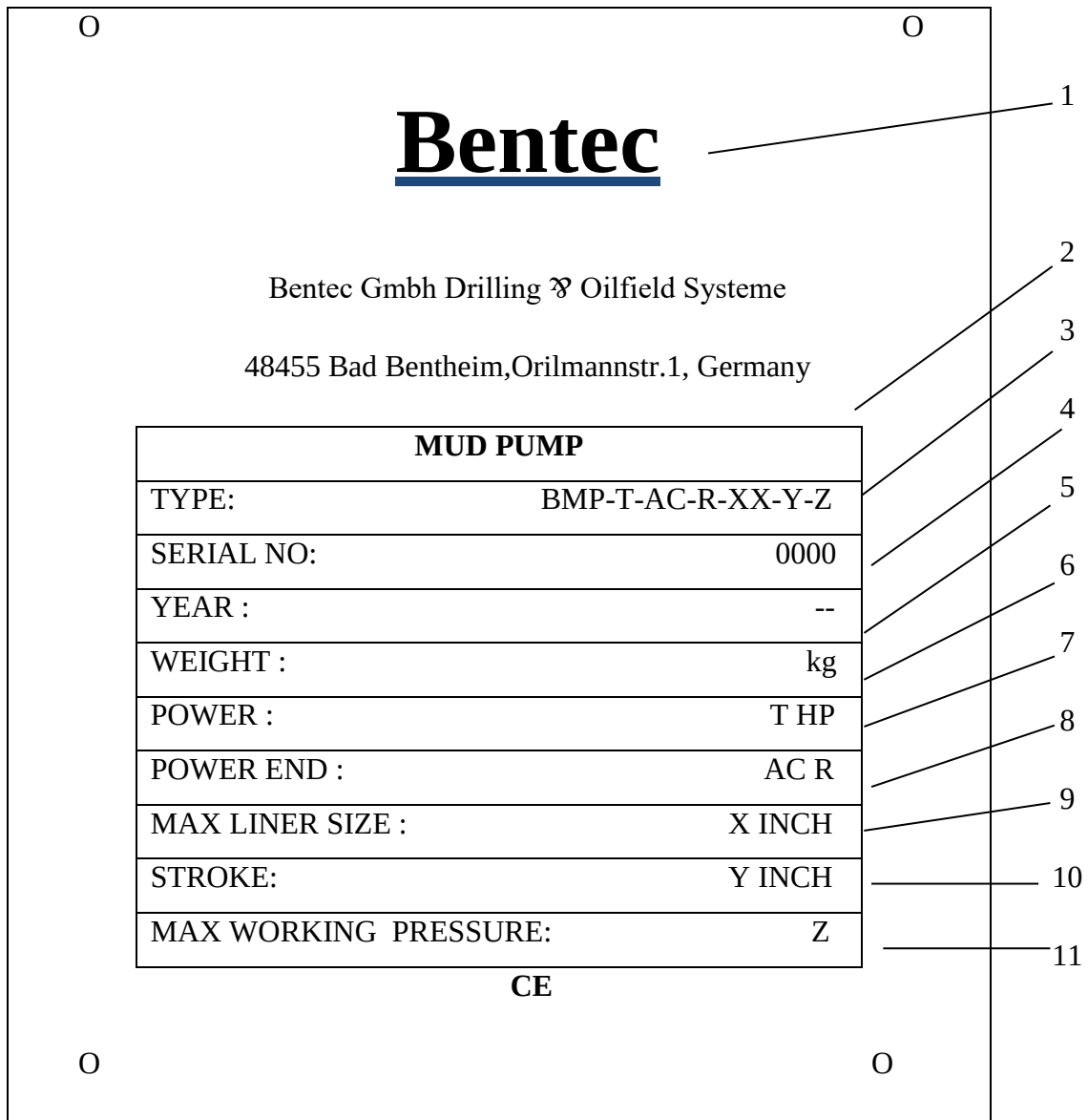


Figure III.2. Pump's sign plate BMPT-1600-AC [19] .

Manufacturer (1), Machine Designation (2), Type (3), Serial Number (4), Year of Manufacture (5), Weight (6), Power (7), Drive Mode (8).Maximum Cylinder Liner Size (9), Stroke Length (10), Maximum Operating Pressure (11).

III.2.4 Technical Specifications

The table III. 2 and III.3 show the general characteristics and power of the pump.

Table III.2. General characteristics [19] .

Characteristic	Value
Weight (ready to operate)	37 000 kg
Length	6 700 mm
Width	2 906 mm
Height (in operation)	4 030 mm

Table III.3. Power characteristics [19] .

Characteristic	Value
Maximum power consumption	1 200 / 1 600 (kW / HP)
Maximum operating pressure	350 / 5 000 (bar / PSI)
Maximum flow rate	3 127 / 826 (l/min / gpm)
Stroke length	304,8 / 12 (mm / in)
Maximum number of strokes	120 (1/min)

III.2.5 Operating Limits and Conditions

The liquid supply conditions are essential for the proper operation of the flushing pump and are directly related to the NPSH theory. Single-acting piston pumps provide optimal performance when supplied with flushing fluid at an adequate pressure and volumetric flow rate adapted to the pump operating conditions. Insufficient flushing fluid supply leads to poor suction conditions and promotes cavitation inside the flushing pump. [19]

❖ Charging Pump Requirements

1. The feed must be via a centrifugal pump.
2. The charge pump must deliver approximately 150% of the maximum flow rate of the flushing pump.

3. The charge pressure must be greater than 1.2 bar and less than 3.5 bar.

If the charge pressure exceeds 3.5 bar, the flushing pump's suction valves may not open and close as designed. Maintaining the charging pressure within the recommended range is essential for ensuring sufficient available NPSH. A pressure below 1.2 bar reduces the available NPSH and promotes cavitation, whereas a pressure above 3.5 bar may prevents the suction valves from operating as designed.

❖ Temperature limits

The operating temperature of the drilling fluid also affects suction performance. As the fluid temperature increases, its vapor pressure rises, which reduces the available NPSH and increases the risk of cavitation. For water, the vapor pressure increases from approximately 0.023 bar at 20°C to 0.073 bar at 40°C The operating temperature limits shown in Table III.4. [19]

Table III.4.Temperature limits [19] .

Indication	Value	Unit
Normal temperature range	+1° à +40°	°C
Range with tank heating	-20° à +40°	°C

III.2.6 Suction System Configuration

The figure III.3 and the table III.5 show the connections and fittings of the pump.

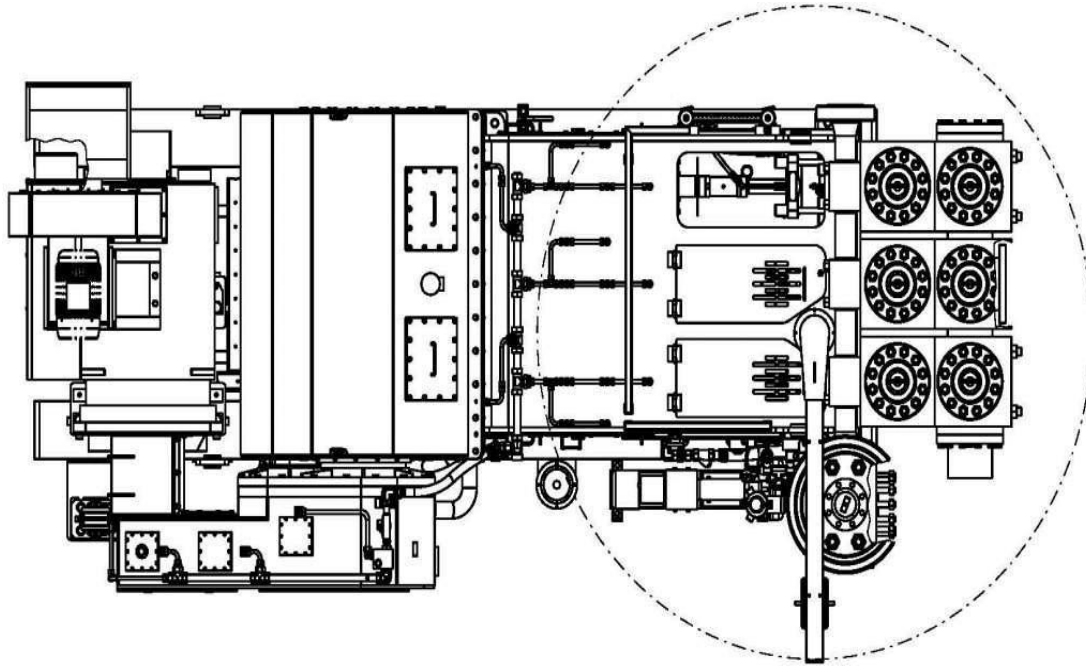


Figure III.3. Pump connections BMPT-1600-AC [19] .

Table III.5. Critical connections for suction [19]

Position	Designation	Role
4	Suction connection (10" flange)	Sludge entry into the pump
5	Pressure outlet (5 1/8" flange)	Reduces water hammer
7	Pressure pulsation damper	Reduces suction pulsations (essential for NPSH)
8	Suction damper	High-pressure sludge exit

An incorrectly adjusted suction damper (position 8) is a direct cause of **beat in the hydraulic part** suction pressure pulsations can cause cavitation even if the average NPSH is sufficient.

III.3 Diagnostic Analysis of the Suction System

III.3.1 Instrumentation and Monitoring Points

The Figure III.4 shows the pump control panel. The Table III.6 illustrates the diagnostic instruments for aspiration. Continuous monitoring of suction pressure and volumetric efficiency allows for early detection of problems. A sudden drop in pressure reading on the pressure gauge (11) or rapid fluctuations are signs of cavitation.

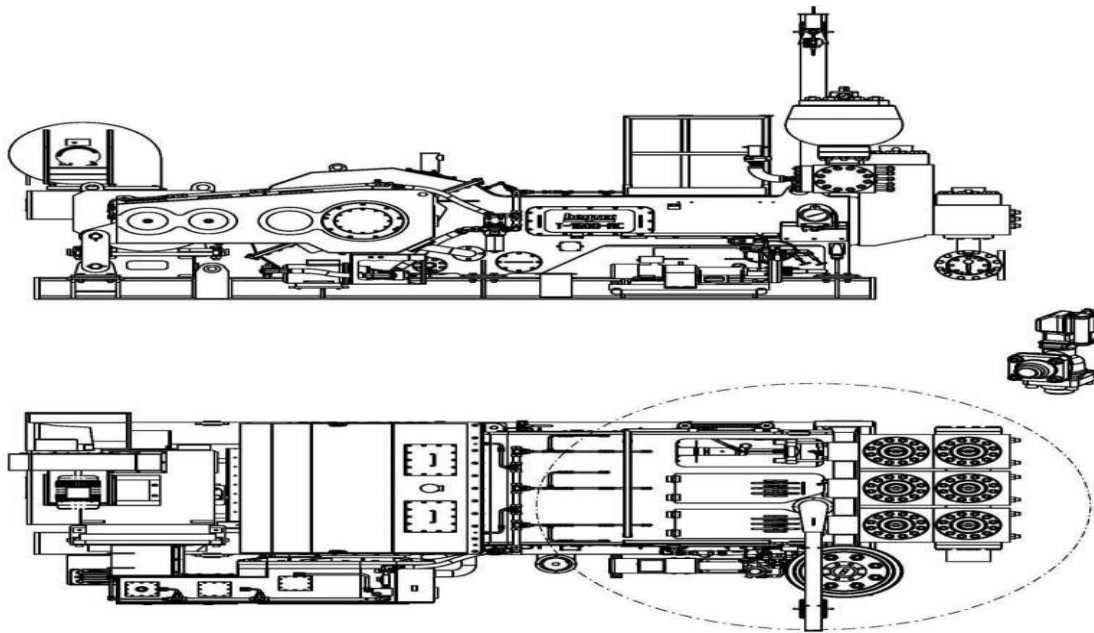


Figure III.4. Pump control panel BMPT-1600-AC [19].

Table III.6 Diagnostic instruments for aspiration [19].

Position	Designation	Function
1	Main pressure gauge	Conveying pressure in bar and PSI (real-time parameters)
8	Cooling system pressure gauge	Cooling circuit pressure
11	Suction damper pressure gauge	Pressure fluctuations (Critical)
12	Pressure damper pressure gauge	Pressure settings
14	Overpressure valve	Trigger pressure setting

III.3.2 Identification of Suction-Related Problems

The table III.7 identifies several causes directly related to suction.

Table III.7 Suction problems and solutions [19].

Observed defect	Possible cause	Solution
Rub in the hydraulic section	Insufficient suction damper preload	Check the preload
	Insufficient charging pump function ($P < 1.2$ bar)	Charging pressure between 1.2 and 3.5 bar
	Charging pressure > 3.5 bar	Reduce the pressure
Narrowing or obstruction	Blocked rinse strainer	Clean the line
Heavy rub	Cavitation in liner/piston	Reduce the stroke; check the charging pump
Rapid piston wear	Insufficient cooling water volume	Adjust the volumes, clean the filter

Insufficient charging pump function corresponds to insufficient available NPSH. Indeed,

if $P_{charge} < 1.2$ bar, the term $\frac{P_A + P_{charge} - p_v}{\rho g}$ decreases,

which can make $NPSH_{Avail} < NPSH_{requis}$, thus causing cavitation.

III.4 Mathematical Modeling of the Suction System

III.4.1 Available NPSH Model

The condition for avoiding cavitation is:

$$NPSH_{Avail} > NPSH_{requi} \quad (III.1)$$

With, according to equation :

$$NPSH_{Avail} = \frac{P_A + P_{charge} - P_v}{\rho g} - (H_{asp} + \Delta H_{asp}) \quad (III.2)$$

with:

P_A = atmospheric pressure (Pa)

P_{charge} = pressure supplied by the charging pump (Pa)

P_V = fluid vapor pressure (Pa)

ρ = fluid density (kg/m³)

g = gravitational acceleration (m/s²)

H_{asp} = geometric suction height (m)

ΔH_{asp} = pressure losses in the suction line (m)

The vapor pressure of the fluid is a function of temperature and can be estimated using Antoine's equation:

$$\log_{10}(P_V) = A - \frac{B}{C+T} \quad (III.3)$$

P_V : vapor pressure (mmHg)

T: fluid temperature (°C)

A, B, and C: empirical constants depending on the fluid. A=8.0713, B=1730.63, C=233.426

III.4.2. Pressure Loss Model (Darcy-Weisbach)

The total pressure losses in the suction line are the sum of the linear losses and the singular losses.

✓ Linear losses

$$\Delta H_r = \lambda \cdot L \cdot \frac{V_m^2}{D \cdot 2g} \quad (III.4)$$

Where:

λ : friction coefficient

L: pipe length

D: pipe diameter

V_m : Average fluid velocity

g: gravitational acceleration

✓ Singular losses

$$\Delta H_s = K \cdot \frac{V_m^2}{2g} \quad (III.5)$$

Where:

K: local loss coefficient

V_m : Fluid velocity

✓ **Total losses**

$$\Delta H = \Delta H_s + \Delta H_r \quad (\text{III.6})$$

The fluid velocity was calculated using:

$$V = \frac{4 \times Q}{\pi \times D^2} \quad (\text{III.7})$$

Where Q : Nominal flow rate

III.5 Application to the BMPT-1600-AC Pump

III.5.1 Application of the NPSH calculation to the BMPT-1600-AC

❖ Input Data for the NPSH Calculation

The table III.8 presents the operating and fluid properties used to evaluate the available NPSH of the BMPT-1600-AC pump under normal operating conditions.

Table III.8. Data used for the NPSH calculation

Parameter	Value
Atmospheric pressure (typical site)	$P_{Atm} = 1,01 \times 10^5 \text{ Pa}$
Minimum required load pressure	$P_{charge} = 1,2 \times 10^5 \text{ Pa (1,2 bar)}$
Vapor pressure of water at 40°C	$P_{Vapor} \approx 0,073 \times 10^5 \text{ Pa}$
Mud density	$\rho = 1,2 \times 10^3 \text{ kg/m}^3$
Geometric suction height (basin above pump)	$H_{asp} = +1,5 \text{ m}$

❖ Calculation of the Available NPSH

Using Equation (III-2) and the data presented in the table III.8, the available Net Positive Suction Head $NPSH_{Avail}$ is determined under normal operating conditions.

❖ Step 1: Calculating the pressure term

$$H_{press} = \frac{1,01 \times 10^5 + 1,2 \times 10^5 - 0,073 \times 10^5}{1200 \times 9.81} = \frac{2.137 \times 10^5}{11772} \approx 18.1 \text{ meters}$$

❖ Step 2: NPSH available without load losses

$$NPSH_{Avail} \approx 18,1 - 1,5 = 16,6 \text{ meters}$$

The calculated available NPSH of approximately 16.6 m is considerably higher than the NPSH typically required by triplex reciprocating mud pumps, which generally ranges from 3 to 5 m. This indicates that the BMPT-1600-AC pump operates with an adequate suction margin under normal conditions.

Consequently, cavitation is unlikely to occur during normal operation. However, excessive suction losses ΔH_{asp} , resulting from a clogged suction strainer, undersized suction piping, or flow restrictions can significantly reduce the available NPSH and increase the risk of cavitation.

III.5.2 Evaluation of Suction Pressure Losses

❖ Input Data for Pressure Loss Calculations

The hydraulic losses at the suction side of the BMPT-1600-AC pump were evaluated using Equations (III-4), (III-5), (III-6), and (III-7). The analysis was carried out under the nominal operating conditions of the pump and based on the hydraulic characteristics of the suction system. The parameters used in the calculations are summarized in Table III.9.

Table III .9. Parameters used for suction pressure loss calculations of the BMPT-1600-AC pump.

Parameter	Value
Nominal flow rate	$Q = 0.0521 \text{ m}^3/\text{s}$
Suction flange diameter	$D = 0.254 \text{ m}$
Average flow velocity	$V = 1.03 \text{ m/s}$
Suction line length	$L = 20 \text{ m}$
Friction factor	$\lambda = 0.02$
Local loss coefficient (clean strainer)	$\Sigma K = 2.5$
Local loss coefficient (partially blocked strainer)	$\Sigma K = 10$

❖ Calculation of Suction Pressure Losses

The total head loss in the suction line was determined by considering both frictional losses along the pipe and local losses generated by fittings and the suction strainer.

a) Clean Strainer Condition

For a clean strainer, the local loss coefficient is taken as $\Sigma K = 2.5$. Substituting the parameters listed in Table III.9 into the equation (III-6) yields:

$$\Delta H_{asp} = (0.02 \times \frac{20}{0.254} + 2.5) \times \frac{(1.03)^2}{2 \times 9.81} \approx 0.22 \text{ meters.}$$

b) Partially Blocked Strainer Condition

To evaluate the impact of strainer fouling, a higher local loss coefficient of $\Sigma K = 10$ was considered. The resulting suction head loss is:

$$\Delta H_{asp} = (0.02 \times \frac{20}{0.254} + 10) \times \frac{(1.03)^2}{2 \times 9.81} \approx 0.62 \text{ meters}$$

The obtained results indicate that the hydraulic losses at the suction side of the BMPT-1600-AC pump remain relatively low, even when the suction strainer is partially obstructed. The maximum calculated loss does not exceed **0.62 m**, demonstrating that the suction system operates under favorable hydraulic conditions.

This behavior is mainly attributed to the large suction flange diameter (**10 inches**), which maintains a low flow velocity of approximately **1.03 m/s**. As a result, both frictional and local losses remain limited, ensuring adequate suction performance and preserving the available Net Positive Suction Head (NPSH).

However, the diameter of the suction line plays a critical role in the hydraulic performance of the pumping system. A reduction in diameter would significantly increase the flow velocity and, consequently, the associated pressure losses. Therefore, maintaining an adequately sized suction system is essential for ensuring reliable and efficient pump operation.

III.6 Parametric Study

To evaluate the influence of key operating and design parameters on the hydraulic performance of the BMPT-1600-AC pump, a parametric study was conducted. The analysis focuses on three parameters that directly affect suction conditions and cavitation risk.

III.6.1 Influence of Suction Pipe Diameter

The influence of suction line diameter on hydraulic losses and available NPSH was evaluated while maintaining the pump at its maximum nominal flow rate. The parameters used in the calculations are presented in Table III.10.

Table III.10. Input parameters used for the suction diameter analysis.

Parameter	Value
Flow rate, Q	0.0521 m ³ /s (3127 L/min)
Friction factor, λ	0.02
Suction line length, L	20 m
Local loss coefficient, ΣK	2.5
Atmospheric pressure, P _A	1.01 bar
Charge pressure, P _{charge}	1.2 bar
Vapor pressure, P _v	0.073 bar
Fluid density, ρ	1200 kg/m ³
Suction height, H _{sp}	1.5 m

The suction pressure losses were determined using the Darcy–Weisbach equation III.6.

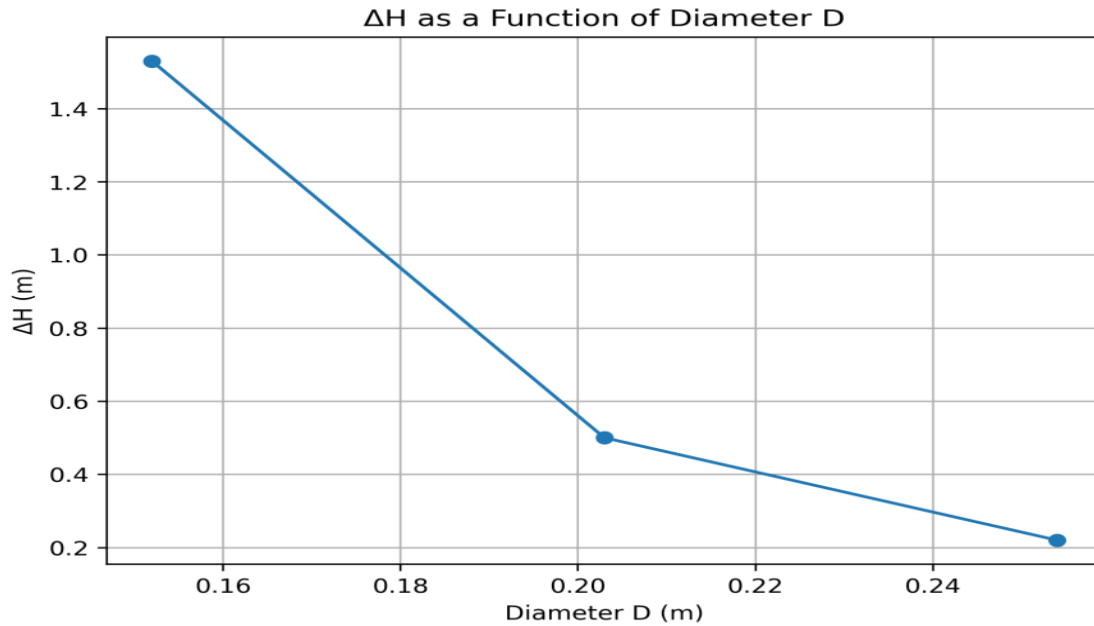
The available NPSH was evaluated from the equation III.2.

The influence of suction line diameter on fluid velocity, suction pressure losses, and available NPSH was evaluated for three different diameters while maintaining a constant flow rate. The calculated results are summarized in Table III.11. The Figure III.5 illustrates the influence of suction line diameter on fluid velocity, pressure losses, and available NPSH.

The results indicate that reducing the suction line diameter significantly increases the fluid velocity and pressure losses within the suction system. As a consequence, the available NPSH decreases, increasing the likelihood of cavitation. Conversely, the recommended 10-inch suction line diameter minimizes hydraulic losses and ensures stable suction conditions.

Table III. 11. Effect of suction line diameter on hydraulic performance

D(")	V(m^3 / h)	$\Delta H(m)$	NPSH available(m)
10"(0.254m)	1.03	0.22	16.2
8"(0.203m)	1.61	0.50	15.9
6"(0.152m)	2.87	1.53	14.9

*Figure III.5. Influence of the suction pipe diameter with a constant flow rate.*

III.6.2 Influence of Fluid Temperature

The influence of fluid temperature was investigated by analyzing the variation of vapor pressure with temperature while maintaining all other operating parameters constant. The data used in the analysis are summarized in Table III.12.

Table III.12: Input parameters used for the temperature analysis

Parameter	Value
Atmospheric pressure, P_A	1.01 bar
Charge pressure, P_{charge}	1.2 bar
Fluid density, ρ	1200 kg/m ³
Suction height, H_{asp}	1.5 m
Suction pressure loss, ΔH_{asp}	0.22 m

The vapor pressure values corresponding to the selected operating temperatures were calculated using Antoine's equation (Equation III.3) and are presented in Table III.13.

Table III.13. Effect of fluid temperature on vapor pressure and available NPSH.

Temperature (°C)	Vapor Pressure (bar)	NPSHa (m)
20	0.023	16.68
30	0.042	16.45
40	0.073	16.16

The temperature analysis shows that an increase in fluid temperature leads to a higher vapor pressure. As a result, the available NPSH decreases progressively, bringing the operating conditions closer to the cavitation threshold. Although the reduction in NPSHa remains moderate within the studied temperature range.

III.6.3 Influence of Flow Rate

❖ Input Data and Calculation Conditions

The influence of flow rate on suction pressure losses and available NPSH was evaluated while maintaining the nominal suction diameter of 10 inches (0.254 m). The calculation parameters are summarized in Table III.14.

Table III.14. Input parameters used for the flow rate analysis

Parameter	Value
Suction diameter, D	0.254 m
Friction factor, λ	0.02
Suction line length, L	20 m
Local loss coefficient, ΣK	2.5
Atmospheric pressure, PA	1.01 bar
Charge pressure, Pcharge	1.2 bar
Vapor pressure, Pv	0.073 bar
Fluid density, ρ	1200 kg/m ³
Suction height, Hasp	1.5 m

The fluid velocity and suction pressure losses were calculated using equations (III.7) and (III.6), while the available NPSH was determined using Equation (III.2). The table III.15 illustrates the influence of flow rate on the studied parameters.

Table III.15. Influence of flow rate on available NPSH.

Q (m ³ /s)	V (m/s)	ΔH (m)	NPSH disponible (m)
0,03	0,59	0,07	16,53
0,04	0,79	0,13	16,47
0,05	0,99	0,20	16,40
0,06	1,18	0,29	16,31

The figure III.6 illustrates the influence of the flow rate on the available NPSH. The results show that increasing the flow rate leads to higher fluid velocities within the suction system. As velocity increases, frictional and local losses become more significant, causing suction pressure losses to increase from 0.07 m to 0.29 m. As a result, the available NPSH gradually decreases from 16.53 m to 16.31 m. Although the variation remains limited within the studied operating range, the observed trend confirms that

higher flow rates reduce the available suction head. When combined with other unfavorable factors such as elevated temperatures, reduced suction diameters, or partial blockage of the suction strainer, high flow rates may contribute to cavitation initiation. Therefore, operation near the design flow rate is recommended to maintain stable hydraulic conditions and ensure reliable pump performance.

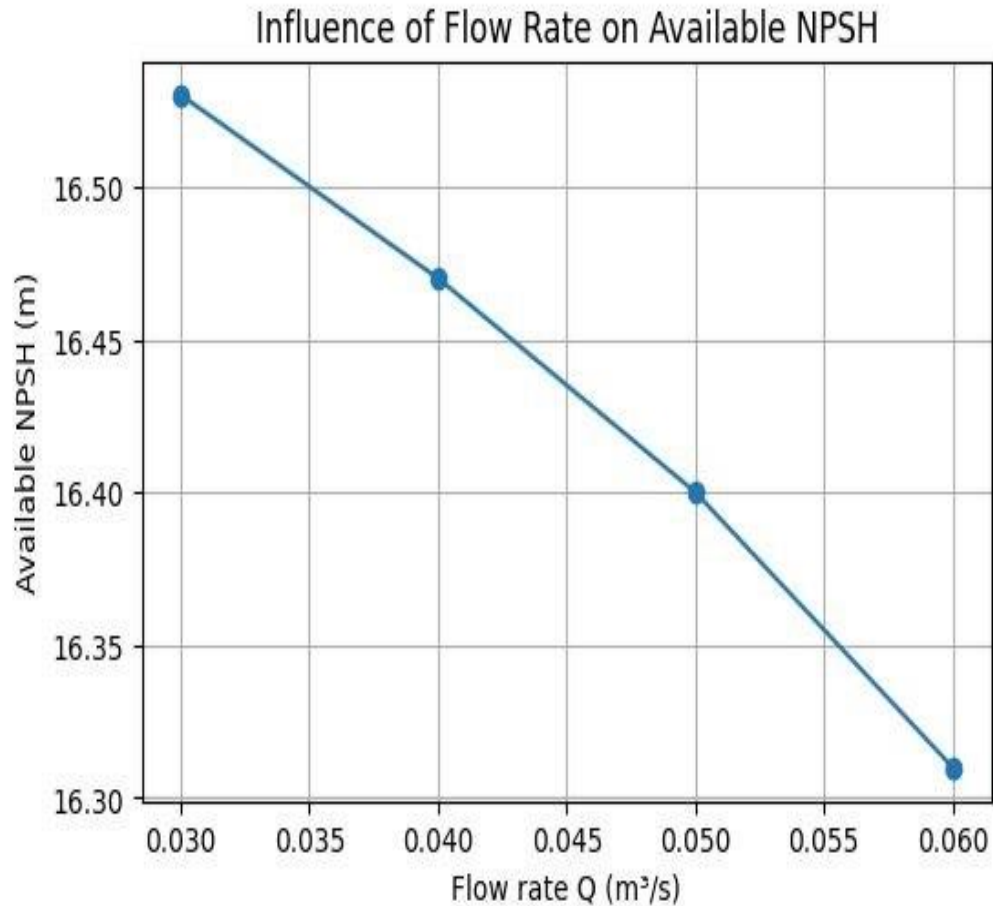


Figure III.6: Influence of flow rate on available NPSH.

The performed analyses confirm that cavitation can be effectively mitigated by maintaining adequate suction conditions. Proper sizing of the suction line, controlling fluid temperature, and operating within the recommended flow rate range are key factors in preserving a sufficient NPSHa margin and improving the operational reliability and service life of the BMPT-1600-AC pump.

III.7 Suction System Improvement Measures

Based on the diagnostic analysis and the results of the parametric study, several optimization measures can be implemented to improve suction conditions and reduce the risk of cavitation in the BMPT-1600-AC pump. The proposed actions focus on maintaining sufficient available NPSH, reducing pressure fluctuations, minimizing suction losses, and ensuring reliable operation of the hydraulic components.

III.7.1 Selection of Suitable Operating Parameters

The operating parameters of the BMPT-1600-AC pump should be selected to ensure adequate suction conditions and minimize the risk of cavitation. As shown in Table III.15, increasing the liner diameter increases the flow rate, but also raises the required NPSH. Therefore, excessively large liner sizes operating at high speeds should be avoided unless sufficient charging pressure is maintained. Appropriate selection of liner size and pump speed helps maintain favorable suction conditions, reduce pressure losses, and improve the reliability of the pumping system. Table III.16 presents the operating characteristics of the BMPT-1600-AC pump for different liner sizes and operating speeds.

Table. III.16. Operating characteristics of the BMPT-1600-AC pump.

Fluid end size		5000 psi								
Liner size	[inch]	7 ½	7	6 ¾**	6 ½	6 ¼**	6	5 ⅝**	5 ½	
Max discharge pressure	[mm]	190.5	177.8	171.5	165.1	158.8	152.4	146.1	139.7	
	[psi]	2988	3430	3689	3978	4303	4669	5000*	5000*	
	[bar]	206	236	254	274	297	322	345	345	
Volume per stroke	[gal]*	6.88	6.00	5.58	5.17	4.78	4.41	4.05	3.70	
	[l]	26.1	22.7	21.1	19.6	18.1	16.7	15.3	14	
Speed	Max input	Max input	Gal/min	Gal/min	Gal/min	Gal/min	Gal/min	Gal/min	Gal/min	Gal/min
SPM	HP	KW	l/min	l/min	l/min	l/min	l/min	l/min	l/min	l/min
120	1600	1193	826	720	669	621	574	529	486	444
110	1467	1094	3127 757	2724 660	2533 613	2349 569	2172 526	2002 485	1838 445	1682 407
100	1333	994	2867 688	2497 600	2322 558	2153 517	1991 478	1835 441	1685 405	1542 370
90	1200	895	2606 620	2270 540	2111 502	1958 465	1810 430	1668 397	1532 364	1402 333
80	1067	795	2346 551	2043 480	1900 446	1762 414	1629 382	1501 353	1379 324	1261 296
70	933	696	2085 482	1816 420	1689 390	1566 362	1448 335	1334 308	1226 283	1121 259
60	800	597	1824 413	1589 360	1478 335	1370 310	1267 287	1168 264	1072 243	981 222
50	667	497	1564 344	1362 300	1267 279	1175 259	1086 239	1001 220	919 202	841 185
40	533	398	1303 275	1135 240	1056 223	979 207	905 191	834 176	766 162	701 148
			1042	908	844	783	724	667	613	561

Stroke: 12 inch (304.8mm), SPM: stroke/min, gal: us standard, *: max working pressure,
 **: not prefer size.

III.7.2 Charging Pressure Optimization

Maintaining the charging pressure within the recommended range of 1.2 to 3.5 bar is the most important action for preventing cavitation. This requirement is directly derived from the NPSH criterion (equation III.1).

Practical procedure:

1. Measure the suction pressure using pressure gauge position 11.
2. If the pressure is lower than 1.2 bar:
 - Clean the suction strainer of the charging pump.
 - Increase the speed of the centrifugal charging pump.
 - Check the suction line for air leaks.
3. If the pressure exceeds 3.5 bar:
 - Reduce the charging pump speed (to prevent valve malfunction).

III.7.3 Damper Adjustment Optimization

Proper adjustment of the dampers is essential for reducing pressure pulsations and water hammer effects. Proper damper precharging reduces pressure pulsations, improves flow stability, and limits transient pressure fluctuations that may adversely affect suction performance.

a) Suction Damper

The preload pressure should be at least 1 bar above atmospheric pressure and should not exceed atmospheric pressure plus 1.5 bar. For an atmospheric pressure of approximately 1 bar, the recommended preload pressure ranges from 2 to 2.5 bar absolute.

b) Pressure Damper

The preload pressure must not exceed two-thirds of the discharge pressure and should remain below the maximum allowable value of 45 bar (650 PSI). For a discharge pressure of 350 bar, a preload pressure of approximately 30 bar is recommended.

III.7.4 Reduction of Suction Pressure Losses

The cleanliness of suction strainers and filters is essential for maintaining low hydraulic losses. A partially blocked strainer increases the local loss coefficient K , resulting in higher suction pressure losses and a reduction in the available NPSH. Regular inspection and cleaning of strainers therefore contribute directly to cavitation prevention.

III.7.5 Maintenance of Hydraulic Components

Proper tightening of piston assemblies contributes to stable pump operation and prevents misdiagnosis of mechanical vibrations as cavitation phenomena.

Recommended specifications:

- Tightening torque: 1000 N·m (750 lb·ft).
- Replacement of self-locking nuts after two to three uses.

Loose piston assemblies may generate vibrations and abnormal noise that can be confused with cavitation symptoms.

III.7.6 Maintenance Safety Procedure

During maintenance operations, manual rotation of the pump may be required (*Figure III.7*). The following procedure shall be followed:

1. Disconnect the electrical power supply and apply lockout protection.
2. Relieve pressure from the hydraulic section.
3. Remove the locking screw.
4. Rotate the drive shaft manually using an appropriate wrench.
5. Reinstall and tighten the locking screw after maintenance.

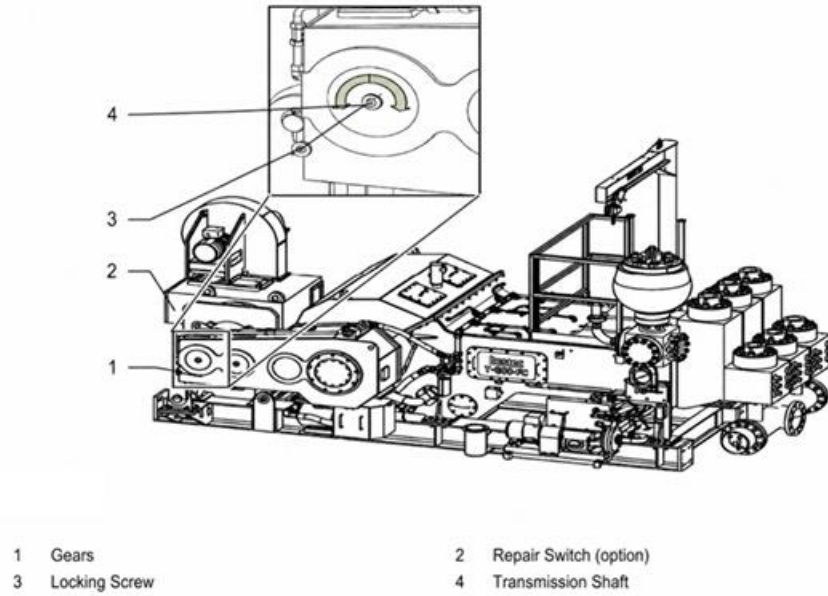


Figure III.7 Manual pump rotation device [19] .

III.7.7 Summary of Optimization Actions

The optimization actions proposed for the BMPT-1600-AC suction system are summarized in Table III.17.

Table III.17: Summary of optimization actions for suction system [19] .

Action	To do	Target	Frequency
1	Charging pressure	1,2 – 3,5 bar	Continuous (monitoring)
2	Suction damper	Prestressing $\geq \text{atm} + 1 \text{ bar}$	Weekly
3	Pressure damper	Prestressing $\leq 2/3 \times P_{out}$ (max 45 bar)	Weekly
4	Rinsing sieve	Clean (no obstruction)	Monthly (cleaning)
5	Piston nuts	1000 Nm (replace after 2-3 uses)	At each disassembly
6	Manual rotation	Use after power outage	During maintenance

III.8.Conclusion

This chapter presented the analysis of the BMPT-1600-AC mud pump suction system. The available NPSH and suction pressure losses were evaluated through mathematical modeling, while a parametric study was conducted to assess the influence of key operating parameters on suction performance.

The parametric analysis demonstrated that suction pipe diameter, fluid temperature, and flow rate have a significant influence on the available NPSH. Consequently, maintaining adequate operating conditions and implementing the proposed improvement measures are essential for reducing cavitation risk and ensuring reliable operation of the BMPT-1600-AC pump.

Mud pumps play a crucial role in drilling operations by ensuring the continuous circulation of drilling fluid throughout the well. Their performance and reliability depend strongly on the quality of suction conditions. Among the various problems affecting mud pumps, cavitation remains one of the most significant due to its adverse effects on performance, equipment durability, and maintenance costs.

This work focused on the analysis of suction-related problems in the BMPT-1600-AC triplex mud pump using hydraulic modeling and pressure-loss calculations. The study aimed to identify the main factors influencing suction performance and evaluate their impact on cavitation risk.

The results showed that the available NPSH under normal operating conditions reaches approximately 16.6 m of mud column, which is significantly higher than the required NPSH values generally ranging between 3 and 5 m. This indicates that the pump normally operates with an adequate safety margin against cavitation. However, the analysis revealed that several operational factors can considerably reduce this margin and increase cavitation susceptibility.

Three main causes of cavitation were identified: insufficient charge pressure below 1.2 bar, clogging of suction strainers leading to excessive pressure losses, and reduction of the suction pipe diameter below the nominal 10-inch size. The parametric analysis also demonstrated that operating conditions have a direct influence on suction performance. Increasing the fluid temperature from 20°C to 40°C decreases the available NPSH by approximately 0.5 m, while reducing the suction pipe diameter from 10 inches to 6 inches results in a decrease of about 1.3 m. In addition, higher flow rates increase pressure losses in the suction line, thereby increasing the risk of cavitation.

Based on these findings, a set of maintenance and corrective actions was proposed, including proper adjustment of the charge pressure, maintenance of suction and discharge dampers, regular cleaning of suction strainers, tightening of piston nuts, and safe manual rotation procedures. These measures can contribute to improving suction performance and reducing cavitation-related problems.

In conclusion, this study demonstrates the importance of maintaining favorable suction conditions to ensure reliable operation of the BMPT-1600-AC mud pump. The proposed recommendations provide practical solutions for minimizing cavitation risk, enhancing pump reliability, and extending equipment service life in drilling applications. Future work may include experimental validation and CFD-based investigations to further optimize suction system performance.

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