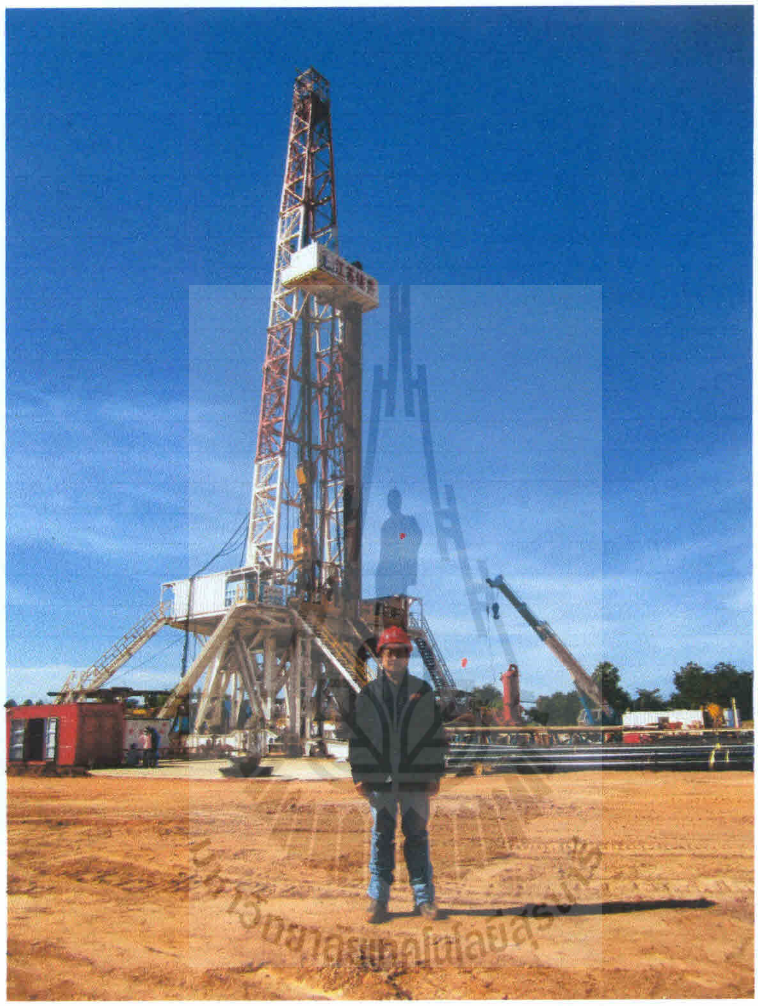
ADVANCED DRILLING ENGINEERING



Prepared by
Kriangkrai Trisarn

Petroleum Engineering
School of Geotechnology
Institute of Engineering

ADVANCED DRILLING ENGINEERING 2014

By
Kriangkrai Trisarn

Chatturat-3 Exploratory Well

Amphoe Chatturat, Chaiyaphum province

534620 ADVANCED DRILLING ENGINEERING
4(4-0-8) @ 1/2557, 2014
Course Contents

1. How to Get Drilling Permission (2hrs.) Asso. Prof. KK
2. Introduction to Rotary Drilling (4 hrs.) Asso. Prof. KK
3. Well Planning and Proposal (4 hrs.) Asso. Prof. KK
4. Cost Estimation and Control (4 hrs.) Asso. Prof. KK
5. Hole Problems.(3 hrs.) Asso. Prof. KK
6. Drilling Fluids (5 hrs.) Asso. Prof. KK
7. Factors Affecting Rate of Penetration (4 hrs.) Asso. Prof. KK
8. Pressure Control (4 hrs.) Dr. Akkaphun
9. Pore Pressure and Pressure Gradient (4 hrs.) Dr. Akkaphun
10. Blowout Control Procedure and Equipment (4 hrs.) Dr. Akkaphun
11. Directional and Slimhole Drilling (4 hrs.) Dr. Akkaphun
12. Rotary Bit Design (2 hrs.) Dr. Akkaphun
13. New Technology Drilling (6 hrs.) Dr. Akkaphun

Grading

Homework I= 15%, Quiz I =10 %,Mid - term =25% Asso. Prof. KK
Homework II= 20%, Final Exam=30% Dr. Akkaphun

13. New Technology Drilling (6 hrs.) Dr. Akkaphun

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TEXTS

1. Lecture note and Document on "Petroleum Drilling Technology" by Assoc. Prof. Kriangkrai Trisarn
2. Adam T. Bourgoune Jr., Heith K. Millheim, Martin E. Chenevert, and F.S. Young Jr. "Applied Drilling Engineering"@1986, Society of Petroleum Engineers, Richarson, TX, USA.

2.CARL GATLIN,: *DRILLING AND WELL COMPLETION@1960*, PRENTIC-HALL, INC., ENGLEWOOD, N.J.

REFFERENCE

1. Neal J Adams, Tommie Charrier, Research Associate. " Drilling Engineering A Complete Well Planning Approach"@1985, Penn Well Publishing Company, Tulsa, Oklahoma, U.S.A.
3. J.-P.NGUYEN, *DRILLING-OIL AND GAS FIELD DEVELOPMENT TECHNIQUES@1996*, 27 RUE GINOUX 75737 PARIS.
4. SCHLINGAREON & P. VORABUTH : *DRILLING AND DRILLING FLUIDS.*
5. Preston L. Moore " DRILLING PRACTICE MANUAL"@ 1974 Penn Well Publishing Company, Tulsa, Oklahoma, U.S.A.
6. BAROID MUD TECHNOLOGY HANDBOOK
7. API SPECIFICATIONS, CODES
8. Short, J.A.,1993 , Introduction to Directional and Horizontal Drilling, Penn Well Books, Tulsa, Oklahoma USA. 232p
9. Steve Devereux "Practical Well Planning and Drilling Manual"@ 1998 Penn Well Publishing Company, Tulsa, Oklahoma, U.S.A.

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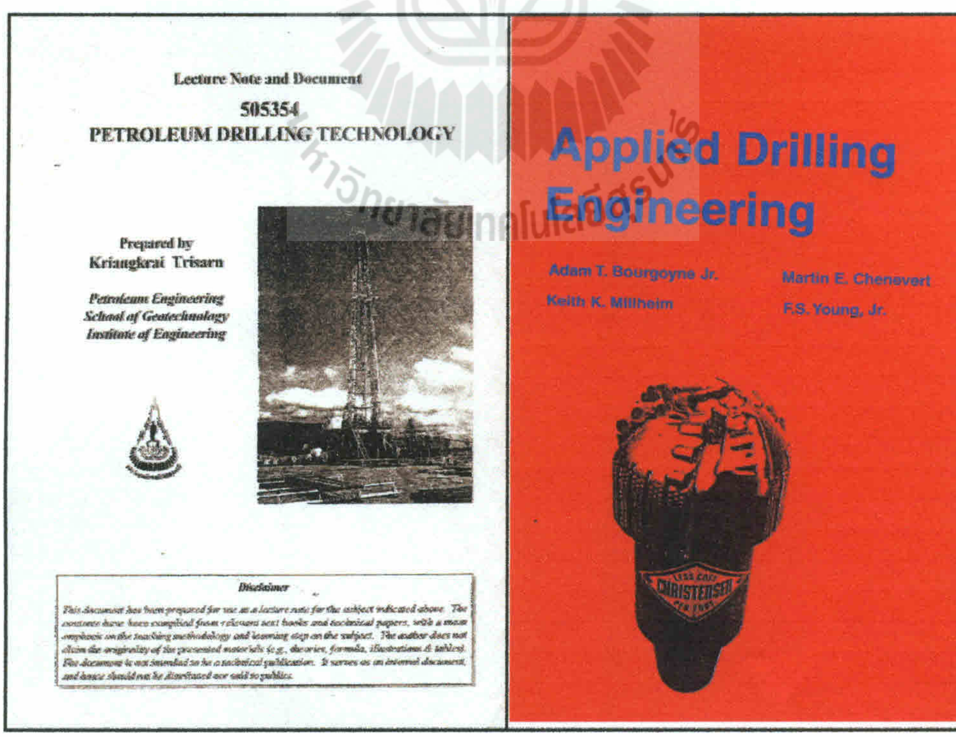

HOW TO GET DRILLING PERMISSION

1. Get Concessions
2. Explore to find prospects
3. Exploration Well Proposal, Drilling Program.
4. Land Permission.
5. EIA approval
6. Drilling Permission from DMF

Getting the Well Drilled

1. The Lease Purchases
2. Capital to Drill the Well
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   Maintain Staff or Sub-Contract
4. Full-Interest Well
5. Joint-Operating Agreements
6. Cash Contribution
   Reduced-Acreage
7. Farmouts(Farmor-Farmee)
8. Carried Interest; an arrangement interest of Co-owners
9. Land and Working Permit, EIA, Well Proposal, and Well Program

Origin of Petroleum

น้ำมัน และก๊าซฯ มาจากไหน

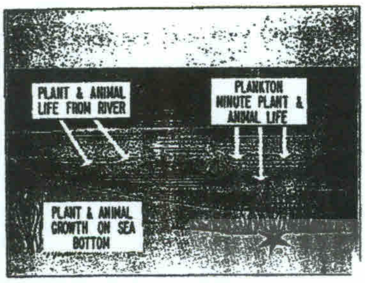


Figure 1.15 —Sources of organic material.

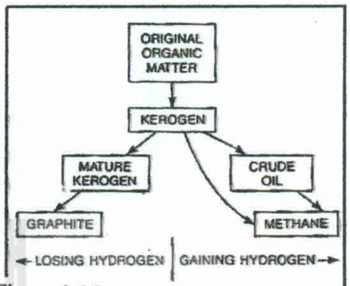


Figure 1.16 — Alteration of organic material to hydrogen-poor and hydrogen-rich compounds. From Barker, 1979. Permission to publish by AAPG.

การเกิดแหล่งปิโตรเลียมจะต้องมีปัจจัย 5 ประการ

1.หินต้นกำเนิดปิโตรเลียม (Source Rocks)

เช่น หินดินดาน หินโคลน หินปูน เป็นต้น

2การเคลื่อนที่ของปิโตรเลียม (Migration)

3หินกักเก็บปิโตรเลียม (Reservoir Rocks) เป็นหินที่มีความพรุน และมีความสามารถให้ของเหลวไหลผ่านได ได้แก่ หินทราย หินปูน หรือหินอัคนีที่มีรอยแตก เป็นต้น

4.หินปิดกั้น (Seal หรือ Cap Rocks) เช่น หินดินดาน หินเกลือ

5โครงสร้างกักเก็บปิโตรเลียม (Trap)

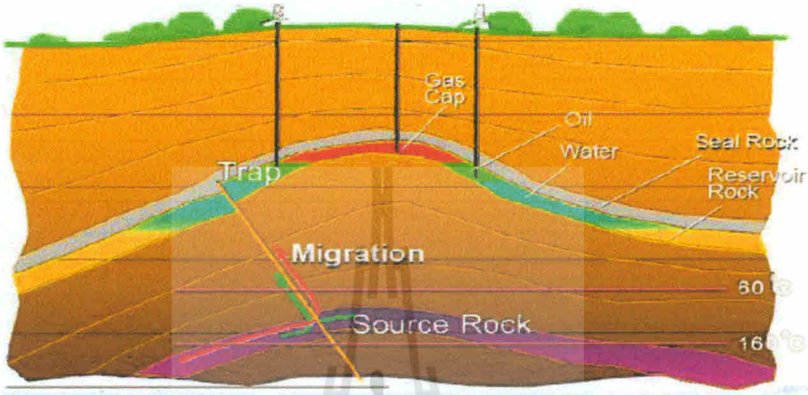
๒

Petroleum System

การเกิดแหล่งปิโตรเลียมจะต้องมีปัจจัย 5 ประการ

การจะเกิดปิโตรเลียมได้จะต้องมีองค์ประกอบ 5 อย่าง

1) หินต้นกำเนิดปิโตรเลียม (Source Rock)
2) ระยะเวลาและการเคลื่อนตัวของปิโตรเลียม (Timing and Migration)
3) หินกักเก็บ (Reservoir Rock)
4) หินปิดกั้น (Seal Rock)
5) โครงสร้างที่สะสมปิโตรเลียม (Trap)



ที่มา: รูปจาก http://petroleumsupport.com/reservoir-system-to-accumulate-hydrocarbon/

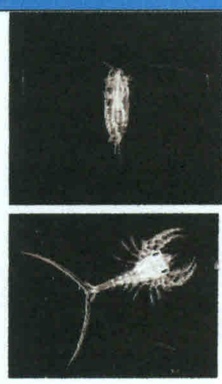
Origin 1: Plankton

10,000 of these bugs would fit on a pinhead!

Plant plankton

en.wikipedia.org/wiki/Image:Ceratium_hirundinella.jpg

Animal plankton



- Most oil and gas starts life as microscopic plants and animals that live in the ocean.

Kerogen Types

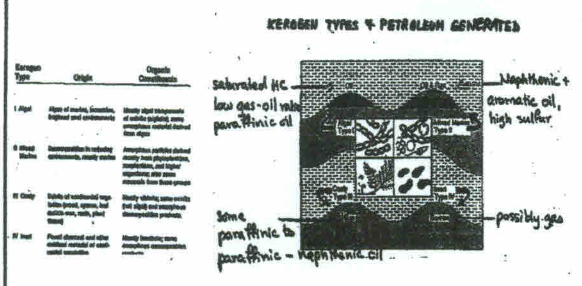


Figure 1.17 Kerogen types, Origin , and Organic Constiuents

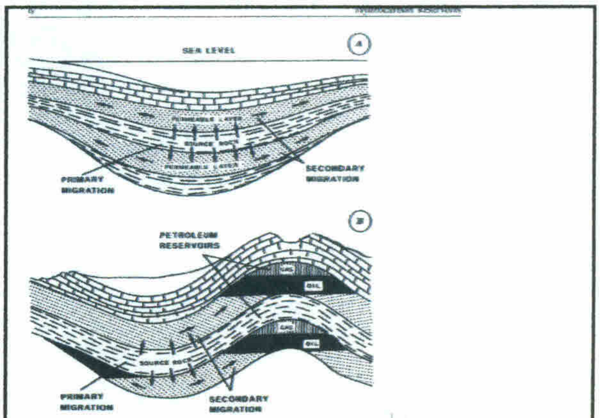
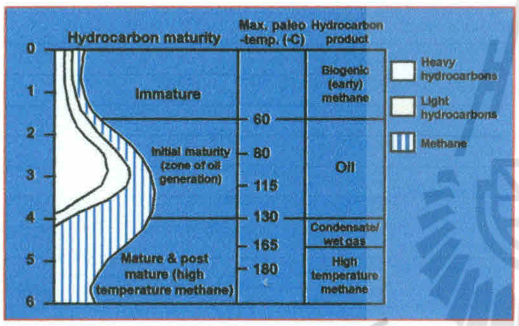


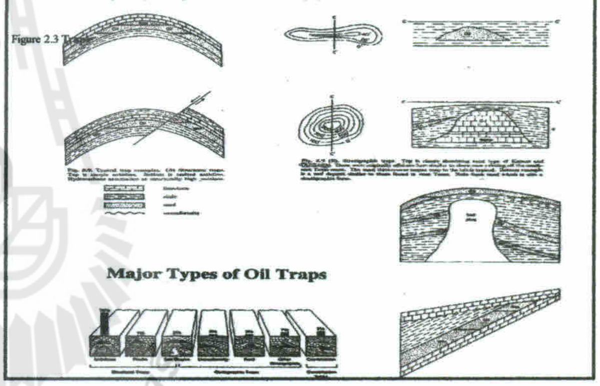
Fig. 1.3A, B. The formation of a hydrocarbon reservoir. A: initial stages of primary and secondary migration. B: advanced stage of hydrocarbon accumulation.

Hydrocarbon Maturation

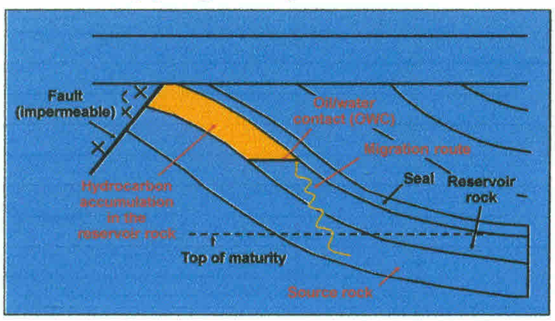


1.*Structural Traps* : those traps formed by deformation of the earth's crust by either faulting or folding.
2.*Stratigraphic Traps* : those formed by changes in lithology, generally a disappearance on containing bed or porosity zone.
3.*Combination Traps*: traps having both structural and stratigraphic features.

Figure 2.3 Traps



Generation, Migration, and Trapping of Hydrocarbons



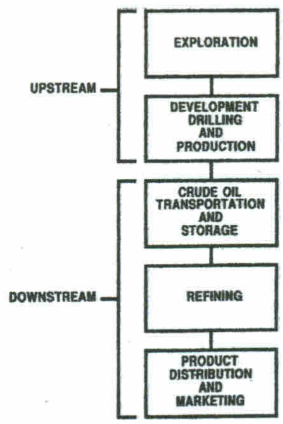
2.2 Oil Industry Functions

•

- **Oil Industry** can be grouped into ***Upstream*** and ***Downstream*** .
- The ***Upstream*** function will include:

1.Exploration
2.Development Drilling and Production.

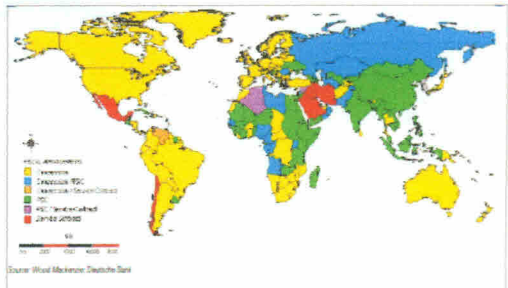
- The ***Downstream*** function will include:
- 3 Transportation and Storage.
- 4. Refining and Petrochemical.
- 5. Product Distribution and Marketing.



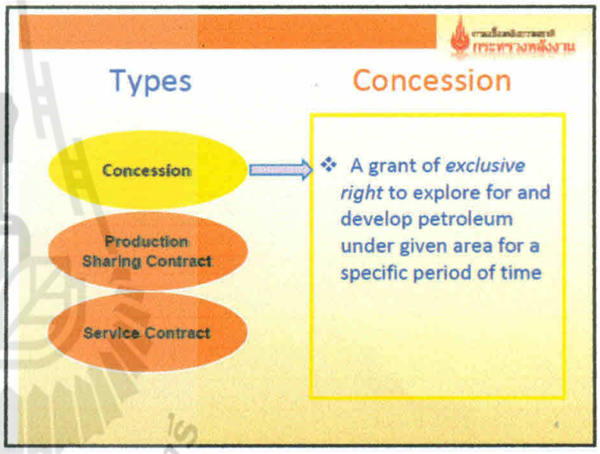
Introduction

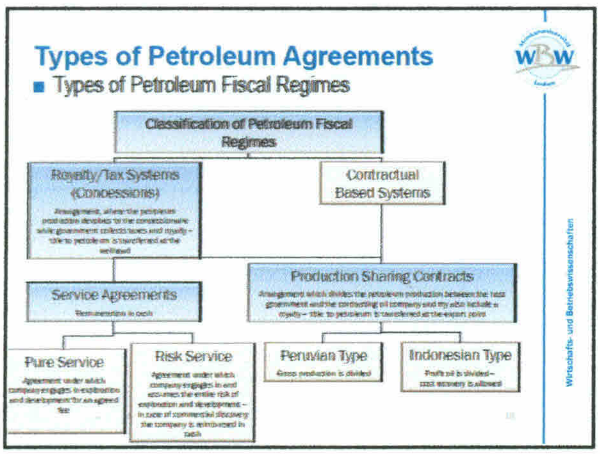
- **Petroleum arrangement** is the legal tool for oil company to explore for, and exploit of petroleum.
- Parties: the host country(HC) and oil company(OC)
- 3 basic types
  - Concession
  - Production Sharing Contract (PSC)
  - Service Contract (SC)
- However, variations of these 3 types are commonly seen nowadays.

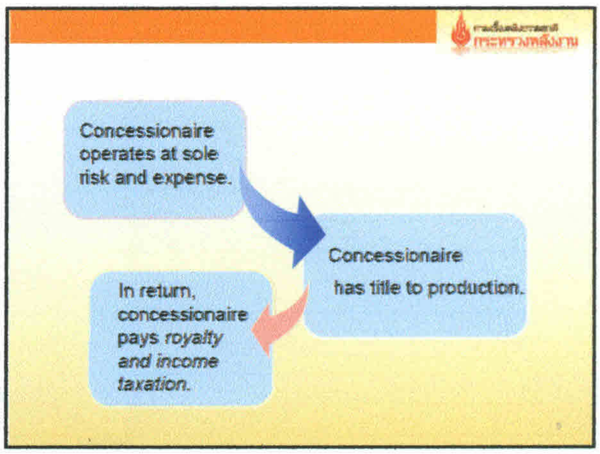
Distribution of fiscal regimes



Source: Deutsche Bank.







Current Petroleum Concessions

65 concessions 84 blocks (March 2010)

	No. of concessions	No. of block
Onshore	34	44
Gulf of Thailand	30	37
Andaman	1	3
Total	65	84

Concession Bidding:

During 1971-2009; 20 rounds

PSC

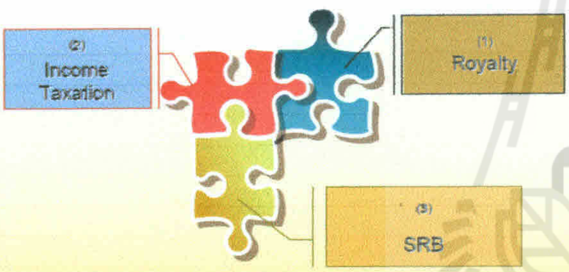
❖ Cost recovery

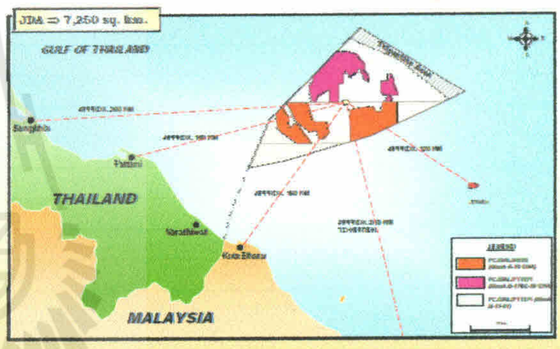
➢ PSC allows OC to recover its costs and expenses from the production, referred to as "Cost Oil".

❖ Production Split

➢ After the deduction of cost oil, the remaining production is shared between HC and OC as agreed in the contract, referred to as " Profit Oil".

➢ Profit oil is subject to taxation.





Types

- Concession
- Production Sharing Contract
- Service Contract

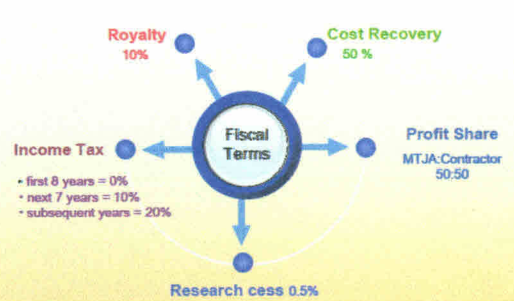
PSC

❖ PSC was originally created in 1960's in Indonesia.

❖ Like concession, OC operates at sole risk and expense.

❖ But....Ownership of production remains with HC.

MTJA's PSC



Types — SC

- Concession
- Production Sharing Contract
- Service Contract

- OC provides capital investment, technology, and equipments.
- Ownership of production remains with HC.
- In return, OC receives the service fee.

Petroleum Arrangements	Concession	PSC	SC
Right of the company	-exclusive right to explore for and produce petroleum -acquire ownership of petroleum -right to dispose/market production freely	-right to explore for and produce petroleum in exchange for a share of the oil and/or gas produced -acquire ownership of a percentage of the oil and gas produced -right to dispose/market the-respective share of petroleum freely	-right to be the exclusiv provider of the exploration and production services -*In some cases*, right to be paid in kind, or to preferential purchase th production
Duty of the company	-almost no duty imposed(However, in the modern concession, a concessionaire is obligated to conduct an exploration and development according to a work program and budget stipulated by host state	- obligation to conduct operations according to the PSC's terms	-obligation to conduct operations according to the contract's terms
Risk Bearer	-Oil Company	-Oil Company	-Oil Company (Risk service contract) -Host State (Non-Risk service contract)
Capital(incl. equipment, technology) Provider	-Oil Company	- Oil Company	- Oil Company
Production Ownership	-Concessionaire	-Host State (company is merely entitled to a portion of the production ... oil, as pre-agreed in the contract)	-Host State
Transfer Point of Production	-Wellhead	-Delivery point	-
Asset (equipment and installations) Ownership	-Oil company (However, when the concession expires they may be transferred, at no cost, to host state, upon request of host state.)	-Host state	-Host state
Power of Control of Operations	-Oil company (However, the modern concession is designed to allow a considerable degree of involvement by the state)	-Host state and Oil company (depending on the terms of the contract)	-Host State
Government Take	-Royalty -Tax -etc. e.g. signature bonus	-Royalty(if any) -Govt. share of Profit oil -Tax -etc.	-All Production
Company Take	-All Production	-Cost oil and company share of Profit oil	- Service Fee

Comparing between Thai I and Thai III, it can be noticed that the later has been designed to capture so-called marginal petroleum fields, the small fields with higher investment costs, which previously had been classified as uneconomic. This reflects in changing the pattern of royalty from the fixed rate of 12.5% to sliding scale system in which royalty rate can be fro 5% to 15%. In addition, it encourages t concessionaires to expedite their exploration a development with shorter duration of exploration a production periods, as well as limited number of are granted. Furthermore, Thai III regime also introduc

Comparison of Petroleum Arrangements: Concession, Production Sharing Contract and Service Contract, Sirinuch Chotipanvittayakul and Jittima Mantyp

Service Contract

Risk SC

- OC is paid only if the commercial discovery is declared.

Non-Risk SC

- OC is paid for service rendered, not depending on the success of the discovery.

- Possibility of SC in Thailand?
  - ✓ Some concessions are going to be expired.
  - ✓ Mature fields, with some potential left
  - ✓ Fully-equipped facilities and access to existing infrastructures

OIL AND GAS LEASES

1. The Landowner's (Lessor) Interest
   - Property Lease
   - Royalty (Interest)~ 1/8
2. Lessee Interest
   - Working Interest~ 7/8

3. Overriding Royalty; Sub-Lease

- Overriding Royalty; Interest~ 1/16 of 7/8

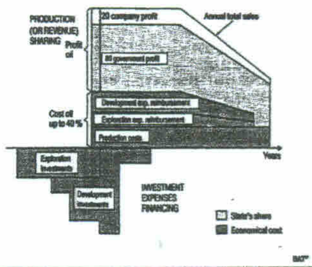
Getting the Well Drilled

1. The Lease Purchases
2. Capital to Drill the Well
3. Sources of Prospects
   Maintain Staff or Sub-Contract
4. Full-Interest Well
5. Joint-Operating Agreements
6. Cash Contribution
   Reduced-Acreage
7. Farmouts(Farmor-Farmee)
8. Carried Interest; an arrangement interest of Co-owners

Production Sharing Agreements

- History of Development
- Typical Terms
  - Bonus
  - Work obligations
  - Terms
  - Royalty
  - Cost Recovery
  - Production sharing
  - Taxation
  - Relinquishment

Standard Production Sharing Agreement



EXPLORATION AGREEMENT TERMS

1. ACQUISITION
2. AREA OF CONTRACT OR CONCESSION
3. EXPLORATION PERMIT TERM
4. PRODUCTION PERMIT TERM
5. WORK COMMITMENTS
6. LAND RELINQUISHMENT
7. NATIONAL GOODS AND SERVICES
8. PRODUCTION AND/OR REVENUE SHARING TERMS

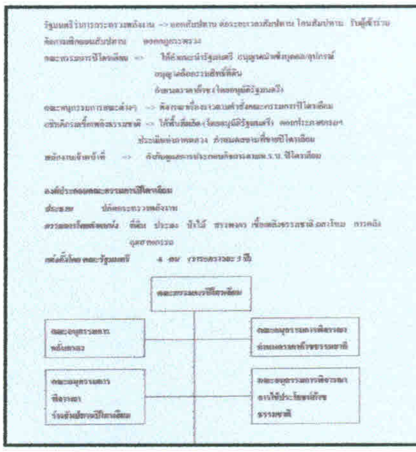
HOW TO GET A CONCESSION in THAILAND

Suranaree University of Technology

By Kriangkrai Trisarn

THAILAND III PETROLEUM ACTS

1. EXPLORATION PERIOD 6 YEARS
2. PRODUCTION PERIOD 20 YEARS
3. ROYALTY 5-15%
4. INCOME TAX 50%



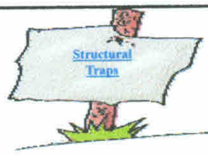
GEOLOGICAL EXPLORATION

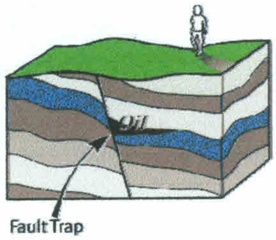
1. SOURCE ROCK POTENTIAL

2. RESERVOIR ROCK POTENTIAL

3. TRAP POTENTIAL

4. SEDIMENT BASIN ANALYSIS

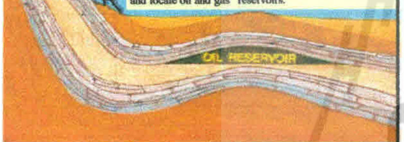




Fault traps are formed by movement of rock along a fault line. In some cases, the reservoir rock has moved opposite a layer of impermeable rock. The impermeable rock thus prevents the oil from escaping. In other cases, the fault itself can be a very effective trap.

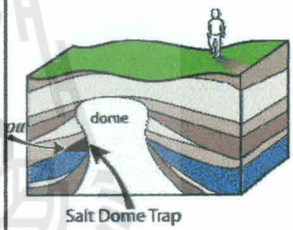
Geological

Surface Inspection



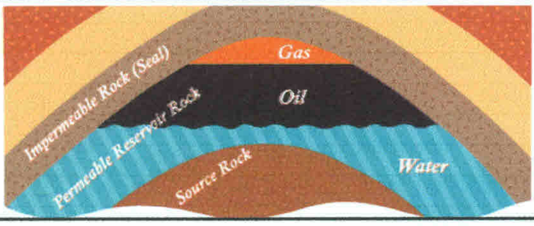
-Geologist looks for clues like outcrops, which are parts of rock beds appearing at the surface.
-Geologist studies an outcrop, by mapping the locations,
-thickness and angels
-From this and other information, geologist try to map
-the sites and shapes of rock beds beneath the surface, and locate oil and gas reservoirs.

Satellite Imagery

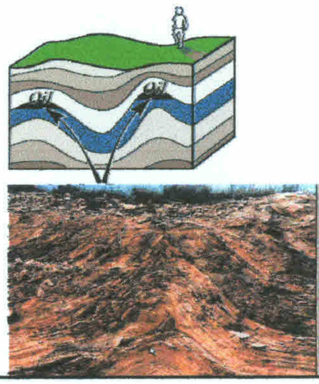


In this type of trap salt moves up through the Earth, punching through and bending rock along the way.
Oil can come to rest right up against the salt, which makes salt an effective trap rock.

-The source rock is the place where, millions of years ago, tiny sea plants and animals lived, died, and were preserved. Source rock contains the source of the hydrocarbon. Shale is a common source rock.
-The reservoir rock is a layer of permeable sedimentary rock, usually sandstone or limestone. The gas migrates into the pores of the reservoir rock.
-The seal is a dome-shaped layer of impermeable rock, often made of granite, above the reservoir rock that trap the gas and keeps it from moving upward. The seal is also called a cap rock.



Structural Traps



An anticline is an example of rocks which were previously flat, but have been bent into an arch. Oil that finds its way into a reservoir rock that has been bent into an arch will flow to the crest of the arch, and get stuck (provided, of course, that there is a trap rock above the arch to seal the oil in place).

Prospectingหาแหล่งปิโตรเลียม

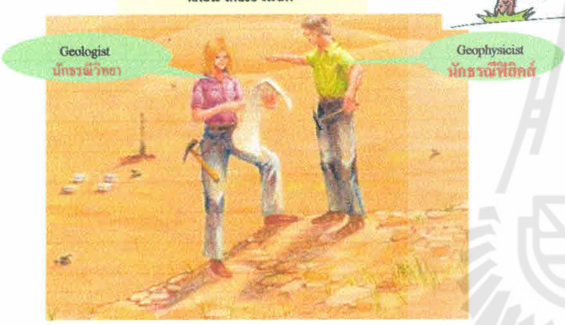
Data Acquisition

- Surface Inspection
- สำรวจธรณีวิทยาผิวดิน
- Geologic Evaluation
- วิเคราะห์ธรณีวิทยา
- Satellite Imagery
- Gravity - Magnetic Interpretation
- Seismic Prospecting

Geologist
นักธรณีวิทยา

Geophysicist
นักธรณีฟิสิกส์

Before you know prospecting, also know these two!!



PETROLEUM EXPLORATION

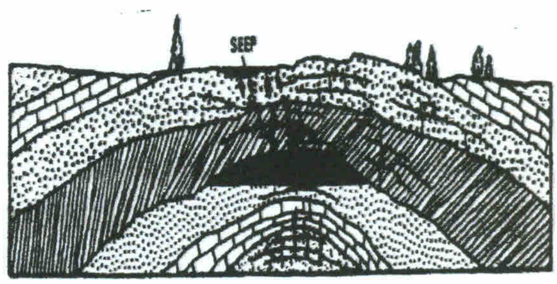
1. GEOLOGICAL EXPLORATION
2. GEOPHYSICAL EXPLORATION
3. DRILLING

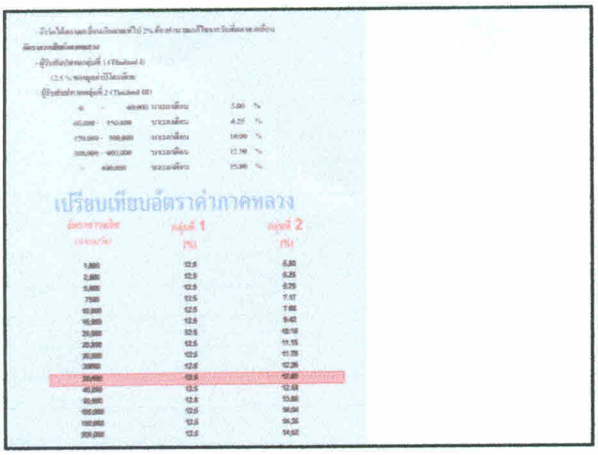
What they do?

- Geologist- studies the Earth-its history, structure, composition, life forms and the processes that continue to change it.
- Geophysicist- studies the physics of the Earth, especially its electrical, gravitational and magnetic fields and propagation of elastic (seismic) waves within it.

The subsurface maps are typically in basic form as; ***Structural contour maps***, ***Isopachous maps***, and ***Cross section maps***.
The data for subsurface maps are obtained from a number of sources such as :

Well logs: such as Mud logs, Drilling logs, Electric logs, Radioactivity logs , et.
(1)Core drilling and analysis.
(2)Strata test.





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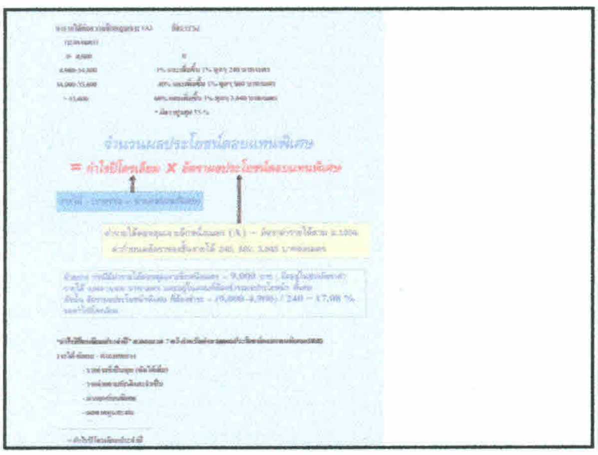
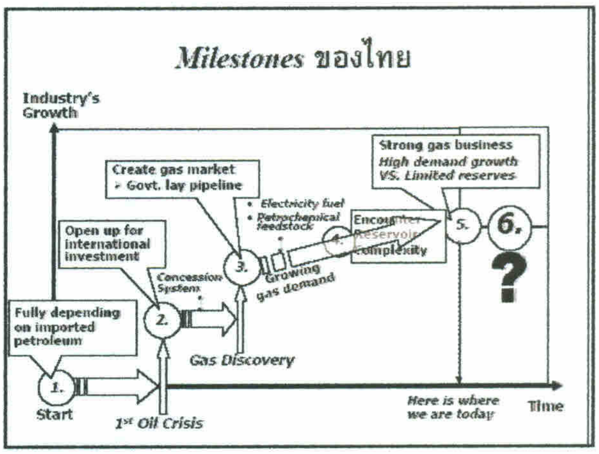
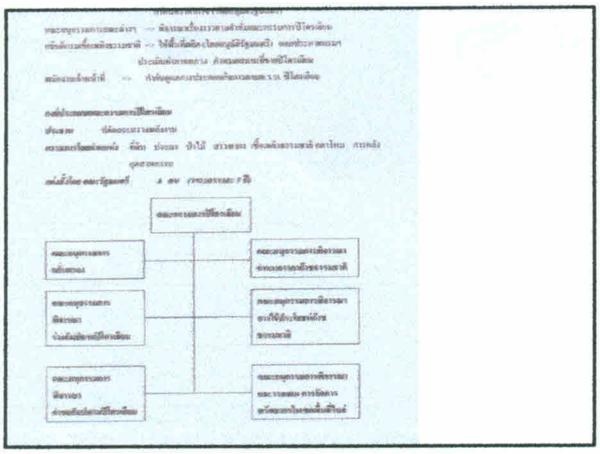
5. EIA approval
6. Drilling Permission from DMF







คณะอนุกรรมการพิจารณาคำขอสัมปทานนำเสนอ | คณะรัฐมนตรีอนุมัติ

คุณสมบัติของผู้ยื่นขอสัมปทานปิโตรเลียม

1. เป็นบริษัท
2. มีหลักฐานที่แสดงว่ามีทุน เครื่องจักร เครื่องมือฯ บุคลากร เพียงพอเพื่อการสำรวจ ผลิต ขาย และจำหน่ายปิโตรเลียม
3. ถ้ามีคุณสมบัติตามข้อ 2. ไม่ครบต้องมีผู้ที่มีความสัมพันธ์ ในด้านทุน หรือการจัดการกับผู้ขอสัมปทานและมีคุณสมบัติดังกล่าวให้การรับรองที่จะให้การสนับสนุน

การพิจารณาคัดเลือกผู้รับสัมปทาน

โครงการสำรวจเหมาะสมกับพื้นที่มากที่สุด และปริมาณงานไม่น้อยกว่าเกณฑ์ที่กำหนด ผลประโยชน์พิเศษที่เสนอ จะพิจารณาจากคุณค่า และโอกาสที่จะเกิดขึ้น

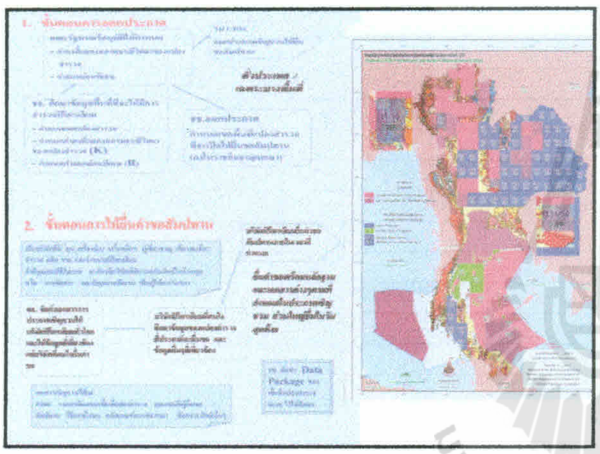
การให้คะแนนคำขอ

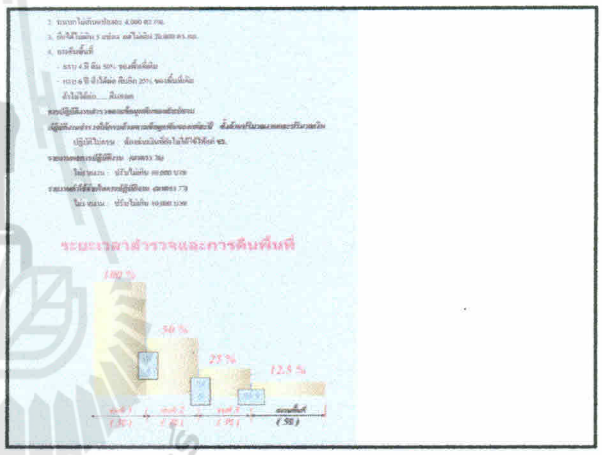
ข้อผูกพันสำหรับการสำรวจ 80 คะแนน

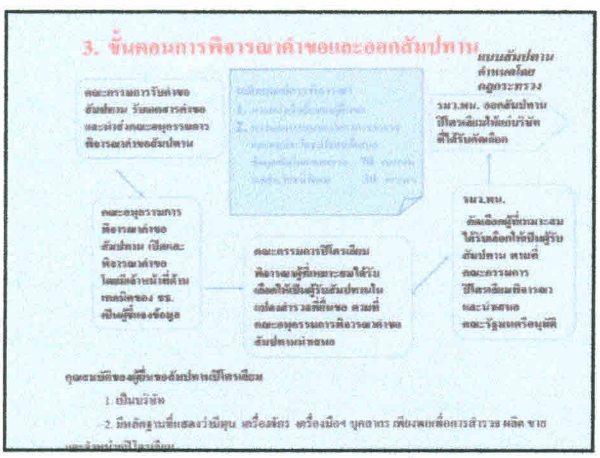
ผลประโยชน์พิเศษ 20 คะแนน

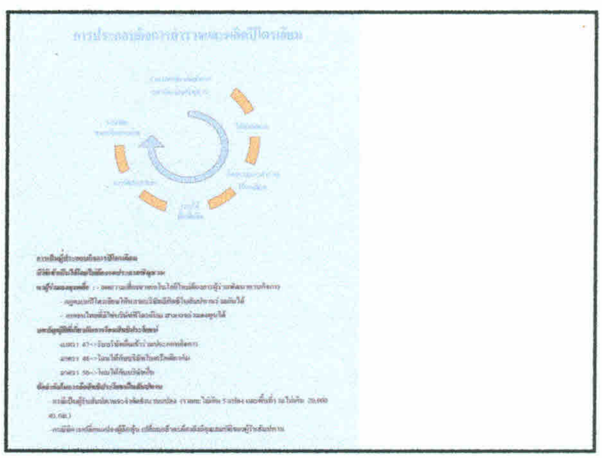
แปลงสำรวจปิโตรเลียม

1. ชธ.กำหนดโดยประกาศในราชกิจจาฯ (บนบก & ในทะเล)









GEOPHYSICAL EXPLORATION

- วิธีวัดค่าความเข้มสนามแม่เหล็กโลก
- วิธีวัดค่าแรงดึงดูดโลก
- วิธีวัดคลื่นไหวสะเทือนของชั้นหิน

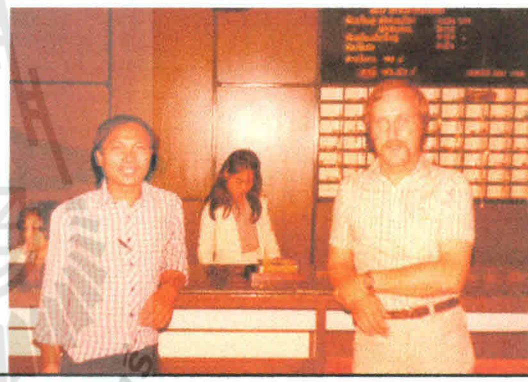
หา ลักษณะ รูปร่าง และขนาด
โครงสร้างชั้นหินใต้ดิน

AEROMAGNETIC EXPLORATION


GEOPHYSICAL EXPLORATION

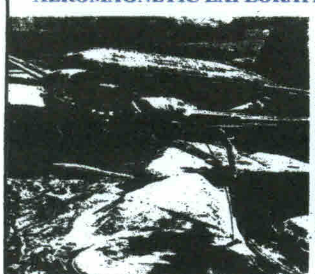
การสำรวจธรณีฟิสิกส์

- IDENTIFY PETROLEUM RESERVOIR
- RESERVOIR BOUNDARY
- PETROLEUM VOLUMETRIC ESTIMATION
- BASIN STRUCTURE & SHAPE
- หา ลักษณะ รูปร่าง และขนาด โครงสร้างชั้นหินใต้ดิน

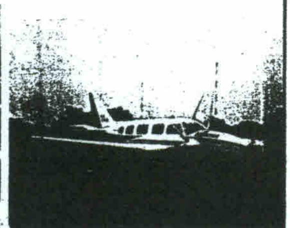


บินสำรวจสนามแม่เหล็ก

AEROMAGNETIC EXPLORATION



An airplane towing a magnetometer during inflight recording. (Aero Service Corporation.)



รูปที่ เครื่องบิน PIPER NAVAJO

GEOPHYSICAL EXPLORATION

1. GRAVITY SURVEY
2. MAGNETIC SURVEY
3. SEISMIC SURVEY

Geo-physical

- Magnetic method
- Gravity
- Stratigraphy
- Seismic method

$$F = \gamma \frac{m_1 m_2}{r^2}$$ where

F = attractive force
$m_{1,2}$ = masses of particles in question
r = distance between particle
γ = gravitational constant (6.67×10^{-8} in gas unit)

The denser rocks are closer to the surface cause a higher gravitational force in their vicinity. Such an area, when mapped, shows a *gravity high*(or anomaly) indicated a possible structure.

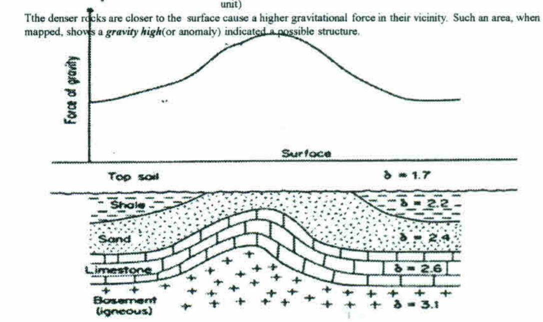


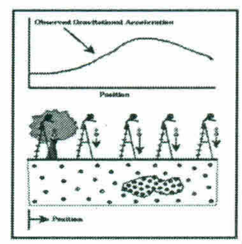
Figure 2.9 Schematic illustration of gravity effect over a buried anticline. δ = specific gravity of various rocks. From Stommel,[3] courtesy Colorado School of Mines.

GEOPHYSICAL EXPLORATION

1. IDENTIFY PETROLEUM RESERVOIR
2. RESERVOIR BOUNDARY
3. PETROLEUM VOLUMETRIC ESTIMATION
4. BASIN STRUCTURE & SHAPE

Gravity

- The oil bearing rocks are generally Sedimentary rocks. They exert less gravitational force than the surrounding rocks. The profiling of gravitational field can be done to determine the oil formation



Gravity & Magnetic Methods

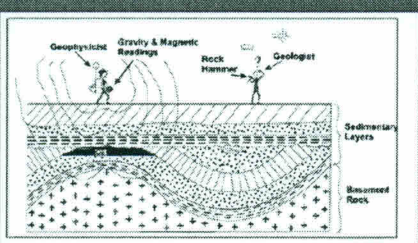
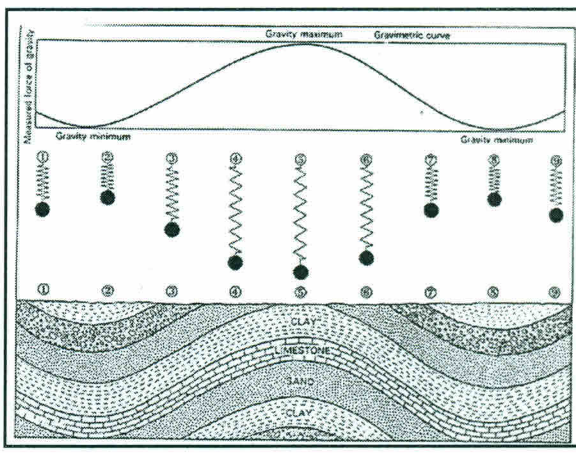
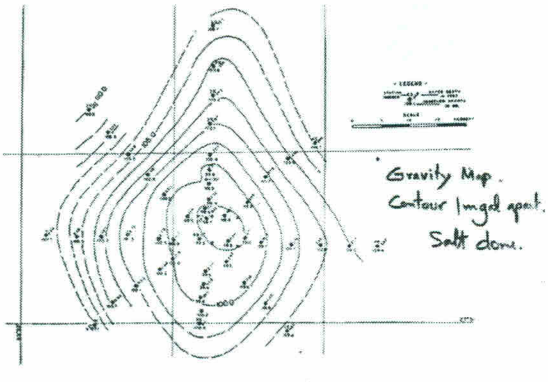


Figure 6.2

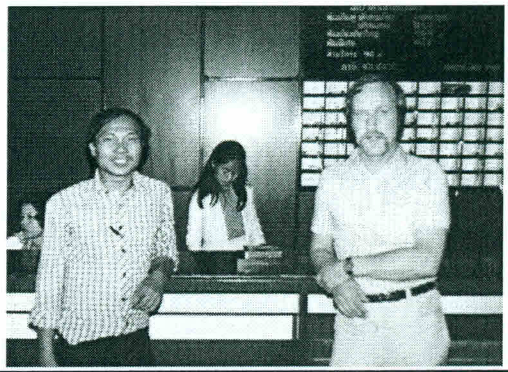
In many areas there are no clues to the subsurface structure visible at the surface. Geophysical methods must be utilized to estimate subsurface structure in such areas. Here the geophysicist is recording gravity and magnetic measurements to determine the topography of the basement rocks. Hydrocarbon traps are often formed over basement highs as shown here.

Society of Petroleum Engineers

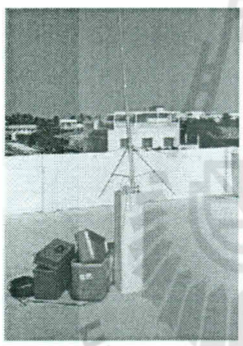


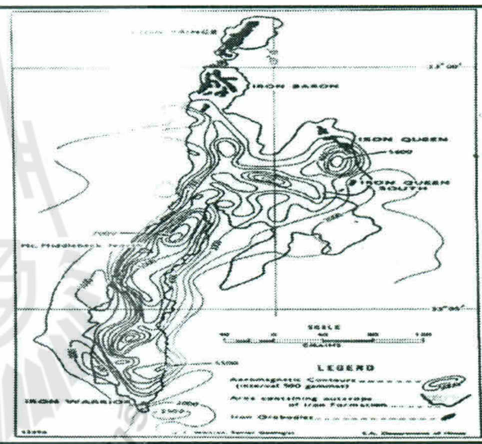


AEROMAGNETIC EXPLORATION



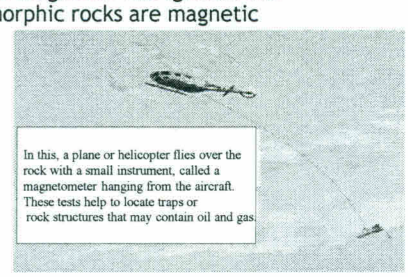
AEROMAGNETIC EXPLORATION





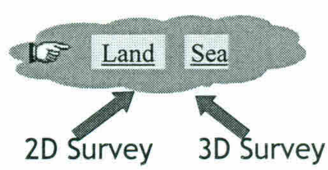
Magnetic

- Magnetic method involves magnetic profiling since the sedimentary rocks are non magnetic. The Igneous and Metamorphic rocks are magnetic

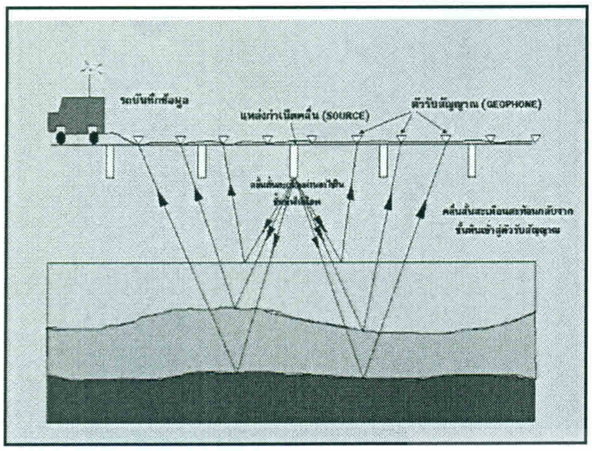


In this, a plane or helicopter flies over the rock with a small instrument, called a magnetometer hanging from the aircraft. These tests help to locate traps or rock structures that may contain oil and gas.

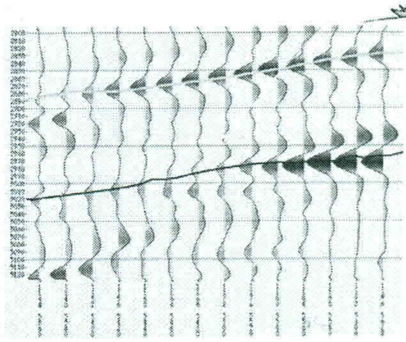
Seismic Method



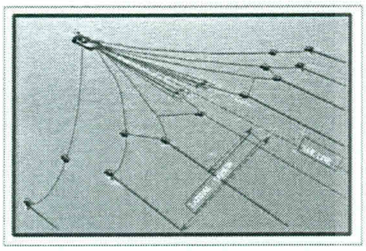
Seismic surveys are conducted both on land and sea.
Land surveys require crews to deploy geophones necessary to record the data.
The seismic source is either dynamite, or vibrations created by vibroseis trucks.
For sea seismic survey, air gun is used as a source and geophones a Are called hydrophones



Seismic Traces – A Snapshot V

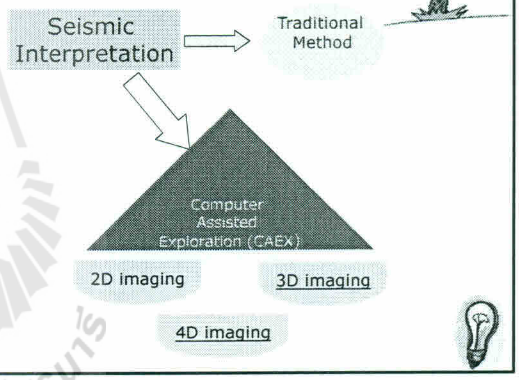


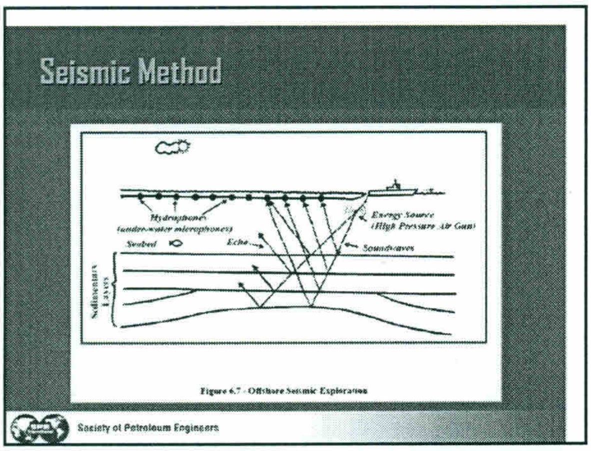
3D model of data acquisiti
a bird's eye view



In 3D survey, the source and the receivers are placed in a grid-like manner. It is used for characterizing and modeling reservoirs, for planning and executing enhanced oil-recovering strategies.

Seismic Interpretatior





3 D Imaging

- Though expensive, 3D imaging is more successful as it
  - Gives a more accurate picture of location of reservoir.
  - Allows for the more accurate placement of wells to be drilled increasing their productivity
  - Can increase the recovery rate of productive wells to 40-50 percent, as opposed to 25-30 percent with traditional 2-D exploration techniques

4 D Imaging

•Changes in structures and properties of underground formations are observed over time.

•Fourth dimension in 4-D imaging is time, it is also referred to as 4-D 'time lapse' imaging.

•Through studying how seismic images change over time, geologists can gain a better understanding of many properties of the rock, including underground fluid flow, viscosity, temperature and saturation.

•Using 4-D imaging on a reservoir can increase recovery rates above what can be achieved using 2-D or 3-D imaging.

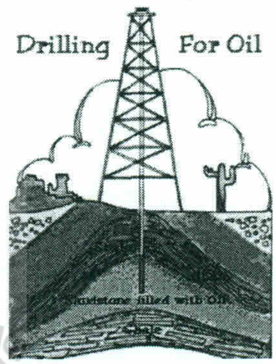
- Decision Making
  - Yes, there is oil
  - No, Slim Chances
- Prospect Proposal
  - OK! there is a "prospect" But whether there really are hydrocarbons trapped in the rock

---

Stratigraphy

- Stratigraphy involves establishing correlations between wells, matching fossils, strata, electrical and radioactivity data to determine the origin, composition, distribution, and succession of rock strata
  - Sample logs - Strata, rock hardness
  - Driller's logs - Lithological sequences
  - Radioactive logs - Origin and composition
  - Electrical logs - Origin and composition
  - Acoustic logs - Porosity of a formation

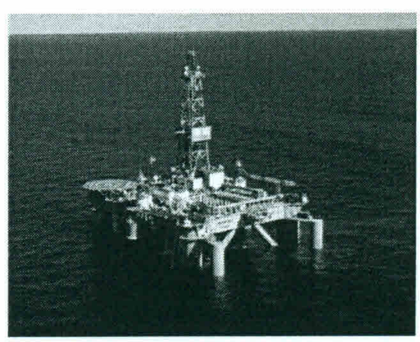
Drilling



Data Synthesis

- Results are aggregated and studied
- Geologists, geophysicists, petroleum architects, together with drilling, production and reservoir engineers supply data to economists and financial planners

Exploration



Drill Site Determination

Drill Site Determination
Wild Cat Drilling
Well Logging
Core Sampling
Prospect Confirmation
Economic Feasibility

- The site of the drill rig is determined based on the existing state of knowledge of underground conditions and the topography of the terrain.
- This is generally sited vertically above the thickest part of the stratum thought to contain hydrocarbons.

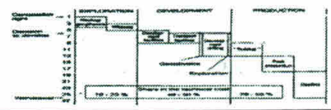
Figure 2.13 Phase III *Exploration Well*, Phase IV *Development*
Figure 2.14 Phase V *Production*

Figure 2.15 **Field Development Schedule**

Phase III: Exploration Wells

Phase IV: Discovery (play and productive analogs)

Phase V: Production



Wild Cat Drilling

Drill Site Determination
Drilling
•Wild Cat
Well Logging
Core Sampling
Prospect Confirmation
Economic Feasibility

- To find out whether there really are hydrocarbons trapped in the rock, team decides to drill down to that zone.
- In first-time drilling little if anything about the subsurface geology is known with certainty, especially the pressure regime.
- This higher degree of uncertainty necessitates that the drilling crews be appropriately skilled to deal with uncertainty like sudden kick from the well.

SEISMIC EXPLORATION

Exploration& Production Phases: consist of:
Phase I. *Surface Mapping and Reconnaissance Geophysics*
Phase II *Seismic Survey and Results*
Phase III *Exploration Well*
•These phases will cost 10-20 % of the total E & P cost
Phase VI *Development* Phase; this phase will cost 40-60%
Phase V *Production* Phase will cost about 20-50 %.

Phase I: Surface Mapping and Reconnaissance Geophysics

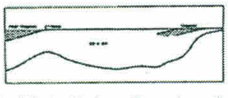
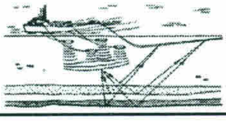
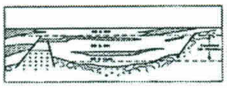


Figure 2.11 Phase I. *Surface Mapping and Reconnaissance Geophysics*
Figure 2.12 Phase II *Seismic Survey and Results*

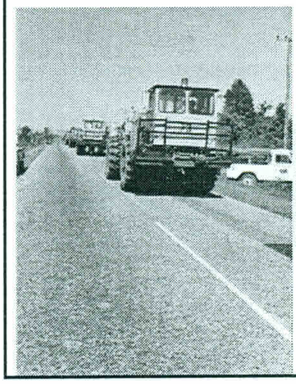
Marine Seismic Method

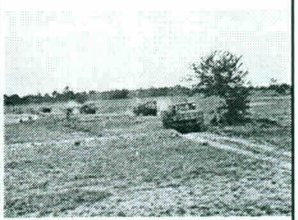


Phase II: Results from Preliminary Seismic Survey



SEISMIC EXPLORATION





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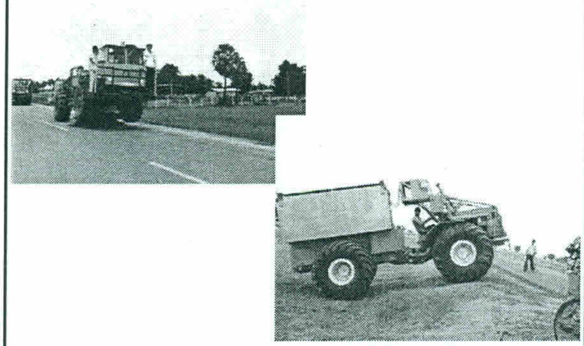

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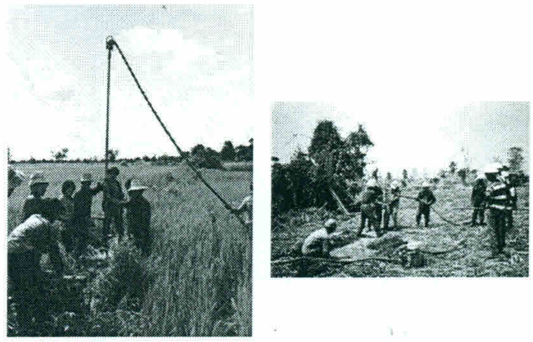

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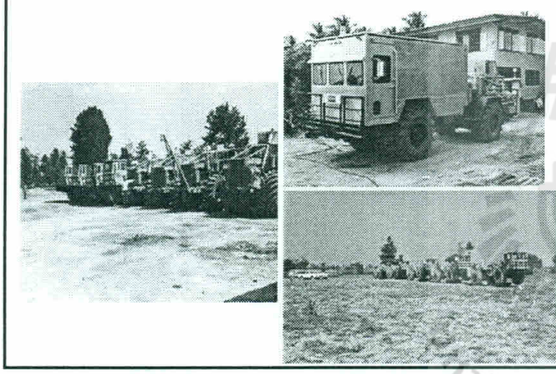
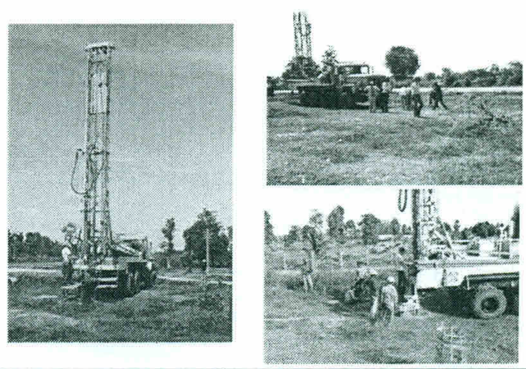


SEISMIC EXPLORATION

SEISMIC EXPLORATION

DRILLING RIG



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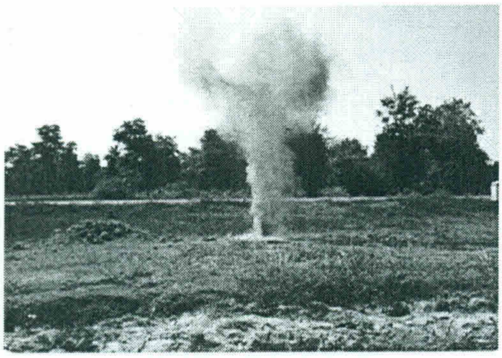

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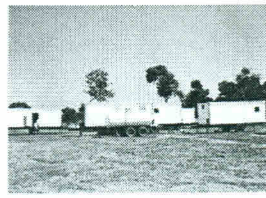
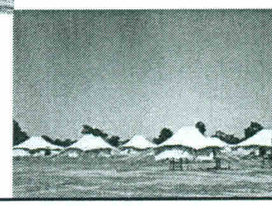
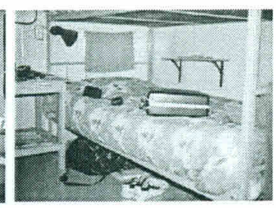




SEISMIC EXPLORATION

SEISMIC EXPLORATION



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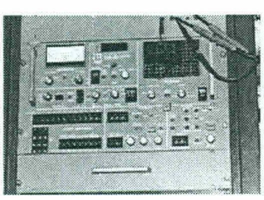
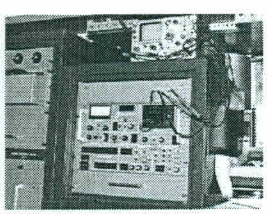
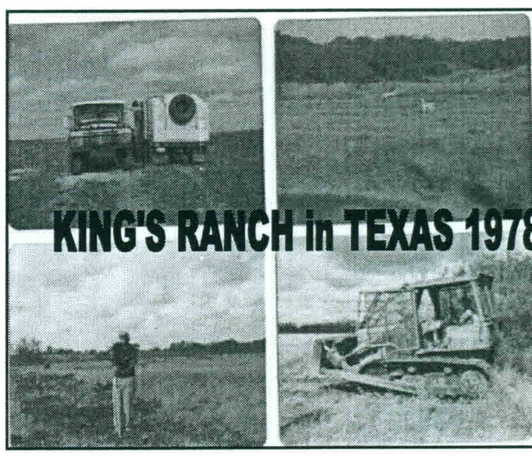
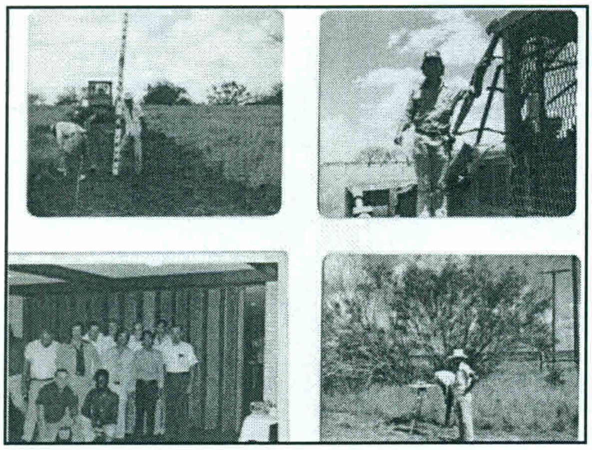








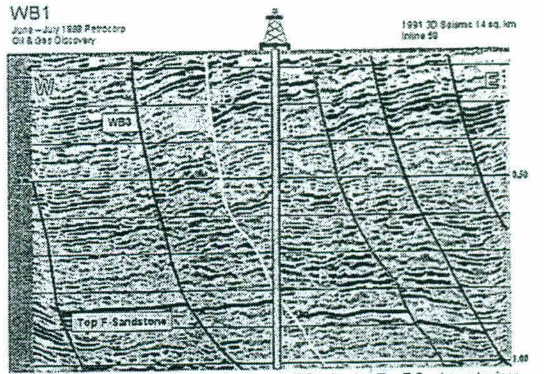
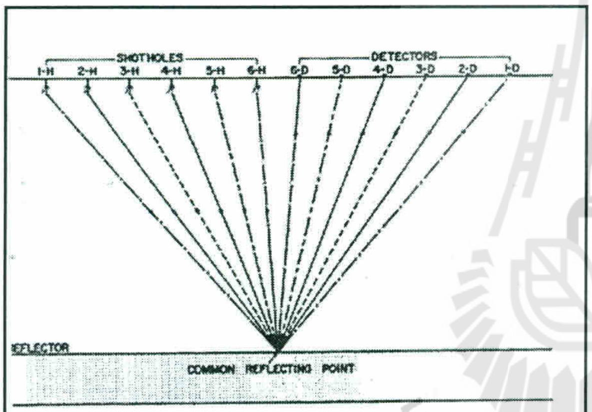


Figure 5: East – West 3D seismic section through WB1 showing Top F-Sandstone horizon and structural elements.



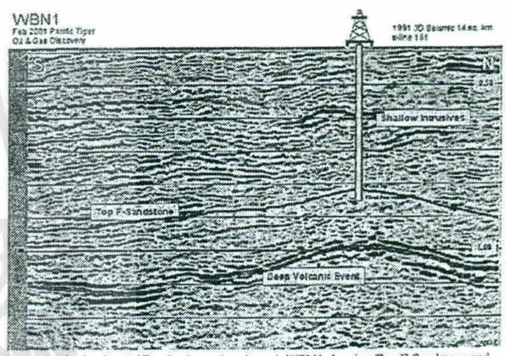
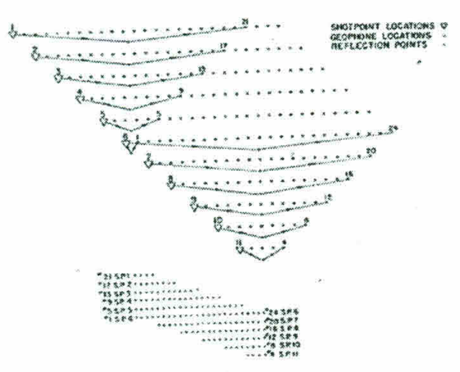


Figure 6: North - South 3D seismic section through WBN1 showing Top F-Sandstone and Deep Volcanics horizons.



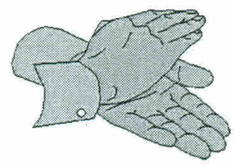
DATA PROCESSING TECHNIQUES

1. FILTER
2. COMMON DEPTH POINT
3. CONVOLUTION
4. DECONVOLUTION
5. ADJUST VELOCITY PROFILE
6. MIGRATION

HOW TO GET DRILLING PERMISSION

1. **Get Concessions**
2. **Explore to find prospects**
3. **Exploration Well Proposal, Drilling Program.**
4. **Land Permission.**
5. **EIA approval**
6. **Drilling Permission from DMF**

THANK YOU



Getting the Well Drilled

1. **The Lease Purchases**
2. **Capital to Drill the Well**
3. **Sources of Prospects**
   Maintain Staff or Sub-Contract
4. **Full-Interest Well**
5. **Joint-Operating Agreements**
6. **Cash Contribution**
   Reduced-Acreage
7. Farmouts(Farmor-Farmee)
8. Carried Interest; an arrangement interest of Co-owners
9. Land and Working Permit, EIA, Well Proposal, and Well Program

HW no.1: Due date; Friday 25 July 2014

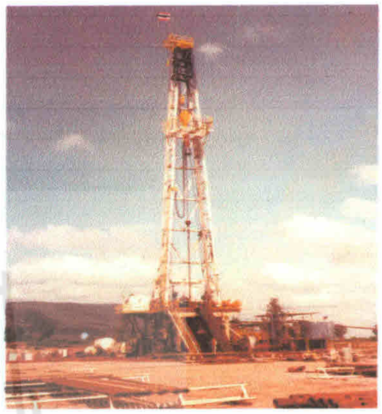
1. **HOW TO GET A CONCESSION**

2. **HOW TO GET DRILLING PERMISSION**

ADVANCED DRILLING ENGINEERING2014

CHAPTER 2. ROTARY DRILLING

By
Kriangkrai Trisarn



CHAPTER II ROTARY DRILLING

1. Rotary Drilling History
2. Rig types
3. Rotary Drilling Rig & Accessories.
4. Derrick Load and Horse Power.
5. hoisting System & Rotating Components
6. Mud System
7. Drill Pipe and Components
8. Bits
9. Fishing Tool

DRILLING HISTORY

⇒ 2500 years ago, wells had been drilled in China, Persia, Egypt and Europe by PERCUSSION DRILLING

⇒in 1844, First ROTARY DRILLING were issued by Robert Beart in England by using water as the drilling fluid.

⇒in 1860, Leschot, French engineer applied diamond bits to drill hard rock in Swiss Alps tunnel construction

⇒ 1850's ,Catlin issued a rolling cutter bits in U.S.A

⇒in 1866, Sweeney issued hand-power rotary drilling in U.S.A

⇒in 1887, Chapman covered the use of clay, bran, grain, cement and similar material to be used as drilling fluid in U.S.A

⇒Beginning of 20th century, Antony Lucas showed the whole world how effective ROTARY DRILLING was with the discover of Spindeltop field in Texas.

Drilling Fluid History

- Long time ago
  Chinese used water 2-3 ft/day
  To
  - Soften the rocks
  - Remove the cuttings
- a.d. 1901 - Capt. Anthony LUCAS
  In Texas
- a.d. 1901-1928 - First Development Period by Baroid
- 1921 Stroud - First "Drilling Fluid Engineer"
  Controlled Drilling Fluid Properties
- 1926 the use of Barite → BAROID®
- 1935 Baroid Registered AQUAGEL for Viscosity & Filtration Control

Oil History – A chronology

- Oil was first discovered in ancient times, and asphalt was used to caulk the seams of ships
- 1814 First oil well in Caldwell, Ohio discovered oil instead of salt water; Darn! (:-((
  www.aoghs.org
- 1829 Oil discovered in Burkesville KY; 50,000 bbls total; they wanted salt water – Why? Hint: food
  http://www.fohbc.com/images/American%20Oil.pdf
- 1850 Samuel Kerr distilled oil shale to produce oil
- 1857 E. L. Drake hired to drill for industrial oil in Pennsylvania
- 1866 First "gusher"(a flow of oil) in Texas
- 1866 PA oil was about $6 a barrel (~$35, 2004; $73, 2010)
- 1901 Lucas Spindletop "gusher" (a person who gushes) near Beaumont, Texas, and "Big Oil" began

http://www.sjgs.com/history.html

100128

History of Use

- 1858: first oil drilled in Canada
- 1859: Edwin Drake!
- Who is he?
  - He was the first person in the U.S. to drill for oil
- Where?
  - Titusville, Pennsylvania
- Initial cost: $20 per barrel, within three years dropped to 10 cents
- Now why do we measure oil in barrels?

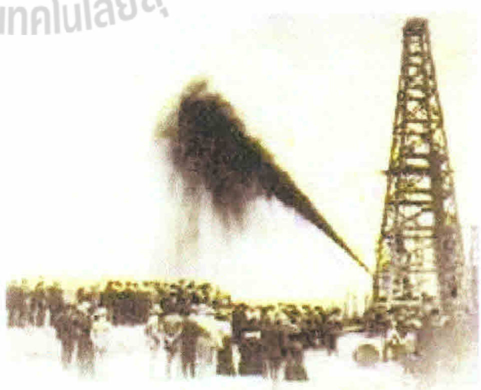
Oil Tidbits:

- **Though barrels are no longer used to ship oil, in America they are still the unit of measurement in commerce.**
- **The size was determined by the practices of Pennsylvania oil companies. They shipped oil to market by wagon or train in open wine barrels that held 48 gallons. By the time they reached the market only 42 gallons was left because of spillage and therefore the measurement became 42 gallons.**

Rotary Drilling History

- Developed originally in France in the 1860's
- It did not catch on at first because drilling companies believed petroleum only lay in hard formations where cable-tool drilling was the norm.
- In the 1880's two brothers named Baker gained a reputation for drilling successful water wells in the soft formations of the Great Plains in the United States.
- The rig they used was a rotary unit with a fluid circulating system.
- This system proved equally successful in the soft unconsolidated rocks of Texas in the Corsicana oilfield (which was discovered while drilling for water)

Spindletop



Rotary Drilling History

- **Spindletop:**
  - In 1900 several unsuccessful attempts to drill the great Lucas well at Spindletop (near Beaumont, TX) provided the proving ground for rotary drilling.
  - **Anthony Lucas** an Austrian-born Mining Engineer believed there was oil under the dome of Spindletop. He set out to use rotary drilling to find it.
  - Historians estimate that between **80,000** and **100,000** barrels of oil per day gushed from the well in the first nine days. (1 barrel = 42 gallons) **336,000-420,000 gal/day.**

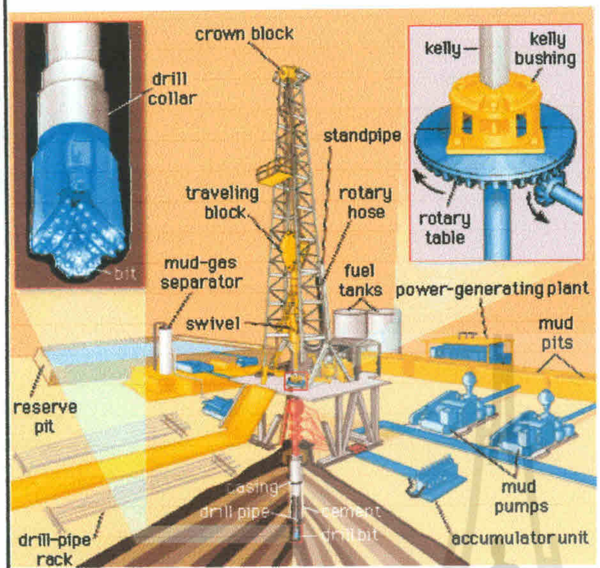
Spindletop

Boiler Avenue in Spindletop, TX

By 1903 over 400 wells had been drilled

Population rose in Beaumont from 10,000 to 50,000

Rotary Drilling



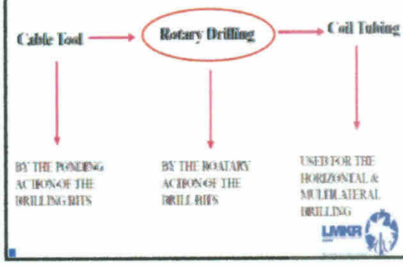
The action of rotating the drill bit with the application of pumping fluid (Mud) through the drill string, drill bit, and annular to remove cuttings.

Drilling Today

Historical Background

- 1808 PERCUSSION DRILLING BY CHINESE
  FIRST COMMERCIAL WELL
- 1859 CABLE TOOL PERCUSSION DRILLING
- 1918 WORLD DEEPEST WELL BY CABLE TOOL (7386 ft)
- 1930 ROTARY DRILLING

Modification In Drilling



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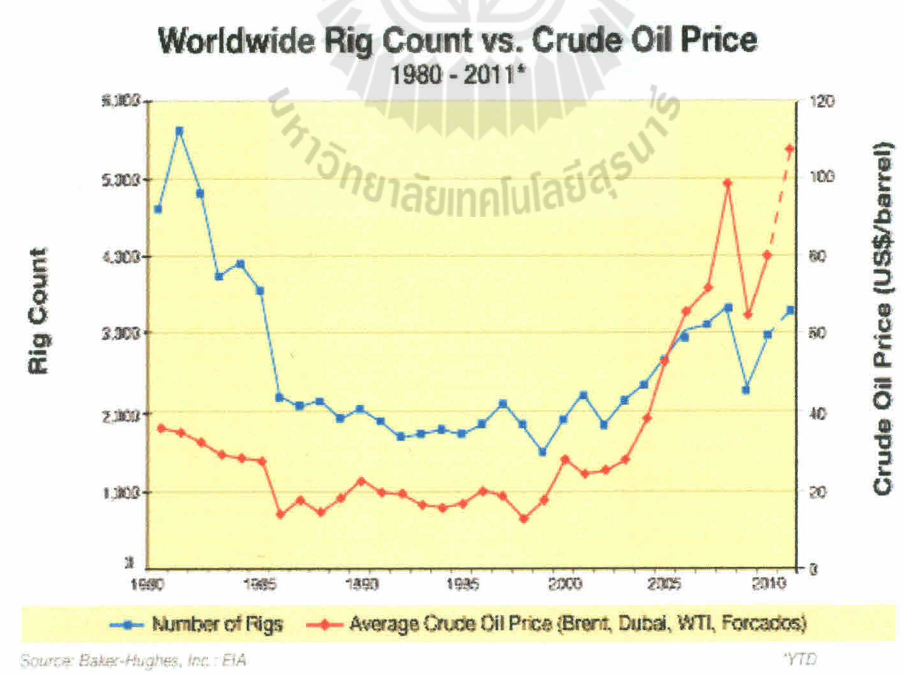

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Society of Petroleum Engineers

	NOV	DEC	2013 JAN	FEB
Brent	109.06	109.49	112.96	116.02
WTI	86.53	87.86	94.76	95.3

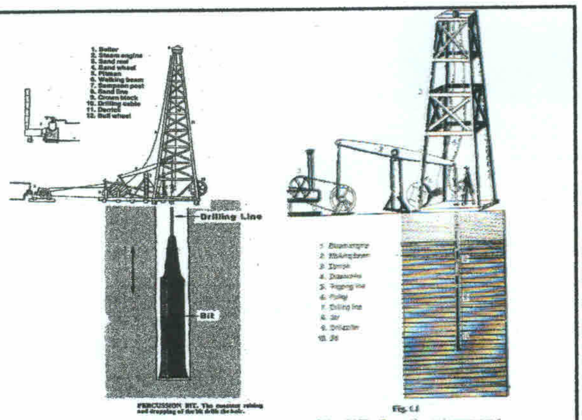
WORLD ROTARY RIG COUNT[1]

REGION	2012 AUG	SEP	OCT	NOV	DEC	2013 JAN	FE
US	1913	1859	1834	1809	1784	1757	176
Canada	316	355	365	385	353	503	64
Latin America	417	411	412	398	414	414	42
Europe	118	124	124	127	136	134	13
Middle East	388	381	377	394	363	379	35
Africa	111	108	104	102	102	115	11
Asia Pacific	227	230	242	246	238	237	25
TOTAL	3490	3468	3458	3461	3390	3539	367

WORLD OIL SUPPLY AND DEMAND[1]

MILLION BOPD	2012			
Quarter	1st	2nd	3rd	4th
SUPPLY	88.97	88.95	89.07	89.13
DEMAND	88.80	88.72	89.11	89.86

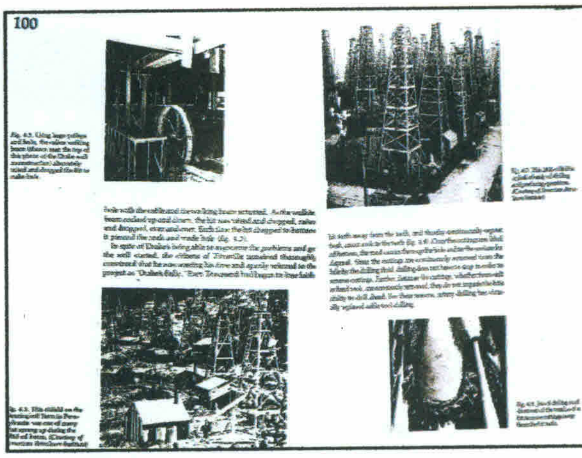
INDICES KEY
- Figures do not include NGLs and oil from nonconventional sources.
- Includes approximately one-half of Neutral Zone production.
- Includes crude oil, lease condensates, natural gas plant liquids, other hydrocarbons for refinery feedstocks, refiner

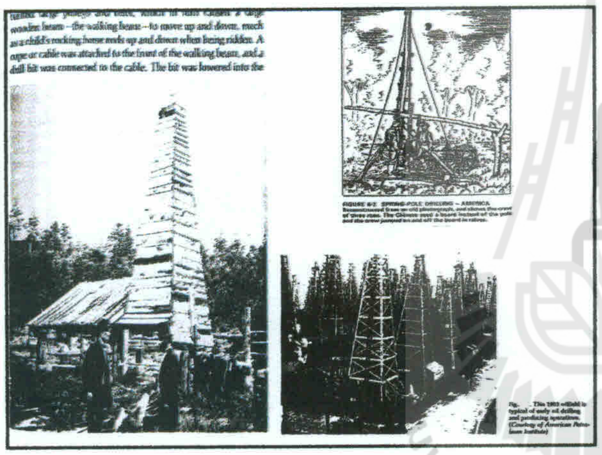


PERCUSSION BIT. The constant raising and dropping of the bit drills the hole.

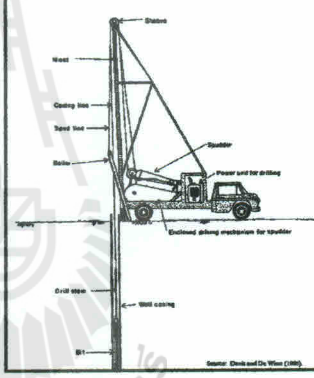
Fig. 1.1

Fig 3.1 Cable Tool Rig (Percussion Bit)





Portable Cable-Tool Rig



Source: Davis and De Wiest (1966).

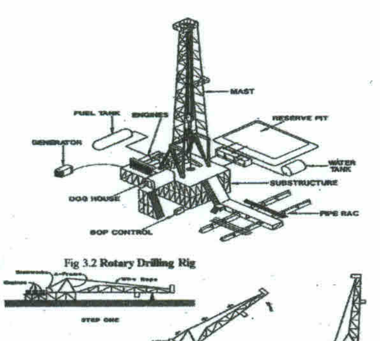
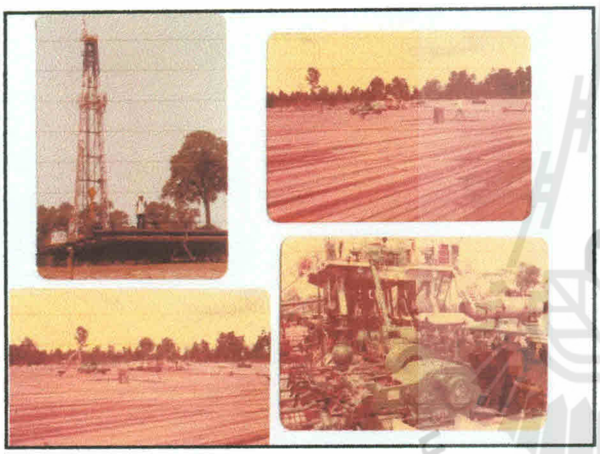
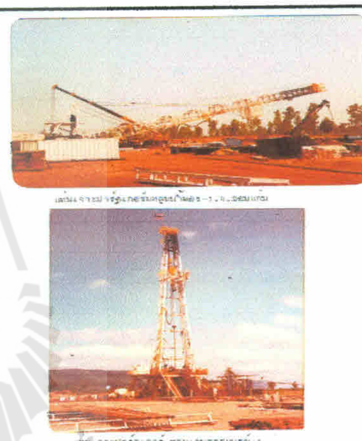


Fig 3.2 Rotary Drilling Rig

TYPICAL MAST RAISING OPERATION. The mast is raised using the rig's power system, the drawworks, and a wire rope line.

DRILLING RIG





22 February 56 SINOPEC Rig 50765

YPT-2 : ตั้งอยู่ที่
อ.ชุมพลบุรี จ.สุรินทร์

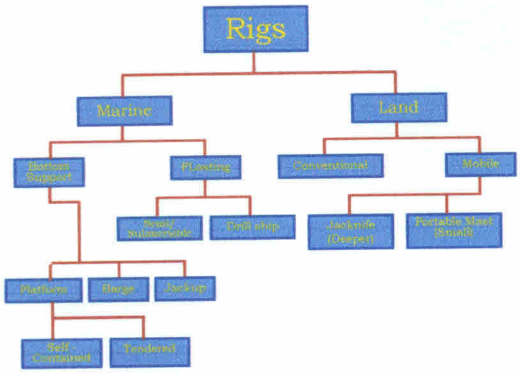
Type of Oil and Gas Wells

Wildcat / Exploration Well:
- A well drills in the area with little known geological information.

Appraisal / Delineation Well:
- A well drills to investigate the extent of the reservoirs and to evaluate potential.

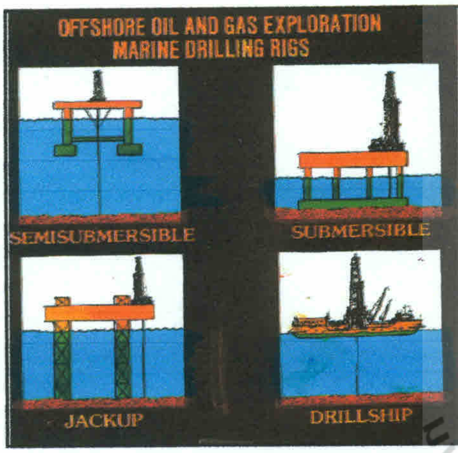
Production / Development Well:
- A well drills to produce hydrocarbon.

In-filled Well:
- A well drills to optimize hydrocarbon recovery.

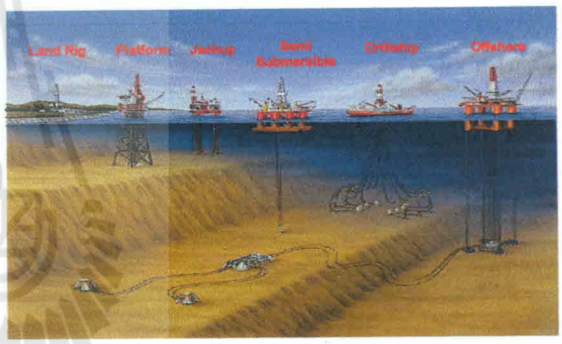


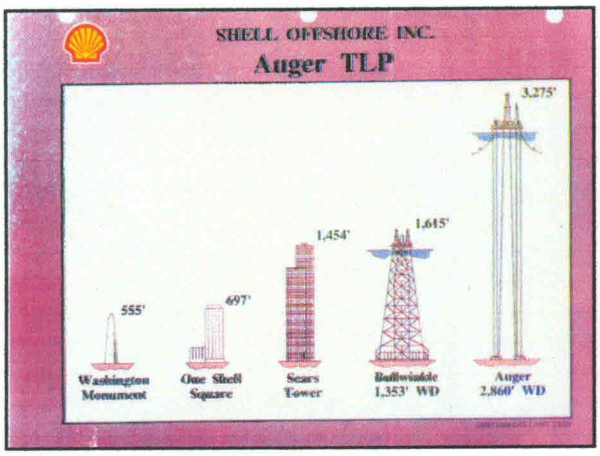
Drilling Rigs

- Land Rig



Drilling Rigs



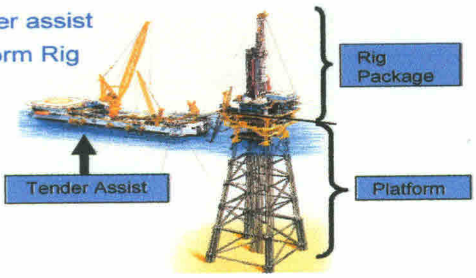


Drilling Rigs

- Offshore Rig

Drilling Rigs

- Tender assist Platform Rig



Drilling Rigs

- Jack-Up Rig


Drilling Rigs

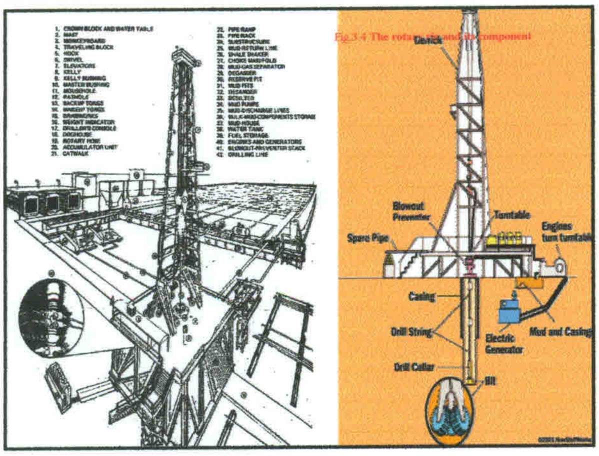
- Semi-submersible


1.3Dynamic Derricks


Drilling Rigs

- Drillship





Rotary Drilling Rig & Components

1. Derricks, Masts and Substructure
2. Hoisting Equipment
3. Pipe Handling Equipment
4. Prime Movers
5. Power Transmission, BIT
6. Mud System
7. Instruments
8. Well Control Equipment
9. Fishing TOOLS

The following considerations may influence rig selection.

1. Mechanical rating and suitability for the job
2. Capital cost or contractual rate
3. Mobility
4. Dependability
5. Ease of operation

   Quality of supervision and rig personnel, if supplied with rig.

To chose the best rig for drilling a particular well consider.

1. Anticipated formation, pressures
2. Hole and Casing programmes
3. Preferred drill string size and grade (s) to be used.
4. Hoisting requirements
5. Derrick requirements
6. Hydraulic requirements
7. Rotary requirements
8. Auxiliary equipment needed.

3.4.1 DERRICKS AND MASTS

Types of derricks and masts:

1. Conventional or standard type derrick
2. Portable skid types, "jack knife" -, "full view" masts
3. Mobile – or trailer mounted mast
4. Dynamic – marine type derricks
5. Multiple well derricks.

1.Derricks, Masts and Substructure

1.1.Convention Rig

1.2 Standard Derricks,

Rating 6,500-50,000 ft.

Drawwork 250-4,000 H.P.

Pump 250-4,000 H.P.

Mud Tanks 200-2,000 bbls

Drill Pipe Size 3.5-5.5 inches

The specifications of two types of Dreco derrick are given below as an illustration

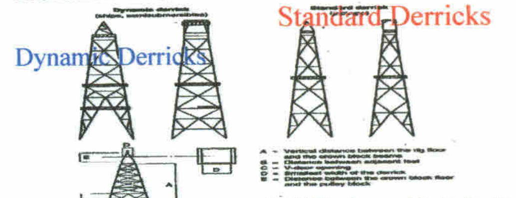


Fig. 3.6 Offshore Dynamic and Standard Derricks

Fig. 4.2
Examples of derricks.

A. *Dynamic derricks*

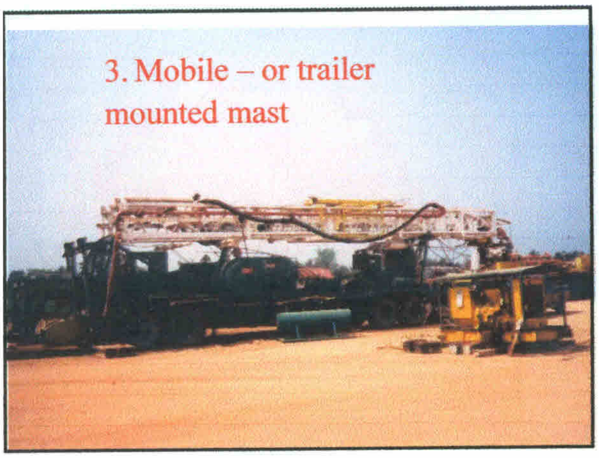
Height .... 160 ft (useful hook stroke length)
Base .... 40 ft
Crown block platform .... 18 ft
V-door .... 60 ft
Maximum hook load .... 1,000,000 lb

B. *Standard derricks (jackups)*

Height .... 147 ft
Base .... 30 ft
Top .... 8 ft
V-door .... 34 ft

a. *Drilling*
1,000,000 lb static hook load.
No racking.
85 mph wind speed.

b. *Extremely severe conditions*
115 mph wind speed.
No racking.



Drilling a Well

- Steps in Drilling a Well
- Duties of Drilling Engineer
- Making a Connection
- Making a Trip
- Rig Selection Criteria
- Derrick Loading
- Definitions (Lesson 2B) (separate)
- Copies of ADE # 1.1, 1.2 and 1.3

Steps to Drill A Gas/Oil Well

1. Complete or obtain seismic, log, scouting information or other data.
2. Lease the land or obtain concession.
3. Calculate reserves or estimate from best data available.
4. If reserve estimates show payout, proceed with well.
5. Obtain permits from conservation/ national authority.

Steps to Drill a Well - cont'd

6. Prepare drilling and completion program.
7. Ask for bids on footage, day work, or combination from selected drilling contractors based on drilling program.
8. If necessary, modify program to fit selected contractor equipment.

Steps to Drill a Well - cont'd

9. Construct road, location/platforms and other marine equipment necessary for access to site.
10. Gather all personnel concerned for meeting prior to commencing drilling (pre-spud meeting)
11. If necessary, further modify program.
12. Drill well.

Steps to Drill a Well - cont'd

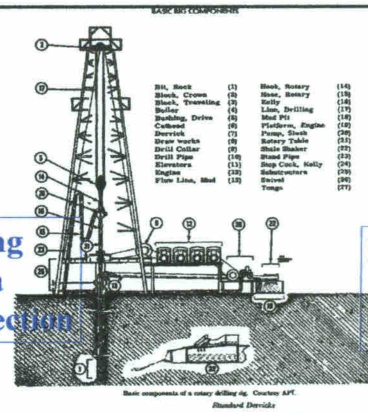
13. Move off contractor if workover unit is to complete the well.
14. Complete well.
15. Install surface facilities.
16. **Analysis** of operations with concerned personnel.

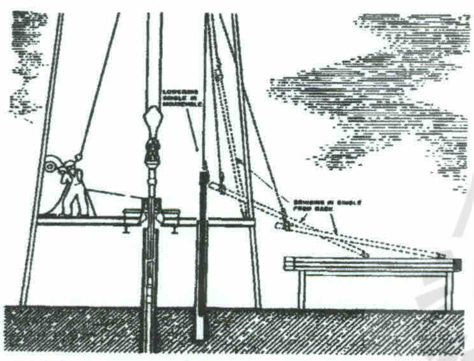
Drilling Operations

Field Engineers, Drilling Foremen

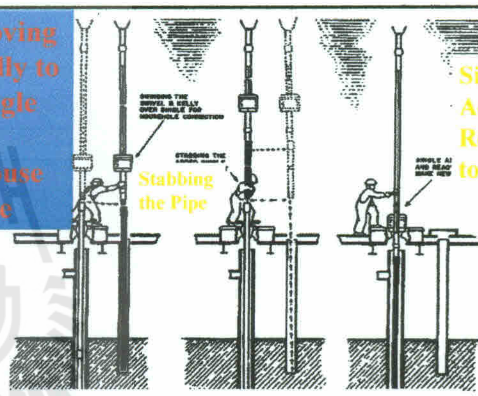
A. Well planning prior to SPUD
B. Monitor drilling operations
C. After drilling, review drilling results and recommend future improvements
- prepare report.
D. General duties.

What are the well requirements?
Objectives, safety, cost



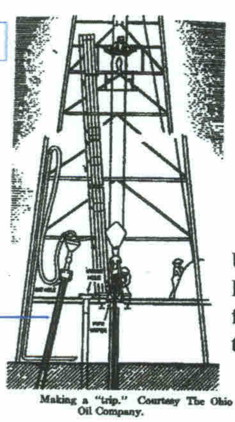


Making a mouse hole connection

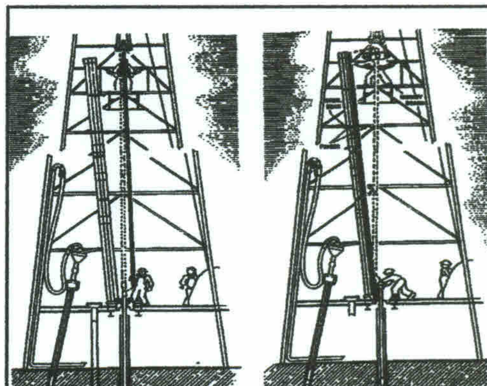


Making a mouse hole connection - cont'd

Making a trip



Making a "trip." Courtesy The Ohio Oil Company.



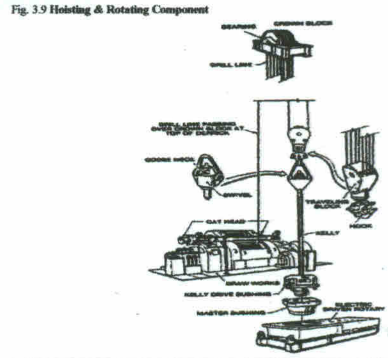
Making a trip - cont'd

Criteria for determining depth limitation

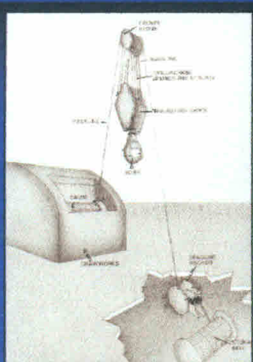
- Derrick
- Drawworks
- Mud Pumps
- Drillstring
- Mud System
- Blowout Preventer
- Power Plant

Hoisting & Rotating Components

Fig. 3.9 Hoisting & Rotating Component

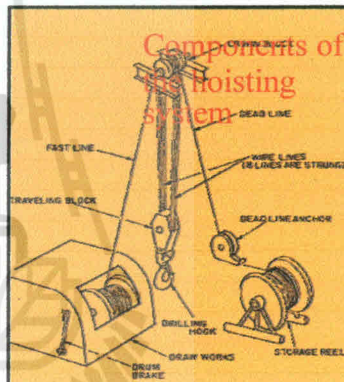


Rig and it's components



- Drawworks
- Crown block
- Travelling Block
- Deadline anchor
- Storage reel

Components of the hoisting system



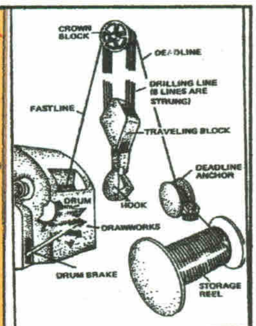
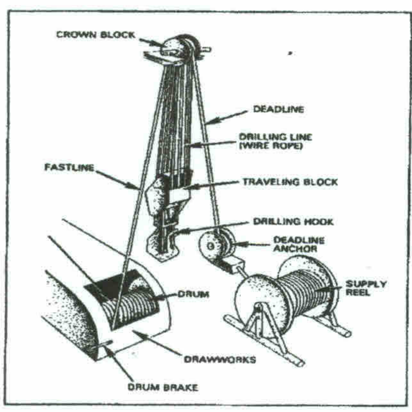


FIGURE 9. A ROTARY RIG HOISTING SYSTEM

A Rotary Rig Hoisting System



n*T

W
down

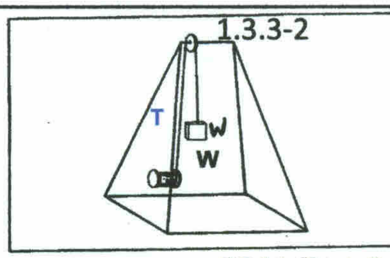


FIG 1-1 Simple pulley system

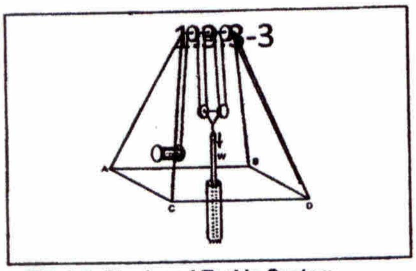
• FIG 1-1 Simple Pulley System

$F_F = W$

$L_D = 2W$ (no friction)

T = W

$L_D = 2W$ (no friction in sheave)



n = number of lines

W = weight (hook load)

L_D = load on derrick

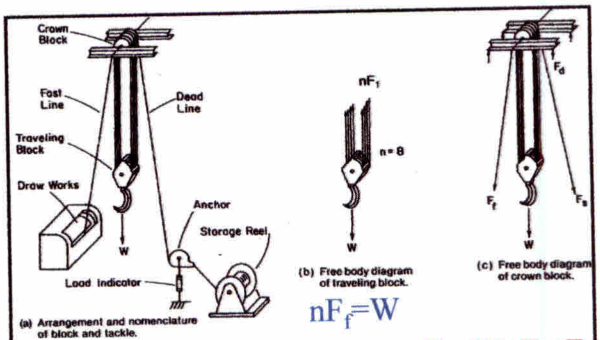
- FIG 1-2 Block and Tackle System

Assuming no friction

W = 4 T — T = W/4

L_D = 6 T = 6 W/4

$$L_D = \left(\frac{n+2}{n}\right) W$$



$nF_f = W$

$F_d = W + F_f + F_s$

$M = W/F_f$

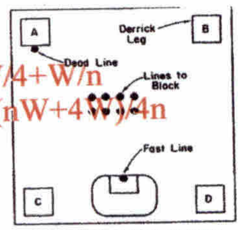


Fig. 1.17 – Projection of drilling lines on rig floor.

W/4+W/n
=(nW+4W)/4n

Projection of Drilling Lines on Rig Floor

E = efficiency = $P_h/P_i = W/(n F_f)$ or $F_f = W/(nE)$… (1.7)

TABLE 1.3 – EXAMPLE CALCULATION OF DERRICK LEG LOAD

Load Source	Total Load	Load on Each Derrick Leg: Leg A	Leg B	Leg C	Leg D
hook load	W	W/4	W/4	W/4	W/4
fast line	W/En			W/2En	W/2En
dead line	W/n	W/n			
		W(n+4)/(4n)	W/4	W(En+2)/4En	W(En+2)/4En

$$TOTAL = \left(\frac{n+4}{4n}\right) * W$$

— TOTAL

Power efficiency is

$$E = \frac{W}{F_f n}$$ actual system

Tension in the fast line

$$F_f = \frac{W}{E_h} \quad (1.7)$$

Eq. 1.7 is used to select drilling line size.

F_d = W + F_f + F_s (1.8a)

F_d = load applied to the derrick

F_s = tension in the dead line

$$F_d = W + \frac{W}{En} + \frac{W}{n} = W\left(\frac{1+E+En}{En}\right) \quad (1.8b)$$

fast dead

Load on Derrick

(considering friction in sheaves)

Derrick Load = Hook Load
+ Fast Line Load
+ Dead Line Load

$$F_d = W + F_f + F_s$$

$$F_d = W + \frac{W}{En} + \frac{W}{n} = \left(\frac{1+E+En}{En}\right) W$$

E = overall efficiency: $E = e^n$

e.g., if individual sheave efficiency = 0.98 and n = 8, then E = 0.851

APPLIED DRILLING ENGINEERING

TABLE 1.3 – EXAMPLE CALCULATION OF DERRICK LEG LOAD

Load Source	Total Load	Load on Each Derrick Leg: Leg A	Leg B	Leg C	Leg D
hook load	W	W/4	W/4	W/4	W/4
fast line	W/En			W/2En	W/2En
dead line	W/n	W/n			
		W(n+4)/(4n)	W/4	W(En+2)/4En	W(En+2)/4En

Max. leg load= W(N+4)/4N

Fde=Max Equivalent derrick load=4*max leg load

Nominal Diameter (in.)	Approximate Mass (lbm/ft)	Nominal Strength: Improved Plow Steel (lbf)	Extra Improved Plow Steel (lbf)
1/2	0.46	23,000	26,600
9/16	0.59	29,000	33,600
5/8	0.72	35,800	41,200
3/4	1.04	51,200	58,800
7/8	1.42	69,200	79,600
[illegible]	1.85	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	3.50	[illegible]	[illegible]
1 1/2	4.16	197,800	228,000
1 5/8	4.88	230,000	264,000
1 3/4	5.67	266,000	306,000
1 7/8	6.50	304,000	348,000
2	7.39	344,000	396,000

*Six strands having 19 wires per strand.

… in Table … greater than the load on the other three legs. Since if any leg fails, the entire derrick also fails, it is convenient to define a *maximum equivalent derrick load*, F_{de}, which is equal to four times the maximum leg load. For the usual drilling line arrangement shown in Fig. 1.17,

$$F_{de} = \left(\frac{n+4}{n}\right) W. \quad (1.9)$$

Fde=4*(n+4)*W/(4*n)=(n+4)W/n

… various … *efficiency factor*, defined as the ratio of the actual derrick load to the maximum equivalent load. For a maximum equivalent load given by Eq. 1.9, the derrick efficiency factor is

$$E_d = \frac{F_d}{F_{de}} = \frac{\left(\frac{1+E+En}{En}\right)W}{\left(\frac{n+4}{n}\right)W} = \frac{E(n+1)+1}{E(n+4)}.$$

Example 3.2

A rig must hoist a load of 300,000 lbf. The drawworks can provide an input power to the block and tackle system as high as 500 hp. Eight line are strung between the crown block and traveling block.

(Assume that the rig floor is arranged as shown in Fig. 3.13)

Calculation:

1. The static tension in the fast line when upward motion is impending.
2. The maximum hook horsepower available.
3. The maximum hoisting speed.
4. The actual derrick load.
5. The maximum equivalent derrick load.
6. The derrick efficiency factor.

1. The power efficiency for $n = 8$ is given as 0.841 in Table 1.2. The tension in the fast line is given by Eq. 1.7.

Solution

$$F = \frac{W}{E\ n} = \frac{300{,}000}{0.841*8} = 44{,}590\ lb$$

(alternatively, $E = 0.98^8 = 0.851$)

2. The maximum hook horsepower available is

Solution

$$P_h = E \bullet p_i = 0.841(500) = 420.5 \text{ hp.}$$

Solution

$$v_b = \frac{P_h}{W}$$

$$= \frac{420.5 \text{ hp} \left(\frac{33{,}000 \text{ ft-lbf/min}}{\text{hp}} \right)}{300{,}000 \text{ lbf}}$$

$$= 46.3 \text{ ft/min}$$

Solution to 3, cont.

To pull a 90-ft stand would require

$$t = \frac{90 \text{ ft}}{46.3 \text{ ft/min}} = 1.9 \text{ min.}$$

Solution:

1. The power efficiency for $n = 8$ is given as 0.841 in Table 3.1. The tension in the fast line is given by Eq. 3.12.

$$F_f = \frac{W}{En} = \frac{300,000}{(0.841)(8)} = 44,590 \text{ lbf}$$

2. The maximum hook horsepower available is

$$P_h = E \cdot p_i = (0.841)(500) = 420.5 \text{ hp}$$

3. The maximum hoisting speed is given hp= Vw*W/(33000*E)

$$v_b = \frac{P_h}{W} = \frac{420.5 \text{ hp}\left(\frac{33,000 \text{ ft-lbf/min}}{\text{hp}}\right)}{300,000 \text{ lbf}} = 46.3 \text{ ft/min}$$

Vw= 500*0.841*33000/300,000

To pull a 90-ft stand would require

$$t = \frac{90 \text{ ft}}{46.3 \text{ ft/min}} = 1.9 \text{ min}$$

4. The actual derrick load is given by Eq.1.8b:

Solution

$$F_d = \left(\frac{1+E+En}{En}\right)W$$

$$= \left(\frac{1+0.841+0.841(8)}{0.841(8)}\right)(300,000)$$

$$= 382,090 \text{ lbf.}$$

Solution

5. The maximum equivalent load is given by Eq.1.9:

$$F_{de} = \left(\frac{n+4}{n}\right)W = \left(\frac{8+4}{8}\right) * 300,000$$

$$F_{de} = 450,000 \ lbf$$

6. The derrick efficiency factor is:

$$E_d = \frac{F_d}{F_{de}} = \frac{382090}{450000}$$

$$E_d = 0.849 \text{ or } 84.9\%$$

4. The actual derrick load is given by Eq. 3.13b

$$F_d = \left(\frac{1+E+En}{En}\right)W = \left(\frac{1+0.841+(0.841)(8)}{(0.841)(8)}\right)(300,000)$$

$= 382,090$ lbf

5. The maximum equivalent load is given by Eq. 3.14

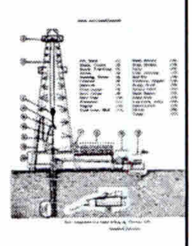
$$F_{de} = \left(\frac{n+4}{n}\right)W = \left(\frac{8+4}{8}\right)(300,000) = 450,000 \text{ lbf}$$

6. The derrick efficiency factor is

$$E_d = \frac{F_d}{F_{de}} = \frac{382,090}{450,000} = 0.849 \text{ or } 84.9\%$$

Rig Power

- Mechanical (Power)
- Diesel Electric
- Electric



3.6 Prime Movers

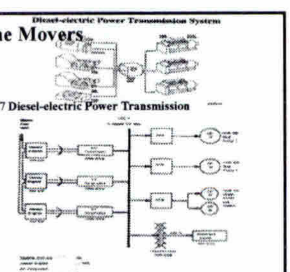
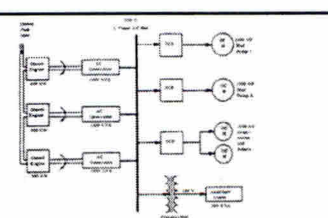


Fig. 3.17 **Diesel-electric Power Transmission**



SILICON CONTROLLED RECTIFIER (SCR)

Fig 3-24 AC-SCR Drive

3.4.2 Derrick Loads

(3.1) $p = 0.004 \ V^2$

where p = wind load, lb/ft^2

V = wind velocity, mph

Calculation of Derrick Loads

(3.2)
$$Fd = \frac{n+2}{n}W$$

where Fd = total compressive load on the derrick

n = number of lines through the travelling block (those supporting W)

w = hook load

3.4.2 Derrick Loads

(3.1) $p = 0.004\ V^2$

where p = wind load, lb/ft²
V = wind velocity, mph

Calculation of Derrick Loads

(3.2) $$Fd = \frac{n+2}{n}W$$

where Fd = total compressive load on the derrick
n = number of lines through the travelling block (those supporting W)
w = hook load

(3.3) $\upsilon_L = n\,\upsilon_h$

where υ_L = velocity of line being spooled (or unspooled) at the drawworks during hoisting

υ_h = hook velocity

3.4.4 Derrick Loads Calculation Example

Drilling@6238feet. Mud Gradient 0.519 psi/ft. DC: 600 ft;146.35 lbs/ft. Block Assembly 25,000 lbs., 5" DP : 20.99 lb/ft, No of line =8. Find Dynamic Derrick Load.

SOLUTION :

Dynamic Derrick Load = Fast Line + Hook Load + Deadline

Buoyancy Force of Steel = 1 – (0.2936 x Mud Gradient)
= 1 – (0.2936 x 0.519) = 0.847

Hook Load = Wt. String in Mud + Wt. Travelling Block
= [600 x 146.35 +(6238-600) x 20.99] x 0.847 + 25,000
= **200,000 lbs.**

Fast Line = $\frac{\text{Hook Load}}{\text{No of Lines} \times \text{Eff Factor}} = \frac{200,000}{8 \times 0.841} =$ 29,691 lbs.

Dead Line = $\frac{\text{Hook Load}}{\text{No of Lines}} = \frac{200,000}{8} =$ **25,000 lbs.**

Dyn. Derrecrick Load = 200,000 + 25,000 + 29,691
= **254,691 lbs.**

3.5.1 Slings design calculation

Type of Wire Rope "Lay"

Points of critical wear :

1. Contact points between line and sheaves
2. Cross-over point on drum,

In order to spread the wear as uniformly as possible over the block line, a **slip and cut** procedure is designed, related to the cumulative **ton-miles** of work done by the line.

Ton Mile Formulae (Field Units)

Round trip ton miles :

(3.4) $T_r = D\frac{(L_s + D)W_m}{10,560,000} + \frac{D(M + \frac{1}{2}C)}{2,640,000}$ (API RP 9B)

D = hole depth or trip depth ft
L_s = drill pipe : stand length ft
W_m = weight / ft. of drill pipe in mud lbs
M = weight of block, hook, elevator, ect. lbs
C = effective drill collar weight
= (D.C weight in Mud – D.P weight of ...

Drilling ton miles :

(3.5) $T_d = 2\,(T_2 - T_1)$, hole drilled only.
(3.6) $T_d = 3\,(T_2 - T_1)$, if hole reamed once.

Where : $T_1 = T_r$ at depth 1.
$T_2 = T_r$ at depth 2.

Ton miles coring (no reaming with core barrel) :

(3.7) $T_m = 2\,(T_2 - T_1)$

Ton miles casing

(3.8) $T_c = \frac{1}{2}\left[\frac{W_c(L_c + D) + 4DM}{10,560,000}\right]$

Where W_c = effective casing weight lbs/ft. in mud.
L_c = length average casing joint.

1 mile = 5280 ft. ; 1 ton = 2000 lbs. (short ton)

DIMENSIONS AND STRENGTHS OF COMMONLY USED 6 x 19 PREFORMED IPS IWRC BLOCK LINES

SIZE		APPROX MASS	BREAK STRENGTH	
In	mm	kg/m	kN	Short tons*
1	26	2.75	399	44.9
1 1/8	29	3.48	503	56.5
1 ¼	32	4.30	617	69.4
1 3/8	35	5.21	745	83.7
1	38	6.19	880	98.9
1 ¾	45	8.44	1180	133.0

* NOTE : 1 short ton = 2000 lb

Minimum Safety Factors 3.5 for drilling
2.5 for casing

String to more lines if safety factor is too low.

Line Size		T.M. between cuts, per ft cut	10³ daN·km between cuts, per metre cut	MJ between cuts, per metre cut
Inch	mm			
1	26	8	37.58	375.8
1 1/8	29	12	56.37	563.7
1 1/4	32	16	75.16	751.6
1 3/8	35	20	93.95	939.5
1 1/2	38	24	112.74	1127.4

Drum & Drawwork Horse Power

work = Force x Distance .....ft-lbs

Power = $\frac{\text{Force} \times \text{Distance}}{\text{Time}}$ ....**ft. lbs/sec.**

E = Efficiency factor
W = Hook load (including traveling block) lb.

F = Fast line pull. Also F = $\frac{W}{E \times N}$ **lb**

N = **Number of Lines**
V_F = **Velocity of fast line ft/min**
V_w = **Velocity of travelling block. Ft/min**

Velocity of fast line, $V_F = V_w \times N$ **ft/min**

(3.9) $HP_{drum} = \frac{F\,2\pi R n}{33000}$ **Also**

$F = \frac{W}{E \times N}$, $2\pi R n = V_F = V_w \times N$

(3.10) $HP_{drum} = \frac{W\,V_w}{33000 \times E}$

Note : 1 HP (British) = 33000 ft.lbs/min

The efficiency factor E is given by the following equation:

$$E = \frac{K(1-K^n)}{n(1-K)}$$

where n = number of line, K = sheave and line efficiency per sheave; K = 0.9615 is in common use. During lowing of the hook load, it can be shown that the efficiency factor and fast line load are given by

$$E_{lowering} = \frac{nK^n(1-K)}{(1-K^n)}$$

$$F_{lowering} = \frac{WK^n(1-K)}{(1-K^n)}$$

Fig. 3.12 Schematic of block and tackle.

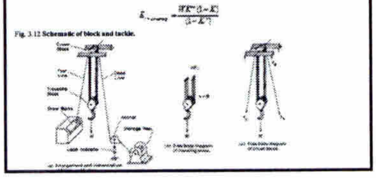


Table 3.1 Average Efficiency Factors For Block-and-Tackle System

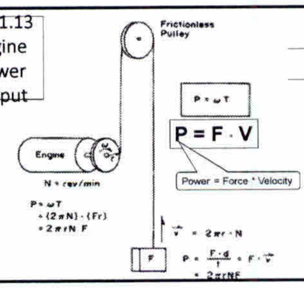
Number of line (n)	Efficiency (E)
6	0.874
8	0.841
10	0.810
12	0.770
14	0.740

$$F_f = \frac{W}{En}$$

$$F_d = W + F_f + F_s$$

$$F_d = W + \frac{W}{En} + \frac{W}{n} = \left(\frac{1 + E + En}{En}\right)W \quad (3.13b)$$

Fig. 1.13 Engine power output



Power-System Performance Characteristics

Are stated in terms of:

1. ***Output horse power***
2. ***Torque***
3. ***Fuel consumption for various engine speeds***

$$P = \omega T = 2\pi N.F.r$$

Where,

P = shaft power (hp)

ω = 2πN, Angular velocity of the shaft (engine speed), rad/min

T = output torque (lb-ft)

N = Rev./min

3.5.4 Rig power system.

Rig power system performance characteristic generally are stated in terms put horsepower, torque, and fuel consumption for various engine speeds. The fol equations perform various design calculation:

$$P = \omega T / 33000$$

(3.16)

$$Q_i = 0.000393 W_f \rho_d H \qquad E_t = \frac{P}{Q_i}$$

(3.17)

where

P = shaft power developed by engine, hp

ω = angular velocity of the shaft, rad/min

= $2\pi N$, where N is speed in revolutions/minute(rpm)

T = output torque, ft – lbf

Q_i = heat energy consumed by the engine, hp

W_f = fuel consumption, gal/min

TABLE 1.1 - HEATING VALUE OF VARIOUS FUELS

Fuel Type	Density (lbm/gal)	Heating Value (Btu/lbm)
diesel	7.2	19,000
gasoline	6.6	20,000
butane	4.7	21,000
methane	---	24,000

Example 1.1. A diesel engine gives an output torque of 1,740 ft-lbf at an engine speed of 1,200 rpm. If the fuel consumption rate was 31.5 gal/hr, what is the output power and overall efficiency of the engine?

Solution: The angular velocity, ω, is given by

$\omega = 2\pi\ (1{,}200) = 7{,}539.8$ rad/min.)

The power output can be computed using Eq.1.1

$$P = \omega T = \frac{7{,}539.8(1{,}740)\ \text{ft-lbf/min}}{(33{,}000\ \text{ft-lbf/min})/\text{hp}} = 397.5hp$$

Since the fuel type is diesel, the density is 7.2 lbm/gal and the heating value H is 19,000 Btu/lbm (Table 1.1). Thus, the fuel consumption rate w_f is:

$$w_f = 31.5\ \text{gal/hr}\ (7.2\ \text{lbm/gal})\left(\frac{1\ \text{hour}}{60\ \text{minutes}}\right)$$

$$w_f = 3.78\ \text{lbm/min.}$$

The total heat energy consumed by the engine is given by Eq. 1.2:

Efficiency = (Power Out / Power in)

$$Q_i = w_f H$$

$$Q_i = \frac{3.78\ \text{lbm/min}\ (19{,}000\text{Btu/lbm})\ (779\ \text{ft-lbf/Btu})}{33{,}000\ \text{ft-lbf/min/hp}}$$

$$= 1{,}695.4\ \text{hp.}$$

Thus, the overall efficiency of the engine at 1,200 rpm given by Eq. 1.3 is

$$E_t = \frac{P}{Q_i} = \frac{397.5}{1695.4} = 0.234\ \text{or}\ 23.4\%$$

$$= 3.78\ \text{lbm/min} \qquad \left(\frac{1\text{hour}}{60\text{minutes}}\right)$$

The total heat energy consumed by the engine is given by Eq. 1.2:

$$Q_i = w_f H, \quad = \frac{3.78 lbm/min(19{,}000 Btu/lbm)(779\ ft-lbf/Btu)}{33{,}000\ ft-lbf/min/hp}$$

$$Q_i = 0.000393 W_f \rho_d H$$

$$Q_i = 0.000393 * 31.5 * 7.2 * 19000 \quad = 1695.4$$

= 1,695.4 hp. Thus, the overall efficiency of the engine at 1,200 rpm given by Eq. 1.3 is

$$E_t = \frac{P}{Q_i} = \frac{397.5}{1695.4} = 0.234\ \text{or}\ 23.4\%$$ **Answer**

Example 3.3

A diesel engine given an output torque of 1,650 ft-lbf at an engine speed of 800 rpm. If the diesel consumption rate is 15.7 gal/hr, what the brake horsepower and the overall engine efficiency?

Compute the fuel consumption per 12-hour work day. $P = \frac{2\pi N * T}{33{,}000 ft-lbf/min/hp}$

Solution: Using Equation 3.15.

$$P = 2\pi(800)(1{,}650)/33{,}000 = 251.3\ \text{hp}$$

Using Equation 3.17

$$E_t = \frac{P}{0.000393\ \omega_f \rho_d H} = \frac{251.3}{(0.000393)(15.7)(7.2)(19{,}000)}$$

$= 0.298$ or 29.8%

Fuel consumption = (12)(15.7) = 188.4 gal/day

According to API Standard 7B-11C, the mechanical horsepower requirements must be modified for high-temperature environments or altitudes. Approximate conversions are as follows:

1. Deduct 3% of the standard brake horsepower for each 1,000 ft rise in altitude above sea level.
2. Deduct 1% of the standard brake horsepower for each 10° rise or fall in temperature above or below 85° F, respectively.

3.5.1 Slings design calculation

Type of Wire Rope "Lay"

Points of critical wear :

1. Contact points between line and sheaves
2. Cross-over point on drum,

In order to spread the wear as uniformly as possible over the drill line, a **slip and cut** procedure is designed, related to the cumulative **ton-miles** of work done by the line.

Ton Mile Formulae (Field Units)

Round trip ton miles :

$$T_r = D\frac{(L_s + D)W_m}{10{,}560{,}000} + \frac{D(M + \frac{1}{2}C)}{2{,}640{,}000} \quad \text{(API RP 9B)}$$

D = hole depth or trip depth ft

L_s = drill pipe stand length ft

W_m = weight / ft. of drill pipe in mud lbs

M = weight of block, hook, elevator, ect. lbs

C = effective drill collar weight

= (D.C weight in Mud – D/P weight of same length, in mud lbs

Derivation of Ton-miles Formula

① Block & Hook [illegible]

[illegible]

Round Trip = [illegible]

② Drill Pipe

[illegible]

③ Drill Collar [illegible]

Total work = ① + ② + ③

Drilling ton miles :

(3.5) $T_d = 2(T_2 - T_1)$, hole drilled only.

(3.6) $T_d = 3(T_2 - T_1)$, if hole reamed once.

Where : $T_1 = T_r$ at depth 1.
$T_2 = T_r$ at depth 2.

Ton miles coring (no reaming with core barrel) :

(3.7) $T_c = 2(T_2 - T_1)$

Ton miles casing

(3.8) $T_s = \frac{1}{2}\left(\frac{W_c(L_c + D) + 4DM}{10560000}\right)$

Where W_c = effective casing weight lbs/ft in mud.
L_c = length average casing joint.

1 mile = 5280 ft. ; 1 ton = 2000 lbs. (short ton)

3.5.5 Block line calculations Example
Example 3.1

Ton mile program

Determine length of rope to be cut.
Calculate ton miles between cuts.
How much should the ton miles change as the safety factor changes?
Slip the block line between cuts at least twice.
Derrick: 142 ft.
Drum: 30" with counter balance grooving
Drill line: 1 3/8" IPS IWRC
Traveling block: 8 lines
Hole depth: 13500'
Mud Gradient = 0.831 psi/ft
Drill pipe : 5" – 19.5 lb/t Nom. wt with NC 50 connections and 6 3/8" OD x 3 3/4" ID tool joints
Drill collars – 600' x 8" x 3".
Weight block + hook = 20000 lbs
Casing: 9 5/8" – 47 lbs/ft – N 80/P 110.

Calculate:

1. The derrick loading (= Safety factor when drilling at 13500'
2. crown load or dynamic load)?
3. Pipe set back load
4. Length of cut
5. Ton miles between cuts
6. R/trip ton miles at 13500'
7. Casing ton miles when run in at 13500'
8. How much is the wire line safety factor with the casing string at 13500'. Do we need to take any action?
9. How much is the dynamic or crown load?

Solution

1. Safety Factory when drilling at 13500' :

String Weight in Air = D/P wt in air + D/C wt in air

D/P wt in air = 12900' x 20.99 lbs/ft = 270771 lbs

D/C wt in air = 600' x (2.67 (8^2-3^2)) lbs/ft = 88110 lbs

Total (set back load) = 358881 lbs

String wt in mud = 358881 x B.F.

Buoyancy Factor, B.F. = 1- $\frac{\text{Mud Density}}{\text{Steel Density}}$ 0.831*62.4/0.433=119.76

0.756

String Weight in Mud = 358881 x (1- $\frac{119.69 \text{ lbs ft}^3}{489.5 \text{ lbs ft}^3}$)

= 271147 lbs 271320.6

Hook Load = string Weight in Mud + Weight block + hook

= 271147 + 20000
= 291147 lbs

Safety Factor = $\frac{\text{Breaking strength of rope}}{\text{Fastline pull}}$

Fastline pull = $\frac{\text{Hook Load}}{\text{Number of line} \times \text{Efficiency factor}}$

Fastline pull = 291147/(8*0.841)
= 43273.93 lbs

Safety Factor = 83.5*2000/43274= 3.86

2. Dynamic Derrick loading:

Fastline load = 43273.93 lbs
Hook load = 291147 lbs

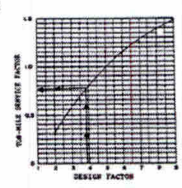
Dead line load: = $\frac{291147}{8}$ = 36393.38 lbs

Dynamic Derrick load = 370814.31 lbs

3. Pipe set back = 358881 lbs

4. Cut-off length. 12 drum laps + 1/4 lap for counter balanced grooving = 12 1/4 laps = 96.8 feet. For a safety factor of 5.0 and 1 3/8" wire rope a ton mile value of 20 per foot cut off is given. For any other safety factor this value must be modified according to the relevant service factor. From the graph below it can be seen that for a safety factor of 3.86 the correspond service factor is 0.76.The modified ton mile value is therefore

20 x 0.76 = 15.2 ton miles/ft cut



5. Ton miles between cuts :

96.8 x 15.2 = 1471 Ton-miles

6. Round trip ton miles at 13500'

$$T_r = \frac{13500(93 + 13500(20.99 \times 0.7555)}{10{,}560{,}000} + \frac{13500(20000 + 0.5(46.85 - 20.99) \times 600 \times 0.7555)}{2{,}640{,}000}$$

275.57 + 248.15 = 523.72 tm

7. Casing tm:

$$T_s = \left(\frac{D(L_{cs} + D) \times (W_{cm})}{10{,}560{,}000} + \frac{D \times M}{2{,}640{,}000}\right) \times \frac{1}{2}$$

$$= \left(\frac{13500(40 + 13500) \times (47 \times 0.7555)}{10560000} + \frac{13500 \times 20000}{2{,}640000}\right) \times \frac{1}{2}$$

$$= \frac{614.64 + 102.27}{2}$$

= 358.46 tm

8. Safety Factor ?

Casing wt in mud: 13500' x 47 lbs/ft x 0.7555 bf = 479364.75 lbs
Block + Hook : = 20000 lbs
Hook load : = 499364.75 lbs

Fast line load : = $\frac{499364.75}{8 \times 0.841}$

= 74221.87 lbs

$$S.F. = \frac{\text{Breaking strength rope}}{\text{Fast line load}} = \frac{83.5 \times 2000}{74221.87}$$

= 2.25 ⇒ Too Low

Therefore string to 10 line and check S.F. again :-

Fast line load with 10 line ⇒ $\frac{499364.75}{10 \times 0.81} = 61650.lb.$

$\frac{83.5 \times 2000}{61650} = 2.71$ = 2.71 ⇒ OK

9. Dynamic crown load with 10 lines

Fast line load : = 61649.97 lbs
Hook load : = 499364.75 lbs

Dead line load : $\frac{499364.75}{10}$ = 49936.48

Then the **Dynamic crown load** = 610951.20 lbs

Note: API RP 9B state that successful field operations indicate the following design factors (safety factors) should be regarded as minimum

Rotary Drilling Line	3.0
General Hoisting Service	3.0
Mast raising + lowering Lines	2.5
Setting casing	2.0
Pulling on stuck pipe or Similar. infrequent operations	2.0

The mechanical efficiency of the linkage between the motor and drum is generally in the region of 85 %

Therefore HP_{drum} (output) = $0.85 \times HP_{motor}$ (input)

For the above system

(3.18) $$HP_{drum} = \frac{F \cdot 2 \cdot \pi \cdot R \cdot n}{33000}$$

Also

$E = 1 - 0.02n$ (2 % per line) $F = \dfrac{W}{E \times N}$

Or $E = (0.98)^n$

$$2\pi . R . n = V_F = V_W \times N$$

(3.19) $$HP_{drum} = \frac{W \cdot V_W}{33000 \times E}$$

Note: 1 HP (British) = 33000 ft.lbsf/min

Example: Field Units

Motor Power = 2000 hp Motor Speed = 1000 rpm

Drum diameter = 30 " = 1.25 ft radius

Block line strung = 10

Hook load = 300,000 lbs (including block & hook = 20,000 lbs)

Questions

1. How fast can the load be pulled ?
2. What motor to drum gear ratio is required ?
3. How fast might the empty block be raised, and at what drum line speed, in theory?
4. If the maximum line speed recommended by the manufacturer is 4000 ft/min; what load could be pulled at this speed and what would be the motor to drum gear ratio?

Solutions :

1) $HP_{drum} = \dfrac{W \cdot V_w}{33000 \times E}$ also HPdrum = HPmotor x 0.85

$V_W = \dfrac{HP_{motor} \times 0.85 \times 33000 \times 0.811}{300000}$

E = Efficiency factor for the umber of lines strung

$VW = \dfrac{2000 \times 0.85 \times 33000 \times 0.811}{300000} = 151.66$ ft/min

2) For drum speed (RPM), The line speed $V_f = V_W \times N$

V_f = 151.66 X 10 = 1516.6 ft/min

Drum speed = $\dfrac{\text{linespeed}}{\text{Circumference}} = \dfrac{1516.6}{2 \times \pi \times 1.25} = 193.1$ rev/min

Motor to Drum gear ratio = 1000 : 193.1 = 5.18 : 1 = 193.1rev/min

3) For an empty block:

$V_W = \dfrac{2000 \times 0.85 \times 33000 \times 0.811}{20,000}$ = 2274.86 ft/min (theoretical)

Now the fast line speed $V_f = V_W \times N$

V_f = 2274.86 x 10= 22748.6 ft/min (theoretical)

4) Maximum recommended line speed from the manufacturer is 400[0] ft/min

Therefore $V_f = 4000$, $V_W = \dfrac{V_f}{N} = \dfrac{4000}{10} = 400$ ft/min

$$HP_{drum} = \frac{W \times V_W}{33000 \times E}$$

Therefore

$$W = \frac{HP_{motor} \times 0.85 \times 33000 \times E}{V_w} = \frac{2000 \times 0.85 \times 33000 \times E}{400}$$

W = 113743 lbs

At 4000 ft/min, drum speed $= \dfrac{4000}{2 \times \pi \times 1.25}$ = 510 rev./min

Motor to Drum gear ratio = 1000 : 510

= 2 : 1 Approx.

1.4 Rotary System

Main Parts:

1. Swivel
2. Kelly
3. Rotary Drive
4. Rotary Table
5. Drill Pipe
6. Drill Collar

1. Swivel:

Supports the weight of the drillstring and permits rotation i.e. Bail and Gooseneck.

2. Kelly:

Square or Hexagonal to be gripped easily. Torque is transmitting through kelly bushings. Kelly saver sub is used to prevent wear on the kelly threads.

Rotary System.....

3. Slips:

During making up a joint slips are used to prevent drillstring from falling in hole.

4. Rotary Drive:

Provides the power to turn the rotary table.

* Power Sub: can be used to connect casing.

5. Drill Pipe:

Specified by (a) Outer Diameter
(b) Weight per foot
(c) Steel grade
(d) Range Length

Range	**Length (ft)**
1	18 to 22
2	27 to 30
3	38 to 45

Rotary System.....

* ***Tool Joint:*** Female is called Box.
  Male is called Pin.
* ***Upset :*** Thicker portion of the pipe.
* ***Internal upset:*** Extra thick.
* ***Thread Type:*** Round, tungsten carbide hard facing.

6. Drill Collar:

Thick walled heavy steel pipe used to apply weight to the bit.

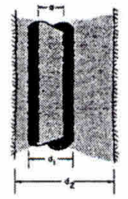
* ***Stabilizer Subs :*** Keep drill collars centralized.
* ***Capacity :*** Volume per unit Length.

$A_p = \frac{\pi}{4} d^2$ = Capacity of pipe (1.13)

$A_a = \frac{\pi}{4}(d_2^2 - d_1^2)$ = Capacity of annulus (1.14)

$A_s = \frac{\pi}{4}(d_1^2 - d^2)$ = Displacement (1.15)

Rotary System.....



CAPACITY OF PIPE

$A_p = \frac{\pi}{4} d^2$

CAPACITY OF ANNULUS

$A_a = \frac{\pi}{4}(d_2^2 - d_1^2)$

DISPLACEMENT OF PIPE

$A_s = \frac{\pi}{4}(d_1^2 - d^2)$

Capacity and displacement nomenclature

TABLE 1.5 – DIMENSIONS AND STRENGTH OF API SEAMLESS INTERNAL UPSET DRILLPIPE

Size of Outer Diameter (in.)	Weight per Foot With Coupling (lbf)	Internal Diameter (in.)	Internal Diameter At Run Upset (in.)	Collapse Pressure: D (psi)	E (psi)	G (psi)	S-135 (psi)	Internal Yield Pressure: D (psi)	E (psi)	G (psi)	S-135 (psi)	Tensile Strength: D 1,000 (lbf)	E 1,000 (lbf)	G 1,000 (lbf)	S-135 1,000 (lbf)
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

TABLE 1.6 – AVERAGE DISPLACEMENTS FOR RANGE 2 DRILL PIPE

Size of Outer Diameter (in.)	Nominal Weight (lbm/ft)	Tool-Joint Type	Actual Weight in Air (lbm/ft)	Displacement (ft/bbl)	Displacement (bbl/ft)	Displacement bbl/90 ft Stand
2⅜	6.65	internal flush	6.50	398.4	0.00251	0.23
2⅞	10.40	internal flush	10.80	251.9	0.00397	0.36
		slim hole	10.40	263.0	0.00379	0.34
3½	13.30	full hole	13.90	197.8	0.00506	0.46
		slim hole	13.40	204.9	0.00488	0.44
		internal flush	13.80	199.2	0.00502	0.45
	15.50	internal flush	16.02	171.5	0.00583	0.52
4	14.00	full hole	15.10	181.8	0.00550	0.50
		internal flush	15.10	176.1	0.00568	0.51
4½	16.60	full hole	17.80	154.3	0.00648	0.58
		xtrahole	18.00	152.7	0.00655	0.59
		slim hole	17.00	161.6	0.00619	0.56
		internal flush	17.70	155.3	0.00644	0.58
	20.00	xtrahole	21.40	128.5	0.00778	0.70
		full hole	21.30	129.0	0.00775	0.70
		slim hole	20.50	134.0	0.00746	0.67
		internal flush	21.20	129.5	0.00772	0.69
	22.82	xtrahole	24.10	114.0	0.00877	0.79
	32.94	xtrahole	36.28	75.7	0.01320	1.19
5	19.50	xtrahole	20.60	133.3	0.00750	0.68
	25.60	xtrahole	26.18	107.4	0.00932	0.84
	42.00	xtrahole	45.2*	60.8*	0.0165*	1.48*

Rotary System.....

Example 1.4: ***A drillstring is composed of 7,000 ft of 5-in. 19.5-lbm/ft drillpipe and 500 ft of 8-in. OD by 2.75-in ID drill collars when drilling a 9.875-in. borehole. Assuming that the borehole remains in gauge, compute the number of pump cycles required to circulate mud from the surface to the bit and from the bottom of the hole to the surface if the pump factor is 0.178 bbl/cycle.***

Solution:

For field units of feet and barrels, Eq. 1.13 becomes

$$A_z = \left(\frac{\pi}{4}d^2\right)in.^2\left(\frac{gal}{231 in.^3}\right)\left(\frac{bbl}{42 gal}\right)\left(\frac{12 in}{ft}\right) = \left(\frac{d^2}{1{,}029.4}\right)bbl/ft$$

Rotary System.....

$$= \frac{4.276^2}{1{,}029.4} = 0.01766\ bbl/ft$$

And the capacity of the drill collars is

$$= \frac{2.75^2}{1{,}029.4} = 0.00735\ bbl/ft$$

The number of pump cycles required to circulate new mud bit is given by

$$= \frac{[0.01776(7{,}000) + 0.00735(500)]bbl}{0.1781\ bbl/cycle} = 719 cycles.$$

Similarly, the annular capacity outside the drillpipe is given by

And the annulus capacity outside the drill collars is *Rotary System.....*

$$= \frac{9.875^2 - 5^2}{1{,}029.4} = 0.0704\ bbl/ft$$

$$= \frac{9.875^2 - 8^2}{1{,}029.4} = 0.0326\ bbl/ft$$

The pump cycles required to circulate mud from the bottom of the hole to the surface is given by

$$= \frac{[0.0704(7{,}000) + 0.0326(500)]}{0.1781\ bbl/cycle} = 2{,}858\ cycles$$

Answer

1.5 Circulating System

Components:

1. Mud Pumps
2. Mud Pits
3. Mud Mixing Equipment
4. Contaminants Removal Equipment

Pumps:

Reciprocating Positive Displacement Piston Pumps.

- Two-Cylinders - Duplex (Double Acting Forward-Backward)
- Three-Cylinders - Triplex (Forward only Single Acting)

Duplex	Triplex
Heavy	Light
Bulky	More Compact
High Output Pressure	Lower
Pulsation	Without Pulsation
Require more Maint.	Cheaper to Operate

Therefore majority of new pumps are Triplex.

Circulating System.....

Advantages

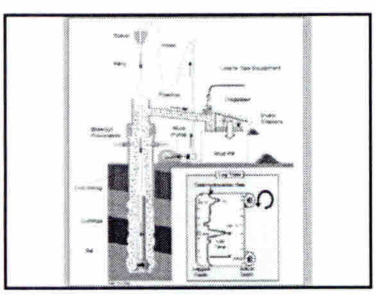
(1) Ability to move high solid content fluids
(2) Ability to move large particles
(3) Ease to operation and maintenance
(4) Reliability
(5) Ability to operate over wide range of pressure s and flow rates by changing the diameters of the pump liners and pistons.

Overall Pump Efficiency=Mechanical Efficiency x Volumetric Efficiency

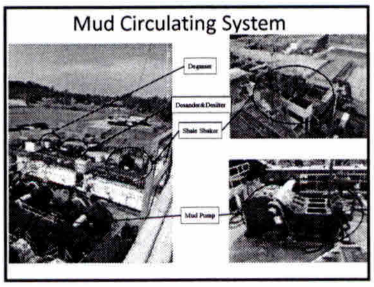
E_m= Mechanical Efficiency ≅ 90%
E_v= Volumetric Efficiency ≅ 100%

Two Circulating pumps are installed on the rig.

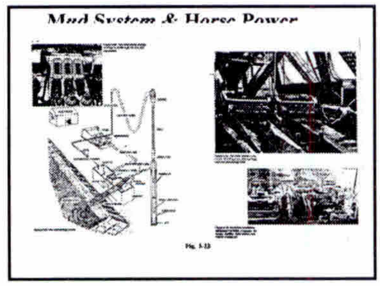
- **Shallow portion both are used.**
- **Deeper portion one is used.**



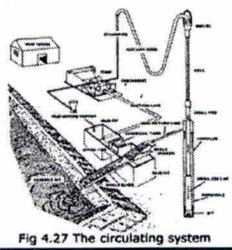
Mud Circulating System



Mud System & Horse Power

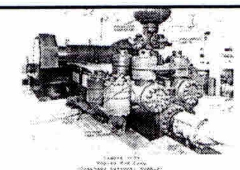


$\Delta p_t = \Delta p_s + \Delta p_p + \Delta p_c + \Delta p_b + \Delta p_{ca} + \Delta p_{dp}$



$$BP_t = \frac{q\Delta pt}{1714}$$

Fig 4.27 The circulating system

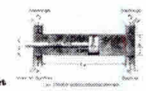


Circulating System......

Pump Displacement

(1) Double Acting

Figure 1.25 (a)



dr = Piston rod diameter
d_L= Liner diameter
L_s= Stroke Length (Stroke = one complet

Forward Stroke Volume Displaced = (π/4) $d_L^2 L_s$
Backward Stroke Volume Displaced = (π/4) (d_L^2 - d_r^2) L_s
(for one Cylinder)

Total Volume =Fp= 2 L_s(π/4) (2L_L^2 - L_r^2) . Ev (1.10)
(for two Cylinders)

Fp= Pump factor or pump displacement cycle.

Mud Pump

1)**Duplex Double Acting Slush Pump**
2)**Triplex Single Acting Pump**

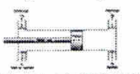


Fig.5.24 Schematic valve operation for double acting slush pump

$$Q = [\,2(\frac{\pi D^2}{4})S + 2(\frac{\pi D^2}{4} - \frac{\pi d^2}{4})S]N \times \frac{1}{231} \times e$$

Q = 0.00679SN(2D2-d2)e

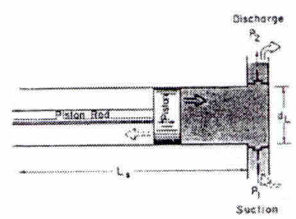
Horse Power = (Q x P)/(1714 x E)

Example 1.3: ***Compute the pump factor in units of barrels per stroke for a duplex pump having 6.5-in. liners, 2.54-in. rods, 18-in. strokes and a volumetric efficiency of 90%?***

Solution:

The pump factor for a duplex pump can be determined using Eq 1.10:

Fp = 2 L_s(π/4) (2L_L^2 - L_r^2) . Ev
= (π/2) (18) [2(6.5)² - (2.5)²] . (0.9)
= 1991.2 in.³ /stroke
or = 0.2052 bbl/stroke. **Answer**



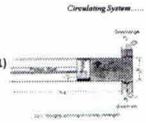
(b) Single-acting (triplex) design.

Circulating System......

(2) Triplex Acting

Figure 1.25(b)

Fp= 2 (π/4) d_L^2 L_s. Ev (1.11)



q=flow rate = Fp . N
(Where N = no. of cycles per unit time)

Pumps are rated for

1. Hydraulic Power
2. Maximum Pressure
3. Maximum Flowrate

$$P_H = \frac{\Delta P * q}{1714} \quad (1.12)$$

P_H = Pump Pressure, hp
ΔP = Increase in pressure, psi
q = Flow rate (gal/min)

ΔP cannot more than 3500 psi

Example 4.5

A mud engineer finds from pilot tests that 2.0 gm of CMC is required to obtain the desired water loss reduction for a one liter mud sample.
(a) How much CMC should be added to the actual 1000 barrel system?
(b) What will be the cycle time for a duplex mud pump system ?.Given ; pump liners = 7.5 in. diam., stroke length = 16 in., piston rod diam. = 2.25 in., and N = 40 spm.

Solution :

(a) CMC needed = (350/1000) x 2.0 x 1000 = 700 lb
(b) Recalling the Eq.(3.32) For a duplex double acting system mud pumps.

$$q = 0.00679\, S\, N\, (2\, D^2 - d^2)e = V_m /\ t_c$$

Where q = pump discharge rate, gal/min
S = stroke length, in. N = complete strokes per minute
D = piston (liner) diameter, in.
d = piston rod diameter, in.
e = pump volume efficiency, commonly used as 90%
V_m = system volume, bbl
t_c = cycle time, min

$$tc = \frac{6190V_m}{SN(2D^2 - d^2)e}$$

$$= \frac{(6190)(1000)}{(16)(40)[((2)(7.5)^2 - (2.25)^2)](0.90)} = 100\,\text{min}$$

If 20 sacks of material were needed, they could be added at the rate of 20/100 = 1/5 (one sack/five min.)

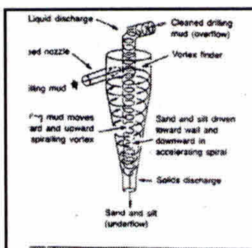
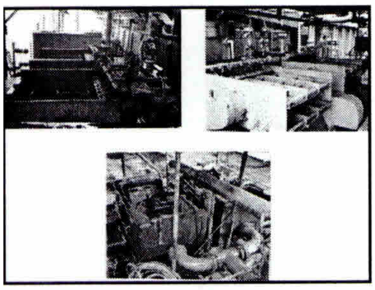
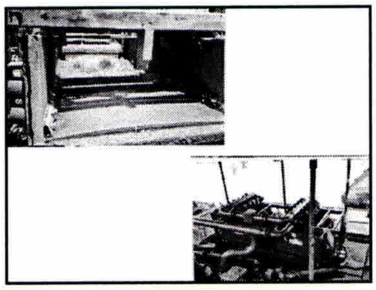
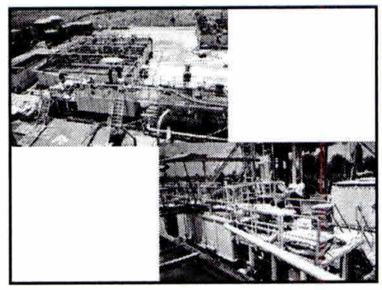
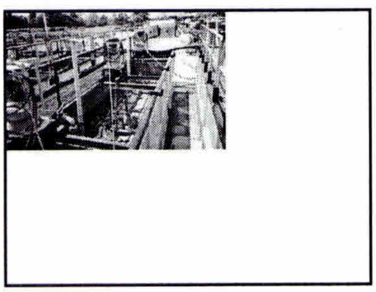


Figure 3-58
cyclone (Courtesy of SWECO)









1.7 Well Control System

Function:

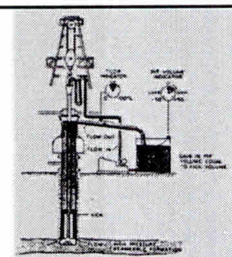
Prevents the uncontrolled flow of formation fluids from the wellbore.

Kick:

Flow of formation fluids in the presence of drilling fluid (blowout).

Uses:

1. Detect the Kick
2. Close the well at the surface.
3. Circulate the well under pressure to remove formation fluids and increase density.
4. Move drillstring under pressure.
5. Divert flow away from rig personnel and equipment.



Kick Detection During Drilling Operation

Well Control System……

Kick Detection:

a. Pit volume indicator
b. Flow indicator
c. Hole fill up indicator (during tripping)
d. Count the pump strokes.

BOP (Blow Out Preventer)

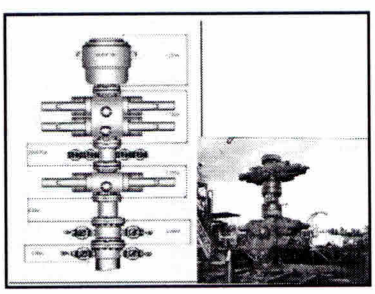
Multiple BOP'S used in series: BOP Stack

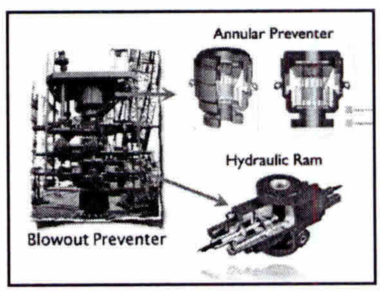
Ram Preventers / ***Pipe Rams*** — Semi circular openings which match diameter of pipe

Blind Rams : Closes the hole, no pipe present.
Shear Rams: Blind rams that shear the pipe.
Working press: 2000, 5000, 10000, 15000 psig.

Annular Preventers (Bag-type): Rubber Ring

BOPE: Closed hydraulically or using screw-type locking.



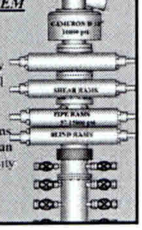


ROTARY RIG COMPONENTS

SAFETY SYSTEM

BOP (Blow Out Preventer)

A large valve at the top of a well that may be closed if the drilling crew loses control of formation fluids. By closing this valve (usually operated remotely via hydraulic actuators), the drilling crew usually regains control of the reservoir, and procedures can then be initiated to increase the mud density until it is possible to open the BOP and retain pressure control of the formation



Well Control System.....

Accumulators

High pressure hydraulic system used to close the BOP.
- Fluid Capacity : 40, 80 120 gal.
- Max. Operating Pressure : 1500-3000 psig.
- has a small pump independent of rig power.

Strip Pipe

Lower pipe with preventer closed. Must be able to vary closing pressure using pressure regulating system.

Drilling Spool

Placed between ram preventers
(1) provide space for stripping
(2) flowline attached to it.

Well Control System.....

Kill Line

conduit used to pump into the annulus.

Choke Line / ***Diverter Line*** — Conduit used to release fluid from the annulus.

Drilling Spools

Must be large enough to allow next casing to be put in place without removing the BOP.

Casing Head (Braden Head)

Attached to BOP, welded to the first string of casing cemented in the well.

Control Panel

To operate the BOP stack. RSRRS

Well Control System.....

Rotating Head

Seals around the kelly at top of BOP stack, used for drilling with slight surface pressure at annulus.

Kelly Cock

Close the flow inside kelly.

Internal Blowout Preventers

Prevents flow inside drill string.

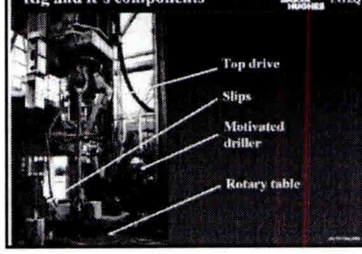
Adjustable Choke

Used during Kick circulation, controlled from a remote panel on the rig floor.

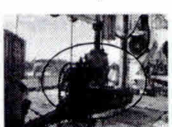
Sufficient pressure must be held against the well by the choke so that the bottomhole pressure in the well is maintained slightly above the formation pressure.

- Working Press Systems: 2000,3000,5000,10000,15000 psig.

Rig and it's components

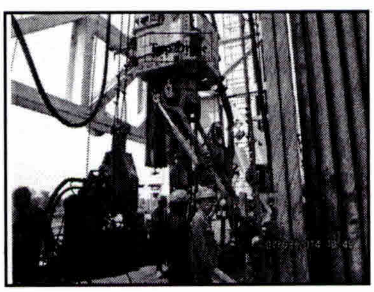


Rotary Table and Top Drive



Automatic Tong

Top Drive



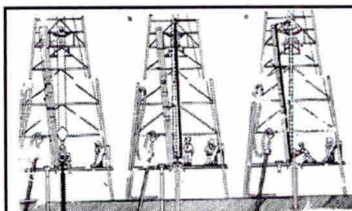


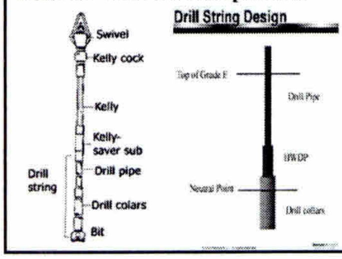
Fig. 1.8

Round trip

a. Latching the elevator, b. Pulling out a stand [illegible], c. Stacking the stand on the setback

(Source: A primer of [illegible], Petex).

Drillstem and Its Components



The drill string services several general purposes, including the following:

1. - provide a fluid conduit from the rig to the bit
2. - impart rotary motion to the drill bit
3. - allow weight to be set on the bit
4. - lower and raise the bit in the well

In addition, the drill string may serve some of the following specialized services:

1. - provide some stability to the bottom-hole assembly to minimize vibration and bit jumping
2. - allow formation fluid and pressure testing through the drill string.
3. - Permit through-pipe formation evaluation when logging tools cannot be run in the open hole

The BHA may contain the following item

1. - Key seat wipers
2. - drill collars (several type and sizes)
3. - stabilizers
4. - jars - Pumpersub (Jar going doen)
5. - reamers
6. - shock subs
7. - bit, bit sub

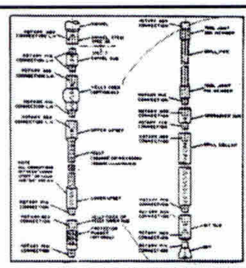


Fig. 3.19 Typical Drill String Assembly

Drill String Design

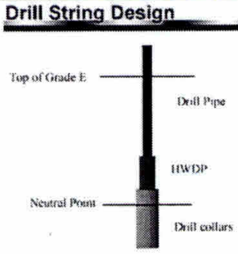
- Common grades of drill pipe with yield strength

Grade	Minimum Yield psi (MPa)	Maximum Yield psi (MPa)	Tensile Strength psi (MPa)
E	75,000 (517)	105,000 (724)	85,000 (586)
X	95,000 (655)	125,000 (862)	105,000 (724)
G	105,000 (724)	135,000 (931)	115,000 (793)
S	135,000 (931)	165,000 (1138)	145,000 (1000)

Drill String Design

- The API recognizes four classes of drill pipe
  - New
  - Premium Class
  - Class 2
  - Class 3
- Pipe is rarely considered new
- If it has been run in the hole, it is considered premium class

Drill String Design



Drill String Design

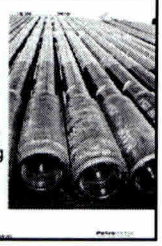
- Drill pipe is usually designed with a design factor plus overpull
- A normal design factor is 1.10 or 10%
- Overpull can range from 50,000 to 100,000 lbs (22,241 – 44,482 daN)

Drill String Design

- Many operators will place approximately 6 joints of HWDP on top of the drill collars as a transition to the drill pipe
- It may help reduce drill pipe failures at the top of the drill collars

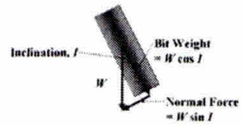
Drill String Design

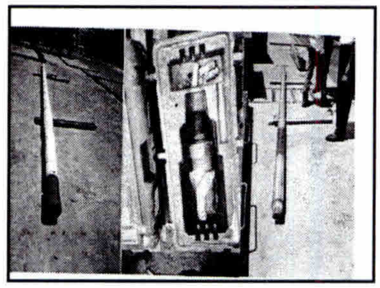
- Most of the drill collars are often replaced by hevi-wate drill pipe (HWDP).
  - Helps reduce torque and drag by reducing string weight
  - Fewer drill collar connection failures



Drill String Design

- In directional wells, the pipe weight available for bit weight is a function of the inclination





Drill pipe is available in several sizes and weights. Common sizes include the following :

3 1/2 in -13.3 lb./ft nominal
4 1/2 in -13.3 lb./ft nominal
5 in -13.3 lb./ft nominal

Various types of tool joints may increase the average weight per foot, i.e., 16.60 – 18.60 lb./ft. pipe. However, it is still termed as 16.60 lb./ft. pipe.

The grade of drill pipe describes the minimum yield strength of the pipe. This value is important because it is used in burst, collapse, and tension calculations. Common grades are as follows :

3.8.2 Drill Pipe Grades

	Grade		
	Letter Designation	Alternate Designation	Yield Strength psi(kPa)
1.	D	D-55	55,000 (379 000)
2.	E	E-75	75,000 (517 000)
3.	X	X-95	95,000 (655 000)
4.	G	G-105	105,000 (724 000)
5.	S	S-135	135,000 (391 000)

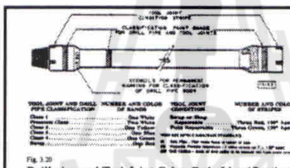


Fig. 3.20

Drill pipe and Tool Joint Color Code Identifications

Drill pipe is available in several length range :

Range	Length,	ft.(m)
1	18-22	(5.49-6.71)
2	27-30	(3.23-9.14)
3	38-40	(11.58-12.19)

Drill String Design

- Premium class assumes that there is 80% wall thickness remaining on the tube and that the reduction in wall thickness comes from the outside diameter of the tube
  - Class 2 has at least 70% of the wall thickness remaining with the loss on the OD
  - Class 2 is seldom used for drilling except small rigs with limited hook load capability
  - Class 3 is less than 70% wall thickness remaining and is considered junk

Drill pipe is available in several length rang

Range	Length, ft.(m)	
1	18-22	(5.49-6.71)
2	27-30	(3.23-9.14)
3	38-40	(11.58-12.19)

Drill Collar Selection; The drill collars;**Buoyancy Factor Method**

The wide use buoyancy factor is calculated from Eq.

(3.20) $$BF = 1 - \frac{MW}{65.5}$$

Where : BF - buoyancy factor, dimensionless
MW - mud weight, lb./gal.
65.5 - weight of a gallon steel, lb./gal.

The available bit weight/force/(ABW) with the buoyancy factor
= Weight (CW)x(BF)x(SF)

The required collar length to achieve an arbitrary ABW can be calculated follows :

$$L_C = \frac{ABW}{(\cos\alpha)(SF)(BF)(CW)} \quad (3.21)$$

where : ABW - desired available bit weight/force, lb.(daN)
BF - buoyancy factor, dimensionless
CM - collar weight (in-air), lb./ft.(kg/m)
α - hole angle from vertical
SF - safety factor, 0.85 %

Operators usually run 10-15 % more collars than ABW would indicate. This gives a safety margin and keeps the buoyancy neutral point within the collars when unforeseen forces (bounce, h

Collar Length Calculaton

Use the following data to calculate the length of drill collars requ for the desired bit weight/force.

Desired Bit Weight/Force : 35,000 lb
Mud Weight : 9.6 lb./gal
Drill Collars : OD 6 1/4 in.,ID 2 13/16 in.
Weight 83 lb./ft
Safety Factor : 0.85

$$BF = 1 - \frac{MW}{65.5} = 1 - \frac{9.6}{65.5}$$
$$= 0.8534$$

$$Length = \frac{ABW}{(SF)(BF)(CW)} = \frac{35000}{0.85(0.8534)(83)}$$
$$= 581 \text{ ft.}$$

Example 3.4

Use the following data to calculate the length of drill collars required for the desired bit weight/for

Desired Bit Weight/Force : 35,000 lb.(15 000 daN)

Mud Weight : 9.6 lb./gal.(1 150 kg/m3)

Drill Collars : OD 6 1/4 in. (158.8 mm)

ID 2 13/16 in. (71.4 mm)

Weight 83 lb./ft.(123.5 kg/m)

Safety Factor : 0.85

$$BF = 1 - \frac{MW}{65.5}$$

$$BF = 1 - \frac{9.6}{65.5} = 0.8534$$

$$Length = \frac{ABW}{(SF)(BF)(CW)}$$

$$= \frac{35000}{(0.85)(0.8534)(83)}$$

$$= \mathbf{581\ ft.}$$

A safety factor of 0.85 to 0.90 of the corrected bit force should be used to neutral point remains in the drill collars.

3.8.5 Drill Pipe Selection

Collapse

$$P_C = \frac{L W_g}{19.251} = 0.052\ L * MW \quad (3.22)$$

Where : P_C = net collapse pressure, psi

L = depth of which PC acts, ft.

W_g = weight of the drilling fluid, lb./gal.

19.251 = a constant

Using the API tables to calculate allowable collapse pressure :

$$P_{ac} = \frac{P_p}{SF} \quad (3.23)$$

Where

P_{ac} = allowable collapse pressure, psi

P_p = theoretical collapse pressure from API tables (tables for proper class of pipe must be used, API RP7G)

SF = safety factor (1.1 - 1.3)

The formulas used are in accordance with the API Bulletin R

P = [(Ldp x Wdp) + (Lhdp x Whdp) + (Ldc x Wdc)] BF

Where

P = submerged load hanging below this section of drill pipe,

Ldp = length of drill pipe, ft.

Lhdp = length of heavyweight drill pipe, ft.

Ldc = length of drill collars, ft.

Wdp = approximate weight per foot of drill pipe assembly (includes tooljoint weight)

Whdp = weight per foot of heavyweight drill pipe, ft

Wdc = weight per foot of drill collars in air

BF = buoyancy factor

Tension Load Safety Factor

$$Pa = Pt \times 0.9 \quad (3.25)$$

Where

Pa = maximum allowable design tension load, lb.

Pt = theoretical tension load from API table, lb.

0.9 = a safety factor relating proportional limit to yield strength.

Overpull

A minimum overpull factor is applied to tension load. The factor was originated to ensure the driller could safe pull a certain load on the pipe in the event of sticking. A typical rang for the overpull value is 50,000-100,000 lb.

The term Margin of Overpull is used to represent the difference between the calculated load (P) and the maximum allowable design tension load (P_a)

$$M.O.P. = P_a - P \quad (3.26)$$

A design safety factor may be calculated as the ratio of the maximum allowable design tension load to the calculated tension load.

$$\text{Safety Factor (SF)} = \frac{P_a}{P} \quad (3.27)$$

3.8.6 Drill Pipe Length Requirements

Depending upon the design criteria the length of drill pipe used for a particular grade of pipe can be calculated as :

$$Ldp1 = \frac{P_t \times 0.90}{SF \times W_{dp1} \times BF} - \frac{(L_{hdp} \times W_{hdp}) + (L_{dc} \times W_{dc})}{W_{dp1}}$$

$$Ldp1 = \frac{P_t \times (0.90 - MOP)}{SF \times W_{dp1} \times BF} - \frac{(L_{hdp} \times W_{hdp}) + (L_{dc} \times W_{dc})}{W_{dp1}}$$

For a second grade of drill pipe :

$$Ldp2 = \frac{P_t \times 0.90}{SF \times W_{dp2} \times BF} - \frac{(L_{dp1} \times W_{dp1}) + (L_{hdp} \times W_{hdp}) + (L_{dc} \times W_{dc})}{W_{dp2}}$$

If more than one size or grade of drill pipe is to be used (ie. Tapered string) then the drill pipe with the lowest load capacity should be placed immediately above the drill collars.

Example 3.5

Give the following data : Total Depth : 12,795 ft.

Hole Deviation : 0o Hole Size : 9 5/8 in.

Margin of Overpull : 50,000 lbs. Mud Weight : 13 lb./gal

Drill Collars : 7 x 2 13/16 in., 5 in., 49.3 lb./ft.

Heavy Weight Drill Pipe : 552 ft., 5 in., 49.3 lb/ft

Average stand length 92 ft.

Drill Pipe 1) 5 in., Nominal Weight – 19.5 lb./ft., Approx. Weight – 20.9 lb/ft., Grade E, Class 2

Tooljoint – NC50 (XH), 6 3/8 OD, 3 3/4 ID

Tensile Strength 311,540 lbs.

2) 5 in., Nominal Weight – 19.5 lb./ft., Approx. Weight – 21.9 lb/ft., Grade G, New Pipe,

Tooljoint – NC50 (XH), 6 1/2 OD, 3 1/4 ID

Tensile Strength 553,830 lbs.

Example 3.5

Give the following data : Total Depth : 12,795 ft.

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Tensile Strength 311,540 lbs.

2) 5 in., Nominal Weight – 19.5 lb./ft., Approx. Weight – 21.9 lb/ft., Grade G, New Pipe,

Tooljoint – NC50 (XH), 6 1/2 OD, 3 1/4 ID

Tensile Strength 553,830 lbs.

Tensile Safety Factor : 1.3

Collapse Safety Factor : 1.125

Collapse Pressure for 5 in. (127 mm), Grade E, Class 2 drill pipe : 4,760 psi

Collapse Pressure for 5 in.(127 mm), Grade G, new drill pipe : 12,990 psi

Maximum Weight on Bit : 55,000 lb.

Weight on Bit Safety Factor : 0.85

Determine :

1. The length of drill collars required and the total air weight.
2. The length of 5 in. Grade E drill pipe that can be used.
3. The length of 5 in. Grade G drill pipe required.
4. The allowable collapse pressure for the 5 in. Grade E drill pipe.
5. The net collapse pressure for the 5 in. Grade E drill pipe.
6. The tension safety factors of the new drill string design.

Solution

1. Drill Collar length

$$BF = 1 - \frac{MW}{65.5} = 1 - \frac{13}{65.5} = 0.8015$$

= 0.8015

$$\text{Drill Collar length} = \frac{ABW}{(\cos\alpha)(SF)(BF)(CW)}$$

$$= \frac{55{,}000\ \text{lbs}}{1(0.85)(0.8015)(110\ \text{lb/ft})} = 734\ \text{ft.}$$

Air weight=734 ft. x 110 lb./ft.= 80,740 lbs.

2. Length of 5 in., 19.5 lb./ft., Approx. Wt. 20.9 lb./ft., Grade E drill pipe.

$$L_{dp1} = \frac{P_t \times 0.90}{SF \times W_{dp1} \times BF} - \frac{(L_{hdp} \times W_{hdp}) + (L_{dc} \times W_{dc})}{W_{dp1}}$$

$$= \frac{311{,}540\ \text{lbs} \times 0.90}{(1.3)(20.9\ \text{lb/ft})(0.8015)} - \frac{(110\ \text{lb/ft} \times 734\ \text{ft}) + (49.3\ \text{lb/ft} \times 552\ \text{ft})}{20.9\ \text{lb/ft}}$$

= 12,875 ft. – 5,165 ft.

= 7,710 ft.

The air weight of the grade E drill pipe, heavy weight pipe and drill collars.

$= (L_{dp1} \times W_{dp1}) + (L_{hdp} \times W_{hdp}) + (L_c \times W_c)$

= (7,710 ft. x 20.9 lb./ft) + (552 ft. x 49.3 lb./ft.) +(734 ft. x 110 lb./ft.)

= 269,093 lbs.

3. Length of 5 in., 19.5 lb./ft., Approx. Wt. 21.9 lb./ft., Grade G drill pipe

$$Ldp2 = \frac{P_t \times 0.90}{SF \times W_{dp2} \times BF} - \frac{(L_{dp1} \times W_{dp1}) + (L_{hdp} \times W_{hdp}) + (L_{dc} \times W_{dc})}{W_{dp2}}$$

$$= \frac{553{,}830\ \text{lbs} \times 0.90}{(1.3)(21.9\ \text{lb/ft})(0.8015)} - \frac{269{,}092\ \text{lbs}}{21.9\ \text{lb/ft}}$$

= 21,843 – 12,287

= 9,556 ft.

There is more drill pipe than required to reach 12,795 ft., so final drill string will consist of the following :

ITEM	LENGTH	BUOYED WEIGHT
Drill Collars	734 ft.	64,713 lbs.
Heavy Weight Drill Pipe	552 ft.	21,812 lbs.
Grade E Class 2 Drill Pipe	7,710 ft.	129, 153 lbs.
Grade G New Drill Pipe	3,799 ft.	66,683 lbs.
TOTALS	12,795 ft.	282,361 lbs.

4. **Allowable collapse pressure for the 5 in., 19.5 lb/ft.,**

$$P_{ac} = \frac{P_p}{SF} = \frac{4760\ \text{PSI}}{1.125} = 4231\ \text{PSI}$$

5. Net collapse pressure

$$Pc = \frac{LW_g}{19.251} = \frac{12{,}795\ \text{ft} \times 13}{19.251} = 8640\ \text{PSI}$$

$$L\max = \frac{P_{ac} \times 19.251}{W_g(SF)} = \frac{4231\ PSI \times 19.251}{13\ lb/gal \times 1.25} = 5{,}569\ \text{ft.}$$

Therefore this drill pipe has a lower collapse pressure than may be encountered in drilling to 12,795 ft. Precautions should be taken to prevent damage to the drill pipe when running the string below 5,569 ft.

6. Tension safety Factor

$$\text{Grade E} = \frac{P_t \times 0.9}{\text{Buoyed Hook Load - D}p_2\ \text{Hool Load}}$$

$$= \frac{311{,}540\ \text{lb} \times 0.9}{215{,}678} = 1.3 = 1.3$$

$$\textbf{Grade G} = \frac{P_t \times 0.9}{\textit{Buoyed Hook Load}} = \frac{553{,}830\ \text{lb} \times 0.9}{282{,}361}$$

= 1.96

3.8.7 Critical Rotation Speeds

Two types of vibration may occur. The pipe between each tool joint may vibrate in nodes, as a violin string. This critical speed may be predicted by the formula :

$$RPM = \frac{4{,}760{,}000}{l^2}(D^2 + d^2)^{0.5}$$

Where

RPM	=	nodal critical speed, revolutions per minute
l	=	length of one pipe, inches
D	=	outside diameter of pipe, inches
d	=	inside diameter of pipe, inches
4,760,000	=	a constant

The critical rotary speed predicted by this formula is probably calculated by this formula should be avoided by plus or minus 15 %

The second type vibration is of the spring pendulum type, and may be approximately predicted by the following formula :

$$RPM = \frac{258{,}000}{L} \quad (3.34)$$

Where

RPM	=	pendulum critical speed, revolution per minute
L	=	total length of string, ft.
258,000	=	a constant

Example 3.6

Given the following data :

TVD : 2789 ft.

Drill Pipe : 3.5 in. , 13.3 lb./ft. ID 2.764 in., joint length 31 ft.

Drill Collars : 6 in. x 2 13/16 in.

Drill Collars length : 551 ft.

Determine :

1. Nodal critical rotational speed.
2. Pendulum critical rotational speed

1. Nodal critical speed.

$$RPM = \frac{4{,}760{,}000}{l^2}(D^2 + d^2)^{0.5}$$

$$= \frac{4{,}760{,}000((3.5)^2 + (2.764)^2)^{0.5}}{(31 \times 12)^2} = 154$$

2. Pendulum critical speed.

$$\textbf{RPM} = \frac{258{,}000}{L} = \frac{258{,}000}{2789} = 93$$

3.8.8 Drill string Stretch

Combined effect of string weight and buoyancy.

$$e_s = \frac{L^2(65.44 - 1.44W_g)}{9.625 \times 10^7} \quad (3.35)$$

where :	e_s	=	stretch, inches
	L	=	length of string, feet
	W_g	=	weight of fluid, lb/gal

Effects of temperature

$$e_t = L\,(7.867 \times 10^{-5}) \times (F-32) \quad (3.36)$$

where :	e_t	=	stretch, due to temperature
	F	=	average temperature, degrees F
	L	=	length of drill string, feet

$$e_{Tot} = e_s + e_t \quad (3.37)$$

Allowable Toque & Pull on A.P.I Drillpipe

Max. allowable Torque/pull ≤ 85 % Min Yield Str

$$Q_T = 0.096167 * J \sqrt{(Y_m * 0.85)^2 - \frac{P^2}{A^2}}$$

Where

Q_T = min. torsional yield strength under tension (1b-ft)

J = Polar moment of Inertia $= \frac{\pi}{32}(D^4 - d^4)$ in⁴

D = O.D. of pipe ; d = I.D. in

Y_m = Min. Yield Stress (psi)

P = Total tensile load (lb)

A = Cross Sectional Area (in2)

Torsion

The torsion strength of drill pipe becomes critical when drilling deviated holes, deep holes, reaming, or when pipe is stuck. The actual torque applied to the pipe during drilling is difficult to measure but may be approximated by the following equation.

$$T = \frac{HP \times 5250}{RPM}$$

Where

T = torque delivered to drill pipe, ft./lb.

HP = horsepower used to produce rotation o pipe

RPM = revolutions per minute

5250 = a constant

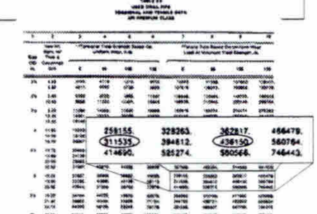
Drill String Design

- The equation for calculating the maximum allowable torque based on tension is as follows:

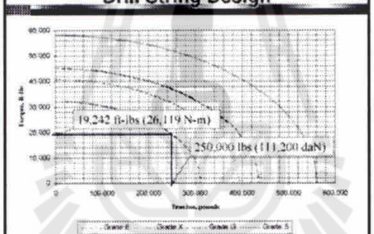
- $$Q_T = \left(\frac{0.096167J}{D_{pw}}\right)\left[Y_p^2 - \frac{T^2}{A_s^2}\right]^{0.5}$$ English

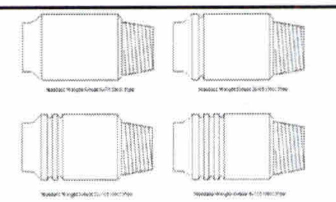
- $$Q_T = \left(\frac{1.1536 \times 10^{-6} J}{D_{pw}}\right)\left[Y_p^2 - \frac{(9800T)^2}{A_s^2}\right]^{0.5}$$ SI

Drill String Design



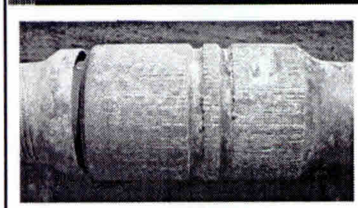
Drill String Design





Mill slot and groove method of drill string identification

Drill String Design



Mill slot and groove method of drill string identification

BIT TYPES

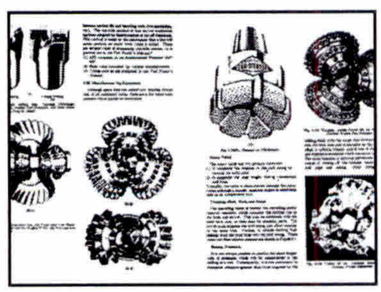
1.Drag Bit
- มีทนดเสใบมีดหมุนตัดชั้นหิน
- ใช้เฉพาะ Soft Formation
- เจาะได้ดีเมื่อ HHP → max.
- WOB → LOW RPM → HIGH

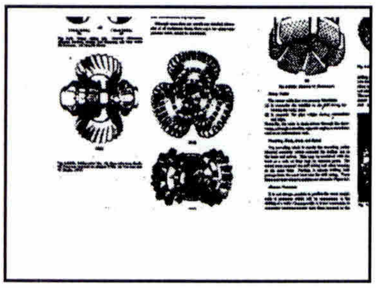
2.Roller Cutter Bit เริ่ม คศ 1909
- 2 cones, 3 cones, 4 cones นิยม 3 cones
- Milled teeth, Tungsten Carbide Insert

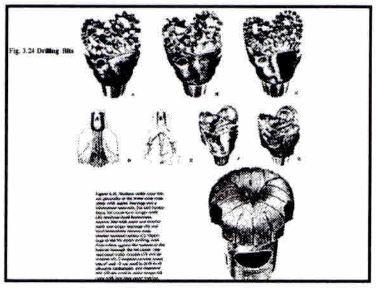
3.DIAMOND BIT
- Real Diamond
- PDC (Poly Crystalline Diamond Compact)
- TSP (Thermally Stable Poly Crystalline)

BIT DESIGN

ออกแบบให้เกิด Max. Action ใน
- Gouging/ Scraping Soft Formation
- Chipping / Crushing Hard Formation
  Journal Angle + offset

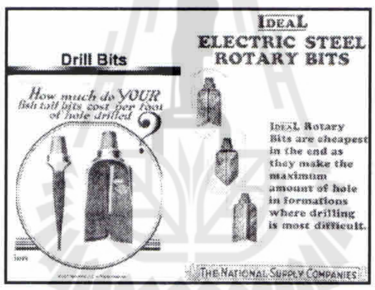


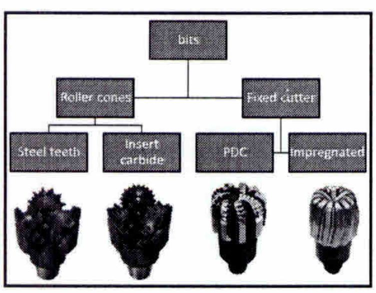


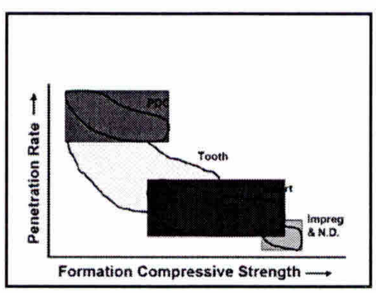


- Drill bits come in a wide variety of types
  - ➢Roller cone bits
    - Steel tooth
    - Tungsten carbide insert (TCI)
  - ➢Drag bits
    - PDC or polycrystalline diamond compact
    - Natural or synthetic diamond (TSP)

- History of bits
  - ➢Original rotary bits were drag bits often call fishtail bits
  - ➢They looked similar to a fish tail
  - ➢Drilled soft formations by gouging and tearing



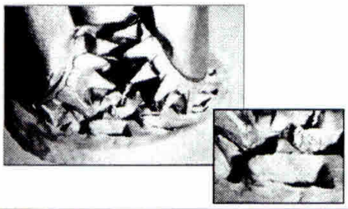




Cutting action

- Soft Formation : Gouging-Scraping
  - Most Aggressive Cutting Action
  - Typically high ROP applications
- Hard Formation : Chipping-Crushing
  - Most Durable Cutting Action
  - Typically low ROP applications

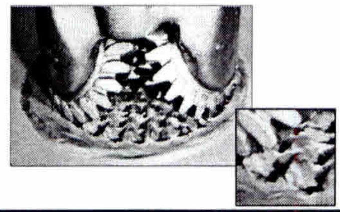
Gouging-Scraping Example



Gouging-Scraping

- Like.....using a shovel in the garden

Chipping-Crushing Example

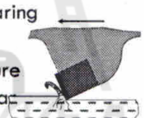


Chipping-Crushing

- Like.....using a hammer and chisel

PDC Mechanics

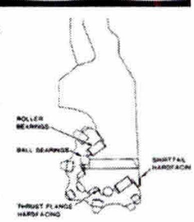
- PDC Bits drill by shearing the rock
- Rocks typically fracture more **easily** with shear loading (less energy, WOB)
- Most efficient cutting action



Polycrystalline Diamond Compact

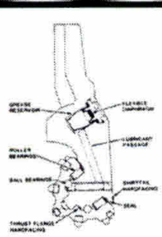
Drill Bits

- Had roller bearings in the cones
- No seal in the bearings and used mud as lubricant
- Solids in the mud caused rapid bearing failure
- Most bearings lasted less than 24 hours

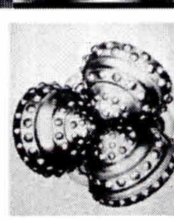


Drill Bits

- **To improve the bit life in soft formations, a seal was added to the bearing**
  - Kept mud out of the bearing until the seal failed
  - Then bit life was longer



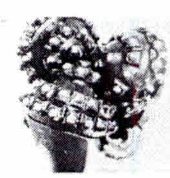
Drill Bits



- As drilling into deeper harder formations expanded, the cutting structure needed improvement
- Hughes introduced the "Chert Bit" in 1949 to drill hard formations

Drill Bits

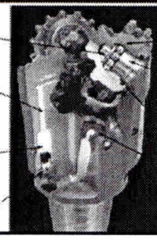
- In the late 1950's, Smith developed the TC-6 bit with longer inserts for drilling softer formations
- With insert bits, the cutting structure could far outlast the bearings as proved in air drilling operations



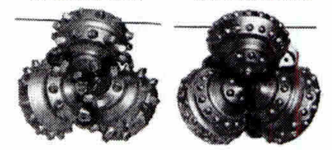
Drill Bits

- **Friction bearing**
  - Because the insert cutting structure lasted much longer, they had to come up with a bearing that would last much longer
  - The friction bearing was developed
  - With the friction bearing, bit life was extended to around 100 hours under normal conditions

Drill Bits

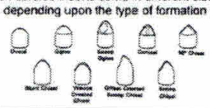


Drill Bits



Drill Bits

- Tungsten carbide inserts come in different sizes and shapes depending upon the type of formation they drill

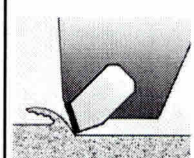


Tooth Shape	Cutting Action	Formation
Ovoid	Chip, crush	Very hard
Ogive	Chip, crush	Hard to very soft
Conical	Chip, crush, gouge and scrape	Medium hard to hard
Chisel	Gouge, scrape	Medium to soft
Scoop Chisel	Gouge, scrape & lift	Medium to soft

Drill Bits

- Roller cone bits come in many different styles and shapes
- The IADC code is one system used in order to identify bits

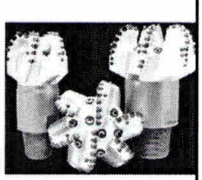
Drill Bits



- The PDC cutter drills by shearing action
- The PDC is self sharpening because the tungsten wears faster than the diamond

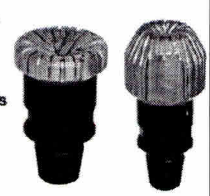
Drill Bits

- **Steel body bits**
  - The body is made from a machined piece of steel
  - In this bit, the PDC cutter is attached to a tungsten stud and pressed into the body similar to an insert bit

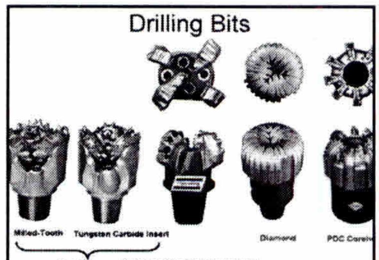


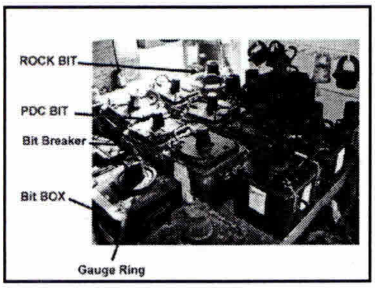
Drill Bits

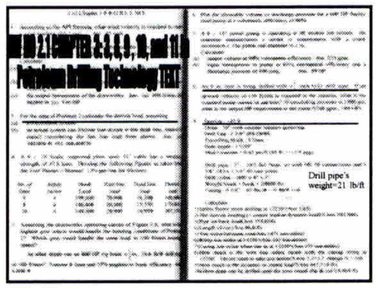
- For diamond or TSP bits, 1 would be a flat profile and 2, 3, and 4 represents an increasing taper

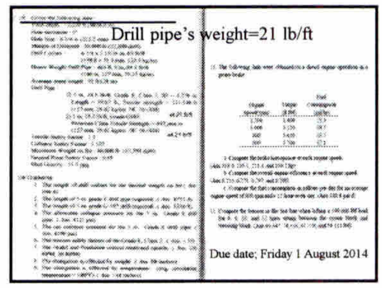


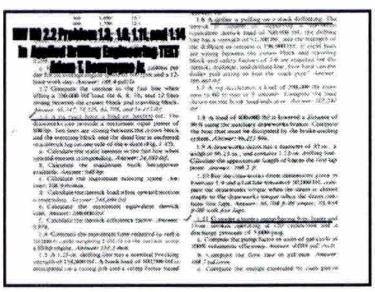
Drilling Bits

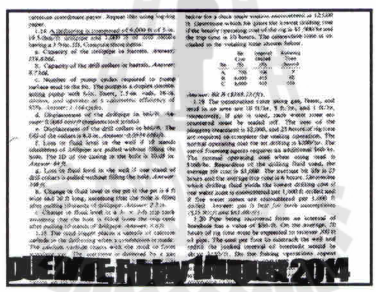


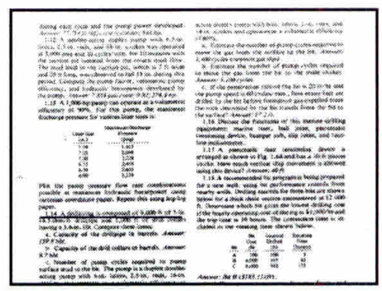

ROCK BIT
PDC BIT
Bit Breaker
Bit BOX
Gauge Ring


Drill pipe's weight=21 lb/ft


Drill pipe's weight=21 lb/ft
Due date; Friday 1 August 2014




DUE DATE: Friday 1 August 2014



ADVANCED DRILLING ENGINEERING 1/2557((2014)

Chapter3 Well Planning and Proposal (3 hrs.)

By
Kriangkrai Trisarn

ADVANCED DRILLING ENGINEERING

CHAPTER 3

WELL PLANNING

OBJECTIVES :

- Anticipate drilling operating Problems.
- Identify parameters effecting rate of progress.
- Identify zones of potential well control problems.
- Identify solutions to the concerns

SAFE

MINIMUM COST

USABLE

Solution to constraints

PLANNING

Proper planning is key to optimizing operations and minimizing expenditures

Classification of Well Types

- The drilling engineer is required to plan a variety of well types, including the following:

- Wildcats
- exploratory holes
- step-outs(appraisal)
- Infills
- reentries

The flow chart how to do well planning since the beginning up to the project approval is shown in Fig. 11.3

Figure 11.3 PLANNING A WELL : Flow path

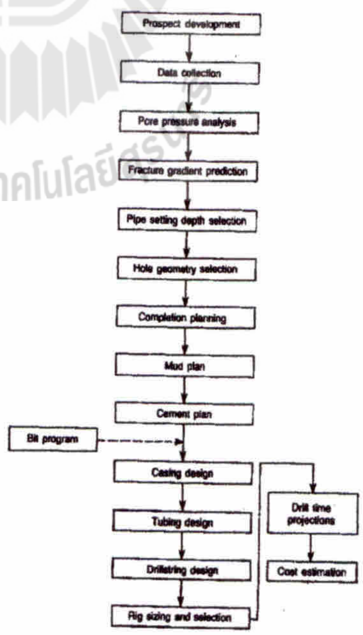


Fig. 1-2 Flow path for well planning

KEY PARAMETERS

WELL TYPES

FORMATION PRESSURE

PLANNING COSTS

Data cost 0.5-1% of well cost

PLANNING A WELL

Three traits(quality) well planner ……………must have

1. SKILLS
2. KNOWLEDGE
3. EXPERIENCE

Engineers, geologists, geophysicists, accountants and other corporate professionals. This integration of professional is often referred to as a **DRILLING TEAM**

Data Collection

The program must have three characteristics

The drilling engineer must work with the geologist to

1.Develop an understanding of the expected drilling geology

2. Define fault block structures (for Offset Well Selection)

3. Identify geological anomalies

As outlined, a major responsibility of the **Drilling Engineer** is to establish the objectives of the well. With respect to this responsibility, the **Drilling Engineer** must obtain a Geologic Prognosis similar to the one illustrated as Fig. 11.1. It is imperative that the prognosis be obtained and is normally provided on request from the Geology Department within the major oil companies.

1.Prospect Generation and Development

•The task of generating and developing a prospect is mainly the responsibility of the geologists, geophysicist and reservoir engineers.

•**Geologists + Geophysicist + Engineers**

- GEOLOGIC CROSS SECTION
- LITHOLOGIC COLUMN
- FAULTS
- STRUCTURAL MAP
- IDENTIFY GEOLOGICAL ANOMALIES
- PORE PRESSURE GRADIENT
- FRACTURE GRADIENT

PLANNING

1.PROSPECT DEVELOPMENT

- Some information is always available
- Geologic prognosis
  - The geologic prognosis contains information about the formation to be drilled
  - It should define the objectives of the well
  - It should indicate the types of logs required and whether cores and drill stem tests will be required

PLANNING

Estimated Formation Tops

Estimated Elevation, KB	2,857'	871m
Top Wichita-Albany Anhydrite	2,950'	899m
Top Wolfcamp Dolomite	4,150'	1,265m
Top Possible Lost Circulation	4,300'	1,311m
Top Douglas Sands	7,100'	2,164m
Top Granite Wash	9,950'	3,033m
Top 13 Finger Lime	10,910'	3,325m
Top Morrow Formation	11,100'	3,383m
Top Morrow Sand	11,165'	3,408m

11.2 Prospect Generation and Development

The task of generating and developing a prospect is mainly the responsibility of the geologists, geophysicist and reservoir engineers.

Geologists + Geophysicist + Engineers

GEOLOGIC CROSS SECTION
LITHOLOGIC COLUMN
FAULTS
STRUCTURAL MAP
IDENTIFY GEOLOGICAL ANOMALIES
PORE PRESSURE GRADIENT
FRACTURE GRADIENT

11.3 Data Acquisition

The engineer called upon to derive a plan for drilling a prospect is typically given only minimal data. The geological department usually supplies a location and the depth of the objective formations. Before beginning additional information must be obtained. This information comes primarily from offset wells.

BIT RECORDS : number and type, jet sizes, footage and drill rate per bit. bit weight and rotary speed, pump data, mud properties, et.

CASIND SIZE & DEPTH: includes hole problem, lost circulation zones, abnormal pressure zones, et.

MUD LOGS: includes lithology, mud and formation parameters, drill bit data, drilling rate, drilling mud gases, et.

ELECTRIC LOGS: given types of lithology, pore pressure prediction, and potential pay zone, et.

DRILLSTEM TEST: type and properties of fluids, pore and formation pressure, et.

MUD RECORDS AND RECAPS: mud properties and hole problem.

DRILLING TIME:

HOLE PROBLEM:

DRILLING RECORDS

COMPLETION REPORDS

though wildcats are currently being drilled, seismic data, as a minimum, should be available for pore pressure estimation.

Common types of data used by the drilling engineer are as follows:

2. Data Collection

DATA SOURCES

- bit records
- mud records
- mud logging records
- IADC drilling reports
- scout tickets
- log headers
- production history
- seismic studies
- well surveys
- geological contours
- databases or service company files

Each type of record contains valuable data that may not be available with other records. For example, log headers and seismic work are useful, particularly if these data are the only reference sources for the well.

Many sources of data exist in the industry. Unfortunately, some operators falsely consider the records confidential, when in fact the important information such as well testing and production data becomes public domain a short time after the well is completed. The drilling engineer often must assume the role of "detective" to define and locate the required data.

Sources of data include bit manufacturers and mud companies who regularly record pertinent relative information on well recaps. Bit and mud companies usually make this data available to the operator. Log libraries provide log

Data Sources

Common types of data used by the drilling engineer are as Follows:

2. Data Collection

* bit records
* mud records
* mud logging records
* IADC drilling reports
* scout tickets
* log headers
* production history
* seismic studies
* well surveys
* geological contours
* databases or service company files

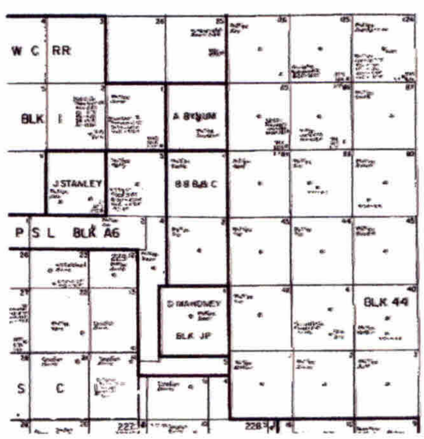
PLANNING

- **Possible Producing Zones:**

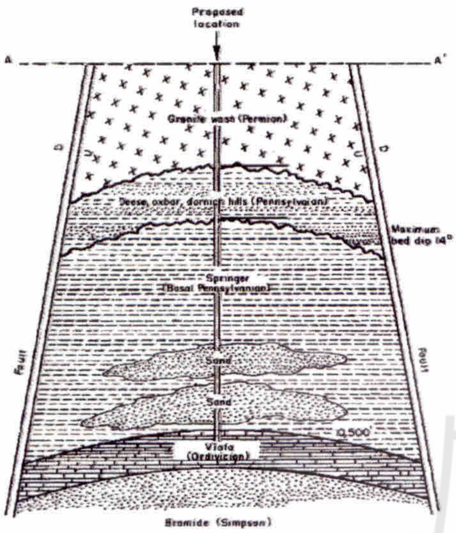
➢ Douglas Sand	7,100-7,200'	2,164-2,194m
➢ Stray Douglas Sand	7,400'	2,256m
➢ Des Moines	9,050-9,900'	2,758-2,018m
➢ Granite Wash	9,950-10,800'	3,033-3,292m
➢ Upper Morrow Sand	11,165'	3,403m

PLANNING

- **Geologic map**
  - ➢ Provides information on offset wells that can be used for a reference



PLANNING



- **Geologic maps**
  - ➢Geologic cross section and structure

11 OGCI PetroSkills

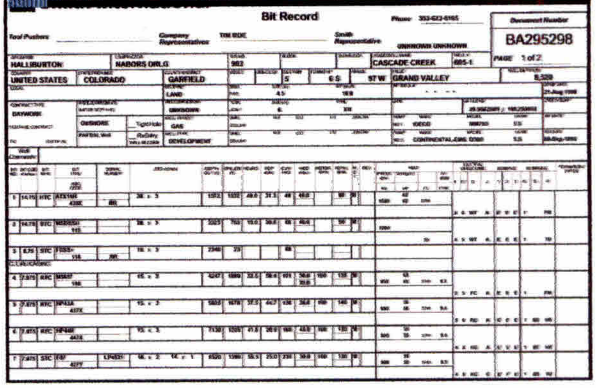
PLANNING

- **Control wells**
  - ➢Control wells should be geologically similar to the well being planned
- **Open hole logs**
  - ➢Information on formation types
  - ➢Caliper log can indicate hole stability
  - ➢Pore pressures from shale values

PLANNING

- **Bit record**
  - Information from offset bit records can show
    - Casing points
    - Mud weights
    - Deviation
    - Time to drill
    - Number of bits
    - Types of bits
    - Hydraulics

PLANNING



PLANNING

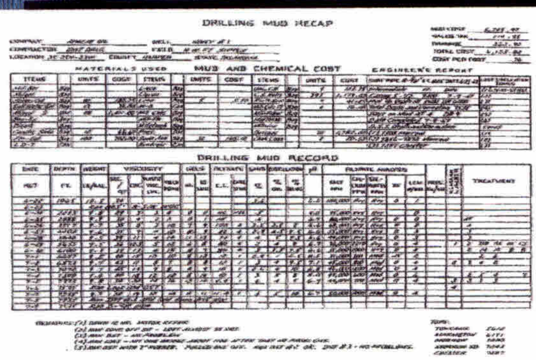
Comments:

BIT NO.	BIT SIZE (inches)	BIT MFR	BIT TYPE / IADC CODE	SERIAL NUMBER	JETS (32nds)	DEPTH OUT (ft)	DRILLED (ft)	HOURS	ROP (ft/hr)	CUM HRS	WO...
1	14.75	HTC	ATX11H 435X	RR	28. x 3	1572	1532	49.0	31.3	49	40.
2	14.75	STC	MSDSSH 115		28. x 3	2325	753	19.0	39.6	68	40.
3	8.75	STC	FDSS+ 116	RR	18. x 3	2348	23			68	
CLEAN CASING											
4	7.875	RTC	M3637 116		15. x 3	4247	1809	32.5	58.4	101	30. 35.
5	7.875	RTC	HP43A 437X		15. x 3	5925	1678	37.5	44.7	138	30.
6	7.875	RTC	HP44H 447X		15. x 3	7130	1205	41.8	28.9	180	45.
7	7.875	STC	F07 427Y	LP4531	16. x 2 14. x 1	8520	1390	55.5	25.0	235	30.

PLANNING

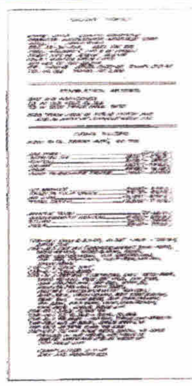
- **Drilling mud recap and proposal**
  - Recommended mud program
  - Information on offset wells
  - Time required to drill offsets
  - Hole problems
  - Mud properties

PLANNING



PLANNING

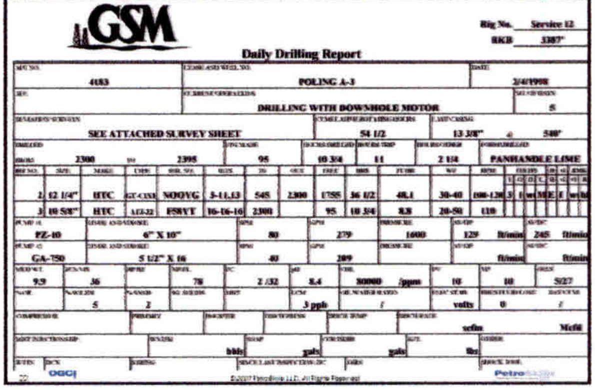
- **Scout ticket**
  - Information on productive horizons and production rates



PLANNING

- When available, daily drilling reports are the most valuable information
  - ➢They give detailed drilling information including an hourly breakdown
  - ➢They may also give descriptions of the drilling problems

PLANNING



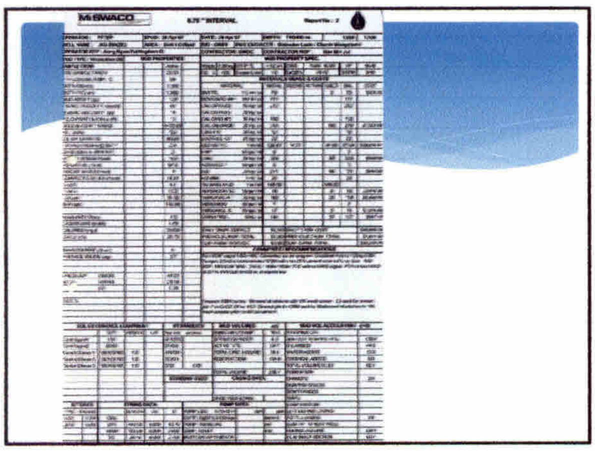
PLANNING

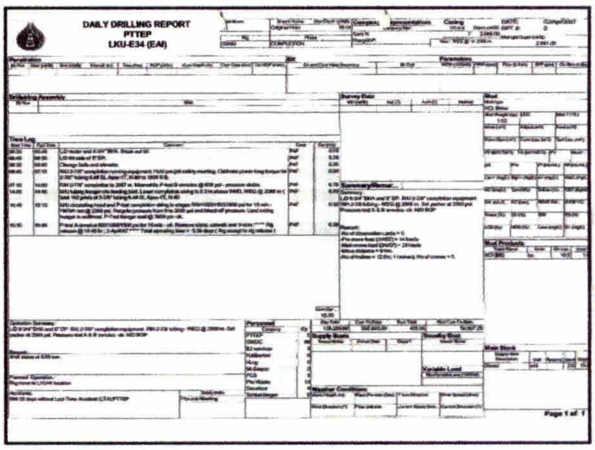
TIME	HRS	WORK DESCRIPTION
0700-0730	1/2	RUN GYRO SURVEY AND RIG DOWN SCIENTIFIC
0730-0830	1	TRIP 11 STDS FROM HOLE. DRAG 10-50,000 OVER FIRST 1000', THEN FREE
0830-1230	4	LAY DOWN 20 JOINTS OF DRILL PIPE AND BOTTOMHOLE ASSEMBLY
1230-1500	2 1/2	PICK UP MOTOR AND NON-MAGNETIC DRILL COLLARS
1500-1830	3 1/2	PICK UP 35 JOINTS OF HWDP AND TRIP IN HOLE, 35' OF FILL
1830-1930	1	RIG UP SCIENTIFIC STEERING TOOL AND WASH TO BOTTOM
1930-2100	1 1/2	DRILL WITH DOWNHOLE MOTOR FROM 2300' TO 2310', 6.7'/HR
2100-2145	3/4	WORK ON PUMPS
2145-0700	9 1/4	DRILL WITH DOWNHOLE MOTOR FROM 2310' TO 2360', 5.4'/HR

PLANNING

MUD MATERIAL USED		TIME	HRS
		0700-0730	1/2
		0730-0830	1
		0830-1230	4
		1230-1500	2 1/2
		1500-1830	3 1/2
BOTTOM HOLE ASSEMBLY		1830-1930	1
		1930-2100	1 1/2
		2100-2145	3/4
		2145-0700	9 1/4

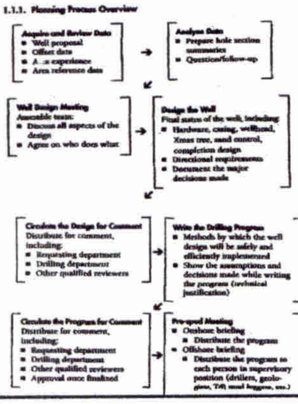
	DAY	TO DATE
MUD COST	$ 1,300	$ 5,610
TANGIBLE	$ -	$ 17,980
INTANGIBLE	$ 13,425	$ 117,822
TOTAL COST	$ 14,725	$ 141,412

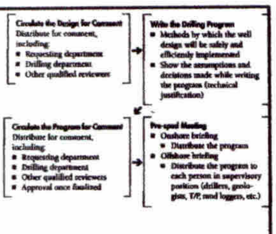




Preliminary Work for the Well Design

1.1.1. Planning Process Overview





1.1.2. Data Acquisition and Analysis

The success or failure of a well, from a drilling viewpoint, is heavily dependent on the quality of well planning prior to spud. The quality of the well planning in turn is heavily dependent on the quality and completeness of the data used in planning. The successful drilling engineer is a natural detective, snooping around for every snippet of useful data to analyze.

The starting point in your data analysis trail is the well proposal. Usually the need for drilling a well starts as a request from the exploration or production department. They will put together a package of information for drilling that will define what the well should achieve and where it should be.

Well proposal checklist. The proposal should contain the following elements as relevant to the particular well:

1. Well objectives (exploration, appraisal, development, and workover)
2. Envisaged timescale (earliest/latest spud date desired)

3. Essential well design data:
   - Precompletion and completion requirements with draft completion design
   - Preparation work required in advance of running the completion, including permanent packers, gravel packs, completion fluid specifications, etc.
   - Perforation intervals; perforation type (if known)
   - Completion or logging sump required below the bottom perf depth (e.g., bottom perf to liner wiper plug and/or bottom of zone of interest to total depth)
   - Completion profile fully defining all elements of the completion hardware with depths; tubing, packers, subsurface safety valves (SSSVs), nipples, electric submersible pumps (ESPs), etc.
   - Completion pressure testing requirements
   - Future stimulation work envisaged, including fluids pumped, pressures used during stimulations, possible gas lift, etc.
   - Temperatures and pressures anticipated during the production life of the well
   - Likely reservoir fluid composition; any H_2S or CO_2 possible?
   - Options envisaged for future well interventions, including wireline/coiled tubing work, workovers, or recompletions (e.g., on another zone once primary zone is depleted)
   - Xmas tree and completion status on handover from drilling (e.g., plugged and depressured, killed, valve configuration, etc.)
   - Type of abandonment envisaged at the end of the well's production life
   - Any other relevant information on the completion not covered above
   - Pore pressure and fracture gradients vs. depth plot (it is useful to ask for the PPFG plot to show "best" and "worst" cases)
   - Shallow gas information (e.g., from shallow seismic surveys and offset wells)
   - Geological/seismic correlation, including all possible faults that may be encountered
   - Lithology/petrophysical correlation
   - Well directional targets (show downhole constraints to justify targets)
   - Surface location including site survey and bathymetry map, if applicable
   - Required zonal isolation of reservoirs
   - Likely temperature profile with depth

Data Acquisition

The engineer called upon to derive a plan for drilling a prospect is typically given only minimal data. The geological department usually supplies a location and the depth of the objective formations. Before beginning additional information must be obtained. This information comes primarily from offset wells.

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ELECTRIC LOGS: given types of lithology, pore pressure prediction, and potential pay zone, et.

DRILLSTEM TEST: type and properties of fluids, pore and formation pressure, et.

MUD RECORDS AND RECAPS: mud properties and hole problem.

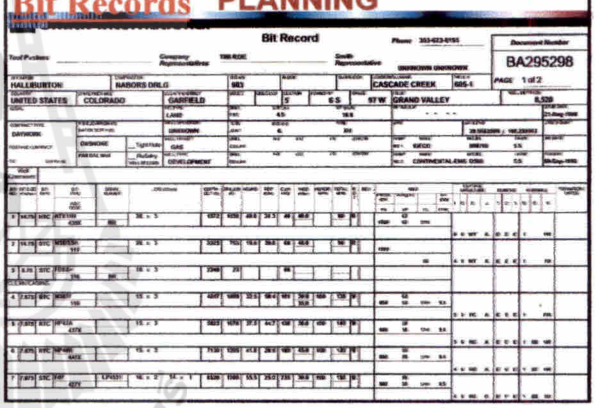
DRILLING TIME:

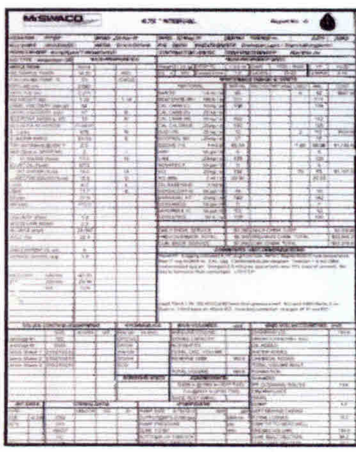
HOLE PROBLEM:

DRILLING RECORDS

COMPLETION REPORDS

Bit Records PLANNING





Mud Records

Mud Logging Records

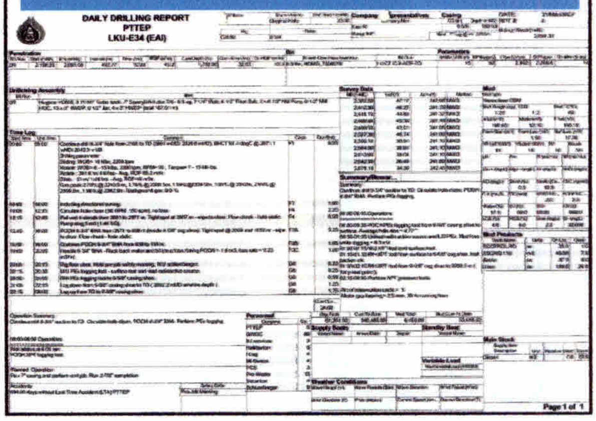
Log Headers

Production History

Seismic Studies

IADC (International Association of Drilling Contractors)

Reports(Daily drilling report)


DAILY DRILLING REPORT
PTTEP
LKU-E34 (EAI)

Page 1 of 1

PLANNING

- Once all the information is collected, it is the drilling engineers responsibility to develop a drilling plan
- Improvements in drilling practices are always possible and expected in an area

PLANNING

- Local problems and drilling conditions must be analyzed with respect to a broad, ever changing expertise in order to develop the best possible drilling program

- Be a skeptic
  - It is our responsibility as drilling engineers to question drilling practices which are inconsistent wi sound judgment or other experienc in similar areas
  - Can the well be drilled more efficiently and at a lower cost

PLANNING

- Attack general practices in view of new technology
- For real savings, attack the hazards
  - Attack the abnormal pressure problems, the deviation, the lost circulation, or the pipe sticking problems

PLANNING

- Support conclusions and recommendations with data, analysis, and calculations
- Follow up and honestly evaluate your efforts
  - ➢Report success and failures alike
  - ➢Don't place blame; find solutions

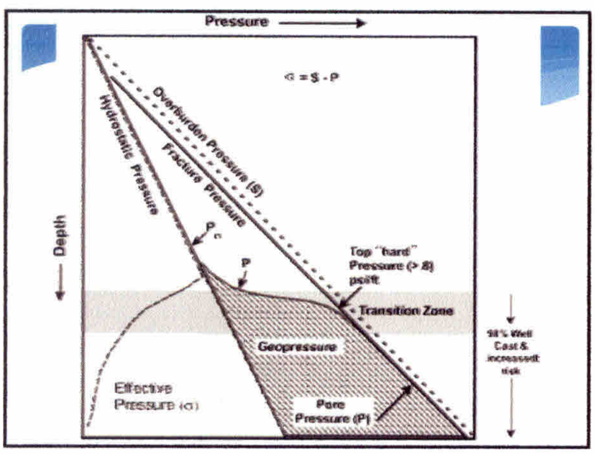
PLANNING

- The "Technical Limit" ("Drilling the Limits") is defined as the best possible well construction performance for a given set of design parameters
  - ➢The technical limit is a well design process by which drilling and completion costs are reduced

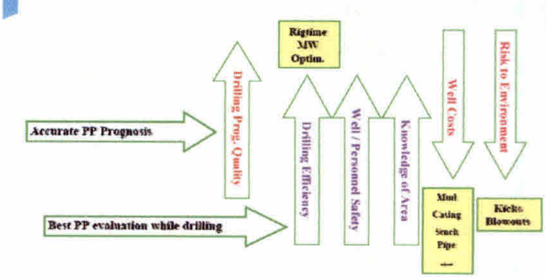
Formation Pressure Prediction

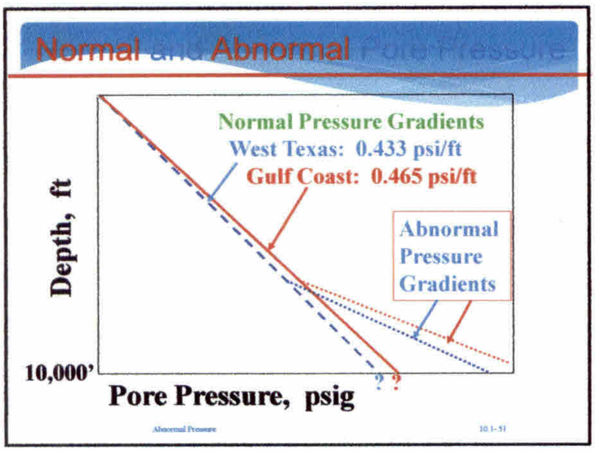
3.1 Predicting Formation Pressuress

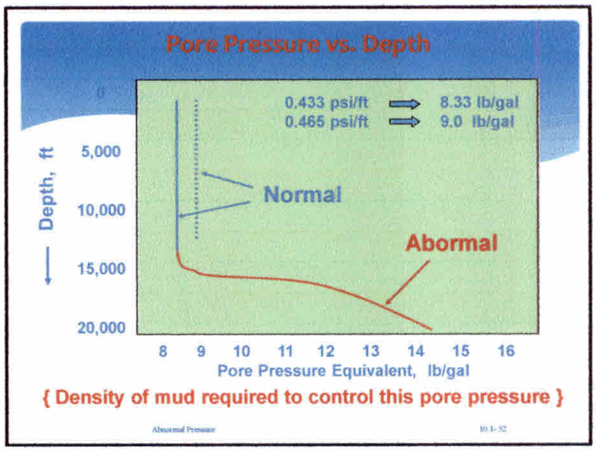
Geopressure

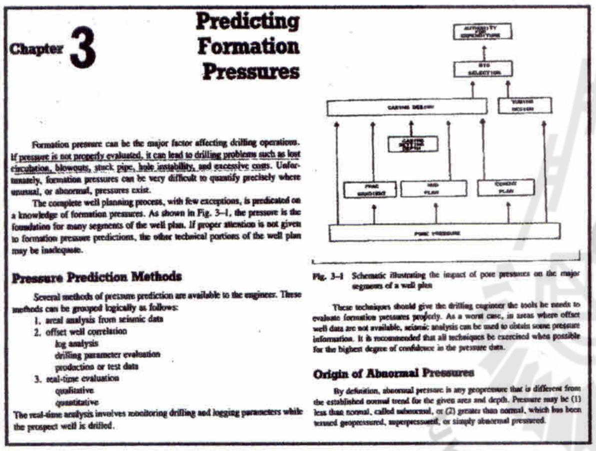


Motivations for Understanding Geo-pressures









Chapter 3

Predicting Formation Pressures

Formation pressure can be the major factor affecting drilling operations. If pressure is not properly evaluated, it can lead to drilling problems such as lost circulation, blowouts, stuck pipe, hole instability, and excessive costs. Unfortunately, formation pressures can be very difficult to quantify precisely where unusual, or abnormal, pressures exist.

The complete well planning process, with few exceptions, is predicated on a knowledge of formation pressures. As shown in Fig. 3–1, the pressure is the foundation for many segments of the well plan. If proper attention is not given to formation pressure predictions, the other technical portions of the well plan may be inadequate.

Pressure Prediction Methods

Several methods of pressure prediction are available to the engineer. These methods can be grouped logically as follows:

1. areal analysis from seismic data
2. offset well correlation
   - log analysis
   - drilling parameter evaluation
   - production or test data
3. real-time evaluation
   - qualitative
   - quantitative

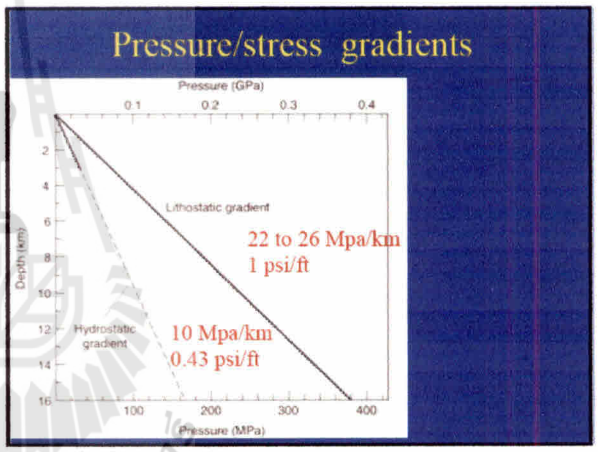
The real-time analysis involves monitoring drilling and logging parameters while the prospect well is drilled.

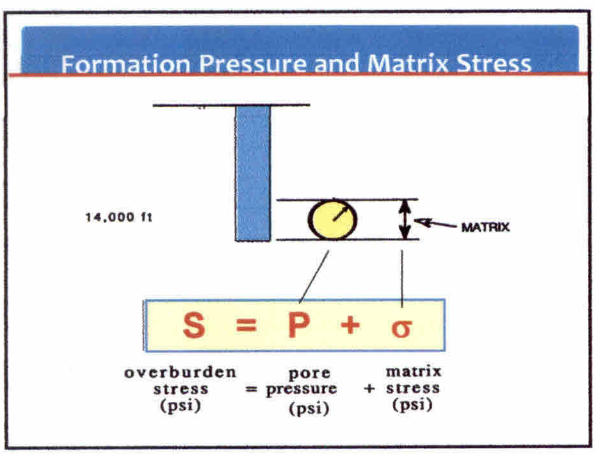
Fig. 3–1 Schematic illustrating the impact of pore pressures on the major segments of a well plan

These techniques should give the drilling engineer the tools he needs to evaluate formation pressures properly. As a worst case, in areas where offset well data are not available, seismic analysis can be used to obtain some pressure information. It is recommended that all techniques be exercised when possible for the highest degree of confidence in the pressure data.

Origin of Abnormal Pressures

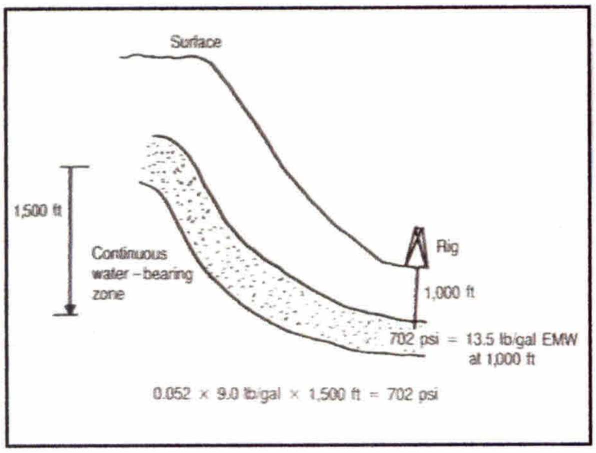
By definition, abnormal pressure is any porepressure that is different from the established normal trend for the given area and depth. Pressure may be (1) less than normal, called subnormal, or (2) greater than normal, which has been termed geopressured, superpressured, or simply abnormal pressured.

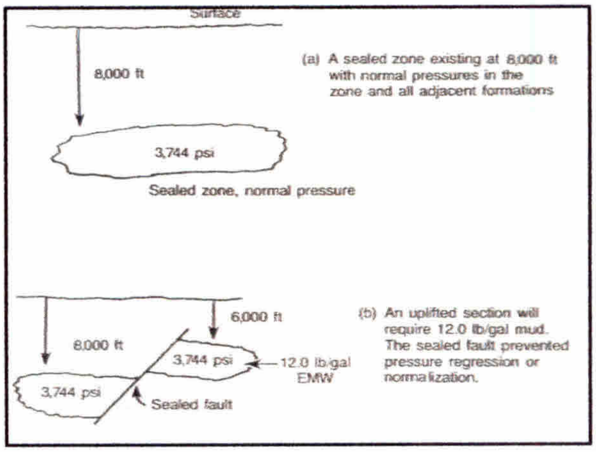


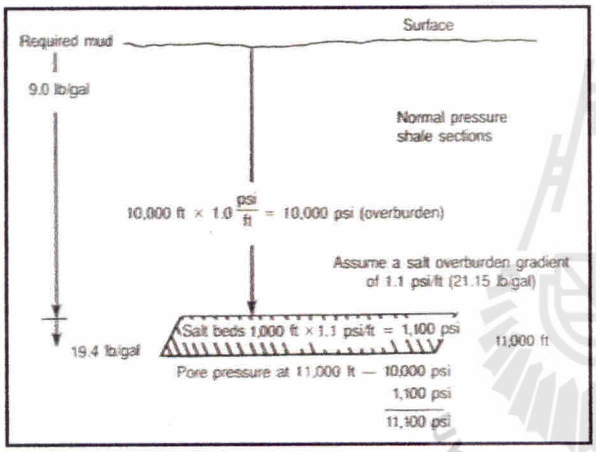


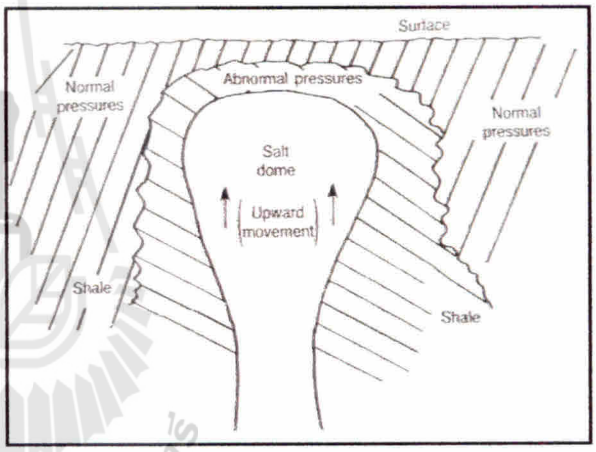
Causes of Abnormal Pressure

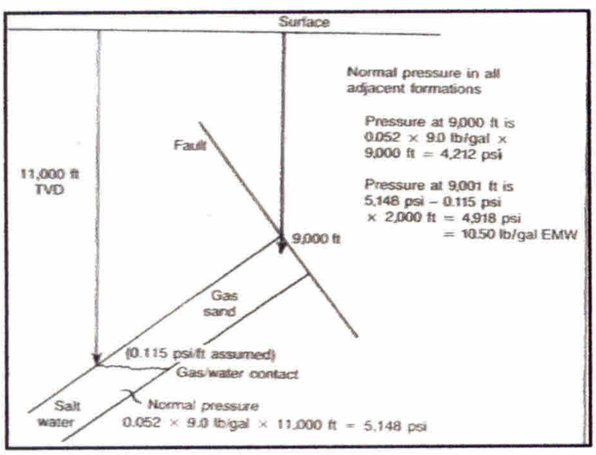
* 1. Under-compaction
* 2. Artesian System
* 3. Faults
* 4. Salt Beds
* 5. Salt Domes
* 6. Density Differences







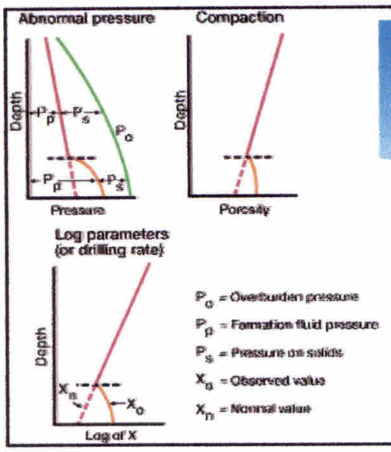


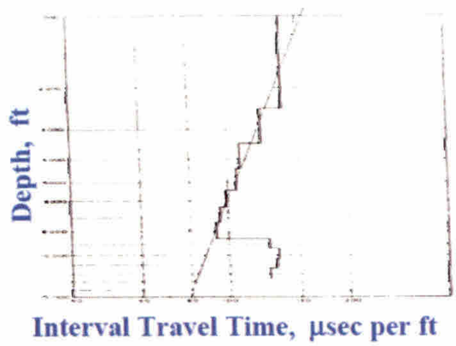


Prediction of Abnormal Pore Pressure

- Resistivity of Shale
- Temperature in the Return Mud
- Drilling Rate Increase
- d_c - Exponent
- Sonic Travel Time
- Conductivity of Shale

2





Ben Eaton

also found a way to determine pore pressure from interval travel times.

Example:

In a Gulf Coast well, the speed of sound is 10,000 ft/sec at a depth of 13,500 ft. The normal speed of sound at this depth, based on extrapolated trends, would be 12,000 ft/sec. What is the pore pressure at this depth?

Assume: S/D = 1.0 psi/ft

28

Ben Eaton

From Ben Eaton,

$$\frac{P}{D} = \frac{S}{D} - \left[\frac{S}{D} - \left(\frac{P}{D}\right)_n\right]\left(\frac{\Delta t_n}{\Delta t}\right)^{3.0}$$

$$= 1.0 - [1.0 - 0.465]\left(\frac{10,000}{12,000}\right)^3$$

$$= 0.6904 \text{ psi/ft}$$

$(\Delta t \alpha 1/v)$

29

3.2 Fracture Gradient Determination

Prediction of Fracture Gradients

- Well Planning
- Theoretical Fracture Gradient Determination
  - Hubbert & Willis
  - Matthews & Kelly
  - Ben Eaton
  - Comparison of Results
- Experimental Frac. Grad. Determination
  - Leak-off Tests

1.11-67 Fracture Gradients

Well Planning

Safe drilling practices require that the following be considered when planning a well:

- Pore pressure determination
- Fracture gradient determination
- Casing setting depth selection
- Casing design

1.11-68 Fracture Gradients

Formation Pressure and Matrix Stress

Given: Well depth is 14,000 ft. Formation pore pressure expressed in equivalent mud weight is 9.2 lb/gal. Overburden stress is 1.00 psi/ft.

Calculate:

1. Pore pressure, psi/ft , at 14,000 ft
2. Pore pressure, psi, at 14,000 ft
3. Matrix stress, psi/ft
4. Matrix stress, psi

1.11-69 Fracture Gradients

Formation Pressure and Matrix Stress

Calculations:

Depth = 14,000 ft
Pore Pressure = 9.2 lb/gal equivalent
Overburden stress = 1.00 psi/ft.

1. Pore pressure gradient

   = 0.433 psi/ft * 9.2/8.33 = 0.052 * 9.2

   = 0.478 psi/ft

2. Pore pressure at 14,000 ft

   = 0.478 psi/ft * 14,000 ft

   = 6,692 psig

1.11-70 Fracture Gradients

Formation Pressure and Matrix Stress

Calculations:

3. Matrix stress gradient,

$$S = P + \sigma \qquad \text{psi}$$

$$\text{or} \quad \frac{S}{D} = \frac{P}{D} + \frac{\sigma}{D} \qquad \text{psi/ft}$$

$$\text{i.e.,} \quad \frac{\sigma}{D} = \frac{S}{D} - \frac{P}{D} = (1.000 - 0.478) \quad \text{psi/ft}$$

$$\sigma / D = 0.522 \text{ psi/ft}$$

1.11-71 Fracture Gradients

Formation Pressure and Matrix Stress

Calculations:

4. Matrix stress at 14,000 ft

   = 0.522 psi/ft * 14,000 ft

   σ = 7,308 psi

1.11-72

Fracture Gradient Determination

In order to avoid lost circulation while drilling it is important to know the variation of **fracture gradient** with depth.

Leak-off tests represent an **experimental** approach to fracture gradient determination. Below are listed and discussed **three** approaches to **calculating** the fracture gradient.

1.11-73 Fracture Gradients

Fracture Gradient Determination

1. Hubbert & Willis:

where F = fracture gradient, psi/ft

$\frac{P}{D}$ = pore pressure gradient, psi/ft

1.11-74 Fracture Gradients

Fracture Gradient Determination

2. Matthews & Kelly:

where K_i = matrix stress coefficient

σ = vertical matrix stress, psi

Fracture Gradient Determination

3. Ben Eaton:

where S = overburden stress, psi

γ = Poisson's ratio

Example

A Texas Gulf Coast well has a pore pressure gradient of 0.735 psi/ft. Well depth = 11,000 ft.

*Calculate the fracture gradient in units of lb/gal using **each of the above three methods.***

Summarize the results in tabular form, showing answers, in units of lb/gal and also in psi/ft.

Hubbert and Willis

and vertical stresses. They believed this stress relationship to be in the r… ⅓ to ½ of the total overburden. Therefore, fracture gradient determ… according to Hubbert and Willis would be as follows:

$$\frac{P}{Z}\,(\text{min}) = 1/3\left(\frac{S_z}{Z} + \frac{2p}{Z}\right)$$

Or:

$$\frac{P}{Z}\,(\text{max}) = 1/2\left(1 + \frac{p}{Z}\right)$$

Where:

P = fracture pressure, psi
Z = depth, ft
S_z = overburden at depth Z, psi
p = pore pressure, psi

If an overburden stress gradient (S_z) of 1 psi/ft is assumed, Eq. 4.1 red…

$$\frac{P}{Z} = 1/3\left(1 + \frac{2p}{Z}\right)$$

and likewise for Eq. 4.2.

These procedures can be used in a graphical form for a quick solu… Fig. 4–1, enter the ordinate with the mud weight required to balance … mation. With a horizontal line, intersect the formation pressure gradient … construct a vertical line from this point to the minimum and maximum … gradients. Read the fracture mud weight from the ordinate. From the …

Matthews and Kelly

Example - Hubbert and Willis

1. Hubbert & Willis:

$$F_{min} = \frac{1}{3}\left(1 + \frac{2P}{D}\right)$$

The pore pressure gradient,

$$\frac{P}{D} = 0.735\ \frac{psi}{ft}$$

$$F_{min} = \frac{1}{3}(1 + 2 * 0.735) = 0.823\ \frac{psi}{ft}$$

Example - Hubbert and Willis

Also,

Fracture Gradient Determination

2. Matthews & Kelly:

$$F = \frac{K_i \sigma}{D} + \frac{P}{D}$$

where K_i = matrix stress coefficient
σ = vertical matrix stress, psi

Fracture Gradient Determination

3. Ben Eaton:

$$F = \left(\frac{S-P}{D}\right) * \left(\frac{\gamma}{1-\gamma}\right) + \frac{P}{D}$$

where S = overburden stress, psi
γ = Poisson's ratio

Example

A Texas Gulf Coast well has a pore pressure gradient of 0.735 psi/ft. Well depth = 11,000 ft.

*Calculate the fracture gradient in units of lb/gal using **each of the above three methods.***

Summarize the results in tabular form, showing answers, in units of lb/gal and also in psi/ft.

Hubbert and Willis

and vertical stresses. They believed this stress relationship to be in the r… ⅓ to ½ of the total overburden. Therefore, fracture gradient determ… according to Hubbert and Willis would be as follows:

$$\frac{P}{Z}(\text{min}) = 1/3\left(\frac{S_z}{Z} + \frac{2p}{Z}\right)$$

Or:

$$= \frac{1}{3}\left(1 + \frac{2p}{Z}\right)$$

$$\frac{P}{Z}(\text{max}) = 1/2\left(1 + \frac{p}{Z}\right)$$

Where:
P = fracture pressure, psi
Z = depth, ft
S_z = overburden at depth Z, psi
p = pore pressure, psi

If an overburden stress gradient (S_z) of 1 psi/ft is assumed, Eq. 4.1 red…

$$\frac{P}{Z} = 1/3\left(1 + \frac{2p}{Z}\right)$$

and likewise for Eq. 4.2.

These procedures can be used in a graphical form for a quick solu… Fig. 4–1, enter the ordinate with the mud weight required to balance … mation. With a horizontal line, intersect the formation pressure gradient … construct a vertical line from this point to the minimum and maximum … gradients. Read the fracture mud weight from the ordinate. From the …

Matthews and Kelly

Example - Hubbert and Willis

Also,

$$F_{min} = \frac{0.823\ \text{psi/ft}}{0.052\left(\frac{\text{psi/ft}}{\text{lb/gal}}\right)}$$

$$F_{min} = 15.83 \quad \text{lb/gal}$$

Example - Hubbert and Willis

$$F_{max} = \frac{1}{2}\left(1 + \frac{P}{D}\right) \qquad = \frac{1}{2}(1 + 0.735)$$

$$= 0.8675 \quad \text{psi/ft}$$

$$F_{max} = 16.68 \quad \text{lb/gal}$$

Example - Matthews and Kelly

(iv) Find κ_i from the plot on the right, for

D_i = 5,449 ft

For a south Texas Gulf Coast well,

K_i = 0.685

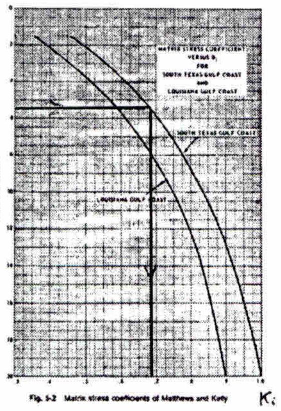


Fig. 5-2 Matrix stress coefficients of Matthews and Kelly

Example - Matthews and Kelly

(v) Now calculate F:

$$= 0.9165 \quad psi/ft$$

$$F = \frac{0.9165}{0.052} = 17.63 \quad lb/gal$$

111-55 Fracture Gradients

The matrix stress coefficient relates the actual matrix stress condit... the formation to the conditions of matrix stress if the formation were com... normally. The authors believed that the conditions necessary for fractur... formation would then be similar to those for the normally compacted form...

The stress coefficient vs depth is presented in Fig. 4-2. Matthew... Kelly believed that the coefficient would vary with different geological... tions. The values shown were obtained by substituting actual field data of... down pressures into Eq. 4.4 and solving for K_i.

The procedure for calculating fracture gradients using the Matthew... Kelly technique is as follows:

1. Obtain formation fluid pressure, P. This can be measured by dr... tests, kick data, logs, or another satisfactory method.
2. Obtain the matrix stress by using Eq. 4.4 and assuming a grad... 1.0 psi/ft for the overburden:

$$\sigma = S - P$$

3. Determine the depth, D_i, for which the matrix stress, σ, would... normal value. Assume that the overburden pressure is 1.0 psi/ft... this it follows that:

$$0.535\ D_i = \sigma$$

from which the value of D_i can be found.

4. Use the value of D_i and apply it to Fig. 4-2 to obtain the corresp... value of K_i.
5. Using the values of D, σ, P, and K_i, calculate the value of the f... gradient, F.

Example 4.1

Casing was set on a Texas Gulf Coast well at 7,200 ft. It was estimat... formation pressure was equivalent to 11.0-lb/gal mud. What is the f... *gradient immediately below the casing seat?* Use the Matthews an... procedure.

Solution:

1. P = (11.0 lb/gal)(0.052)(7,200 ft)
   = 4,118 psi
2. σ = S − P
   = 7,200 − 4,118
   = 3,082 psi

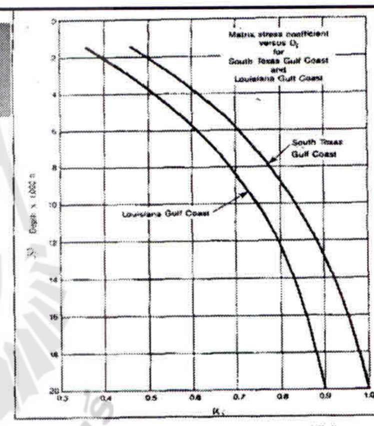


Fig. 4-2 Matrix stress coefficients of Matthews and Kelly

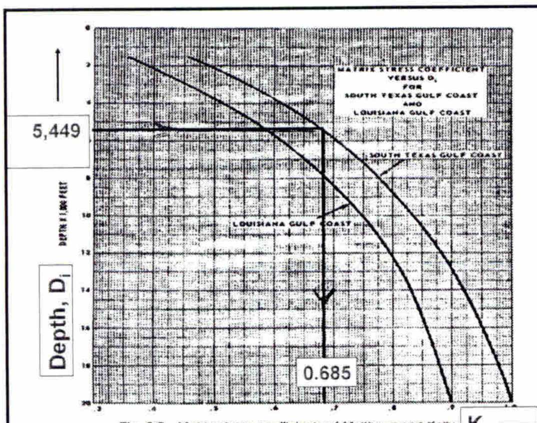


Fig. 5-2 Matrix stress coefficients of Matthews and Kelly

*Ben Eaton:

Eaton. Eaton extended the concepts presented by Matthews and Kelly to introduce Poisson's ratio into the expression for the fracture pressure gradient:

$$F = \frac{S - P}{D}\left(\frac{\nu}{1 - \nu}\right) + \frac{P}{D} \qquad (4.7)$$

Where:
- P = wellbore pressure, psi
- D = depth, ft
- S = overburden stress, psi
- ν = Poisson's ratio
- F = fracture gradient, psi/ft

Eaton assumed that both overburden stress and Poisson's ratio were variable with depth. Using actual field fracture data and log-derived values, he prepared graphs illustrating these variables (Figs. 4-4 and 4-5). Using a suitable choice for each variable, the nomograph prepared by Eaton et al. (Fig. 4-6) can be used to calculate a fracture gradient.

A graphical presentation for the Eaton approach provides a quick solution. The chart (Fig. 4-7) is used in the same manner as the Matthews and Kelly

In these equations, Hubbert and Willis assumed that the matrix stress and the overburden gradients were constant for all depths. Since this has been proven untrue in most cases, subsequent methods have attempted to account for one or both of these variables more accurately.

Matthews and Kelly. In realizing that the cohesiveness of the rock matrix is usually related to the matrix stress and varies only with the degree of compaction, Matthews and Kelly developed the following equation for calculating fracture gradients in sedimentary formations:

$$F = \frac{P}{D} + \frac{K_i\sigma}{D} \quad (4.4)$$

Where:

P = formation pressure at the point of interest, psi
D = depth of interest, ft
σ = matrix stress at the point of interest, psi
K_i = matrix stress coefficient for the depth at which the value of σ would be normal matrix stress, dimensionless
F = fracture gradient at the point of interest, psi/ft

Matthews and Kelly

$$F = \frac{P}{D} + \frac{K_i\sigma}{D}$$

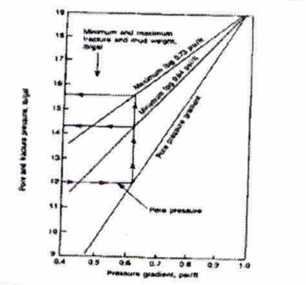


Fig. 4-1 Graphical determination of fracture gradients as proposed by Hubbert and Willis

Example

2. Matthews & Kelly

In this case P and D are known, may be calculated, and is determined graphically.

(i) First, determine the pore pressure gradient. K_i

$$F = \frac{P}{D} + \frac{K_i\sigma}{D}$$

$$\frac{P}{D} = 0.735 \text{ psi/ft} \quad \text{(given)}$$

the formation to the conditions of matrix stress if the formation were compacted normally. The authors believed that the conditions necessary for fracturing the formation would then be similar to those for the normally compacted formation.

The stress coefficient vs depth is presented in Fig. 4–2. Matthews and Kelly believed that the coefficient would vary with different geological conditions. The authors derived the curves by substituting actual field data of breakdown pressures into Eq. 4.4 and solving for K_i.

The procedure for calculating fracture gradients using the Matthews and Kelly technique is as follows:

(i) First, determine the pore pressure gradient

1. Obtain formation fluid pressure, P. This can be measured by drill stem tests, kick data, logs, or another satisfactory method.
2. Obtain the matrix stress by using Eq. 4.4 and assuming a gradient of 1.0 psi/ft for the overburden:

* (ii) Next, calculate the matrix stress.

$$\sigma = S - P$$

3. Determine the depth, D_i, for which the matrix stress, σ, would be the normal value. Assume that the overburden pressure is 1.0 psi/ft. From this it follows that:

$$0.535\ D_i = \sigma$$

from which the value of D_i can be found.
4. Use the value of D_i and apply it to Fig. 4–2 to obtain the corresponding value of K_i.
5. Using the values of D, σ, P, and K_i, calculate the value of the fracture gradient, F.

Example - Matthews and Kelly

(ii) Next, calculate the matrix stress.

S = P + σ

S = overburden, psi
σ = matrix stress, psi
P = pore pressure, psi
D = depth, ft

σ = S - P
= 1.00 * D - 0.735 * D
= 0.265 * D
= 0.265 * 11,000
σ = 2,915 psi

Example 4.1

Casing was set on a Texas Gulf Coast well at 7,200 ft. It was estimated formation pressure was equivalent to 11.0-lb/gal mud. What is the fracture *gradient immediately below the casing seat? Use the Matthews and* procedure.

Solution:

1. P = (11.0 lb/gal)(0.052)(7,200 ft)
= 4,118 psi
2. σ = S − P
= 7,200 − 4,118
= 3,082 psi

3. Depth equivalent, D_i:
$0.535\ D_i = \sigma$
$$D_i = \frac{\sigma}{0.535} = \frac{3{,}082}{0.535} = 5{,}760 \text{ ft}$$
where 0.535 psi/ft is the rock matrix stress
4. From Fig. 4–2, K_i = 0.695
5. $F = \frac{P}{D} + \frac{K_i\sigma}{D}$
$= \frac{4{,}118}{7{,}200} + \frac{(0.695)(3{,}082)}{7{,}200}$
= 0.571 + 0.298
= 0.869 psi/ft

Example - Matthews and Kelly

(iii) Now determine the depth, D_i, where, under normally pressured conditions, the rock matrix stress, σ would be **2,915 psi.**

$S_n = P_n + \sigma_n$ **n = "normal"**

$1.00 * D_i = 0.465 * D_i + 2{,}915$

$D_i * (1 - 0.465) = 2{,}915$

$$D_i = \frac{2{,}915}{0.535} = 5{,}449\ ft$$

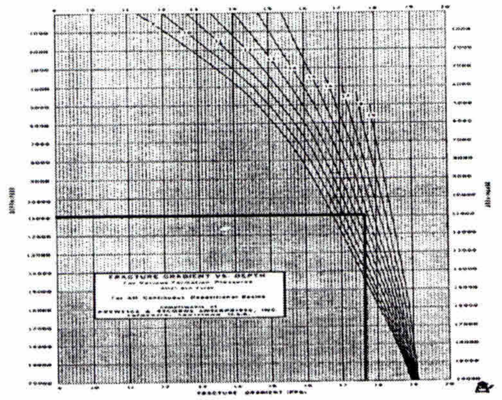


Fig. 5-7 Graphical determination of fracture gradients using the Eaton approach

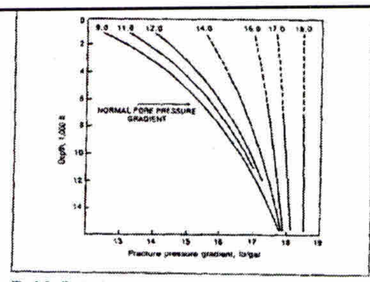


Fig. 4-3 Graphical determination of fracture gradients using the Matthews and Kelly approach

chart (Fig. 4-3). Although the Eaton chart (Fig. 4-7) uses the curves in Figs. 4-4 and 4-5, a similar chart can be established for a different area if the overburden stress or Poisson's ratio values differ greatly.

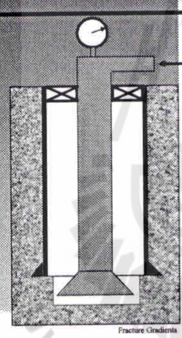
Eaton's method or its modifications are perhaps the most widely used procedure in the industry. It has proved successful both on- and offshore throughout the world. Ferti has shown that Eaton's predictions agree within an acceptable range to actual field-derived values from such places as Delaware Basin fields in West Texas, offshore Louisiana, and the Green River Basin of Wyoming.

Christman. The previously discussed fracture gradient determination procedures assume that overburden stress consists of rock matrix stress and formation fluid stress. Offshore, the water (over a distance from the rig flow line to the

Experimental Determination of Fracture Gradient

The leak-off test

- Run and cement casing
- Drill out ~ 10 ft below the casing seat
- Close the BOPs
- Pump slowly and monitor the pressure



1.11- 101 Fracture Gradients

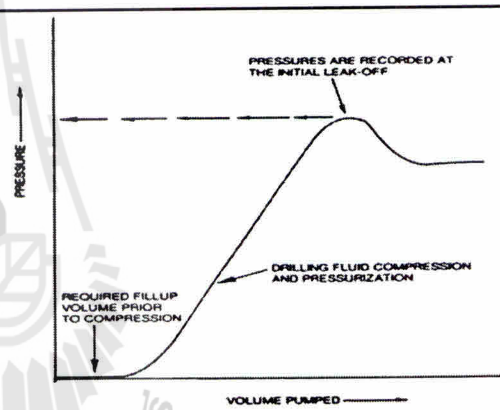


Fig. 5-10 Typical results from a leak off test

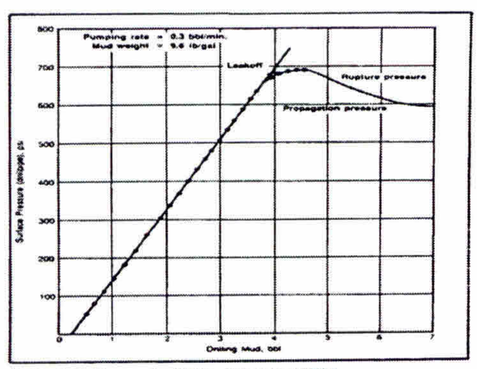
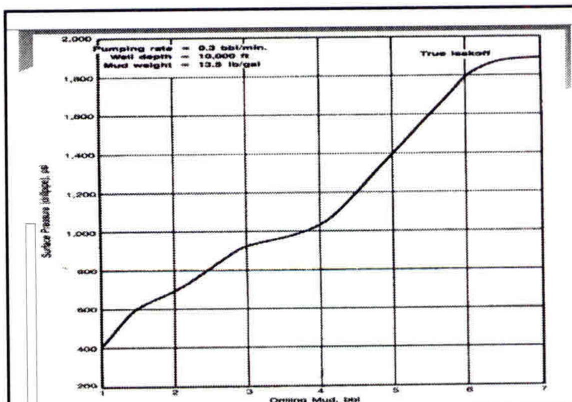


FIG. 13-12 Casing seat leakoff test—casing seat at 3,000 ft



1.11- 104 Fracture Gradients

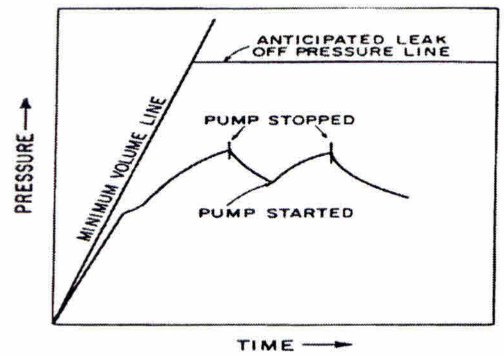


Fig. 6.54—Leakoff test results indicative of a poor cement bond.

3. Depth equivalent, D_e:

$0.535\,D_e = \sigma$

$$D_e = \frac{\sigma}{0.535} = \frac{3{,}082}{0.535} = 5{,}760 \text{ ft}$$

where 0.535 psi/ft is the rock matrix stress

4. From Fig. 4–2, $K_i = 0.695$

5. $F = \frac{P}{D} + \frac{K_i\sigma}{D}$

$$= \frac{4{,}118}{7{,}200} + \frac{(0.695)(3{,}082)}{7{,}200}$$

$= 0.571 + 0.298$

$= 0.869$ psi/ft

$= 16.7$ lb/gal (equivalent mud weight)

A graphical solution to the Matthews and Kelly technique is presented in Fig. 4–3. Note that the curved lines on the graph represent actual formation pressures and not mud weight in use. Unfortunately, these are often erroneously interchanged. To solve for fracture gradients with Fig. 4–3, enter at the desired depth and read horizontally until the actual formation pressure line is intersected. Plot a vertical line from this point and read the fracture gradient in pounds per gallon.

Eaton. Eaton extended the concepts presented by Matthews and Kelly to introduce Poisson's ratio into the expression for the fracture pressure gradient:

$$F = \frac{S - P}{D}\left(\frac{\nu}{1-\nu}\right) + \frac{P}{D} \qquad (4.7)$$

Where:

- P = wellbore pressure, psi
- D = depth, ft
- S = overburden stress, psi
- ν = Poisson's ratio
- F = fracture gradient, psi/ft

Eaton assumed that both overburden stress and Poisson's ratio were variable with depth. Using actual field fracture data and log-derived values, he prepared graphs illustrating these variables (Figs. 4–4 and 4–5). Using a suitable choice for each variable, the nomograph prepared by Eaton et al. (Fig. 4–6) can be used to calculate a fracture gradient.

A graphical presentation for the Eaton approach provides a quick solution. The chart (Fig. 4–7) is used in the same manner as the Matthews and Kelly

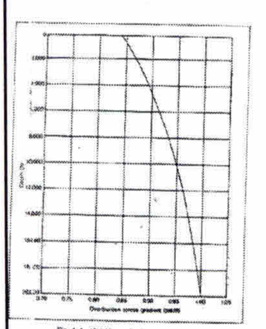


Fig. 4–4 Variable overburden stress by Eaton

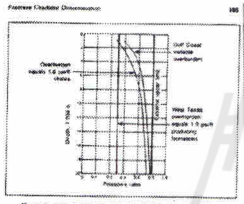


Fig. 4–3 Variable Poisson's ratio with depth as proposed by Eaton

[illegible]

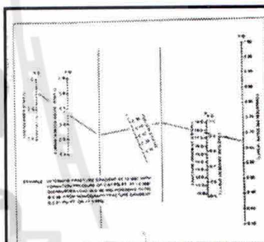


Fig. 4–6 Nomograph determination of fracture gradients as proposed by Eaton

section by Eaton. Example 4.2 illustrates the procedure for a well drilled in 1,000 ft of water.

Example 4.2

In the illustration in Fig. 4–9, what is the effective fracture gradient at the casing seat?

Solution:

1. Convert the water depth to an equivalent section of formation:

1,000 ft × 0.465 psi/ft = 465 psi

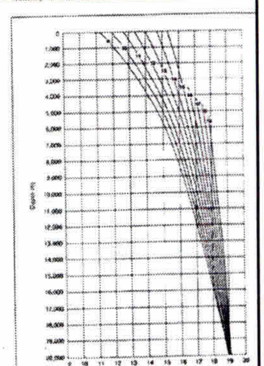


Fig. 4–7 Graphical determination of fracture gradient using the Eaton approach (Courtesy of Adams and Rountree Technology, Inc.)

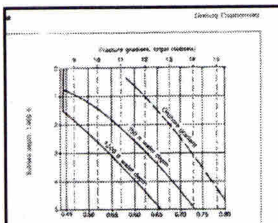


Fig. 4–8 Offshore fracture gradients as a function of depth. Subsea indicates depth below floor. (After Christman)

2. From Eaton's overburden stress chart in Fig. 4–4, the stress gradient at 4,000 ft equals 0.89 psi/ft:

$$\frac{465 \text{ psi}}{0.89 \text{ psi/ft}} = 522 \text{ ft, equivalent}$$

3. Calculate and convert the apparent fracture gradient to actual fracture gradient:

522 + 3,000 ft = 3,522 ft, equivalent

From Eaton's fracture gradient chart, the gradient at 3,522 ft = 13.92 lb/gal, or:

fracture pressure = 0.052 × 13.92 lb/gal × 3,522 ft = 2,549 psi

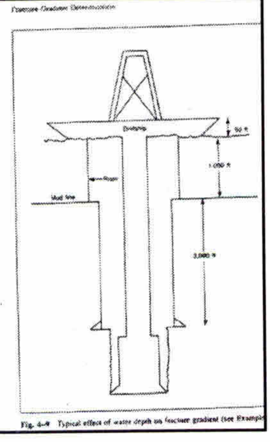


Fig. 4–9 Typical effect of water depth on fracture gradient (see Example

4. The effective fracture gradient from the mud flow line at the drillship deck to the casing seat is:

2,549 psi × 19.23/(50 + 1,000 + 3,000) ft = 12.07 lb/gal

For comparison, the land fracture gradient at 4,000 ft is 14.2 lb/gal.

Field Determination of Fracture Gradients

It is common practice to pressure-test each new casing seat in field applications to determine the exact maximum fracture gradient. The primary reason for this practice is due to the inability of any theoretical procedure to account for all possible formation characteristics. For example, several authors have noted wells that exhibited lower-than-expected fracture gradients due to abnormally low bulk densities in the rock.

The most common procedure used for the field determination of fracture gradients is the leakoff test (often called the pressure integrity test). In the test, the blowout preventers are closed and then pressure is applied incrementally to the shut-in system until the formation initially accepts fluid. The results of the test would be similar to those shown in Fig. 4–10. Example 4.3 illustrates the procedure.

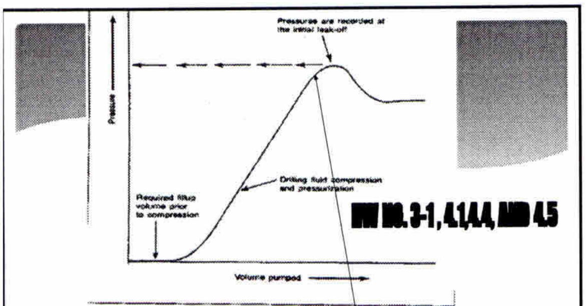
Example 4.3

Casing was set at 10,000 ft in a well. The operator performs a leakoff test to determine the fracture gradient at 10,000 ft. If the mud weight in the well was 11.2 lb/gal, what is the fracture gradient at the casing seat?

Solution:

1. Close the blowout preventers and rig up a low-volume output pump.
2. Apply pressure to the well and record the results as follows:

Volume pumped, bbl	Pressure, psi
0	0
1	45
1½	125
2	230
2½	350
3	470
3½	590



HW NO. 3-1, 4.1,4.4, AND 4.5

Fig. 4-10 Typical results from a leakoff test

4	710
4½	830
5	950
5½	990
6	1010

3. The results are plotted in Fig. 4-11. It appears that the formation will begin to fracture when 950 psi is applied.

HW 0. 3-1, 1, 4.1,4.4, AND 4.5

DRILLING ENGINEERING

DUE DATE: Friday 8 August 2014

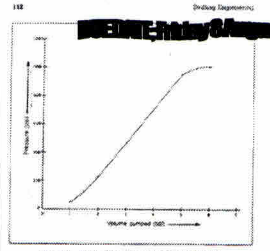


Fig. 4-11 Results of leakoff test data from Example 4.3

Problems

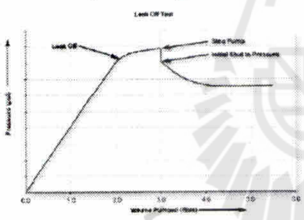
Formation Strength Tests

The knowledge of the pressure at which the formation fracture will occur is essential when designing and drilling of a well, as the integrity of the well in a well control situation depends on the minimum formation strength.

The strength of the formation can be determined by the following tests:

- Leak-off Test (LOT):

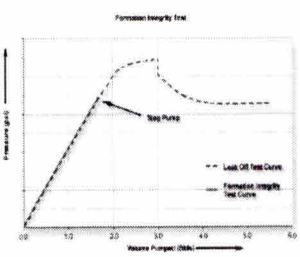
  Determines the pressure at which the formation begins to take fluid. It is used specially in exploratory wells to determine the maximum pressure that the formation at the test point can withstand before a loss of drilling fluid into the formation occurs.



Formation Strength Tests

- Formation Integrity Test (FIT):

  The formation is tested to a predetermined pressure value without breaking. The test is not carried to the point where formation failure occurs. In many cases, this value of formation strength is sufficient to ensure well integrity in a well control situation, especially in development wells.



The second method that can be used to estimate formation pressure at 9,000 ft is an empirically determined relationship between interval transit time and formation pressure. (See Fig. 6.13.) The ratio of observed transit time to normal interval transit time at 9,000 ft is

$$\frac{t}{t_n} = \frac{129}{92} = 1.40.$$

From Fig. 6.13, the formation pore pressure gradient is 0.93 psi/ft. Thus, the formation pressure is

$$p = 0.93(9,000) = 8,370 \text{ psig}.$$

Solution. First, the interval transit time data are plotted vs. depth (Fig. 6.14). The average normal pressure trend line for the Louisiana Upper Miocene trend was determined in Example 6.5 to be

$$t_n = 50 + 339\phi_{o}e^{-0.000085D} - 180\phi_{o}^{2}e^{-0.00017D},$$

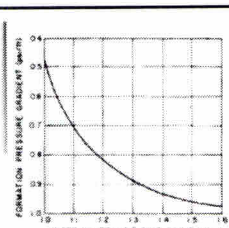


Fig. 6.13—Pennebaker relationship between formation pore pressure and seismic-derived interval transit time.

Ben Eaton

also found a way to determine pore pressure from interval travel times

Example:

In a Gulf Coast well, the speed of sound is 10,000 ft/sec at a depth of 13,500 ft. The normal speed of sound at this depth, based on extrapolated trends, would be 12,000 ft/sec. What is the pore pressure at this depth?

Assume: S/D = 1.0 psi/ft

Ben Eaton

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Example:

In a Gulf Coast well, the speed of sound is 10,000 ft/sec at a depth of 13,500 ft. The normal speed of sound at this depth, based on extrapolated trends, would be 12,000 ft/sec. What is the pore pressure at this depth?

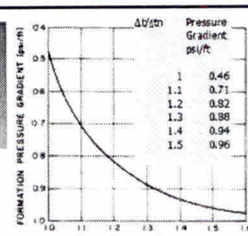
Assume: S/D = 1.0 psi/ft

$$\frac{P}{D} = \frac{S}{D} - \left[\frac{S}{D} - \left(\frac{P}{D}\right)_n\right]\left(\frac{\Delta t_n}{\Delta t}\right)^{3}$$

$$= 1.0 - \{1.0 - 0.465\}\left(\frac{10,000}{12,000}\right)^{3}$$

$$= 0.6904 \text{ psi/ft}$$

$(\Delta t \propto 1/V)$



Δt/Δtn	Pressure Gradient psi/ft
1	0.46
1.1	0.71
1.2	0.82
1.3	0.88
1.4	0.94
1.5	0.96

Fig. 6.13—Pennebaker relationship between formation pore pressure and seismic-derived interval transit time.

PORE PRESSURE PREDICTION BY BEN EATON METHOD

Depth ft.	S/D psi/ft	(P/D)n psi/ft	Vn/Δtn FT/SEC	Δtn μsec/ft	V FT/SEC	Δt μsec/ft	ΔTn/ΔT	ΔT/ΔTn	Eaton P/D psi/ft	Pennebaker Relationship
10000	1	0.45	10000	100	8500	118	0.85	1.18	0.66	0.80
10000	1	0.46	12000	83	12000	83	1.00	1.00	0.46	0.46
12000	1	0.45	13000	77	9500	105	0.73	1.37	0.79	0.91
13500	1	0.465	12000	83	10000	100	0.83	1.20	**0.69**	**0.82**

HW NO. 3-1, 1, 4.1, 4.4, AND 4.5 of NEAL J. ADAMS

DRILLING ENGINEERING

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HOME WORK NO 3.1

1. Find the pore pressure by Eaton and Pennebaker for the data in the following table.

Depth ft	S/D psi/ft	[illegible] psi/ft	[illegible] FT/SEC	[illegible] usec/ft	[illegible] FT/SEC	[illegible] usec/ft	Eaton P/D psi/ft	Pore Pressure psi	Pennebaker Relationship Gradient psi/ft	Pore Pressure psi
10000	1	0.45	10000	100	8700	115				
10000	1	0.46	11000	91	10500	95				
12000	1	0.465	13000	77	10000	100				
13500	1	0.465	12000	83	10000	100				

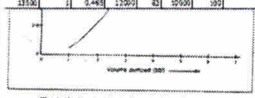

Fig. 4-11 Results of leakoff test data from Example 4.3

4. Fracture gradient
= 811.2 lb/gal/(0.052)(10,000 ft) + 9860/10,000 ft
= 6,734 psi/10,000 ft = 0.6734 psi/ft
= 12.92 lb/gal, equivalent

Problems

4.1 Determine fracture gradients for the following conditions. Use the methods of (1) Hubbert and Willis, (2) Matthews and Kelly, and (3) Eaton. Assume "Louisiana" conditions for the Matthews and Kelly calculations.

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Depth ft	Formation Pressure, lb/gal
3,000	Normal
13,500	13.1
9,000	9.6
6,500	9.0
8,000	10.2
11,000	15.1
12,500	18.0
4,300	9.9
10,500	Normal
15,000	15.6

Solution: 3,000 ft
Hubbert and Willis — 12.2–14.0 lb/gal
Matthews and Kelly — 13.8 lb/gal
Eaton — 13.9 lb/gal

4.2 Prepare a graph of fracture gradients vs depth for the methods used in Problem 4.1. Assume normal formation pressures.

4.3 Calculate the fracture gradient for the following set of deepwater conditions. Use the approach described in Example 4.2.
Freeboard = 30 ft
Water depth = 1,200 ft
Casing depth below seafloor = 8,000 ft

4.4 Use the following leakoff data to determine the formation fracture gradient. Casing is set at 12,000 ft and the mud weight = 13.9 lb/gal.

Volume Pumped, bbl	Pressure, psi
0	0
1	175
2	400
2½	390
3	680
3½	780
4	850
4½	790
5	830

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Volume Pumped, bbl	Pressure, psi
5½	920
6	1,010
6½	1,100
7	1,190
7½	1,200
8	1,280
8½	1,300

4.5 Calculate the formation fracture gradient for the following conditions. Use the pressure data from Problem 4.4.

Depth of casing, ft	Mud weight in use, lb/gal
9,500	9.0
16,000	13.9
13,100	13.1
6,600	9.5

Solution: 9,500 ft, 11.6 lb/gal

4.6 Use the Eaton fracture gradient chart to calculate fracture gradients for Problems 5.2, 5.3, 5.4, and 5.5.

References

Christman, Stan A. "Offshore Fracture Gradients." JPT, August 1973.

Eaton, B.A. "Fracture Gradient Prediction and its Application in Oilfield Operations." JPT, October 1969.

Pertl, W.H. "Predicting Fracture Pressure Gradients for More Efficient Drilling." Petroleum Engineer, December 1976.

Pertl, W.H., and D.J. Timko. "Application of Well Logs to Geopressure Problems in the Search, Drilling, and Production of Hydrocarbons." French

Fracture Gradient Determination

Matthews, W.R., and J. Kelly. "How to Predi[ct] Fracture Gradient." Oil & Gas Journal, 20 Fe[b]

Pilkington, P.E. "Fracture Gradient Estimates in [...] Engineer International, May 1978.

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- provide a means for attaching the blowout preventers
- support the weight of all casing strings (except liners) run below the surface pipe

Intermediate Casing. The primary applications of intermediate casing involve abnormally high formation pressures. Since higher mud weights are required to control these pressures, the shallower weak formations must be protected to prevent lost circulation or stuck pipe. Occasionally, intermediate

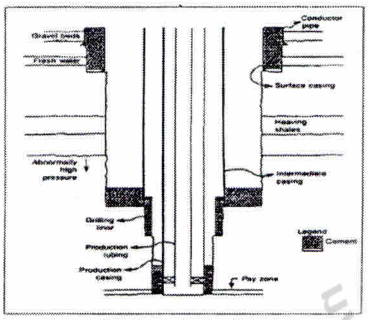


Fig. 5-1 Typical casing string relationships

pipe is used to isolate salt zones or zones that cause hole problems, s[uch as] heaving and sloughing shales.

Liners. Drilling liners are used for the same purpose as interm[ediate] casing. Instead of running the pipe to the surface, an abbreviated string i[s run] from the bottom of the hole to a shallower depth inside the intermediate [casing]. Usually the overlap between the two strings is 300–500 ft. In this ca[se the] intermediate pipe is exposed to the same drilling considerations as the lin[er] (Fig. 5-1).

Drilling (and production) liners are used frequently as a cost-ef[fective] method to attain pressure or fracture gradient control without the expe[nse of] running a string to the surface. When a liner is used, the upper exposed c[asing,] usually intermediate pipe, must be evaluated with respect to burst and co[llapse] pressures for drilling the open hole below the liner. Remember that a full [string] of casing can be run to the surface instead of a liner if required, i.e. [as] intermediate strings.

Production Casing. The production casing is often called the oil [string]. The pipe may be set at a depth slightly above, midway through, or belo[w the] pay zone. The pipe has the following purposes:

- isolate the producing zone from the other formations
- provide a work shaft of a known diameter to the pay zone
- protect the production tubing equipment

Tie-back String. The drilling liner is often used as part of the prod[uction] casing rather than running an additional full string of pipe from the surf[ace to] the producing zone. The liner is tied-back or connected to the surface by r[unning] the amount of pipe required to connect to the liner top. This procedure i[s] particularly common when 1) producing hydrocarbons are behind the line[r], 2) the deeper section is not commercial.

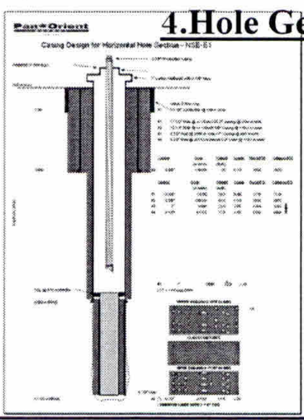
Setting Depth Design Procedures

Casing seat depths are directly affected by geological conditions. In [some] cases, the prime criterion for selecting casing seats is to cover exposed, [...] lost circulation zones. In others, the seat selection may be based on diffe[rential] sticking problems, perhaps resulting from pressure depletion in a field. In [most] wells, however, the primary consideration is usually based on controllin[g] normal formation pressures and preventing their exposure to weaker sh[allower] zones. The design criteria of controlling formation pressures generally a[pplies] to most drilling areas.

Selecting casing seats for pressure control purposes starts with kno[wn] geological conditions such as formation pressures and fracture gradients. [This] information is generally available within an acceptable degree of accuracy

Figure 5 Well Casing Design Schematic

4.Hole Geometry Selection



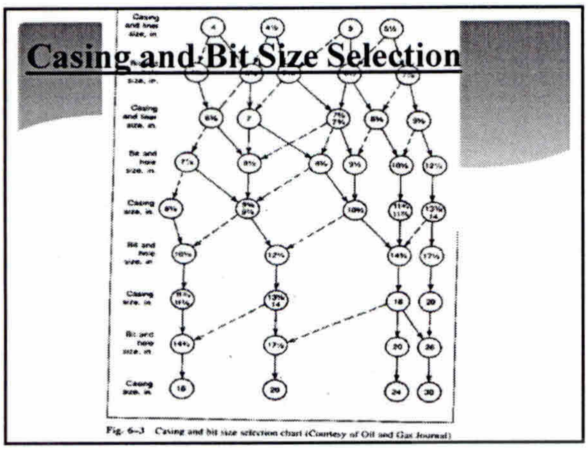
Well Sections

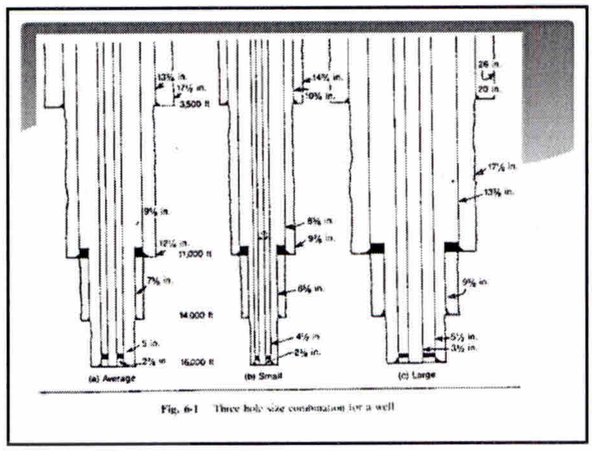
4.Hole Geometry Selection

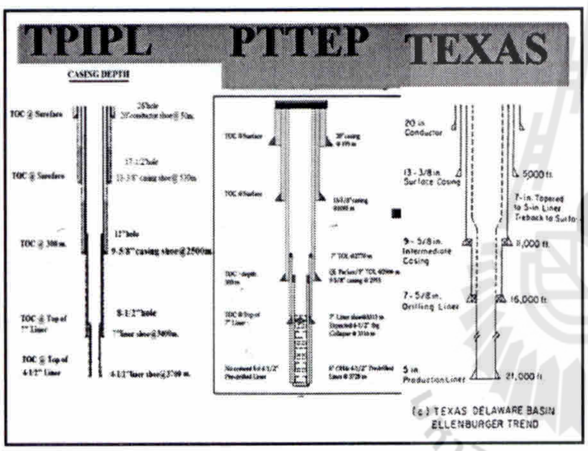
It is planned that the well will be drilled in four sections, as summarised below:

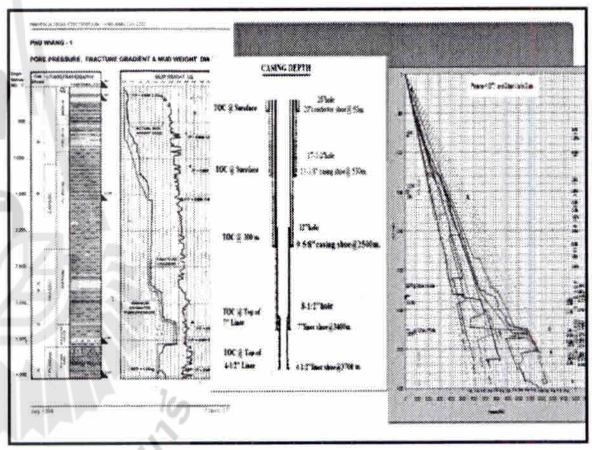
Hole Size (Inches)	Casing Size (Inches)	Shoe Depth (Metres-RT)	Formation at Setting Depth
Excavated* & Cemented 3m below base of cellar during site construction	30	± 13.7 (45')	
26	20	183 (600)	Sao Khua
17 1/2	13 3/8	1524 (5,000)	Phu Kradung
12 1/4	9 5/8	3551 (11,650)	Kuchinarai/Upper Clastics
8 3/8	6 5/8 (Liner)	4206 (13,800)	Rat Buri / Pre-Permian

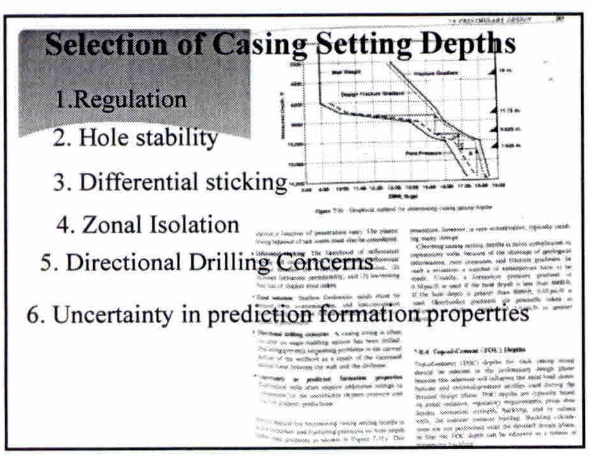
*30" casing cemented with reinforcing bars into extremely hard rock. Approximately 1m of lowermost rock penetrated with pneumatic hammers prior to entire 30" annulus being cemented back to cellar floor. Conductor has no shoe and does not have any cement inside.

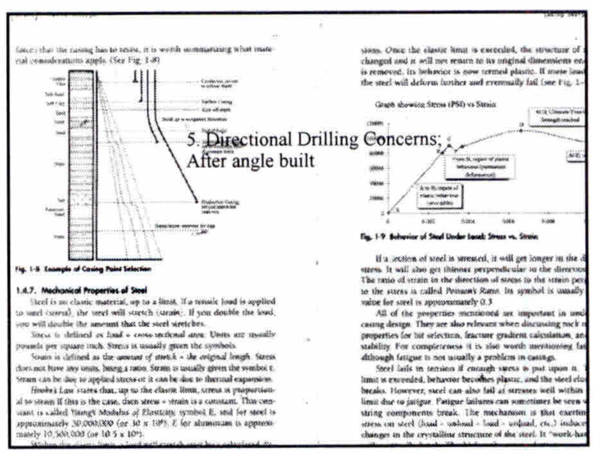

Casing and Bit Size Selection
Fig. 6-3 Casing and bit size selection chart (Courtesy of Oil and Gas Journal)


(a) Average
(b) Small
(c) Large
Fig. 6-1 Three hole size combination for a well


TPIPL
PTTEP
TEXAS
CASING DEPTH
20 in. Conductor
13 - 3/8 in. Surface Casing
9 - 5/8 in. Intermediate Casing
7 - 5/8 in. Drilling Liner
5 in. Production Liner
(c) TEXAS DELAWARE BASIN ELLENBURGER TREND


PORE PRESSURE, FRACTURE GRADIENT & MUD WEIGHT
CASING DEPTH

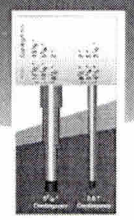

Selection of Casing Setting Depths
1.Regulation
2. Hole stability
3. Differential sticking
4. Zonal Isolation
5. Directional Drilling Concerns
6. Uncertainty in prediction formation properties


5. Directional Drilling Concerns;
After angle built
Fig. 1-8 Example of Casing Point Selection
1.4.7. Mechanical Properties of Steel
Fig. 1-9 Behavior of Steel Under Load: Stress vs. Strain

Well Bore Geometry

•Many interrelated size selection problems must be considered before the final hole geometry is determined. Some of the problems to be considered are as follows :

1.CASING DESIGN.
2.CEMENTING PROBLEM ; may occur if the casing to hole annulus is too small.
3.CLEARANCE BETWEEN DRILLSTRING AND HOLE; if too large the circulation will not sufficiently clean the hole, or if too small the result may be increased friction pressures and turbulent erosion.



Casing and Bit Size Selection

5. Casing Point Selection and COMPLETION DESIGN

The first design task facing the drilling engineer in preparing a well plan is selecting the casing setting depth. The drilling engineer must consider such things as :

FORMATION PRESSURE.
FRACTURE GRADIENT.
HOLE PROBLEM.
COMPANY POLYCY.
GOVERNMENT REGULATIONS
SAFETY.

The drilling engineer has the following casing strings at his disposal in designing a well plan :

Conductor Pipe.,Structural Casing.
Surface Casing.
Intermediate Casing.
Production Casing.
Liners., Tubing.

5.Casing Program

The drilling engineer must design the casing with regard to the following :

1. Bottom hole pressure and temperature.
2. The type of drilling fluid to be used
3. The type of cement to be used.
4. Potential hole problem.
5. Reservoir fluid expected, for example corrosive fluids such hydrogen sulphide, and carbon dioxide.
6. The casing setting depth.
7. Company and Government policies.
8. Safety.

An example of CASING program is shown in Fig.11.7

CASING AND TUBING PROGRAM

Casing/Tubing Size (In)	Shoe Depth (ft RKB)	Wt (Lb/Ft)	Grade	Hole Size (In)	Drift ID (in)	Connection	Collapse (Psi)	Burst (Psi)	Tension (Kips)
20	120	94	X-52	26	18.936	Vetco L	-	-	-
13-3/8	1,500	61	K-55	17-1/2	12.359	Buttress	1540	3090	962
9-5/8	9,500 TVD/10,200 MD	47	L-80	12-1/4	8.525	Buttress	4760	6870	1086
7	10,710 TVD/12,000MD	32	L-80	8-1/2	5.969	VAM-Ace	8610	9060	745
4	as required	13	L-80	5.969	3.215	VAM-Ace	12110	11550	306

Notes:

1. The Collapse, Burst and Tension values listed above do not include Safety Factors.
2. Detailed 9-5/8 and 7 inch casing/cementing programs and completion procedure will be provided later.
3. *Design Factors:*

Casing	Collapse	Burst	Tension
20, 13-3/8, 9-5/8	1.000	1.375	1.333
7	1.125	1.25	1.333
4	1.125	1.250	1.333

BOP/Wellhead/Casing Testing

Casing	Wellhead			Annular BOP		Ram BOP		Test Pressures			
Size (in)	Section	Size (in)	Rating (psi)	Size (in)	Rating (PSI)	Size (in)	Rating (psi)	Choke Manifold (psi)	Casing (psi)	Annular (psi)	Ram BOP (psi)
20	-	-	-	none		none					
13-3/8	"A"	13-5/8	3k	13-5/8	5k	13-5/8	10k	3000	1500	200/3000	200/3000
9-5/8	"B"	11	5k	13-5/8	5k	13-5/8	10k	5000	4500	200/3500	200/5000
7	"C"	7-1/16	10k	13-5/8	5k	13-5/8	10k	7000	5000	200/3500	200/7000

6. Drill Bit Program

Several factors must be considered in selecting the bit program. Some of these factors are as follows :

COST OF THE BIT
EXPECTED FORMATIONS
EXPECTED PENETRATION RATE
COST OF DRILLING RIG
TYPE OF MUD
OTHER RIG PARAMETERS

Many type of bits may be recommended to used based on above conditions :

1.MED-HARD ROCK BITE
HARD ROCK BIT
PDC(Polycrystalline Diamond Compact) BIT
DIAMOND BIT

All bit and mud conditions are also recommended for each drilling interval. An example of bit and hydraulic program is shown in Fig.11.5

Bit Planning

BIT AND HYDRAULICS PROGRAM

Hole Size (inch)	Depth (m-RKB)	Bit Type (or similar type)	IADC Code	Nozzles (32^{nd} inch)	RPM	WOB (KLBs)	Pressure (psi)	Flow Rate (gpm)	Liners (inch)	Remark
26	0-60	TCI New V515 (VAREL)	1-1-1	20-20-20-18	80-100	10-20	500-3500	1000	6-1/2	
17-1/2	60-540	ATM-33 (Hughes) or PDC	1-3-5	18-18-18 13's	70-120 70-80	30-50 40-70	3500	900	6-1/2	
12	540-2500	PDC or TSP		13's	80-150	20-30	4000	700 (2500L/m)	5	
8	2500-3400	ATM-33 (Hughes) or PDC	5-3-7	16-16-16 13's	80-150	50-60	4000	600 (2200L/m)	5	
6	3400-3700	ATJ-44 (Hughes) or PDC	5-4-7	12-12-12 13's	100-180	35-45	4000	300 (1100L/m)	5	

Figure 11.5 BIT and HYDRAULIC PROGRAM

Hole Size (inch)	MD Interval (ft - RKB)	Bit Type (or similar type)	IADC Code	Nozzles (32nd inch)	RPM	WOB (KLBs)	Press (psi)	Flow Rate (gpm)	Liners (in)
26	0 - 120	CR1	1-1-1	20-20-20-18	80-100	10-20	450	1000	6-1/4"
17-1/2	120 - 600	MAX G-3	1-3-5	18-18-18	70-120	30-50	3200	900	6-1/4"
	600 - 1500	ATM-22	5-1-7	18-18-18	70-80	40-70	3200	900	6-1/4"
12-1/4	1,500 - 6,200	PDC (3)		13's	80-150	20-30	4000	600	5"
(Kick-off)	6,200 - 6,800	ATM-22 (4)	5-1-7	16-16-16	80-150	50-60	4000	600	5"
	6,800 - 10,200	ATM-33	5-3-7	16-16-16	80-150	50-60	4000	600	5"
8-1/2	10,200 - TD	ATJ-44	5-4-7	12-12-12	100-160	35-45	4000	400	5"

PDC bit technology is an area experiencing dynamic changes and improvements in the drilling industry. As an example, the recently introduced leached compact technology provides a thermally stable cutter and low wear rates, and opens the door for improved compact-to-bit attachment procedures.

Drilling Optimization

As described at the beginning of this chapter, the three levels or phases of drilling optimization are as follows:

- bit selection
- matching the area average performance
- exceeding the area average by implementing theoretical weight-rotary speed principles

This section of the text will discuss the second group, area average performance. Bit selection will be presented as the final section of this chapter.

During recent years, many attempts have been made to optimize drilling operations. Some of the efforts have been directed in fields such as 1) developing drilling fluids that yield high penetration rates, 2) improving solids control equipment design to improve mud properties, and 3) designing bits to improve penetration rates, bit life, or both. In addition, overall experience has led to techniques and equipment that reduce the final cost to the operator.

In the past, optimization during the actual drilling process was based on several principles:

- Drill at high penetration rates for as long as the bit will drill
- Select bit weights and rotary speeds that will give long bit runs with reasonable penetration rates
- Determine the optimum operating conditions that will drill the given interval at the lowest cost per foot

Economics quickly became the primary design criteria, resulting in most optimization techniques being based on the proper selection of bit weights, rotary speeds, and bit types that produce the lowest cost per foot—*minimum cost drilling* (MCD).

The cost of the footage drilled during a single bit run is the sum of three costs: bit costs, trip costs, and rig operating costs for the time required to drill the footage. If the bit run cost is divided by the footage drilled, the result is the cost per foot for the interval drilled, as shown in Eq. 7.1. The cost per foot given by Eq. 7.1 is the cost to be minimized through proper choice of the bit weight and rotary speed. Eq. 7.1 shows that the choice of weight and rotary speed affects only two items: rotary cost and footage drilled. The cost of the bit and the cost to trip the bit are fixed for a particular bit run.

$$\$/ft = \frac{C_b + C_R T_R + C_R T_T}{Y} \qquad (7.1)$$

Where:

$\$/ft$ = cost per foot, $
C_b = bit cost, $
C_R = rig cost, $/hr
T_T = trip time, hr
T_R = rotating time, hr
Y = footage drilled, ft

Table 7–13 presented average trip time values for various depth and bit sizes, reproduced in this chapter. An alternate, suitable approach is the standard "1 hr/1,000 ft" value.

It is interesting to show that proper selection of bit weights and rotary speeds to give minimum-cost drilling may not yield either the maximum penetration rate nor the longest bit runs. The data used in the following example problem will be shown to be correct in a later chapter. (Costs for items such as bits and rig time are far below present costs but are used for illustration only. They are correct, however, on a relative comparison between cost items.)

Example 7.2

Use the data given below and the minimum cost equation to select the optimum bit weights and rotary speeds.

Data:
Rig cost = $75.00/hr
Bit cost = $232.50
Trip time = 6.5 hr

	Bit Weight, lb	Rotary Speed, rpm	Footage Drilled, ft	Rotating Time, hr
Case 1	75,000	127	149	5.06
Case 2	65,000	92	192	8.65
Case 3	65,000	65	217	12.28

Solution:

1. Use the common data and specific case information to calculate cost per foot for the section drilled.

2. $$\frac{\$}{ft} = \frac{C_b + C_R T_T + C_R T_R}{Y} \qquad (7.1)$$

Table 7–13 Average Trip Times

Depth, ft	Hole (Bit) Size, in: Small (< 8.75)	Medium (8.75–9.875)	Large (> 9
2,000	1.5	3.0	4.5
4,000	2.5	4.2	5.75
6,000	3.5	5.4	7.0
8,000	4.7	6.25	8.0
10,000	5.8	7.25	9.0
12,000	7.0	8.25	10.25
14,000	8.25	9.25	11.50
16,000	9.75	10.25	12.50
18,000	11.00	11.25	13.75
20,000	11.8	12.25	15.0

Case 1 $\frac{\$232.50 + (75)(6.5) + (75)(5.06)}{149} = 7.38\ \$/ft$

Case 2 $\frac{\$232.50 + (75)(6.5) + (75)(8.65)}{192} = 7.13\ \$/ft$

Case 3 $\frac{\$232.50 + (75)(6.5) + (75)(12.28)}{217} = 7.56\ \$/ft$

3. In this example, minimum-cost drilling occurs with Case 2, which neither maximum penetration rates nor bit life.

	Penetration Rate, ft/hr	Bit Life, hr	Cost, $/ft
Case 1	29.4	5.06	7.38
Case 2	22.19	8.65	7.13
Case 3	17.67	12.28	7.56

If the fixed cost and the rotating cost are considered separately, the ...cation of the fixed cost to the cost per foot would be high if the bit run terminated after the bit drilled the first foot. But this allocation declines c...uously thereafter as the bit drills more footage. By comparison, the contrib... of the rotating cost to the cost per foot is low initially but increases continu...

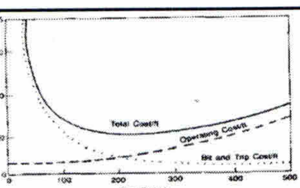


Fig. 7–32 Cost per foot

thereafter, since the penetration rate declines as the bit dulls. These two relations are shown in Fig. 7–32 for a hypothetical bit run at constant weight and rotary speed. The dotted curve is the cost per foot attributed to fixed costs and is independent of the weight and rotary speed chosen. The dashed curve is the rotating cost per foot and is the function of the weight and rotary speed chosen. Its relative position could be changed by other choices of weight and rotary speed. The solid curve is the total cost per foot and is simply the sum of the other two functions. This curve has a minimum value associated with the particular weight and rotary speed chosen. To determine if the value is the lowest cost per foot for all practical combinations of weights and rotary speeds, they must all be calculated and compared.

Matching the Area Average

An easy, beneficial approach to optimizing drilling is to select drilling parameters such as bit type, weight, and rotary speed to ensure that drilling rates (and cost per foot) will equal the area average. Unfortunately, easily accessible field data are often not used. The effort requires less than 1 hour in most cases and can easily save 10–30% in actual rotating costs.

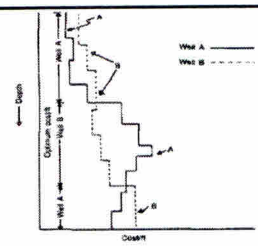


Fig. 7–33 Bit selection based on minimum cost analysis from offset wells A & B

The procedure for this technique is simple:

1. Select the offset control wells.
2. Obtain bit records from the offset wells.
3. Determine the rig cost for the prospect well.
4. Calculate the drilling cost for each bit run on the offset wells with Eq. 7.1.
5. Select the conditions that gave the lowest cost-per-foot results.

Computer programs, such as Adams and Rountree Technology's CSTSUM (cost sum) program, can reduce the required time for the calculations to a few minutes.

A plot of the CSTSUM results is very useful. As an example, assume that Wells A and B are the offset control wells for a prospect. The cost calculations are made and plotted in Fig. 7–33. From the plot, it is clear that Well A had lower drilling costs in the upper and lower sections of the well, while Well B is optimum in the middle sections of the well. Therefore, the bit types, weights, and rotary speeds for the prospect well should be similar to Wells A and B in the respective hole segments in which they had the lowest cost-per-foot results.

Example 7.3

A well is to be drilled in Lafayette parish, Louisiana. The 16,000 ft prospect is in section 25, township 7S, range 5E. The geologist has determined that the two offset needed wells are:

Operator	Well Name	Depth ft
A&RT Oil Co.	E.B. White #1	16,000
McWilliams Ventures	Cochran #3	17,654

The bit records on the wells will be used to select an optimum bit program for minimum-cost drilling of the prospect well. The operating conditions on the offset wells were:

Cochran #3

Bit Run	Size, in.	Type	Cost, $	Depth Out, ft	Feet	Hours
1	17.5	OSC3A	5,062	4,435	4,435	78.5
2	12.25	X3A	2,516	5,867	1,432	37.5
3	12.25	X3A	2,516	6,907	1,040	18
4	12.25	S11	2,516	7,752	845	22.5
5	12.25	FDT	3,052	9,048	1,296	46.5
6	12.25	FDT	3,052	9,509	461	22
7	12.25	S84F	8,388	11,005	1,496	88
8	8.375	S84F	4,377	12,769	1,764	104.5
9	8.375	J22	4,377	12,983	214	33
10	8.375	FP53	4,377	13,230	245	30
11	8.375	F2	4,377	13,595	365	32
12	8.375	Y12	1,101	13,714	119	11.5
13	8.375	J22	4,377	14,519	805	75
14	8.375	F3	4,377	14,797	278	21
15	8.375	J22	4,377	15,600	803	63.5
16	8.375	J22	4,377	15,900	300	29
17	8.375	J22	4,377	16,314	414	36.5
18	8.375	J22	4,377	16,316	2	.5
19	8.375	J22	4,377	17,171	435	77
20	8.375	J22	4,377	17,654	483	53

E.B. White #1

Bit Run	Size, in.	Type	Cost, $	Depth Out, ft	Feet	Hours
1	17.5	X3A	7,422	3,500	3,500	36
2	12.25	X3A	2,516	5,330	1,830	26
3	12.25	X3A	2,516	6,748	1,418	28
4	12.25	X3A	2,516	6,837	89	6
5	12.25	X3A	2,516	7,573	736	32
6	12.25	X3A	2,516	8,098	525	30
7	12.25	J22	8,388	9,442	1,344	80
8	12.25	J22	8,388	10,600	1,158	82
9	8.5	J22	4,377	11,387	787	78
10	8.5	J22	4,377	11,407	20	10
11	8.5	J22	4,377	12,252	845	95
12	8.5	J33	4,377	12,720	468	45
13	8.5	J33	4,377	13,103	383	45
14	8.5	J33	4,377	13,470	367	40
15	8.5	J33	4,377	13,655	185	20
16	8.5	J55	4,377	13,745	90	18
17	8.5	J33	4,377	14,017	272	30
18	8.5	Diamond	14,875	14,467	450	150
19	8.5	Diamond	14,875	15,139	672	160
20	8.5	J22	4,377	16,000	861	98

The bit costs are provided with the previous data. Diamond bit costs are net cost after accounting for salvage value. Use the trip time values from Table 2-8. The rig cost is $6,900/day.

Solution:

1. Cost per foot for each bit run is:

$$\$/ft = \frac{C_b + C_R T_R + C_R T_T}{F}$$

The cost for the first bit run of the Cochran #3 well is:

$$\$/ft = \frac{5{,}062 + (6{,}900/24)(78.5) + (6{,}900/24)(4.6)}{4{,}435} = \frac{28{,}953}{4{,}435} = 6.53$$

2. A summary of the cost calculations for each well is shown in Tables 7-14 and 7-15.

Table 7-14 $/ft Summary for the E.B. White Well

Run	Bit Size	Bit Type	Bit Code	Cost	Depth Out	Feet	Hours	Ft/hr	Trip Time	Run Cost	$/ft
1	17.500	X3A	1.1.4	7422	3500	3500	36.0	97.2	4.3	19084	5.45
2	12.250	X3A	1.1.4	2516	5330	1830	26.0	70.0	5.8	11662	6.41
3	12.250	X3A	1.1.4	2516	6748	1418	29.0	51.9	6.7	12506	8.76
4	12.250	X3A	1.1.4	2516	6837	89	6.0	14.8	7.2	6307	70.86
5	12.250	X3A	1.1.4	2516	7573	736	32.0	23.0	7.4	13890	18.62
6	12.250	X3A	1.1.4	2516	8098	525	30.0	17.5	7.6	13379	25.48
7	12.250	J22	5.1.7	8388	9442	1344	80.0	16.8	8.3	33783	25.13
8	12.250	J22	5.1.7	8388	10600	1158	82.0	14.1	9.0	34563	29.85
9	8.500	J22	5.1.7	4377	11387	787	78.0	10.1	6.4	28707	36.48
10	8.500	J22	5.1.7	4377	11407	20	10.0	2.0	6.9	9225	461.26
11	8.500	J22	5.1.7	4377	12252	845	95.0	8.9	7.1	33736	39.92
12	8.500	J33	5.3.7	4377	12720	468	45.0	10.4	7.3	19417	41.61
13	8.500	J33	5.3.7	4377	13103	383	45.0	8.5	7.6	19544	51.03
14	8.500	J33	5.3.7	4377	13470	367	40.0	9.2	8.0	18169	49.51
15	8.500	J33	5.3.7	4377	13655	185	20.0	9.2	8.1	12466	67.38
16	8.500	J55	6.5.7	4377	13745	90	18.0	5.0	8.2	11914	132.38
17	8.500	J33	5.3.7	4377	14017	272	30.0	9.1	8.3	15395	56.60
18	8.500	Diamond	D1.0.0	14875	14467	450	150.0	3.0	8.5	60434	134.30
19	8.500	Diamond	D1.0.0	14875	15139	672	160.0	4.2	8.9	63424	94.38
20	8.500	J22	5.1.7	4377	16000	861	98.0	8.8	9.3	35230	40.92

Mill Tooth	Insert Bits	Dia. Bits	Strat. Bits	Bit Cost	Total Footage	Rotating Hours	Trip Hours	Net Days	Interval Cost
6	12	2	0	110290.	16000	1109.0	151.9	52.5	472787.

Courtesy, Adams and Prospect Technology's CSTSUM program.

Table 7-15 $/ft Summary for the McWilliams Well

Run	Bit Size	Bit Type	Bit Code	Cost	Depth Out	Feet	Hours	Ft/hr	Trip Time	Run Cost	$/ft
1	17.500	OSC3A	1.1.1	5062	4435	4435	78.5	56.5	4.6	13940	6.53
2	12.250	X3A	1.1.4	2516	5867	1432	37.5	38.2	6.2	13091	10.54
3	12.250	X3A	1.1.4	2516	6907	1040	18.0	57.8	7.0	9489	9.12
4	12.250	S11	1.1.4	2516	7752	845	22.5	37.5	7.5	12537	14.84
5	12.250	FDT	1.2.6	3052	9048	1296	46.5	27.9	8.1	18752	14.47
6	12.250	FDT	1.2.6	3052	9509	461	22.0	21.0	8.6	11854	25.71
7	12.250	S84F	5.1.7	8388	11005	1496	88.0	17.0	9.2	38127	25.28
8	8.375	S84F	5.1.7	4377	12769	1764	104.5	16.9	7.2	36477	20.68
9	8.375	J22	5.1.7	4377	12983	214	33.0	6.5	7.7	16089	74.48
10	8.375	FP53	5.3.7	4377	13230	245	30.0	8.2	7.9	15264	62.30
11	8.375	F2	5.3.7	4377	13595	365	32.0	11.4	8.0	15891	43.54
12	8.375	Y12	1.2.1	1101	13714	119	11.5	10.3	8.2	6752	56.82
13	8.375	J22	5.1.7	4377	14519	805	75.0	10.7	8.5	28532	35.24
14	8.375	F3	5.3.7	4377	14797	278	21.0	13.2	8.8	12939	46.54
15	8.375	J22	5.1.7	4377	15600	803	63.5	12.6	9.1	25299	31.44
16	8.375	J22	5.1.7	4377	15900	300	29.0	10.3	9.4	13425	44.41
17	8.375	J22	5.1.7	4377	16314	414	36.5	9.4	9.7	16046	39.77
18	8.375	J22	5.1.7	4377	16316	2	5.0	.4	10.0	8690	4342.99
19	8.375	J22	5.1.7	4377	17171	435	77.0	5.9	10.1	29425	64.62
20	8.375	J22	5.1.7	4377	17654	483	53.0	9.1	10.4	23604	46.80

Mill Tooth	Insert Bits	Dia. Bits	Strat. Bits	Bit Cost	Total Footage	Rotating Hours	Trip Hours	Net Days	Interval Cost
7	13	0	0	89716.	17654.	839.0	164.2	46.0	786431.

3. The cost per foot to drill each well is compared in Fig. 7-34. The drilling conditions (such as bit type, bit weight, and rotary speed) for the prospect well should be similar to the E.B. White well to 6,650 ft. The drilling conditions below 6,650 ft should follow the Cochran #3 well.

Bit Type Conversion. Occasions will arise when conversion to another bit type is recommended. For example, an operator may elect to convert to an insert, journal-bearing bit from a steel tooth bit. The most significant conversion questions arise, however, when a roller bit to a diamond or PDC bit is considered. The diamond or PDC bits are more expensive with respect to purchase costs. However, they generally run longer than roller bits and reduce trip-time requirements.

The decision process for bit type conversion is simple. If drilling performance for a bit type is known in an area, will a different type of bit reduce drilling costs? For example, if a roller cone bit can drill a section for $25/ft, can a diamond bit reduce the cost by virtue of the fact that it has the ability to reduce trip costs or drill faster?

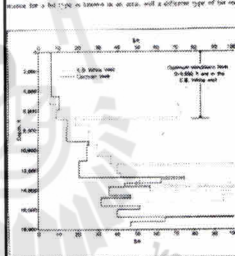


Fig. 7-34 Cost comparisons for Example 7.3

Example 7.4

An operator is considering running a diamond bit into a well. Using the data given below, is it economically feasible to run the bit?

Data:

Previous bit run:
- Bit size = 8.5 in.
- Bit cost = $900
- Total footage = 217 ft
- Rotating time = 14 hr
- Trip time = 6 hr
- Rig cost = $300/hr

Diamond bit data:
- Bit cost = $6800/in. (bit diameter)
- Salvage value = 40%
- Rotating time = 100 hr (assumed)

Solution:

1. Calculate the cost per foot for the section drilled by the previous bit:

$$\$/ft = \frac{C_b + C_R T_R + C_R T_T}{F} = \frac{5900 + (300)(6) + (300)(14)}{217} = \$54.83/ft$$

2. Compute the penetration rate required by the diamond bit to equal the cost per foot for the previous bit.

(a) Actual bit cost = $6800/in. × 8.5 in. × 60% = 34,680

(b) Required penetration rate:

$$\$54.83 = \frac{34{,}080 + (200)(100) + (200)(20)}{(100)(PR)}$$

Where:

PR = penetration rate, ft/hr

($54.83) (100) (PR) = $58,080

PR = 10.59 ft/hr

3. Compare the computed rate of 10.59 ft/hr to actual field cases in the given area. If the comparison shows that the rate cannot be achieved, run a bit similar to the previous bit.
4. It is interesting to note that increasing the rotating time for the diamond bit to 150–200 hr does not significantly change the cost results.

A useful tool in making the bit type conversion decision is a plot of $/ft for several life expectancies of the diamond or PDC bit. The $/ft calculations are repeated several times for various drill rates and life expectancies (Fig. 7-35). If the drill rate required for lower cost per foot cannot be achieved for the expected life of the bit, then conversion to the new bit is not recommended.

Bit Selection

Selecting the right bit for the drilling conditions requires an evaluation of numerous parameters. The selection was reasonably simple several years ago before the introduction of innovative bit designs and improved existing designs. Although the variety of bits is much greater currently and the selection process seems more complicated, a few simple guidelines can be used to increase drill rates and create significant cost savings.

The parameters involved in drill bit selection are very complicated if all factors are considered. However, the following items may be major considerations in bit evaluation:

- formation hardness and abrasiveness
- mud types
- directional considerations
- rotating systems
- coring
- bit size

The major bit types to be considered in this discussion are roller cone, diamond, and PDC bits.

Formation Hardness and Abrasiveness

Most bits are categorized according to the type of formation hardness that they can drill. The usual classifications are soft, medium-soft, medium-

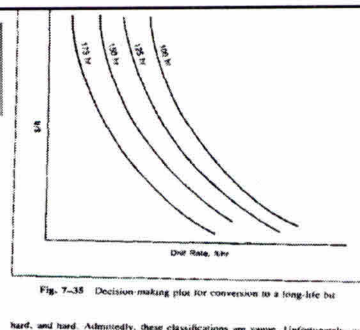


Fig. 7-35 Decision-making plot for conversion to a long-life bit

hard, and hard. Admittedly, these classifications are vague. Unfortunately, no other widely used system is available and, as such, this classification will be followed.

Many formations are erroneously defined as "medium to hard" due to low drill rates. This occurs in areas such as South Louisiana and the Gulf of Mexico and is obviously the result of poor bit selection or operating conditions. Many drilling supervisors have tolerated low drill rates in past years due to uncertainty as to proper selection of bit operating conditions.

The three common bit types can effectively drill soft formations with low compressive strengths. The actual bit to be used depends on other conditions,

Directional Considerations

Mud Types

Rotating Systems

Coring

Bit Size

Starting the Diamond Bit

Table 7–16 Diamond Bit Problem/Solution Checklist

Symptom	Possible Cause	Solution/Action
Torque	Bit-plastic Formations	Increase flow rate*
		Decrease weight
	• Low ΔP	
	• Slow RPM	Increase rotary*

Table 7–16 Diamond Bit Problem/Solution Checklist—cont'd

Problems

7.10 Rework Problem 7.9 and assume that the rig costs are $400 and $200/hr. Plot the three results.

7.11 Rework Problem 7.9 and assume that the trip time average is 2,000 ft/hr and 500 ft/hr. Plot these results with Problem 7.10.

7.12 Refer to Fig. 7–27. Identify the 11 individual bit features.

References

HW NO. 3-2, 7.9, and 7.11
of NEAL J. ADAMS
HW NO. 3-3, ASSIGNMENT # 1
PLANNING A WELL
DUE DATE; Friday 15 August 2014

CHAPTER 7 – ASSIGNMENT #1

PLANNING A WELL

1. The objectives of well planning is to formulate a program from many variables. The program must have three characteristics, name them:
(a) ______
(b) ______
(c) ______

2. A drilling team is generally comprised of individual with expertise in the areas of:
(a) ______
(b) ______
(c) ______
(d) ______
(e) ______
(f) ______
(g) ______
(h) ______

3. Define porosity
______
______
______

4. The objectives of a well program are:
(a) ______
(b) ______
(c) ______
(d) ______

5. At what stage of well planning does the following take place:
(a) Cost Estimate (AFE) ______
(b) Prospect Generation ______

6. List three traits well planners must have:
(a) ______
(b) ______
(c) ______

HW NO. 3-3, ASSIGNMENT # 1
PLANNING A WELL
Due Date; Friday 15 August 2014

4. The objectives of a well program are:
(a) ______
(b) ______
(c) ______
(d) ______

5. At what stage of well planning does the following take place:
(a) Cost Estimate (AFE) ______
(b) Prospect Generation ______

6. List three traits well planners must have:
(a) ______
(b) ______
(c) ______

7. Drilling Fluid Program

An understanding of lithology that will be encountered with the bit will assist in designing the drilling fluid program. Data acquired, as discussed earlier in this chapter, will assist with this program. The available drilling fluid technologies will be :

1. WATER-BASED MUDS
2. OIL-BASED MUDS
3. GASEOUS DRILLING MUDS

An example of MUD PROGRAM is shown in Fig.11.4

•Figure 11.4 MUD PROGRAM

MUD PROGRAM

Hole Size (In)	MD Interval (Ft)	Mud type	Mud Wt. (ppg)	Solids Volume (%)	PV	YP	API FL cc/30min	Oil/Water Ratio	pH	Cl G/L	CEC
26	0 - 120	Gel/Water	8.5 - 9.0	≤ 5	5 - 15	30-40	N/C	N/A	9.0 - 9.5	N/A	< 35
17-1/2	120 - 1500	± 15% KCL/Polymer	9.3 - 10.0	≤ 13	10 - 15	20-30	N/C	N/A	9.0 - 9.5	78,000	≤ 10
12-1/4	1500 - 10,200	Diesel OBM	7.0 - 9.0	≤ 8	20 - 30	10-30	< 18	90/10 - 85/15	N/A	N/A	N/A
8-1/2	10,200 - TD	± 6% KCL/Polymer	9.8 - 14.0	≤ 25	10 - 20	15-25	< 10	N/A	9.0 - 9.5	30,000	≤ 10

NOTES:

1) Hole conditions and/or abnormal pressure may dictate changes from the proposed guidelines. To maximize ROP and minimize lost returns potential, it is recommended that the minimum MW schedule listed above be followed as much as practical (i.e., until well/hole conditions indicate an increase in MW is required or if dilution required to maintain minimum MW becomes excessive). The mud engineer is expected to make any recommendations which he feels will improve this program and the overall well efficiency. Recommendations should be made to the Esso Operations Supervisor and Superintendent via the daily mud report.

2) Minimum of one complete mud check (in & out) per eight hours of drilling and a complete mud check on bottoms up after each trip is required. Mud checks while drilling will include in and out properties, with samples being taken after proper lag time (catch sample at suction pit, allow for cycle time, and catch sample at flowline). Mud properties to be measured at 120° F (API).

3) H.T.H.P. water loss will be run at 250° F and 500 psi or maximum anticipated B.H.T. (whichever is higher) and maintained at 12-15cc/30 minutes below the surface casing shoe. Filter cake description should be made at API conditions (120° F and 100 psi).

4) Consideration should be made to use Glycol/KCL/PHPA mud if used mud can be economically sourced for 17-1/2" hole section. Analysis should look at availability, volume of mud that can be returned, potential ROP enhancements and reduced disposal costs. Due to the inhibitive properties of Glycol, it may also be possible to reduce the KCL concentration of the mud system (e.g., 15% down to ± 8%).

5) Refer to Drilling Operations manual for Oil Base Mud Guidelines and Checklist. Ensure all personnel working near OBM wear appropriate Personnel Protective Equipment (PPE) and follow recommended safety precautions. To reduce time spent in critical path - (*Fast Track*) and to minimize OBM contamination, consideration should be made to displace/bump 13-3/8" casing top wiper plug with OBM during cementing (may require additional mud tanks; active mud tanks can be dumped/cleaned while WOC and nippling up "A" section & BOP's).

7.5. Mud Program

Hole Section (in)	**12 ¼" AND 8 ½"**	**6 1/8"**
Mud System	Potassium Sulphate - polymer	Potassium Sulphate - polymer
Requirements	Prevent wellbore stability problems.	TREATED WATER Biocides & Oxygen Scavanger
	Minimize mud losses into the shallow sands of the Chaliang Lab Formation.	**Minimizo Environmental impact**
	Mimimise Environmental impact	
Density (ppg):	< 9.6+	< 9.4
FV (sec / qt):	50 – 60	35 – 45
PV (cps):	As low as possible	As low as possible
YP (lbs/100 sq ft)	15 – 20	10 – 15
API Fluid Loss (ccs):	< 5	< 10
PH:	8.5 - 9.5	8.5 – 9.5
LGS (%v/v):	< 5%	< 5%
K_2SO_4 (%wt/v):	**> 7% (25 ppb)**	**>7% (25 ppb)**

Note: Actual Mud Weights and properties will depend on wellbore conditions.

7.5.1 **Recommended Formulations**

Chemical	Function	Hole section (in) 12 ¼ & 8 ½" (ppb)	Chemical	6 1/8" (ppb)
Caustic Soda	pH	0.5	Biocide	0.3
PAC	Viscosifier	1.5	Oxygen Scav	0.5
PAC LV	Fluid Loss	2.0		1.0
Xanthan Gum Polymer	Viscosifier	0.4		0.4
Pregelatinized Starch	Fluid Loss	2.0		2.0
PHPA	Encapsulation	1.0		0
K_2SO_4	Inhibition	> 25.0		>25.0
Barite	Density	As required		

7.5.2 **Mixing Procedure**

1. Fill the tank with volume required.
2. Mix required concentration of Potassium Sulphate (25 ppb).
3. Mix the polymers slowly and smoothly through the hopper at the following rates:

Xanthan gum polymer	0.4 ppb at 20 minutes per sack
PAC (or equiv.)	1.5 ppb at 15 minutes per sack
PAC LV (or equiv.)	2.0 ppb at 10 minutes per sack
Pregelatinized starch	2.0 ppb at 5 minutes per sack

4. Adjust pH to 9.5 with caustic soda.

C. MUD PROGRAMME

C.1 36" and 17-1/2" Hole sections

1.1 Mud Type

Seawater/HI-VIS sweeps, with the following properties:

MW	:	8.9 ppg
VIS	:	40+ sec/qt.
YP	:	Above 24 lbs/100 sq.ft.

1.2 Operational Details

Prior to spud-in build at least 400 bbls of viscous pre-hydrated bentonite slurry. Spud in and drill 36" and 17-1/2" hole sections with seawater. Sweep with 20 - 25 bbls pills of Viscous pre-hydrated Bentonite slurry before every connection or as required to ensure hole cleaning.

Control drilling rate (i.e. relate penetration rate to mud flow rate) to maintain hole cleaning and hole straightness, however directional drilling may necessitate compromises.

Circulate the hole clean with seawater while on bottom and displace the hole with HI-VIS 9.0-9.5 ppg gel slurry before pulling out to run casing.

C.2 12-1/4" Hole section

2.1 Mud Type

Seawater/HI-VIS sweeps to seawater/gel/polymer with the following properties:

MW	:	8.6 - 9.0 ppg
VIS	:	40 - 50 sec./qt.
PV	:	6 - 12 cps
YP	:	10 - 20 lbs/100 sq.ft.
Fluid Loss	:	Below 10 cc
pH	:	9.5 - 10.5
Solids	:	3 - 5%
MBT	:	below 20 lbs/bbl

In offshore operation, an emergency response plan and an oil spill contingency plan will be added to a drilling program outlines as in the following example:

DRILLING PROGRAM

WELL DATA
LOCATION MAP
SUMMARY INTRODUCTION
DRILLING TIME VS DEPTH CURVE
SEQUENCE OF OPERATION
ANTICIPATED DRILLING PROBLEMS
DRILLIND MUD PROGRAMME
CASING PROGRAMME
CEMENTING PROGRAMME
DRILLING SURVEY PROGRAMME
TESTING PROGRAMME
PLUG AND ABANDON(TENTATIVE)
PRESSURE CONTROL
OPERATIONAL LIMITS

GEOLOGICAL PROGNOSIS

GEOLOGICAL SUMMARY
LITHOLOGICAL PROFILE
LOGGING PROGRAMME
DRILLIND HAZARD
SAMPLING PROGRAMME
CORING
MUD LOG

EMERGENCY RESPONSE PLAN

RIG SAFETY, HOUSEKEEPING
FIRE PREVENTION
ACCIDENT RESPONES, STAND BY HELICOPTERS
KICK CONTROL
MEDICAL EVACUATION
RIG DISASTER PROCEDURE

OIL SPILL CONTINGENCY PLAN

LOCAL POLLUTION RISK
INCIDENT RESPONSE, ORGANIZATION AND ACTION
RESPONSE STRATEGY
OIL SPILL STAFF PROCEDURES CHECKLISTS
CLEAN UP RESOURCES
RESOURCES DIRECTORY

GEOLOGICAL OUTLINE

Fig. 11.1. Geological Outlines

Name and Location:
Dry Hole No. 1-"A," 700' FNL & 660' FEL Section 82.
Block B-1, H&GN RR Survey, Northwest Mendota Field, Roberts County, Texas

Objective Horizon and Contract Depth:
Base of Upper Morrow Sand plus 100'; Approved depth 11,350'

Estimated Formation Tops:

Estimated Elevation K. B.	2,857'
Top Wichita-Albany Anhydrite	2,950'
Top Wolfcamp Dolomite	4,150'
Top Possible Lost Circ.	4,300'
Top Douglas Sands	7,100'
Top Granite Wash	9,950'
Top 13 Finger Lime	10,910'
Top Morrow "Formation"	11,000'
Top Morrow Sand	11,165'

Possible Producing Zones:

Douglas Sand	7,100–7,200'
Stray Douglas Sand	7,400'
Des Moines	9,950–9,900'
Granite Wash	9,950–10,800'
Upper Morrow Sand	11,165'

Samples:
Catch 10' samples from 6,800' to TD. Wash thoroughly, air dry, and tie in 100' bundl... ing time from 3,350' to TD.

Coring:
One 50, oriented core of Upper Morrow Sand 11,165 to 11,215', approximately. (N... dipmeter study and environmental analysis.)

Drill Stem Testing:
Possibly one test in Granite Wash

Surveys:
Schlumberger IES & Compensated Density log

Remarks:
Set surface casing at 3,350'; set intermediate casing at 10,950' (5½"). Possible ... tubing to be set outside of 5½" casing in order to test Granite Wash

A DRILLING PERFORMANCE PROGNOSIS WESTHEIMER-NEUSTADT CORPORATION'S COMANCHE COUNTY, OKLAHOMA, PROSPECT

CONTENTS

In offshore operation, an emergency response plan and an oil spill contingency plan will be added to a drilling program outlines as in the following example:

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CEMENTING PROGRAMME
DRILLING SURVEY PROGRAMME
TESTING PROGRAMME
PLUG AND ABANDON(TENTATIVE)
PRESSURE CONTROL
OPERATIONAL LIMITS

GEOLOGICAL PROGNOSIS

1. **GEOLOGICAL SUMMARY**
2. **LITHOLOGICAL PROFILE**
3. **LOGGING PROGRAMME**
4. **DRILLIND HAZARD**
5. **SAMPLING PROGRAMME**
6. **CORING**
7. **MUD LOG**

EMERGENCY RESPONSE PLAN

- **RIG SAFETY, HOUSEKEEPING**
- **FIRE PREVENTION**
- **ACCIDENT RESPONES, STAND BY HELICOPTERS**
- **KICK CONTROL**
- **MEDICAL EVACUATION**
- **RIG DISASTER PROCEDURE**

OIL SPILL CONTINGENCY PLAN

LOCAL POLLUTION RISK
INCIDENT RESPONSE, ORGANIZATION AND ACTION
RESPONSE STRATEGY

•Coring Program

•Normally the geologists and reservoir engineers will determine the intervals from which they require core data, and also determine whether they require a side wall core or a bottom core. The informative rocks such as reservoir, seal, source, and basement rocked are usually being cored.

• Testing Program

Despite the tremendous value of core analysis, some shadow of doubt always remains concerning the potential productivity of an exploratory well, and this doubt is not dispelled until a sizeable sample of oil has been delivered to the surface. The type and period of tests will be planned upon the encountered hydrocarbon, condition, and situation data requirement. The available testing techniques are as follows: WIRELINE TEST; FIT(Formation interval tester) and RFT(Repeated Formation Tester)
DST (Drill Stem Test).
PRODUCTION TEST: Short Term, or Long Term

8. Logging Program

Logging is an important operation in oil and gas production. In addition to identifying oil and gas zones, logging can be used effectively for drilling progress evaluation. The geologists and reservoir engineers will design the intervals and depths from which they require logging. The available logs will be

DRILLER'S LODS
MUD LOGS
WIRELINE LOGS
Electric Logs
Radioactive Logs
RFT, FIT
Wave Propagation Logs
Electromagnetic Logs

9. Well Completion Design

The factors affecting the completion are as follows :

1. RESERVOIR CHARACTORISTIC.

WATER SENSIVITY.
POROSITY.
PERMEABILITY.
THICKNESS.
LITHOLOGY.
PRESSURE.
RESERVOIR DAMAGE.
PRODUCTIVITY

The following completion types will have to be considered along with the reservoir parameters listed above:

OPEN HOLE COMPLETION
CASED HOLE COMPLETION
LINER COMPLETION

10.Cementing Program

- The cement program should consider and include details for the formulation of the following types of cement jobs:

- 1.PRIMARY CEMENT JOBS,
- 2.SECONDARY CEMENT JOBS,
- 3.CEMENT PLUGS.
- An example of CEMENT program is shown in Fig.11.6

Figure 11.6 CEMENTING PROGRAM

Casing Size (in)	Shoe Depth (ft RKB)	Type & Amount	Additives	Yield (Cu.Ft/Sk)	Density (Lb/Gal)	Comments
20	120	Class G 315 sx	2% BWOC $CaCl_2$ and 1.0 Gal/10 Bbl D-Air2 in Fresh Water; FW ratio = 5.00 Gal/Sk	1.15	15.8	Use a stab-in Float Shoe. Volume is based on 100% excess in open hole section. Pilot Test Pump Time (hr:min) = 3:30
13-3/8" *(Lead)*	1500	Class G 500 sx	2.5% (BWOW) prehydrated gel in Fresh Water; FW ratio = 8.93 Gal/Sk	1.67	13.6	Volume is based on bringing cement to surface and using 50% excess in open hole. Ensure float equipment is PDC drillable.
(Tail)		Class G 400 sx	Neat (no additives); FW ratio = 5.00 Gal/Sk	1.15	15.8	Pilot Test Pump Times (hr:min): Lead = 4:30; Tail = ± 3:00
9-5/8" *(Lead)*	9,500 TVD 10,200 MD	Class G 825 sx	Retarder, Dispersant, Fluid Loss *(type & quantities to be specified in 9-5/8" Casing program)*; FW ratio = 8.93 Gal/Sk	1.67	13.6	TOC is planned @ ± 6,800 ft MD (cmt lower 1/3 of casing for stability). Volumes shown (estimated) were calculated using 80% excess in open hole; actual volumes to be based on caliper log.
(Tail)		Class G 500 sx	Retarder, Dispersant, Fluid Loss, Latex *(type & quantities to be specified in 9-5/8" Casing program)*; FW ratio = 5.00 Gal/Sk	1.15	15.8	Slurry to include additives to block annular flow
7"	10,710 TVD 12,000 MD	Class G 440 sx	Retarder, Dispersant, Fluid Loss, Latex, LCM *(type & quantities to be specified in 7" Casing program)*	1.15	15.8	TOC is planned @ ± 9,200 ft MD (1000 ft above 9-5/8" shoe). Volume shown (estimate) was calculated using 50% excess in open hole; actual volume to be based on caliper log. Slurry to include additives to block annular flow.

11. Drill Pipe Design

The drilling engineer must design and request the drill pipe assembly to serve these following purposes :

1. Provide a drilling fluid conduit from the drilling rig to the bit.
2. Transfer the rotary motion from the drilling rig to the bit.

CASING AND TUBING PROGRAM

Casing/Tubing Size (In)	Shoe Depth (ft RKB)	Wt (Lb/Ft)	Grade	Hole Size (In)	Drift ID (in)	Connection	Collapse (Psi)	Burst (Psi)	Tension (Kips)
20	120	94	X-52	26	18.936	Vetco L	-	-	-
13-3/8	1,500	61	K-55	17-1/2	12.339	Buttress	1540	3090	962
9-5/8	9,500 TVD/10,200 MD	47	L-80	12-1/4	8.525	Buttress	4760	6870	1086
7	10,710 TVD/12,000MD	32	L-80	8-1/2	5.969	YAM-Ace	8610	9060	745
4	as required	13	L-80	5.969	3.215	YAM-Ace	12110	11550	304

Notes:

1. The Collapse, Burst and Tension values listed above do not include Safety Factors.
2. Detailed 9-5/8 and 7 inch casing/cementing programs and completion procedure will be provided later.
3. *Design Factors:*

Casing	Collapse	Burst	Tension
20, 13-3/8, 9-5/8	1.000	1.375	1.333
7	1.125	1.25	1.333
4	1.125	1.250	1.333

BOP/Wellhead/Casing Testing

Casing Size (in)	Wellhead Section	Wellhead Size (in)	Wellhead Rating (psi)	Annular BOP Size (in)	Annular BOP Rating (PSI)	Ram BOP Size (in)	Ram BOP Rating (psi)	Test Pressures Choke Manifold (psi)	Test Pressures Casing (psi)	Test Pressures Annular (psi)	Test Pressures Ram BOP (psi)
20	-	-	-	none		none					
13-3/8	"A"	13-5/8	3k	13-5/8	5k	13-5/8	10k	3000	1500	200/3000	200/3000
9-5/8	"B"	11	5k	13-5/8	5k	13-5/8	10k	5000	4500	200/3500	200/5000
7	"C"	7-1/16	10k	13-5/8	5k	13-5/8	10k	7000	5000	200/3500	200/7000

12. Drilling Sizing and Selection

Rotary rig selection for the drilling of a well is the final task in the well planning process. Using the knowledge and experiences of the well plan will impose sufficient limitations to allow the drilling engineer an accurate design of the drilling rig requirements. A specification sheet for a drilling rig will normally include the following items :

1. Drawworks power capability and cable size.
2. Derrick height and maximum capable hook load.
3. Substructure height and load capacity.
4. Power source and size.
5. Drillstring size, weight and grade.
6. Blow out preventer type, size and pressure rating.
7. Mud pump size, including rate and pressure limitations.
8. Mud tank volume.
9. Mud cleaning equipment including the shale shaker, desilter and desander.

Miscellaneous rig equipment including such items as communication equipment, crew accommodation, and drilling recorder.

13. Drilling Rate Prognosis

The single most important consideration in establishing a cost estimate for a well is time. A sample drilling time plot is shown on Fig 11.9. An estimation of the time required for each section of hole is tabulated (as shown in Fig 11.10). This tabulation will include such a things as :

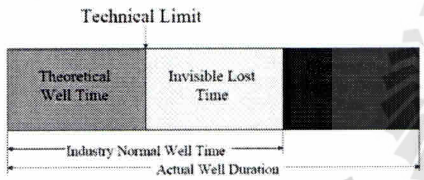
1 Drilling surface hole.
2. Setting surface casing.
3. Drilling intermediate hole.
4.Setting intermediate casing
.5.Coring.
6.Testing.
7.Logging.8.Drilling main hole.
9. Setting production casing, ect.

PLANNING

- Offset wells are evaluated <u>in detail</u> for time required to drill and complete
- Based on the gathered information, the well drilling plan is broken down into many tasks
- Complicated wells may have more than 100 separate tasks

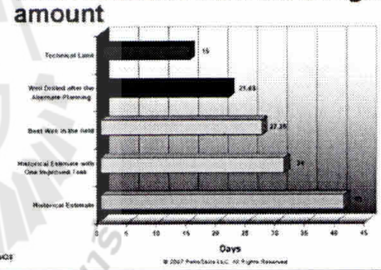
PLANNING

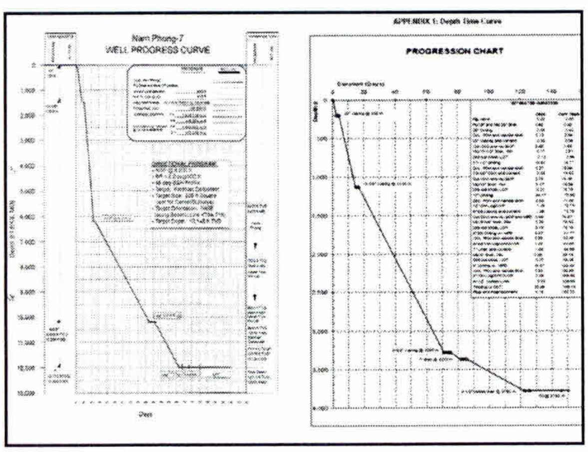
- The time is broken up into
  - Theoretical well time,
  - Conventional lost or down time, and
  - Invisible lost time

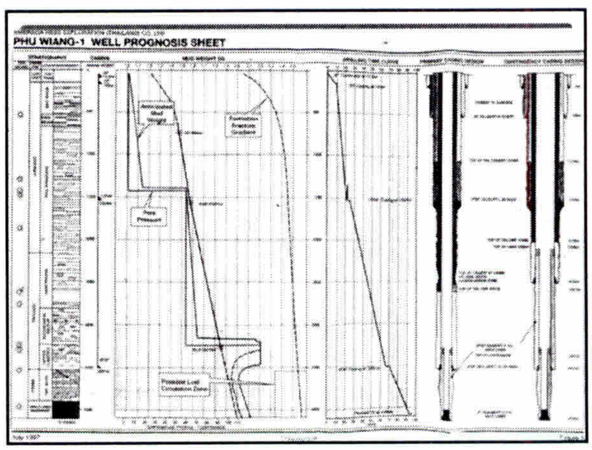


PLANNING

- Jones and Poupet reported 20% improvement from the best previous offset well performance and 25% cost reduction from the budgeted amount







12. Cost Estimate and Project Approval

The cost estimate and project approval are often referred to as AFE or Authority For Expenditure. The AFT provides the drilling team with the opportunity to prepare a detailed cost estimate for the project and have the company allocate the necessary funds. It provides a measuring device to gauge the performance of the team. The AFT includes cost estimates for all materials, services, transportation, and accommodations required for the drilling and evaluation of the well. Often the AFT tabulation will comprise a total for dry hole and another total for a completed well.

Although cost estimates are sometimes very difficult, and often many of costs are just guesses, it is becoming common practice to prepare the AFE on PC computer. The computer uses spreadsheet programs like Lotus 123 or Excell.

The approval of the AFE and the drilling program by the senior management is their acknowledgment of an understanding of the problems and costs expected in the drilling proposed well. The process for obtaining this approval is the circulation of the AFE, approved by the operator at the highest level of management necessary to commit to the level of expenditure, to all the interested participants for their approval.

A sample of cost estimated sheet is shown in Fig 11.11

AUTHORIZATION FOR EXPENDITURE

[illegible]		
COUNTRY:	THAILAND ONSHORE KHORAT PLATEAU	CONCESSION: L 29/50
PROSPECT:	CHATTURAT PROSPECT	CONCESSIONAIRE: TPPL
WELL NAME:	TRIPLE	WELL TYPE: Exploration
SURFACE LOC:		
PROPOSED BHL:	STRAIGHT VERTICAL	
PROPOSED TD:	4000M TVD	
	4000M MD	

	DRY HOLE (140 DAYS) (US$)	TEST PRE-COMPLETED (160 DAYS) (US$)
500 TUBULAR EQUIPMENT		
TANGIBLE COST (WELL INVESTMENT)		
Length (m) Size (inches)		
30 — 20 conductor	20,000	20,000
250 — 13 3/8 CASING	140,000	140,000
1400 — 9 5/8 CASING	400,000	400,000
1900 — 7 LINER	200,000	300,000
4000 — 4 1/2 LINER	100,000	100,000
4000 — 3 1/2 TUBING		200,000
SURFACE AND SUB SURFACE EQUIP.	280,000	200,000
1100 WELL HEAD & MISC. EQUIP (10,000 PSI)	250,000	300,000
TOTAL TANGIBLES	1,390,000	1,660,000
INTANGIBLES COSTS		
MO-DEMO	1,200,000	1,200,000
100 LOCATION AND SITE PREPARATION	500,000	530,000
200 DRILLING RIG AND TOOLS		
RIG 38,000$/D (1520$/m)	4,560,000	6,080,000
BIT	1,000,000	1,000,000
TOOLS	500,000	600,000
300 DRILLING FLUID and Chemicals	1,500,000	1,600,000
400 RENTAL EQUIPMENT	500,000	500,000
500 CEMENT ENGINEERING	700,000	800,000
600 SUPPORT SERVICE		
MUD LOGGING	200,000	250,000
ELECTRIC LOG	600,000	700,000
CASING TOOLS SERVICE	300,000	350,000
WELL TEST		1,000,000
OTHERS	500,000	600,000
700 TRANSPORTATION	200,000	220,000
800 SUPERVISION AND ADMINISTRATION	1,000,000	1,200,000
900-1100 OTHERS	500,000	530,000
1200 WASTE MANAGEMENT	60000	450,000
TOTAL INTANGIBLES	14,440,000	18,030,000
TOTAL WELL COST =	15,830,000	19,690,000
AVERAGE DRILLING COST = 3955 $/m or = 1206 $/ft.		1206 $/ft.

AFE DETAILED SUMMARY

EXPENDITURE	DRY HOLE (140 DAYS) US$	COMPLETED (160 DAYS) US$
100 LOCATION PREPARATION		
110 PERMIT (PURCHASE)	100,000	100,00
120 SURVEY	10,000	16,00
130 RIGHT OF WAY, SPECIAL PERMIT	50,000	50,00
140 LOCATION PREPARATION	320,000	350,00
150 CLEANUP	20,000	20,00
TOTAL	500,000	530,00
200 DRILLING RIG AND TOOLS		
210 MOVE IN AND OUT	100,000	100,00
220 FOOTAGE BID		
230 STRAIGHT DAY WORK BID	4,560,000	6,080,00
240 FUEL	100,000	120,00
250 WATER	10,000	10,00
260 BITS	1,000,000	1,000,00
270 TOOLS	200,000	250,00
TOTAL	5,970,000	7,560,00
300 DRILLING FLUIDS		
310 DRILLING FLUIDS	1,600,000	1,600,00
320 PACKER FLUID		20,00
330 COMPLETION FLUID		
TOTAL	1,500,000	1,620,00
400 RENTAL EQUIPMENT		
410 WELL CONTROL EQUIPMENT	50,000	70,00
420 ROTARY TOOLS AND ACCESSORIES	10,000	25,00
430 MUD RELATED EQUIPMENT	30,000	35,00
440 CASING TOOL	40,000	60,00
450 MISCELLANEOUS	270,000	270,00
TOTAL	400,000	460,00
500 CEMENTING		
510 CONDUCTOR CASING	50,000	50,00
520 SURFACE CASING	80,000	80,00
530 INTERMEDIATE CASING	100,000	100,00
540 INTERMEDIATE CASING	120,000	120,00
550 FIRST LINER	20,000	20,00
560 SECOND (SLOT) LINER	0	
570 PRODUCTION CASING		100,00
580 PLUGS	100,000	100,00
MATERIAL	230,000	220,00
TOTAL	700,000	750,00

600 SUPPORT SERVICES		
[illegible]	[illegible]	[illegible]
621 MUD LOGGING	[illegible]	[illegible]
624 CORE ANALYSIS	600,000	600,000
625 [illegible]		[illegible]
627 COMPLETION SERVICE		[illegible]
630 THREAD INSPECTION		
631 SURFACE CASING	8,000	8,000
632 INTERMEDIATE CASING	20,000	24,000
633 FIRST LINER	2,000	2,000
634 SECOND (SLOT) LINER	2,000	2,000
635 PRODUCTION CASING		20,000
636 TIE BACK STRING		
637 TUBING		
640 GALLEY		
650 WELDING, LABOR, RENTAL EQUIPMENT	10,000	24,000
660 FORMATION TESTING		
670 FISHING DIRECTIONAL CONSULTANT		
680 ACIDIZING FRACTURING	100,000	100,000
690 MISCELLANEOUS/EQUIPMENT	300,000	300,000
TOTAL	1,400,000	1,637,000
700 TRANSPORTATION		
710 TRUCKING	100,000	110,000
720 MARINE		
730 AIR		
740 OTHERS	100,000	110,000
TOTAL	200,000	220,000
800 SUPERVISION AND ADMINISTRATION		
810 FIELD SUPERVISION	400,000	500,000
820 OFFICE SUPERVISION	300,000	300,000
830 INSURANCE, BONDS	300,000	
TOTAL	1,000,000	1,100,000
900 TUBULAR EQUIPMENT		
905 DRIVE PIPE	10,000	20,000
910 CONDUCTOR CASING	20,000	140,000
915 SURFACE CASING	140,000	400,000
920 INTERMEDIATE CASING	400,000	200,000
925 INTERMEDIATE CASING	200,000	100,000
930 FIRST LINER	70,000	70,000
935 SECOND (SLOT) LINER	100,000	100,000
940 SURFACE EQUIPMENT	200,000	250,000
950 TUBING		200,000
960 CASING EQUIPMENT		
961 DRIVE PIPE	10,000	10,000
962 CONDUCTOR CASING		
963 SURFACE CASING	4,000	5,000
964 INTERMEDIATE CASING	4,000	5,000
965 FIRST LINER		
966 SECOND (SLOT) LINER		
967 PRODUCTION CASING		
WELL HEAD & MISC. EQUIP (10,000 PSI)	400,000	300,000
TOTAL	[illegible]	[illegible]

1000 WELL HEAD EQUIPMENT		
1010 CASING HEAD	20000	20,000
1020 INTERMEDIATE SPOOL	40000	30,000
1030 TUBING SPOOL		100,000
1040 TREE		300,000
1050 MISCELLANEOUS BOP	400000	500,000
TOTAL	460,000	950,000
1100 COMPLETION EQUIPMENT		
1105 PACKERS		8,000
1110 BLAST JOINT AND LANDING NIPPLES		10,000
1115 SPECIAL LINER		
1120 SAFETY JOINTS		5,000
1125 SUBSURFACE SAFETY DEVICES		10,000
1130 SEAL ASSEMBLY		10,000
1135 GAS LIFT EQUIPMENT		
1140 GRAVEL PACK EQUIPMENT		
1145 MISCELLANEOUS		200,000
1200 WASTE MANAGEMENT	600000	460000
1300 OTHERS	225000	460000
TOTAL	600,000	1,940,000
TOTAL WELL COST =	14,620,000	18,490,000
MO-DEMO	1,200,000	1,200,000
GRAND TOTAL OPERATION COST	15,820,000	19,690,000

AVERAGE DRILLING COST = 3300$/M IF 4200=3300*4200= MMS 13860000

WELL + PRE-COMPLETION = 14+1.76 million $ = 15.76MM$

AUTHORIZATION FOR EXPENDITURE

27-May-14		
COUNTRY:	THAILAND ONSHORE KHORAT PLATEAU	CONCESSION: L 29/50
PROSPECT:	CHATTURAT PROSPECT	CONCESSIONAIRE: TPPL
WELL NAME:	CHATTURAT-2	WELL TYPE: Exploration
SURFACE LOC:		
PROPOSED BHL:	DIRECTIONAL WELL	
PROPOSED TD:	4200M TVD	
	4500M MD	

	DRY HOLE (120 DAYS) (US$)	COMPLETED AND TESTED (140 DAYS)
500 TUBULAR EQUIPMENT		
TANGIBLE COST (WELL INVESTMENT)		
Length (m) Size (inches)		
200 — 20 CASING	30,000	30,000
900 — 13 3/8 CASING	200,000	200,000
2900 — 9 5/8 CASING	400,000	400,000
3000 — 7 LINER	300,000	300,000
4500 — 3 1/2 TUBING	200,000	200,000
1100 WELL HEAD & MISC.EQUIP (10,000 PSI)	350,000	400,000
TOTAL TANGIBLES	1,400,000	1,480,000
INTANGIBLES COSTS		
MO-DEMO	800,000	800,000
100 LOCATION AND SITE PREPARATION	500,000	500,000
200 DRILLING RIG AND TOOLS		
RIG 40,000$/D	4,800,000	5,200,000
BIT	1,000,000	1,000,000
TOOL	500,000	550,000
Directional Drilling (80*12,000)	960,000	960,000
300 DRILLING FLUID	800,000	900,000
400 RENTAL EQUIPMENT	500,000	700,000
500 CEMENTING SERVICE	900,000	1,000,000
600 SUPPORT SERVICE		
MUD LOGGING	240,000	240,000
ELECTRIC LOG	600,000	700,000
CASING TOOLS SERVICE	100,000	100,000
WELL TEST		200,000
OTHERS	700,000	750,000
700 TRANSPORTATION	200,000	220,000
800 SUPERVISION AND ADMINISTRATION	300,000	400,000
900-1100 OTHERS	1,000,000	1,430,000
DST TEST	1,300,000	1,300,000
Waste Management	1,000,000	1,100,000
TOTAL INTANGIBLES	15,900,000	18,530,000
TOTAL WELL COST =	17,300,000	20,000,000

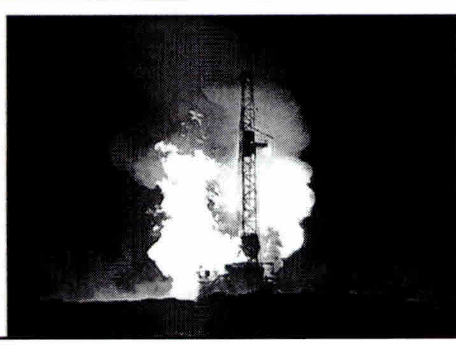
AUTHORIZATION FOR EXPENDITURE for LUMP SUM

27-May-14		
COUNTRY:	THAILAND ONSHORE KHORAT PLATEAU	CONCESSION: L 29/50
PROSPECT:	CHATTURAT PROSPECT	CONCESSIONAIRE: TPPL
WELL NAME:	CHATTURAT-2	WELL TYPE: Exploration
SURFACE LOC:		
PROPOSED BHL:	Directional Well	
PROPOSED TD:	4200M TVD	
	4500M MD	

Item	Description	Price / Time Vertical Depth (US$/m)	Designed Well Time Vertical Depth (meter)	Designed Well Time Measured Depth (meter)	SUM(US$)
1	The charge rate for drilling rig and operation per meter for vertical section	2220	1,800	1800	3996000
2	The charge rate for drilling rig and operation per meter for DIRECTIONAL DRILLING	2520	2,400	2730	6879600
3	The charge rate for drilling Rate of meter 0-4350M	230	4,200	4,530	1041900
4	The charge rate for mud Logging technician services	70	4,200	4530	317100
5	The charge rate for the supply of wellhead, casing and tubing liner hanger and services and tubular running services	311	4,200	4530	1411650
6	The charge rate for the cementing services including casing accessories and well abandonment	220	4,200	4530	996600
7	Mud Logging	52.5	4,200	4530	237825
8	Wireline Logging	137.2	4,200	4530	621516
9	MOBILIZATION				300000
10	OTHERS				300000
LUMP SUM TO SINOPEC COST=					**16136550**
11	Waste Management				1200000
12	DST Test to Sinopec Rangsu				1300000
13	Well Stimulation				300000
14	Well Completion				700000
15	OTHERS				363450
TOTAL WELL COST=				US$	**20,000,000**

Well Control Procedure

Well Control



KILL Procedures

KILL PROCEDURES

Driller's Method

1st Circulation : Circulate Out Kick With Original Weight Mud

1. Open choke, bring pump up to kill sped while maintaining constant casing pressure (or kill line constant with a Subsea Stack)
2. With the pump at kill speed, having allowed for the time lag, switch to drill pipe pressure, maintain constant ICP on the drill pipe by manipulating choke
3. After kick is circulated out, close-in well while maintaining constant casing pressure (or kill line constant with a Subsea Stack).
4. When the well is totally closed-in, SICP must be same as original SIDPP. If not, resume circulation until all the influx is circulated out

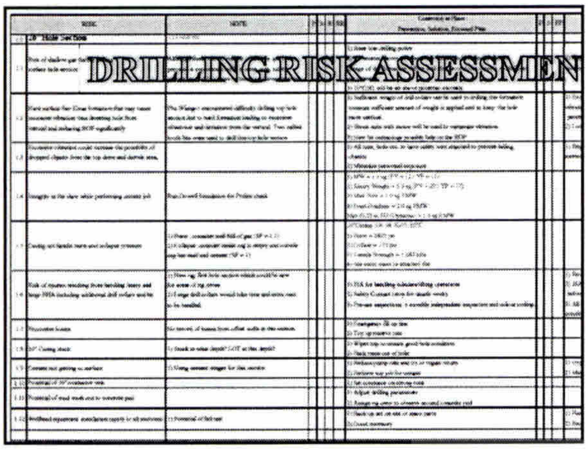
2nd Circulaton: Displace Original Mud With Kill Weight Mud

1st Part - Pumping Kill Mud Weight from Surface to Bit.

5. Reset stroke counter, open choke, bring pump up to kill speed while maintaining constant casing pressure. Re-zero counter when surface lines have been displaced.
6. (If all the influx is out) Maintain constant casing pressure until the heavy mud reaches the bit or follow a DP Pressure Step Down. At this point DP pressure will be at FCP
7. The Supervisor may choose to stop pumping to check that the kill mud is heavy enough to overbalance formation pressure. With pumps off and no safety pressure i.e. SIDPP = zero and SICP = Initial SIDPP

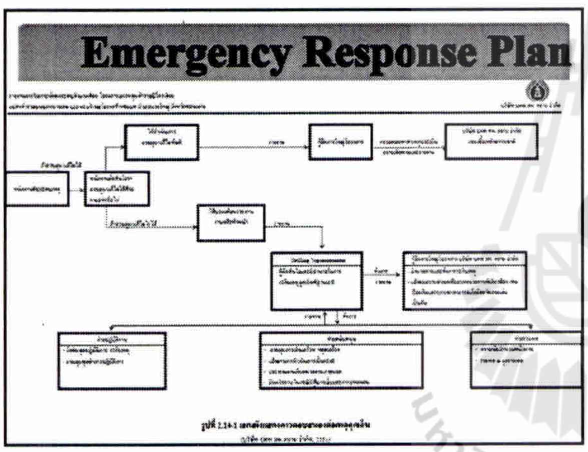
2nd Part - Pumping Kill Mud Weight from Bit to Surface.

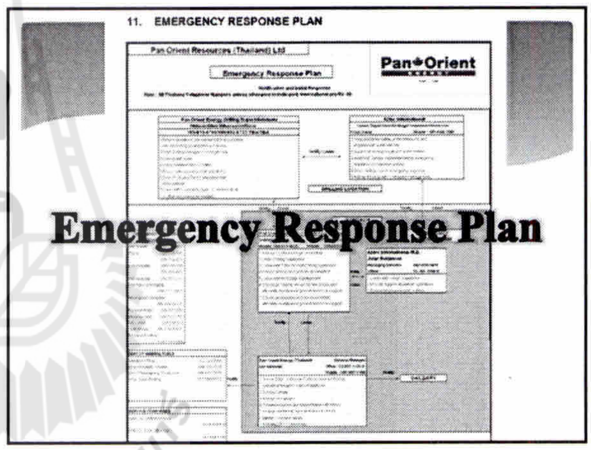
8. Restart pumps holding Casing or Kill Line constant then continue pumping while maintaining constant FCP on the drill pipe until the heavy mud reaches the surface
9. Stop pump. Check for flow.

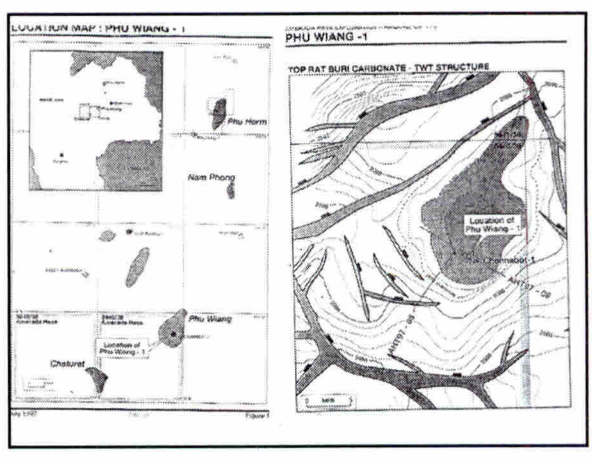


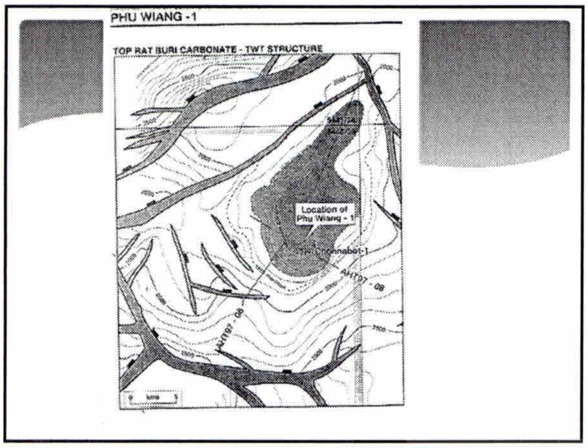
DRILLING RISK ASSESSMENT

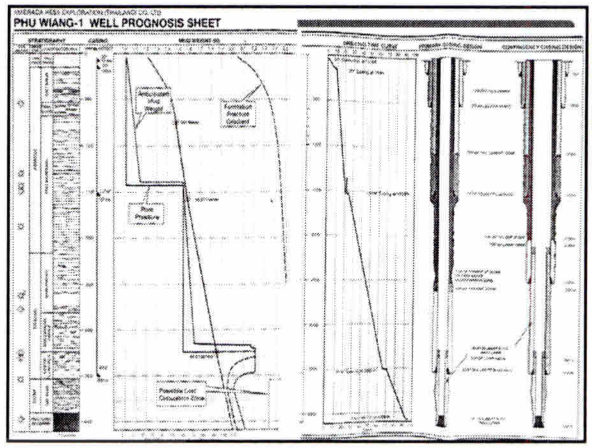
		top hole section.	ROP
1.3	Excessive vibration could increase the possibilty of dropped objects from the top drive and derrick area,		1) All nuts, bolts etc. to have safety wire attached to prevent falling objects. 2) Minimize personnel exposure
1.4	Integrity at the shoe while performing cement job	Run Dowell Simulation for Prelim check	1) MW = 1.1 sg (PV = 12 / YP = 17) 2) Sluury Weight = 1.9 sg (PV = 20 / YP = 17) 3) Max Pore = 1.0 sg EMW 4) Fract Gradient = 2.0 sg EMW Max ECD at TD (Dynamic) = 1.9 sg EMW
1.5	Casing not handle burst and collapse pressure	1) Burst : consider well full of gas (SF = 1.1) 2) Collapse: consider inside csg is empty and outside csg has mud and cement (SF = 1)	20"Casing 106.5#, K-55, BTC 1) Burst = 2410 psi 2) Collase = 770 psi 3) Tensile Strength = 1,683 klbs 4) See excel sheet or attached file
1.6	Risk of injuries resulting from handling heavy and large BHA including additional drill collars and bit	1) New rig, first hole section which could be new for some of rig crews 2) Large drill collars would take time and extra care to be handled.	1) JSA for handling tubulars/lifting operations. 2) Safety Contact (stop for unsafe work) 3) Pre-use inspections, 6 monthly independent inspection and colour coding.







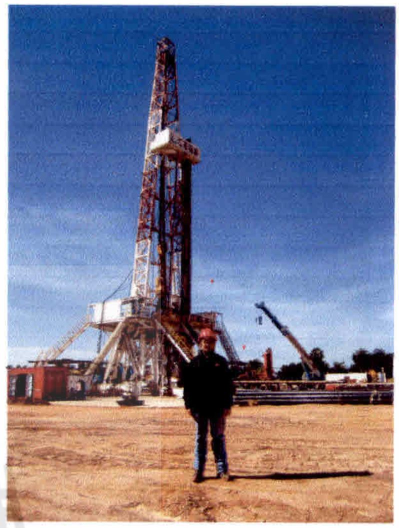

PHU WIANG -1
TOP RAT BURI CARBONATE - TWT STRUCTURE
Location of Phu Wiang - 1


PHU WIANG-1 WELL PROGNOSIS SHEET
Pore Pressure
Possible Lost Circulation Zone

ADVANCED DRILLING ENGINEERING 1/2557(2014)

Chapter4 Cost Estimation and Control (4 hrs.)

By
Kriangkrai Trisarn



534620 ADVANCED DRILLING ENGINEERING
4(4-0-8) @ 1/2557, 2014

Course Contents

1. How to Get Drilling Permission (2hrs.) Asso. Prof. KK
2. Introduction to Rotary Drilling (4 hrs.) Asso. Prof. KK
3. Well Planning and Proposal (2 hrs.) Asso. Prof. KK
4. Cost Estimation and Control (4 hrs.) Asso. Prof. KK
5. Hole Problems.(4 hrs.) Asso. Prof. KK
6. Drilling Fluids (4 hrs.) Asso. Prof. KK
7. Factors Affecting Rate of Penetration (4 hrs.) Asso. Prof. KK
8. Pressure Control (4 hrs.) Dr. Akkaphun
9. Pore Pressure and Pressure Gradient (4 hrs.) Dr. Akkaphun
10. Blowout Control Procedure and Equipment (4 hrs.) Dr. Akkaphun
11. Directional and Slimhole Drilling (4 hrs.) Dr. Akkaphun
12. Rotary Bit Design (2 hrs.) Dr. Akkaphun
13. New Technology Drilling (6 hrs.) Dr. Akkaphun

ADVANCED DRILLING ENGINEERING

CHAPTER 4

•COST and •PENETRATION RATE ESTIMATION and CONTROL

ITEMS IMPACT ON WELL COST

- DRILLING RIG
- MUD
- OFFSHORE TRANSPORTATION
- RENTAL TOOL
- SUPPORT SERVICES

Chapter 19 Well Cost Estimation: AFE Preparation

Authorization for Expenditure

Preparing cost estimates for a well is the final step in well planning. In many cases, the cost estimate is the management tool that determines if the well will be drilled. Although an essential part of the well plan, the cost estimate section is often the most difficult to obtain.

A properly prepared well cost estimate may require as much engineering work as the actual well design. The costs should address dry holes and completed wells. In addition, accounting considerations such as tangible and intangible items must be taken into account. Unfortunately, many cost "guesstimates" are the "back-of-the-napkin" type, with only a small amount of engineering work used in the process.

The cost estimate is the last item to be considered in the well plan since it is heavily dependent on the technical aspects of the projected well. After the technical aspects are established, the expected time required to drill the well must be determined. The actual well cost is obtained by integrating expected drilling and completion times with the well design.

Projected Drilling Time

The time required to drill the well has a significant impact on many items in the well cost. These items may include the following:

- drilling rig
- mud
- offshore transportation
- rental tools
- support services

The effect of these items on the overall well cost is dependent on the actual unit cost, i.e., \$15,000/day for a land rig vs \$100,000/day for a drillship, and the amount of drilling time.

Consider the well in Fig. 19–1. Assume that the well will be drilled in East Texas in mid-1982. Table 19–1 summarizes the projected times for the well

LAND RIG \$35,000/DAY

DRILLSHIP \$100,000/DAY

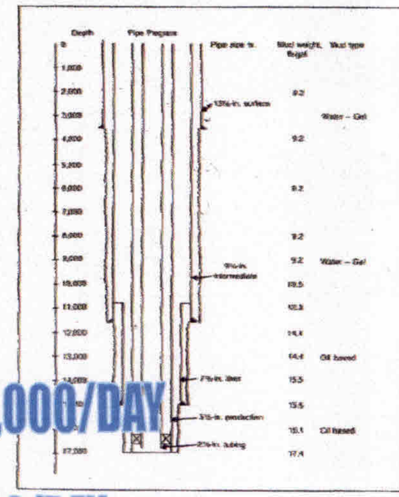


Fig. 19–1 Example hole configuration

12. NSE-E1 WELL COST ESTIMATE

CAPEX Drilling, Completion & Testing AFE

DEVELOPMENT WELL

Rig daily rate = 270000/18= 15,000\$/day

Pan Orient ENERGY

ACCOUNT CODE	COST CATEGORY	DRILLING (18 Days)	TEST-COMPLET (18 Days)	PRODUCTION	WELL TOTAL
TANGIBLES 7710					
7710005	Wellhead Equipment	-	15,000	-	15,000
7710010	30" Conductor	-	-	-	-
7710015	20 & 18 5/8 Surface Casing	-	-	-	-
7710020	13 3/8" Casing	1,000	-	-	1,000
7710025	9 5/8" Casing	4,762	-	-	4,762
7710030	7" Casing	29,496	-	-	29,496
7710035	Production Casing 5 1/2" - 2 7/8"	-	12,074	-	12,074
7710040	Casing Accs	-	-	-	-
7710045	Liner Hanger	-	-	-	-
7710050	Drilling Liner Accs	-	1,500	-	1,500
7710055	Xmas Tree	-	-	-	-
7710060	Completion Downhole Equipment	-	-	-	-
7710065	Surface Pumping Equipment	-	2,500	-	2,500
7710070	Prime Mover	-	3,000	-	3,000
7710075	Sucker Rods	-	12,000	-	12,000
7710080	Bottomhole Pump	-	1,500	-	1,500
7710085	Tanker Truck / Loading Bay / Tank Base	-	-	20,892	20,892
7710090	Electrical Equipment	-	-	42,789	42,789
7710095	Instrumentation & Metering Equipment	-	-	12,000	12,000
7710100	Pumping Unit	-	-	39,669	39,669
7710105	Heaters, Treaters & Exchange Process Equipment	-	-	13,750	13,750
7710110	Tank & Tank Equipment	-	-	62,424	62,424
7710115	Pipes, Valves & Fittings	-	-	6,173	6,173
		35,346	47,574	196,697	279,617
BULKS / CONSUMABLES 7720					
7720005	DGP Consumables	-	-	-	-
7720010	Rock Bits	15,000	-	-	15,000
7720015	Centralizers & Casing Consumables	-	-	-	-
7720020	Other Equipment & Materials	-	-	-	-
7720025	Mud & Chemicals	60,000	-	-	60,000
7720030	Solids Control Shakers / Screens	-	-	-	-
7720035	Cement & Additives	-	-	-	-
7720040	Cementing Consumables	-	-	-	-
7720045	Fuel & Power (trucks, generators & rig)	18,000	-	21,146	39,146
7720050	Lubricants	-	-	-	-
7720055	Water	-	-	-	-
		93,000	-	21,146	114,146
RIG & SITE PREPARATION 7730					
7730005	Licences & Permits	-	-	-	-
7730010	Surface Lease & Land Services	25,000	-	-	25,000
7730015	Survey Location & Road	-	-	-	-
7730020	Site & Road Construction	25,000	-	-	25,000
7730025	Lease Restoration & Cleanup	10,000	5,000	-	15,000
7730030	Rig audit / inspection	-	-	-	-
7730035	Rig Modifications	-	-	-	-
7730040	Drilling Rig Dayrate	270,000	-	-	270,000
7730045	Drilling Rig Standby Rate	-	-	-	-
7730050	Rig Mob / Demob	32,000	-	-	32,000
7730055	Rig Camp, Subsistence & Crew Travel	5,400	-	-	5,400
		357,100	5,000	-	362,400
SERVICES 7740					

7730040	Drilling Rig Dayrate	270,300	-	-	270,000
7730045	Drilling Rig Standby Rate	-	-	-	-
7730050	Rig Mob / Demob	22,300	-	-	32,000
7730055	Rig Camp, Subsistence & Crew Travel	5,400	-	-	5,400
		157,100	5,000	-	362,400
SERVICES 7740					
7740005	Drilling Supervision	63,000	-	12,602	75,602
7740010	Wellhead Services	-	-	-	-
7740015	Mud Engineering & Fluids Services	-	-	-	-
7740020	Fluid / Cutting Cleaning & Disposal	-	-	-	-
7740025	Inspection & Repair Services	-	-	-	-
7740030	Casing Running Services	-	-	-	-
7740035	Cementing Services	51,300	-	-	51,300
7740040	Mud Logging Services	18,000	-	-	18,000
7740045	Directional Drilling	153,000	-	-	153,000
7740050	Wellbore Surveying Services	100,000	-	-	100,000
7740055	MWD/LWD Services	-	-	-	-
7740060	Fishing Services	-	-	-	-
7740065	Communication	3,300	-	-	3,000
7740070	Drill String Tool Rental	-	-	-	-
7740075	Environmental Control	15,000	5,000	-	20,000
7740080	Equipment Rentals	22,500	-	-	22,500
7740085	Safety Services	9,000	-	990	9,990
7740090	Other Miscellaneous Drilling Costs	78,300	-	5,250	83,250
		572,300	5,000	18,940	596,740
EVALUATION / TESTING 7750					
7750005	Wireline Logging	-	-	-	-
7750010	Coring Services	-	-	-	-
7750015	Core Analysis	-	-	-	-
7750020	Wellsite Geology	18,000	-	-	18,000
7750025	Completion Wireline Services	-	-	-	-
7750030	Slickline Services	-	-	-	-
7750035	Perforating	-	15,900	-	15,900
7750040	Well Stimulation	-	-	-	-
7750045	Well Testing	-	-	-	-
		18,000	15,900	-	33,900
COMPLETION 7760					
7760005	Completion Fluids & Brine	-	-	-	-
7760010	Production Logging	-	-	-	-
7760015	Wellbore Cleanout Equipment	-	-	-	-
7760020	Completion Services	-	1,500	-	1,500
		-	1,500	-	1,500
LOGISTICS 7770					
7770005	Water & Water Hauling	3,000	500	-	3,500
7770010	Trucking / Hauling	7,500	2,500	4,231	14,231
7770015	Vessel Support	-	-	-	-
7770020	Shipping / Customs / Taxes	2,500	-	12,102	14,602
7770025	Base / Warehouse / Yard Costs	-	-	-	-
		13,000	3,000	16,333	32,333
OVERHEADS / G&A / REALLOCATION					
7703035	Other Technical & Engineering & Design	-	-	-	-
7703210	Engineering Project Administration	-	-	-	-
7703300	Other Services - Meetings	-	-	-	-
7706135	G&A Overheads	22,500	10,500	-	33,000
7703195	Legal & Insurance Costs	15,000	-	-	15,000
		37,500	10,500	-	48,000
	GRAND TOTAL PER ACTIVITY	1,127,046	46,171	251,116	1,468,636

48

Rig daily rate = 15,500$/day

ESTIMATED COST OF DRILLING AND EQUIPMENT

11–Aug–92

COUNTRY: THAILAND/ONSHORE (KHORAT PLATEAU)

PROSPECT: PHU KHIEO "A" DAO RUANG PROSPECT CONCESSION: 5441/32 AB

WELL NAME: PHU KHIEO "A" WELL DAO RUANG–1 WELL TYPE: RWC

SURFACE LOC.: SEISMIC LINE NO. 148 SHOT POINT, 1822463.00 N & 198337.25 EAST

PROPOSED BHL: STRAIGHT

PROPOSED TD: 6150 TVD / 6150 MD

	DRY HOLE (36 DAYS)	TESTED (58 DAYS)
WELL INVESTMENT (TANGIBLES)		
150' 20" CASING	$17,000	$17,000
1200' 13.375" CASING	$50,000	$50,000
3400' 9.625" CASING	$68,000	$89,000
6150' 7" CASING		$105,000
" LINER		
6150' 3.5" TUBING		$55,000
" TUBING		
WELL HEAD & MISC. EQUIP. (5000 PSI)	$25,000	$104,000
TOTAL TANGIBLES.	$160,000	$400,000
INTANGIBLES		
TRANSPORTATION	$89,000	$113,000
BASE COST	$30,000	$46,000
LOCATION PURCHASE	$75,000	$75,000
LOCATION PREPARATION	$182,000	$182,000
MOB/DEMOB	$300,000	$300,000
RIG COST $15,500 /Day	$589,000	$899,000
COMMUNICATION	$38,000	$58,000
SUPERVISION – DRLG/EXPL	$95,000	$145,000
DRILL PIPE RENTAL	$53,000	$81,000
DIRECTIONAL TOOLS & SERVICES	$3,000	$3,000
OTHER RENTAL EQUIPMENT	$76,000	$116,000
DRILLING MUD & ADDITIVES	$230,000	$260,000
MUD ENGINEER	$23,000	$35,000
BITS	$105,000	$115,000
CEMENT & CEMENTING SERVICES	$165,000	$165,000
FUEL/WATER	$10,000	$15,000
CASING CREWS/CASING TOOLS	$27,000	$29,000
MUD LOGGING	$80,000	$122,000
CONVENTIONAL CORING	$84,000	$84,000
ELECTRIC LOGGING & SURVEYS	$300,000	$330,000
PERFORATING		$40,000
STIMULATION/TESTING		$535,000
CUSTOMS AGENT	$19,000	$29,000
INSURANCE	$34,000	$34,000
ENVIRONMENTAL IMPACT ASSESSMENT	$50,000	$50,000
MISC.	$453,000	$659,000
TOTAL INTANGIBLES:	$3,120,000	$4,520,000
TOTAL WELL COST:	$3,280,000	$4,520,000

EXPENDITURE	million US
OPERATION COST	
LOCATION PREPARATION	0.50
SITE PREPARETION	0.70
MO-DEMO	1.00
DRILLING RIG AND TOOLS 40,000 $/D	4.00
DRILLING FLUIDS	0.30 0.4
RENTAL EQUIPMENT	0.30
CEMENTING	0.20
SUPPORT SERVICES	0.20
TRANSPOTATION	0.20
SUPPERVISION AND ADMINISTRATION	0.50
SUBTOTAL	7.90
FIX COST	
TUBULAR EQUIPMENT	1.00
WELL H	0.50
COMPLETION EQUIPMENT	0.20
SUBTOTAL	1.70
TOTAL	9.60

27-May-14
COUNTRY: THAILAND/ONSHORE(KHORAT PLATEAU) CONCESSION: L 29/50
PROSPECT: CHATTURAT PROSPECT CONCESSIONAIR : TPIPL
WELL NAME: CHATTURAT-2 WELL TYPE: Exploration
SURFACE LOC:
PROPOSED BHL: DIRECTIONAL WELL
PROPOSED TD: 4200M TVD
4500M MD

900 TUBULAR EQUIPMENT TANGIBLE COST(WELL INVESTMENT) Length(m) Size(inches)	DRY HOLE (120 DAYS) (US$)	COMPLETED AND TESTED (140DAYS)
200 20 CASING	50,000	50,000
900 13 3/8 CASING	200,000	200,000
2900 9 5/8 CASING	400,000	400,000
1800 7 LINER	200,000	200,000
4500 3 1/2 TUBING	200,000	200,000
1100 WELL HEAD& MISC.EQIUP.(10,000 PSI)	350,000	400,000
TOTAL TANGIBLES	1,400,000	1,450,000
INTANGIBLES COSTS		
MO-DEMO	500,000	500,000
100 LOCATION AND SITE PREPARATION	500,000	500,000
200 DRILLING RIG AND TOOLS		
RIG 40,000$/D	4,800,000	5,200,000
BIT	1,000,000	1,000,000
TOOL	500,000	500,000
Directional Drilling(80*12000)	960,000	960,000
300 DRILLING FLUID	800,000	900,000
400 RENTAL EQUIPMENT	500,000	700,000
500 CEMENTING$SERVICE	900,000	1,000,000
600 SUPPORT SERVICE		
MUD LOGGINGS	240,000	240,000
ELECTRIC LOG	600,000	700,000
CASING TOOLS SERVICE	100,000	100,000
WELL TEST		500,000
OTHERS	700,000	700,000
700 TRANSPORTATION	200,000	220,000
800 SUPERVISION AND ADMINISTRATION	500,000	600,000
900-1100 OTHERS	1,000,000	1,630,000
DST TEST	1,500,000	1,500,000
waste Management	1,000,000	1,100,000
TOTAL INTANGIBLES	16,300,000	18,550,000
TOTAL WELL COST=	**17,700,000**	**20,000,000**

27-May-14
COUNTRY: THAILAND/ONSHORE(KHORAT PLATEAU) CONCESSION: L 29/50
PROSPECT: CHATTURAT PROSPECT CONCESSIONAIR : TPIPP
WELL NAME: CHATTURAT-2 WELL TYPE: Exploration
SURFACE LOC:
PROPOSED BHL: Directional Well
PROPOSED TD: 4200M TVD
about= 4550M MD

Item	Description	Price/True Vertical Depth (USD/m)	Designed Well True Vertical Depth (meter)	Designed Well True Measured Depth (meter)	SUM(USD)
1	The charge rate for drilling rig and operation per meter for vertical section	2220	1,800	1800	3996000
2	The charge rate for drilling rig and operation per meter for DIRECTIONAL DRILLING	2520	2,600	2750	6930000
3	The charge rate for drilling fluid of WBM 0-4550M	230	4,200	4,550	1046500
4	The charge rate for mud techni technical services	70	4,200	4550	318500
5	The charge rate for the supply of wellhead, casing and tubing, liner hanger and services, and tubular running services	311	4,200	4550	1415050
6	The charge rate for the cementing service(including casing accessories and well abandonment)	230	4,200	4550	966000
7	Mud Logging	52.8	4,200	4550	240240
8	Wireline Logging	137.2	4,200	4550	624260
9	MOBILIZATION				200000
10	OTHERS				300000
LUMP SUM TO SINOPEC COST=					**16036550**
11	Waste Management				1000000
12	DST Test to Sinopec Jiangsu				1400000
13	Well Stimulation				500000
14	Well Completion				700000
15	OTHERS				363450
TOTAL WELL COST=				**US$**	**20,000,000**

AUTHORIZATION FOR EXPENDITURE (AFE)

EXPENDITURE	DRY HOLE (24.5 DAYS)	COMPLETED (32.5 DAYS)
INTANGIBLE COSTS		
LOCATION PREPARATION	30,000	65,000
DRILLING RIG AND TOOLS	298,185	366,613
DRILLING FLUIDS	113,543	116,976
RENTAL EQUIPMENT	77,896	133,785
CEMENTING	49,535	54,369
SUPPORT SERVICES	152,285	275,648
TRANSPORTATION	70,200	83,400
SUPERVISION AND ADMIN.	23,282	30,791
SUB-TOTAL	814,928	1,126,581
TANGIBLE COSTS		
TUBULAR EQUIPMENT	406,101	846,529
WELL HEAD EQUIPMENT	16,864	156,201
COMPLETION EQUIPMENT	0	15,717
SUB-TOTAL	422,965	1,018,447
SUB-TOTAL	1,237,893	2,145,028
+ CONTINGENCY (15% ??) →	1,423,577	2,466,782

5

Costs of Crude Oil and Natural Gas Wells Drilled

Period: Annual

Download Series History | Definitions, Sources & Notes

	GraphClear	2002	2003	2004	2005	2006	2007	View History
Thousand Dollars per Well								
All (Real*)		1,011.9	1,127.4	1,528.5	1,522.3	1,801.3	3,481.8	1960-2007
All (Nominal)		1,054.2	1,199.5	1,673.1	1,720.7	2,101.7	4,171.7	1960-2007
Crude Oil (Nominal)		882.8	1,037.3	1,441.8	1,920.4	2,238.6	4,000.4	1960-2007
Natural Gas (Nominal)		991.9	1,106.0	1,716.4	1,497.6	1,936.2	3,906.9	1960-2007
Dry Holes (Nominal)		1,673.4	2,065.1	1,977.3	2,392.9	2,664.6	6,131.2	1960-2007
Dollars per Foot								
All (Real*)		187.46	203.25	267.28	271.16	324.00	574.46	1960-2007
All (Nominal)		195.31	216.27	292.57	306.50	378.03	688.30	1960-2007
Crude Oil (Nominal)		194.55	221.13	298.45	314.36	402.45	717.13	1960-2007
Natural Gas (Nominal)		175.78	189.95	284.78	280.03	348.36	604.06	1960-2007
Dry Holes (Nominal)		284.17	345.94	327.91	429.92	479.33	1,132.09	1960-2007

- = No Data Reported; -- = Not Applicable; NA = Not Available; W = Withheld to avoid disclosure of individual company data.

Notes: *In chained (2000) dollars, calculated by using gross domestic product price deflators. See Definitions, Sources, and Notes link above for more

1132 $/FT

1132X1.3=1472 $/FT.

1430 $/FT.

DRILLING TIME INFORMATION SOURCE

DRILLING HISTORY

Table 19–1 Drilling Times and Associated Well Costs for Fig. 19–1

Item	Time, days 1	2	3
Move in and out	8	8	8
Drive pipe			
0–200 ft	1	1	1
200–3,580 ft	2	3	4
3,580–11,600 ft	8	12	18
11,600–15,000 ft	15	22	32
15,000–17,000 ft	12	18	24
Run casing strings	8	8	8
Logging	5	5	5
Completion	7	7	7
	66	84	107
Well costs*	$4,175,977	$4,562,372	$5,045,448

*Costs are [illegible] from Adams and [illegible] Technology's AFE program.

in three cases and illustrates the cost differences. The worst case has a 21% greater cost than the best drilling times. This example illustrates the importance of preparing accurate projections for drilling time, or "depth vs days," as it is often termed. A typical depth vs days plot is shown in Fig. 19–2.

Sources of Drilling Time Information. Numerous sources are available to estimate drilling times for a well. As described in Chapter 2, these include bit records, mud records, log header information, and operator's well histories. Other items such as scout tickets and production hist... ...seful because they provide information that will affect the time pr... ...hou... items seldom contain actual drilling times.

Bit records are valuable sources of drilling info... ...can be ... to estimate drilling time. Although few bit manufacturers incorporate a column for dates in the bit record forms, most drilling engineer... ...utinely complete the forms make notes in the remarks column as to the ... ...we... ...ran. In addition, most records contain the dates for we... ...etic... and pipe setting. Additional inferences can be made fr... ...it-... hours and the cumulative drilling time for each well.

Mud records usually provide the most authoritative information about the drilling time data. These records are maintained daily and usually contain remarks about the time required for each drilling activity. In addition, time allocated to ... evaluated to determine if the ... amount of time ... the upcoming w... ...rrence in an area w... activities.

Log header data contain some drilling time information and dates for each successive logging run. In addition, scout tickets attached to some logs include spud and completion dates.

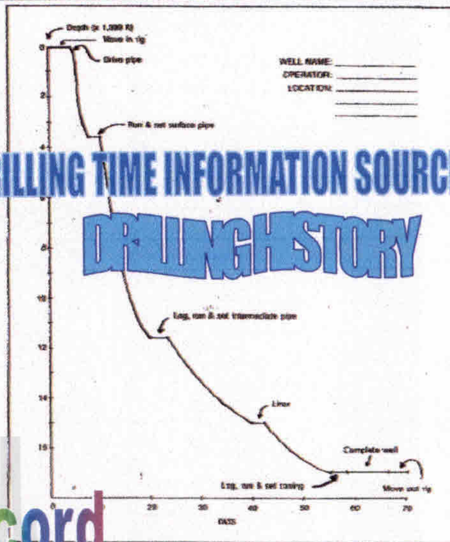


Fig. 19–2 Depth vs days projection

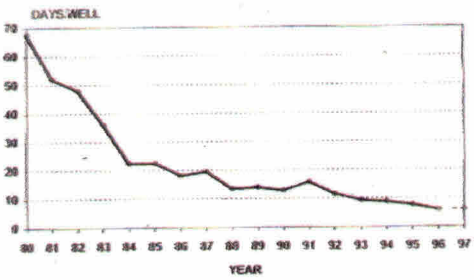
Bit record

Mud record

Log header

Time Considerations

Drill Rate
Trip Time
Hole Problem
Casing Running
Directional Drilling
Completion Type
Move-in and move-out with the rig



DEVELOPMENT WELLS
AVERAGE COST TO DRILL AND COMPLETE

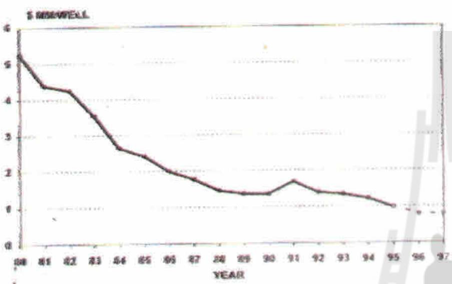
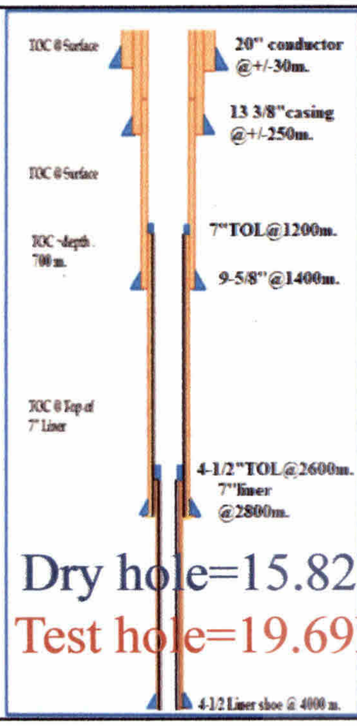


Fig. 19–4 AFE detailed summary

Fig. 19–4 cont'd



Dry hole=15.82MMUS$

Test hole=19.69MMUS$

AUTHORIZATION FOR EXPENDITURE

1-Jan-13
COUNTRY: THAILAND/ONSHORE(KHORAT PLATEAU) — CONCESSION: L 29/50
PROSPECT: CHATTURAT PROSPECT — CONCESSIONAIR : TPIPL
WELL NAME: TPIPL-1 — WELL TYPE: Exploration
SURFACE LOC:
PROPOSED BHL: STRAIGHT-VERTICAL
PROPOSED TD: 4000M TVD
4000M MVD

	DRY HOLE	TEST-PRE-COMPLETED
900 TUBULAR EQUIPMENT	(140 DAYS)	(160DAYS)
TANGIBLE COST(WELL INVESTMENT)	(US$)	(US$)
Length(m) Size(inches)		
20 20 conductor	20,000	20,000
250 13 3/8 CASING	140,000	140,000
1400 9 5/8 CASING	400,000	400,000
2800 7 LINER	200,000	200,000
4000 4 1/2 LINER	100,000	100,000
4000 3 1/2 TUBING		200,000
SURFACE AND SUB SURFACE EQUIP.	250,000	300,000
1100 WELL HEAD& MISC.EQIUP.(10,000 PSI)	250,000	300,000
TOTAL TANGIBLES	1,360,000	1,660,000
INTANGIBLES COSTS		
MO-DEMO	1,200,000	1,200,000
100 LOCATION AND SITE PREPARATION	500,000	530,000
200 DRILLING RIG AND TOOLS		
RIG 38,000$/D(1520$/m)	4,560,000	6,080,000
BIT	1,000,000	1,000,000
TOOLS	500,000	600,000
300 DRILLING FLUID and Chemicals	1,500,000	1,600,000
400 RENTAL EQUIPMENT	500,000	600,000
500 CEMENTING$SERVICE	700,000	800,000
600 SUPPORT SERVICE		
MUD LOGGINGS	300,000	350,000
ELECTRIC LOG	600,000	700,000
CASING TOOLS SERVICE	300,000	350,000
WELL TEST		1,000,000
OTHERS	500,000	600,000
700 TRANSPORTATION	200,000	220,000
800 SUPERVISION AND ADMINISTRATION	1,000,000	1,200,000
900-1100 OTHERS	500,000	550,000
1200 WASTE MANAGEMENT	600000	650,000
TOTAL INTANGIBLES	14,460,000	18,030,000
TOTAL WELL COST=	15,820,000	19,690,000
AVERAGE DRILLING COST= 3955 $/m	or=1206$/ft.	1206 $/ft.

AUTHORIZATION FOR EXPENDITURE

1-Jan-13
COUNTRY: THAILAND/ONSHORE(KHORAT PLATEAU) — CONCESSION: L 29/50
PROSPECT: CHATTURAT PROSPECT — CONCESSIONAIR : TPIPL
WELL NAME: TPIPL-1 — WELL TYPE: Exploration
SURFACE LOC:
PROPOSED BHL: STRAIGHT-VERTICAL
PROPOSED TD: 4000M TVD
4000M MVD

	DRY HOLE	TEST-PRE-COMPLETED
900 TUBULAR EQUIPMENT	(140 DAYS)	(160DAYS)
TANGIBLE COST(WELL INVESTMENT)	(US$)	(US$)
Length(m) Size(inches)		
20 20 conductor	20,000	20,000
250 13 3/8 CASING	140,000	140,000
1400 9 5/8 CASING	400,000	400,000
2800 7 LINER	200,000	200,000
4000 4 1/2 LINER	100,000	100,000
4000 3 1/2 TUBING		200,000
SURFACE AND SUB SURFACE EQUIP.	250,000	300,000
1100 WELL HEAD& MISC.EQIUP.(10,000 PSI)	250,000	300,000
TOTAL TANGIBLES	1,360,000	1,660,000
INTANGIBLES COSTS		
MO-DEMO	1,200,000	1,200,000
100 LOCATION AND SITE PREPARATION	500,000	530,000
200 DRILLING RIG AND TOOLS		
RIG 38,000$/D(1520$/m)	4,560,000	6,080,000
BIT	1,000,000	1,000,000
TOOLS	500,000	600,000
300 DRILLING FLUID and Chemicals	1,500,000	1,600,000
400 RENTAL EQUIPMENT	500,000	600,000
500 CEMENTING$SERVICE	700,000	800,000
600 SUPPORT SERVICE		
MUD LOGGINGS	300,000	350,000
ELECTRIC LOG	600,000	700,000
CASING TOOLS SERVICE	300,000	350,000
WELL TEST		1,000,000
OTHERS	500,000	600,000
700 TRANSPORTATION	200,000	220,000
800 SUPERVISION AND ADMINISTRATION	1,000,000	1,200,000
900-1100 OTHERS	500,000	550,000
1200 WASTE MANAGEMENT	600000	650,000
TOTAL INTANGIBLES	14,460,000	18,030,000
TOTAL WELL COST=	15,820,000	19,690,000
AVERAGE DRILLING COST= 3955 $/m	or=1206$/ft.	1206 $/ft.

AFE DETAILED SUMMARY

EXPENDITURE	DRY HOLE (140 DAYS) US$	COMPLETED (160 DAYS) US$
100 LOCATION PREPARATION		
110 PERMIT (PURCHASE)	100,000	100,000
120 SURVEY	10,000	10,000
130 RIGHT OF WAY, SPECIAL PERMIT	50,000	50,000
140 LOCATION PREPARATIOON	330,000	350,000
150 CLEANUP	10,000	20,000
TOTAL	500,000	530,000
200 DRILLING RIG AND TOOLS		
210 MOVE IN AND OUT	100,000	100,000
220 FOOTAGE BID		
230 STRAIGHT DAY WORK BID	4,560,000	6,080,000
240 FUEL	100,000	120,000
250 WATER	10,000	10,000
260 BITS	1,000,000	1,000,000
270 TOOLS	200,000	250,000
TOTAL	5,970,000	7,560,000
300 DRILLING FLUIDS		
310 DRILLING FLUIDS	1,500,000	1,600,000
320 PACKER FLUID		20,000
330 COMPLETION FLUID		
TOTAL	1,500,000	1,620,000
400 RENTAL EQUIPMENT		
410 WELL CONTROL EQUIPMENT	50,000	70,000
420 ROTARY TOOLS AND ACCESSORIE	10,000	25,000
430 MUD RELATED EQUIPMENT	30,000	35,000
440 CASING TOOL	40,000	60,000
450 MISCELLANEOUS	270,000	270,000
TOTAL	400,000	460,000
500 CEMENTING		
510 CONDUCTOR CASING	50,000	50,000
520 SURFACE CASING	80,000	80,000
530 INTERMEDIATE CASING	100,000	100,000
540 INTERMEDIATE CASING	120,000	120,000
550 FIRST LINER	20,000	20,000
560 SECOND(SLOT) LINER	0	0
570 PRODUCTION CASING		100000
580 PLUGS	100,000	100,000
MATERIAL	230,000	230,000
TOTAL	700,000	750,000

AFE DETAILED SUMMARY

EXPENDITURE	DRY HOLE (140 DAYS) US$	COMPLETED (160 DAYS) US$
100 LOCATION PREPARATION		
110 PERMIT (PURCHASE)	100,000	100,000
120 SURVEY	10,000	10,000
130 RIGHT OF WAY, SPECIAL PERMIT	50,000	50,000
140 LOCATION PREPARATIOON	330,000	350,000
150 CLEANUP	10,000	20,000
TOTAL	500,000	530,000
200 DRILLING RIG AND TOOLS		
210 MOVE IN AND OUT	100,000	100,000
220 FOOTAGE BID		
230 STRAIGHT DAY WORK BID	4,560,000	6,080,000
240 FUEL	100,000	120,000
250 WATER	10,000	10,000
260 BITS	1,000,000	1,000,000
270 TOOLS	200,000	250,000
TOTAL	5,970,000	7,560,000
300 DRILLING FLUIDS		
310 DRILLING FLUIDS	1,500,000	1,600,000
320 PACKER FLUID		20,000
330 COMPLETION FLUID		
TOTAL	1,500,000	1,620,000
400 RENTAL EQUIPMENT		
410 WELL CONTROL EQUIPMENT	50,000	70,000
420 ROTARY TOOLS AND ACCESSORIE	10,000	25,000
430 MUD RELATED EQUIPMENT	30,000	35,000
440 CASING TOOL	40,000	60,000
450 MISCELLANEOUS	270,000	270,000
TOTAL	400,000	460,000
500 CEMENTING		
510 CONDUCTOR CASING	50,000	50,000
520 SURFACE CASING	80,000	80,000
530 INTERMEDIATE CASING	100,000	100,000
540 INTERMEDIATE CASING	120,000	120,000
550 FIRST LINER	20,000	20,000
560 SECOND(SLOT) LINER	0	0
570 PRODUCTION CASING		100000
580 PLUGS	100,000	100,000
MATERIAL	230,000	230,000
TOTAL	700,000	750,000
600 SUPPORT SERVICES		
610 CASING CREWS	30,000	40,000
620 LOGGING		
621 MUD LOGGING	300,000	300,000
623 WIRELINE		
624 LOGGINGS	600,000	650,000
625 PERFORATED		20,000
627 COMPLETION SERVICE		50,000
630 TUBULAR INSPECTION		
631 SURFACE CASING	8,000	8,000
632 INTERMEDIA. CASIN	35,000	35,000
633 FIRST LINER	5,000	5,000
634 SECOND(SLOT) LINE	5,000	5,000
635 PRODUCTION CASING		20,000
636 TIE BACK STRING		
637 TUBING		
640 GALLEY		
650 WELDING, LABOR, RENTAL EQUIPMENT	20,000	24,000
660 FORMATION TESTING		
670 FISHING DIRECTIONAL CONSULTANT		
680 ACIDICZING FRACTURING	100,000	100,000
690 MISCESSLANEOUS(TESTI	300,000	300,000
TOTAL	1,403,000	1,557,000
700 TRANSPORTATION		
710 TRUCKING	100,000	120,000
720 MARINE		
730 AIR		
740 OTHERS	100,000	100,000
TOTAL	200,000	220,000
800 SUPERVISION AND ADMINISTRATION		
810 FIELD SUPERVISION	600,000	800,000
820 OFFICE SUPERVISION	200,000	300,000
830 INSURANCES, BONDS	200,000	
TOTAL	1,000,000	1,100,000
900 TUBULAR EQUIPMENT		
905 DRIVE PIPE	10,000	20,000
910 CONDUCTOR CASING	20,000	140000
915 SURFACE CASING	140,000	400,000
920 INTERMEDIATE CASING	400,000	200,000
925 INTERMEDIATE CASING	200,000	200,000
930 FIRST LINER	70,000	70,000
935 SECOND(SLOT) LINER	100,000	100,000
940 SURFACE EQUIPMENT	300,000	350,000
950 TUBING		200,000
960 CASING EQUIPMENT		
961 DRIVE PIPE	10,000	10,000
962 CONDUCTOR CASING		
963 SURFACE CASING	6,000	5,000
964 INTERMEDIATE CASING	6,000	5,000
965 FIRST LINER		
966 SECOND(SLOT) LINER		
967 PRODUCTION CASING		
WELL HEAD& MISC.EQIUP.(10,000 PSI)	400,000	500,000
TOTAL	1,662,000	2,200,000
1000 WELL HEAD EQUIPMENT		
1010 CASING HEAD	20,000	20,000
1020 INTERMEDIATE SPOOL	40,000	30,000
1030 TUBING SPOOL		100,000
1040 TREE		300,000
1050 MISCELLANEOUS BOP	400,000	500,000
TOTAL	460,000	950,000
1100 COMPLETION EQUIPMEMT		
1105 PACKERS		8,000
1110 BLAST JOINT AND LANDIND NIPPLES		10,000
1115 SPECIAL LINER		
1120 SAFETY JOINTS		5,000
1125 SUBSURFACE SAFETY DEVICES		10,000
1130 SEAL ASSEMBLY		10,000
1135 GAS LIFT EQUIPMEMT		
1140 GRAVEL PACK EQUIPMENT		
1145 MISCELLANEOUS		200,000
1200 WASTE MANAGEMENT	600000	650000
1300 OTHERS	225000	650000
TOTAL	600,000	1,543,000
TOTAL WELL COST=	14,620,000	18,490,000
MO-DEMO	1,200,000	1,200,000
GRAND TOTAL OPERATION COST	15,820,000	19,690,000

Drilling Fluid

Completion Rigs. A completion rig is a small workover rig that costs considerably less than a large drilling rig. Operators often use these rigs when the completion procedures are expected to require significant amounts of time. The drilling rig is used until the production casing is run and cemented.

Costs for completion rigs can be determined from Fig. 19–5. Tubing or small drillstring load requirements are used instead of casing capacity. Economic decisions to use a completion rig must also consider the cost of the rig moving onto the location as well as the daily rate differences between the drilling and completion rigs.

Drilling Fluids

Drilling fluids are an important part of the well plan and drilling programs. The prices are based on build cost for a certain mud weight and a daily maintenance expense. These costs vary for different mud types and are dependent on the chemicals and weighting material required and on the base fluid phase, such as water or oil. Miscellaneous cost factors that may be considered include specialty products such as hydrogen sulfide scavengers, lost circulation materials, and hole stability chemicals.

The build cost for a mud system is the price for the individual components and mixing requirements. Oil-based muds have a higher build cost than most water-based muds because of the expensive oil phase, the mixing and emulsion stability chemicals, and the additional barite required to achieve comparable densities with water-based muds. Fig. 19–7 shows a 1982 comparison of build costs for an oil-based (invert type) mud and a lignosulfonate mud. The total build cost includes 1) purchasing the initial mud system and 2) the expenses involved with increasing the mud weight in the well as it is drilled.

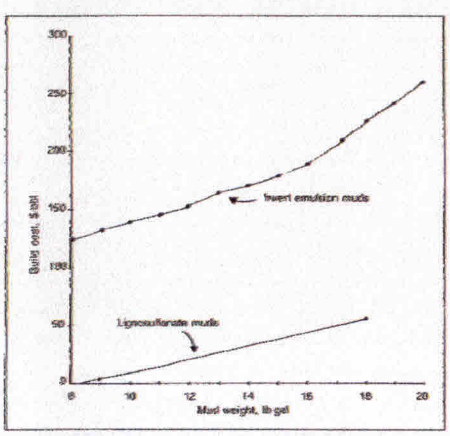


Fig. 19–7 Build costs for invert emulsion and lignosulfonate muds

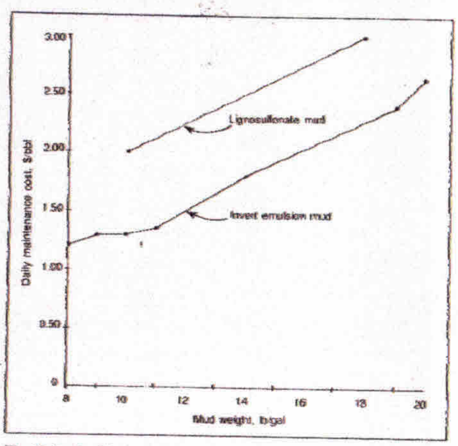


Fig. 19–8 Empirical maintenance costs for invert emulsion and lignosulfonate muds

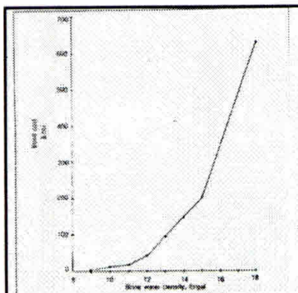


Fig. 19-9 Cost relationship for various brine densities (1982 prices)

The maintenance costs for deep, high pressure wells are usually larger than the build costs. The maintenance fee includes the chemicals required daily to maintain the desired mud properties. These chemicals may include fluid loss agents, thinners, and caustic soda.

Fig. 19-8 shows an estimate of empirically derived maintenance costs for invert emulsion, oil muds, and lignosulfonate water muds. The illustration demonstrates that heavy muds can have high daily fees. A system with 1,000 bbl of 16.0-lb/gal lignosulfonate mud would cost approximately $2,700 for daily maintenance. In addition, note that the maintenance costs for invert emulsion muds is significantly less than lignosulfonate muds, even though the reverse is true for build costs.

Several additional factors affect mud costs. Small mud companies can often provide less-expensive mud systems than larger companies, although a sacrifice is made occasionally in terms of technical support and mud problem testing capabilities. In addition, many mud companies offer mud without technical support at a price reduction over mud with engineering support.

Packer Fluids. Packer fluids are placed between the tubing and production casing above the packer. The fluid is usually a treated brine water but can be an oil mud or treated water-base mud-type fluid. In some cases, a packer fluid will not be used. Although a low-density brine water is commonly used, occasionally a higher-density water or mud is used for pressure control. Fig. 19-9 shows the typical cost relationship for various density brine waters.

Completion Fluids. Special fluids are occasionally used for well completion purposes. They are usually designed to minimize formation damage. The fluids may be filtered brine water, nitrogen, or oil. Costs for these fluids must be considered on a case-by-case basis.

Rental Equipment

Rental Equipment

Drilling equipment that is beyond the scope of the contractor-furnished items is almost always required to drill a well. These items must be rented at the expense of the contractor or operator, depending on the provisions of the contract. They can include well control equipment, rotary tools and accessories, mud-related equipment, and casing tools. These items can represent a substantial sum in deep, high pressure wells.

Well Control Equipment. Drilling contractors usually furnish BOPs, chokes, choke manifolds, and, in some cases, atmospheric degasser units. However, the equipment may not be satisfactory for the well. In addition, numerous land rigs presently operate with well control equipment that is not state of the art, such as positive chokes, manual chokes, and manifold systems that do not have centrally located drillpipe and casing pressure gauges.

Blowout preventer rental is expensive. High pressure stacks range from $1,500–3,000/day, exclusive of chokes or manifolds. The operator must define the worst pressure case that can feasibly be attained and select preventers accordingly. Cost estimates for a complete stack must consider the spherical, multiple ram sets, spools, studs, ring gaskets, and outlet valves.

Remote-controlled, hydraulic adjustable chokes are considered state of the art and are available from several sources. Contractors seldom furnish this type of choke primarily because operators have always assumed this cost responsibility. These chokes usually cost $50–125/day with a 30-day minimum charge. Choke manifolds must be designed to withstand the maximum pressure ratings in addition to coinciding with current company philosophy.

Rotary Tools and Accessories. Rotary tools are items related to the drillstring or equipment that turns the string. The operator may be required to

In addition, it is usually desirable to rent several pieces of backup equipment in case of breakdowns, in most cases an inexpensive type of insurance. These items include the following:

- backup tongs
- backup power unit
- backup elevator-slip combination unit

Laydown and pickup machines were introduced to the industry in the late 1970s. These units increase the efficiency and safety of picking pipe up to the rig floor or laying it down on the pipe rack. Also, they usually minimize possible damage to pipe threads.

Cementing

Cementing

Cost development for cementing charges requires an evaluation of the cement type and volume, spacer fluid requirements, special additives, and pumping charges. These various charges usually apply for each primary cement job, slope slurries, squeeze slurries, plugs, and surface casing top-outs. Cost will vary for land and offshore jobs.

Pumping Charges. Onshore and offshore pumping charges for one cementing company are shown in Fig. 19-10. The charges increase with depth and for the offshore case. Also, pumping charges for casing and drillpipe will vary.

In addition to the primary cementing pump, most operators use a standby pump unit in case of mechanical failure on the primary unit. The ill effects of cementing-up the casing or drillpipe as a result of equipment failure overshadow the standby pumping unit charges. Rates for land-based standby pump trucks are approximately $100–150/hr.

Cement Spacers. A cement spacer is used to separate the cement from the drilling mud in an effort to reduce cement contamination. The chemical cost for a barrel of spacer fluid is approximately $50–100, depending on the amount of retarder. Barite charges or other weight materials must be added. In addition, diesel charges in the spacer must be considered when the drilling fluid has a continuous oil phase.

Cement and Additives. The major cost for large cement jobs such as surface casing is the chemical and additives charges. Typical costs are as follows:

cement	$ 7.00/sack
barite	$15.00/sack
gel	$15.00/sack
mixing charges	$ 0.95/cu ft

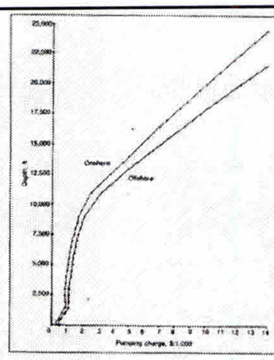


Fig. 19-10 Depth vs pumping charge

A reasonable rule of thumb for computing the cost of special additives such as water loss agents and thinners is 75% of the charges for cement, gel, and barite.

Quick-set, top-out cement is often used on surface casing. It provides short-term strength that allows surface equipment rigging to proceed while waiting on the other cement to cure. The slurry usually consists of 50–100 sacks of cement at about $10/sack.

furnish 1) support equipment for the contractor's drillpipe or 2) a completely different string if the contractor's drillpipe does not meet the requirements, i.e., tapered or work strings. Some of the items that may require consideration include the following:

- drillpipe
- drill collars
- kelly
- kelly drive bushing
- kelly cock valves, upper and lower
- inside BOP
- full-opening safety valve (FOSV)
- safety clamps
- elevators
- slips
- pipe rubbers

The operator must evaluate the requirements for drillpipe sizes different than those offered by the contractor's rig. A recent study of U.S. rigs showed that pipe sizes on the rig could be correlated with the IADC hydraulics code (ref. Table 19-3). In addition, Table 19-3 includes guides for drill collar and casing combinations.

For example, 4.5-in. drillpipe with 6.5-in. collars would not be recommended for drilling inside of 7.625-in. casing due to the wear of the tool joints and collars on the casing. A smaller pipe and collar size combination would be recommended. If the 7.625-in. pipe were a drilling liner, a tapered string would be satisfactory but an extra BOP might be required.

A work string consists of small-diameter drillpipe and collars. It is used generally during completions or workover operations. Since the pipe will be

Table 19-3 Drillpipe and Collar Size Combinations

IADC Code*	Drillpipe,* in.	Drill Collars,** in.	Minimum Acceptable*** Casing Size, in.
1	2.875	3.25–3.75	4.5
2	3.5	5.0–5.5	6.625
3	4.5	6.0–6.5	8.625
4	5.0	7.0–7.5	10.75

*Drillpipe sizes commonly found on rigs
**Size (sizes) most used for rig specified pipe
***Guide for casing pipe collar combinations

used inside production casing, the usual sizes are 2.375–3.5 in. Most operators require a rental string because few rigs drill with this size pipe.

Mud-related Equipment. A properly maintained mud system has many benefits to the operator. To achieve the desired level of system efficiency, several specialized pieces of equipment may be required. Some of the equipment must be rented, even though the drilling rig may be well equipped in terms of other drilling tools.

A complete suite of equipment required for the mud job usually depends on the mud type and weight. The following suite may be used for mud job in the 8.35–12.0-lb/gal range:

- multiscreen shaker
- desilter (with pumps)
- mud/gas separator
- degasser (vacuum)
- pit/flow monitors
- drill rate recorder
- gas detector

Mud weights greater than 12.0 lb/gal may require the use of additional equipment such as a centrifuge or mud cleaner. Oil muds need a cuttings cleaner to remove the oil from the cuttings prior to dumping. The cuttings cleaner is not always used on land since current government regulations do not require its use.

Casing Tools. Recently, great strides have been made in running casing. Specialized equipment and crews normally handle the task rather than using the rig crew and equipment. Since most rigs are not furnished with casing crew equipment, it must be rented.

Casing tools must be selected according to size and loading requirements. A commonly used method for evaluating the load requirement is to add a design factor of 1.5 to the in-air weight of the casing string. For example, a casing string that weighed 500,000 lb in air would require 375-ton casing tools.

The suite of equipment to run casing depends on the operator's preference. It can include the following items:

- elevators
- slips
- bales
- protector rubbers
- power tongs
- power tong hydraulic unit
- stabbing board
- drift gauge
- thread cleaning unit

Supported Services

Support Services

Drilling operations require the services of many support groups. In some cases, these groups are used because they can do a particular job more efficiently than the rig crew. An example of this efficiency is casing crews who are experienced in running large-diameter tubulars. Other support groups may provide services that cannot be performed by the rig crew or operator, i.e., well logging, pipe inspection, or specialized completions. Regardless of the reasons for using support services, their costs affect the total well cost and, as such, must be considered.

Casing Crews. During the early years of the drilling industry, the rig crews ran all casing and tubing strings into the well. However, increasing well depths and tubular sizes made the process more difficult. In addition, items such as specialized couplings and pipe torque measurements gave rise to the requirements for the use of casing crews specialized in running the tubulars. Today's industry uses not only casing crews but also groups specialized in picking up and laying down casing, tubing, and drillpipe.

Casing crew charges are dependent on crew size, pipe size, and well depth. Crew sizes usually range from 1–5 members. Fig. 19-11 shows the charges for a 5-member crew. In addition, a power tong operator is required at rates ranging from $30–40/hr.

Mud Logging. Monitoring services such as mud logging, cuttings interpretation, and gas monitoring are often used on deep or high pressure wells. A variety of services at different costs are available. A few services and general cost ranges are as follows:

Item	Cost, $/day
Gas detection, portable unit	50–60
Gas detection, trailer unit	120–150
Mud logging	400–575
Advanced mud logging	850–1,250
Computerized mud logging	1,250–1,550

Well Logging. Formation evaluation services, or well logging, are done on every well. The service may include formation evaluation, casing and cement logging, and hole inclination surveys.

Charges for well logging vary with suppliers. However, some consistency does exist across the industry. Each logging operation will have a flat setup charge for each time the unit is rigged up, i.e., once for open-hole logging and once for cased-hole logging at each depth. A depth charge, usually on a per-foot basis, is applied to the deepest depth for each tool run. An operation charge is applied for each foot that the tool is operated.

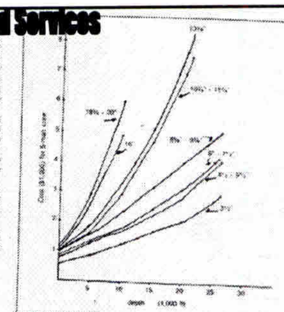


Fig. 19-11 Casing crew costs for various depths and pipe sizes

Estimation of the logging cost requires that a well logging program be established. A typical program may be as follows:

Item	Use	Minimum Operating Footage
ISF	Each open-hole section, except surface, run over entire hole section	2,000
Sonic-BHC	Each open-hole section	2,000
High resolution dipmeter	Bottom 2,000 ft of intermediate hole and all deeper sections; includes cluster computation	2,000
Cores	Take 48 cores on each open-hole section except surface	2,000
CBL	Run on each casing string except surface	2,000
Caliper	Run on all open-hole sections except surface	2,000
Directional	Run over entire well	....
Gamma ray-neutron	Run inside of production casing	2,000
Density	Run in production casing only	2,000

In addition, offshore logging is significantly more expensive than land operations.

Perforating. Perforating charges may not apply if the well is gravel packed or abandoned. The charges include setup, depth charge for minimum shots (usually 20), and a charge per shot over the minimum.

The total shots depend on the length of the productive zone and the shot density, i.e., 4 shots/ft. Assuming a setup charge of $375 and 20 shots as the minimum, the following table illustrates some of the costs involved with perforating.

Depth, ft	20-Shot Minimum Charge, $	Charge per Shot over 20 Minimum, $
5,000	1,355	40
8,000	1,695	44
12,000	2,035	56
15,000	2,535	75
20,000	3,095	126

Formation Testing. Wireline formation testing is an economical method of obtaining reliable formation information. The repeating formation tester is a device that takes samples of fluid pressure and fluids from a zone of interest. It should be included in the cost estimate for every exploratory well.

Charges for the service are on a depth and per-sample basis. Setup charges are usually not applicable, since the service is often run in conjunction with other logs. An example cost for a 15,000-ft sample would be $2,550/sample with a $0.55-/ft depth charge.

Completion Logging. Various types of production logs can be run on the well if it is completed. These logs are generally run prior to perforation so that pre- and post-production formation evaluations can be made. Since production logging is a complex subject, the log suite must be developed jointly by the drilling and production engineers. As a minimum, the suite might contain a packer setting service and a dual-spaced, thermal decay time log.

Tubular Inspection. Pipe inspection is an important aspect of the casing and tubing program. These support services may include magnetic particle inspection, thread and end-area visual inspection, hydrostatic pressure testing, and pipe drifting. Typical charges for the services are $5–20/joint for each item and are service and pipe-size dependent.

Galley Services. Catering services for the galley of offshore or many rigs may not be included in the day-rate charges for the rig. The catering company will supply the cooks, support crews, and food for a per man-day fee. Typical charges are $25/man-day for crews with less than 30 members and $23/man-day for greater than 30-man crews. For cost calculation purposes, average crew sizes for various rigs are as follows:

Marsh barge	— 30 men
Jackup	— 40 men
Floater	— 50 men

Special Labor. Many items used on the rig and used during drilling operations require specialized labor. These services are usually on a per-hour basis and at a minimum charge (4–8 hr). Typical considerations are as follows:

Welding	— drive pipe, casing shoes, general construction
Rental equipment	— equipment installation, repair
Service representatives	— packers, wellhead equipment, chokes

In addition to the hourly charges of this labor, mileage and expenses must be considered.

Transportation

Well costs are often underestimated because of subtle items such as transportation. For example, trucking charges for cementing a casing string may exceed $3,000, which includes round trip charges for two pump units and a bulk truck. Careful evaluation of these charges will provide a better estimate of well costs.

Transportation costs include charges for land-based trucks, barges, boats, and helicopters. Long-distance crew charges via commercial or chartered airplanes may be a significant cost. Accurate estimates of transportation costs require a detailed well plan, knowledge of the distance to the rig from local stock points, and rig characteristics such as standard equipment and crew size.

Trucking charges are computed from estimates of the number of trips, the round-trip mileage, and the per-mile cost. Current trucking costs (1982) are approximately $3.00/mile. A rule of thumb for round-trip mileage is to establish a base of 100 miles from the local stock point to the rig (round trip, 200 miles). The following table gives some guidelines for estimating the number of round trips to be considered on a well.

Transportation

Item	Trips	Remarks
Cementing	3/job	Two pump units, bulk truck
Logging	1/job	
Casing	10/string	Casing, casing crews, welders, rental items
Mud	1 (minimum)	Add 1 trip per lb/gal of mud weight above 9.0 lb/gal, i.e., 7 trips for 15.0-lb/gal mud
Packer fluid	2	
Gravel pack	5	Optional

Marine charges are incurred for offshore operations and marshes. The costs include boats and any dock facilities. Current (1982) charges for boats operating in the Gulf of Mexico are summarized as follows:

Type of Boat	Cost per day (including fuel), $
100-ft crew boat	1,500
Small supply boat	3,310
Large supply boat	5,120
70-ft standby boat	800

Air charges occur only for offshore operations. The helicopter charges are on a day-rate basis and begin at rig move-in. A small helicopter (3–4 passenger capacity) is required for day-to-day operations. A large helicopter is used for weekly crew changes. A summary of the costs (1982) are as follows:

Helicopter Capacity	Base Day Rate, $	Flight Charge, $/hr	Average Time
4	500	147	2 hr/day
11	2,475	450	5 hr/wk

Supervision and Administration

Supervision and Administration

Project management costs must be considered. These charges include well supervision and administration. Large costs can be incurred for deep wells or problem wells, such as H₂S incidences.

Supervision includes direct management of the well, including the on-site supervisor and any members of the office staff who are dedicated to the project. Mud or completion consultants may be considered as supervision. Specialized personnel such as mud loggers are not considered in the supervisory charges.

Administration charges can be handled in several manners. Some companies prefer to apply only direct supervision charges to a given well and charge support office staff members to general company overhead. Other companies divide all overhead charges among the wells to be drilled in a fiscal year. Regardless of the accounting method, some of the charges that must be considered are as follows:

- staff engineering support
- clerical support
- office overhead
- special insurance, including blowout insurance, and bonds
- legal work
- special document preparation

A method for computing supervision and administration costs is to assume that a consultant will handle all operations. The on-site supervisor is the drilling consultant. An office consultant performs all administrative functions on an hourly basis, i.e., 200 hr for a dry hole and 300 hr for a completed well.

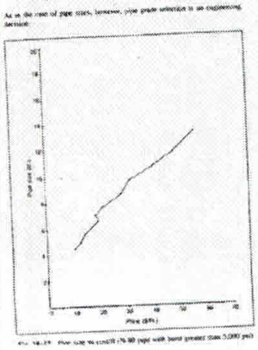
Tubulars

Casing and tubing costs are significant factors in the well cost. In some cases, they may account for 50–60% of the total expenditures. The costs are dependent on well depth, size, grade requirements, and couplings.

Pipe costs are influenced heavily by several factors. Pipe size is a major consideration. Fig. 19-12 illustrates cost variations according to pipe size for N-80 grade LTC pipe that exceeds a burst rating of 5,000 psi in several sizes. Although engineering considerations should have the major impact on the pipe size selection, cost considerations should have some influence.

Costs increase with higher pipe grades. The following items show the costs for 40.0-lb/ft, 9.625-in. pipe with LTC couplings:

Grade	Cost per Foot, $
K-55	29.86
N-80	31.83



Couplings are seldom selected as a result of costs. However, higher-priced premium couplings may allow the use of smaller pipe sizes, which will reduce the overall well costs. The following list illustrates the variations in pipe cost with different couplings. All costs are with 7.625-in., N-80 grade, 26.40-lb/ft pipe (costs may vary slightly with different vendors and market conditions):

Coupling Type	Pipe Costs, $/ft
LTC	21.26
BTC	22.77
SFJ	34.31
FJ-P	34.31
TS	36.65
FL-4S	32.76

Casing Equipment. Casing (or cementing) accessory equipment is used to accomplish an effective primary cement job. Although the equipment does not have a major impact on well costs, it should be considered. A typical suite of equipment might be as follows:

	Casing	Liner
Float shoe	1	1
Float collar	1	1
Centralizers	30	20
Scratchers	10	10
Liner hanger	0	1

This equipment would cost approximately $2,470 for a 7⅝-in. casing string and $25,640 for a 7⅝-in. liner.

Drive pipe costs must be calculated for wells that utilize the pipe. The charges vary for pipe size and wall thickness. A drive shoe cost must be included. Typical drive pipe, size, and costs are as follows:

Size, in.	Wall Thickness, in.	Pipe Cost, $/ft	Shoe Cost, $
14	0.375	19.54	165
16	0.375	22.53	200
20	0.500	37.49	230
24	0.500	45.92	375
26	0.500	47.66	415
30	0.500	55.14	470
36	0.750	98.82	535

HW. NO 4.1; 19.2, 19.3, 19.6

19.2 Refer to Figs. 19–7 and 19–8 and calculate the costs to build and maintain a 15.0-lb/gal lignosulfonate mud for 60 days. Compare it with an oil mud. Assume a 750-bbl system.

19.3 What are the cement pumping charges for a 15,000-ft well onshore and offshore?

19.4 Determine the cost to run 15,000 ft of 6-in. pipe.

19.5 A 60-ft sand zone will be perforated with 4 shots/ft. If the zone is at 20,000 ft, what will be the perforating charge?

19.6 Why is a 20,000-ft high pressure well more expensive than a normal pressure well at the same depth?

Due Date; Friday 15 AUGUST 2014

Cost Control

TABLE 2-1 Separate Well Cost Functions

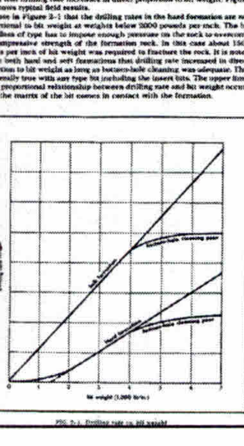


FIG. 2-1. Drilling rate vs. bit weight

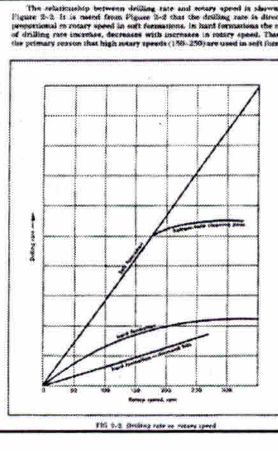


FIG. 2-2. Drilling rate vs. rotary speed

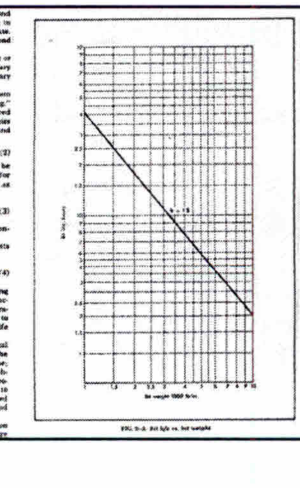


FIG. 2-3. Bit life vs. bit weight

used. This procedure is not very precise and places a premium on bit grading procedures.

Drilling torque has become a common method to determine the need to pull a bit. This procedure is subject to having a good torque indicator and to the operator's recognition that the increase in torque is due to locked bearings and not a change in formations. Even when a bit is pulled because of the increase in drill torque some operators have not graded the bit, B-8. This is a mistake. If the bit bearing locked enough to increase torque the bit bearing should be graded B-8. If grading procedures follow a consistent pattern of using torque properly, then the data in Figure 2-3 should be reliable.

The third method used to determine when to pull bits is the economic analysis. This procedure involves a frequent determination of cost per foot while drilling. The bit is pulled when the cost per foot versus drilling time reaches a minimum. This procedure is shown in Example 2.

■ EXAMPLE 2:

Well depth = 8000 ft.
Bit costs = $200.00
Rig costs = $100.00 per hr
Round trip time = ½ hr. per 1000 ft.
Rate of penetration = 30 − t

Note: a relationship between the rate of penetration and rotating time has been assumed, in field operations this would not be necessary.

Determine: When the bit should be pulled

Solution:

Table 2-2 lists the cost data versus time using Equation 1 and the relationship between penetration rate and rotating time.

TABLE 2-2
Cost per Foot Data for Example 2

t, hrs	R, ft/hr	F, ft	Total Cost	C_f, $/ft
5	25	127.50	1150.00	[illegible]
10	20	256.50	1609.00	6.50
12	18	288.00	1828.00	6.35
14	16	322.50	2032.00	6.30
16	14	352.50	2234.00	6.35
18	12	378.50	2436.00	6.45
20	10	402.50	2640.00	6.60

The data from Table 2-2 have been plotted in Figure 2-4. As shown in Table 2-2 and Figure 2-4 the drilling costs in dollars per foot were a minimum at the end of 14 hours and the normal time to pull the bit would be at the 15 or 16 hour time. At the end of 16 hours of rotating time the bit is still drilling at the rate of 14 fph; however according to these data the drilling costs in dollars per foot have begun to increase. If the bits are being pulled on an economic basis it would not be possible to obtain meaningful bit wear information as shown in Figure 2-3. Almost any grading system

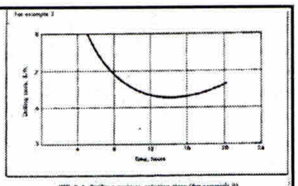


FIG. 2-4. Drilling costs vs. rotating time (for example 2)

based on an interpretation of bearing wear at some level before the bearings lock would not be accurate enough to use as shown in Figure 2-3.

It will be noted from Equation 4, that bit life is inversely proportional to rotary speed. Thus in soft formations where drilling rate is directly proportional to rotary speed this would indicate that rotary speeds should be very high. Actually other limitations have to be considered such as the horsepower available for rotation, pipe wear and the danger of twist-offs and the proper cooling of bits.

There are methods in use to predict the optimum bit weight and rotary speeds for drilling at a minimum cost in dollars per foot. Many techniques have been introduced. There are variable bit weight and rotary speed programs, variable bit weight and constant rotary speed programs and constant optimum weight and rotary speed programs. Most of the methods depend very heavily on the proper interpretation of bit wear.

All of the methods used to optimize bit weight or rotary speed will not be discussed. The basic procedure for optimizing is to begin with a cost per foot equation such as Equation 1, then write expressions for drilling rate as a function of bit weight and rotary speed and finally express bit life as a function of bit weight and rotary speed. This has been done in this chapter in Equations 1, 2, and 4 and an optimum bit weight can be determined using Equation 5.

$$W_{opt.} = \left[\frac{C_r K'}{(b-1)N(B + C_r T)}\right]^{1/b} \quad (5)$$

The use of this equation is shown in Example 3.

■ EXAMPLE 3:

Well depth = 10,000 ft.
Bit costs = $200.00
Rig costs = $100.00 per hr.
Round trip time = ½ hr. per 1000 ft.
Bit weight = 40,000 pound
Rotary speed = 150 RPM
Bit wear, b = 1.5
Bit life = 10 hours

Determine the optimum bit weight

Solution:

Using Equation 4, $\frac{K'}{N} = (L)W^b = (10)(40,000)^{1.5}$

$$W_{opt.} = \left[\frac{(100)(10)(40,000)^{1.5}}{(1.5-1)(200+(100)(5))}\right]^{1/1.5} \qquad W_{opt.} = \left[\frac{C_r K'}{(b-1)N(B+C_r T)}\right]^{1/b}$$

$$W_{opt.} = \left[\frac{(100)(10)}{(0.5)(700)}\right]^{.667} 40,000 = 80,000 \text{ pounds}$$

To show the effect of b consider a change in the bit wear function from 1.5 to 2.0.

$$W_{opt.} = \left[\frac{(100)(10)}{700}\right]^{.5} 40,000 = 47,480 \text{ pounds}$$

To further emphasize the effect of b, consider a doubling of the rig operating cost from $100 to $200 per hour.

$$W_{opt.} = \left[\frac{(200)(10)}{(.5)(1200)}\right]^{.667} 40,000 = 90,400 \text{ pounds}$$

It is noted in Example 3 that an increase in the bit wear function of 33 per cent reduced the optimum bit weight from 80,000 to 47,840 pounds while a doubling of the rig operating costs resulted in an increase in the optimum bit weight from 80,000 to 90,400 pounds. The primary purpose of this example is to illustrate the absolute necessity of obtaining accurate bit wear data for any program of optimizing bit weight or rotary speed.

It should also be mentioned that the rig operating cost, C_r, is dependent on many variables such as drill string maintenance, pump maintenance, mud costs and resulting hole problems. High rotary speeds may not effect the rig operating costs enough to cause concern, however, if a twist-off occurs the resulting hole problem might be significant. This simply means that regardless of calculated results, judgment has to be used in the application of any of the optimizing techniques.

It is difficult to apply optimizing methods with the friction bearing insert bits. Bit wear data as a function of bit weight show an irregular pattern. It is common to use a maximum bit weight of 5000 pounds per inch on these bits. Many operators use less and a few operators have reported using up to 6500 pounds per inch. Some field tests indicate a substantial reduction in bit life when the bit weight is allowed to exceed 5000 pounds per inch. The close tolerances in the bearing areas of these bits make it difficult to cool the bits properly.

Bit overheating is also the reason that rotary speeds are generally maintained in the range of 40 to 60 Rpm's. These ranges of bit weights and rotary speeds are simply reported as common practice. Laboratory and field tests should be maintained in order to optimize future operating levels. It has been noted in many field tests that drilling rates with the insert bits are directly proportional to bit weight as shown in Figure 2-1. The relationships between drilling rate and rotary speed follow the pattern shown in Figure 2-2 for hard formations; where the curve generally flattens at about 50 to 60 Rpm's.

Diamond bits fall in a different category than either roller cone mill tooth bits or insert friction bearing bits. They have no moving parts, diamond sizes are variable and bit designs may be substantially different. Cooling of the diamond bits is of prime importance. Generally an increase in bit weight will produce a proportional increase in drilling rate with diamond bits. The limitation of course occurs when the matrix contacts the formation and this will be determined by bit design, diamond size and formation hardness.

The normal range of bit weight has been from 3000 to 5000 pounds per inch. Drilling rates with diamond bits are directly proportional to rotary speed. As a result high rotary speeds are desirable. The limitations imposed on rotating speed is surface horsepower available, drill string limitations, and the cooling permitted by bit design and the fluid hydraulics program. It is common to rotate diamond bits at speeds above 500 Rpm's using bottom-hole rotating drives. Again common practice has been related, future practices are subject to laboratory and field test programs. It is probable that bottom-hole drives will become more common, thus higher rotary speeds with diamond bits will also become common. No prediction will be made on future bit weight levels.

Bottom-Hole Cleaning

There is a chapter on hydraulics which describes the need for bottom-hole cleaning. There has been a tendency in recent years to ignore bottom-hole cleaning in deep wells with abnormally high pore pressures. This has been done because in many cases a very fine balance is reached between a well kicking and lost circulation. It should be emphasized that with no adverse effect on hole conditions bottom-hole cleaning can many times be increased substantially and the beneficial effect of reduced drilling time should increase the possibilities of reaching the desired objective.

Mud Property Effects

Mud property effects on drilling rate have been an object of research for more than 20 years. At various times there have been papers proving

almost any property of the mud affects drilling rate. Eckel[1] combined the mud properties into a dimensionless quantity, he referred to as Reynold's number. Eckel's[1] basic relationship is shown as Equation 6.

$$R = \left(\frac{266\,\rho Q}{\mu d}\right)^{0.5} \quad (6)$$

Laboratory results using Equation 6 were favorable, field results in general have failed to confirm this relationship. The primary problem is the density term ρ. In most field tests an increase in mud density has the most pronounced detrimental effect on drilling rate and this would not conform to that shown in Equation 6.

Mud properties that have been claimed to affect drilling rate include the following:

1. Mud weight
2. Solids content and type solids
3. Mud viscosity, laminar and turbulent
4. Water-loss and also spurt loss
5. Liquid phase, water or oil

Mud effecting Drilling Rate

Mud Weight

It is known that increases in mud weight will decrease drilling rate. The quantitative relationship between mud weight and drilling rate has not been established for general use. In calculating the d exponent for pore pressure prediction methods, the log of drilling rate is considered inversely proportional to the log of mud weight, and this has proved to be a reasonable relationship. However, this may be substantially in error as shown by Figures 2-5 and 2-6.

Figure 2-5 represents a field test in western Canada by Murray where the increase in pump pressure and the noted back pressure were imposed by a hand adjustable choke in the discharge flow line. It was reported that this test was run at a depth of 2500 feet using a 9.0 ppg mud, thus the increase in back pressure of 250 psi represents an effective mud weight increase of 2.0 ppg. Note the decrease in drilling rate is from about 93 to 30 fph, and this is a common result at these mud weight levels. Figure 2-6 shows a laboratory test of drilling rate versus imposed hydrostatic pressure. Of significance in this test is the fact that the increase in hydrostatic pressure from 0 to 2000 psi resulted in a decrease in penetration rate from 18 to 5 fph. The increase in hydrostatic pressure from 2000 to 4000 psi resulted in a decrease of only 5.0 to 3.5 fph. Results such as those shown in Figure 2-6 are typical of those in actual field operations. The first unit of mud weight in excess of formation pore pressure will reduce drilling rate more than each subsequent unit of mud weight increase.

Figure 2-7 shows the effect of mud weight on rotating time in two South Mississippi wells. Well A was drilled with 10.4 ppg mud and typified the normal practice in the field before drilling well B. Using a thinner mud weighing 9.6 ppg in well B resulted in a rotating time of 210 hours or less than one-half of the 500 plus rotating hours required to drill well A. More

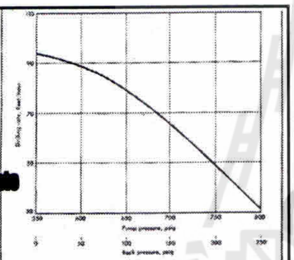


FIG. 2-5. Drilling rate vs. imposed back pressure

than just the mud weight was changed and this test alone does not prove that all of the improvement was due to the reduction in mud weight. However, the reduction in mud weight made the other improvements in mud properties possible.

The effect of mud weight or the additional hydrostatic pressure on drilling rate is believed to be caused by the chip hold-down effect of the differential between hydrostatic and formation pore pressure. This theory gains support when drilling with air or gas as shown in Figures 2-8 and 2-9.

In Figure 2-8, a composite of wells drilled with mud are compared with a composite of wells drilled with gas. The results show 14 days drilling time required for the interval between 1300 and 9800 feet with gas as compared with 30 days for the same interval with mud.

Figure 2-9 shows a comparison between drilling with air and water in 2600 foot wells in the West Texas area. The rotating time with air was about one-half the rotating time with fresh water. In both of the series of field tests in Figures 2-8 and 2-9 the degree of improved performance occurred

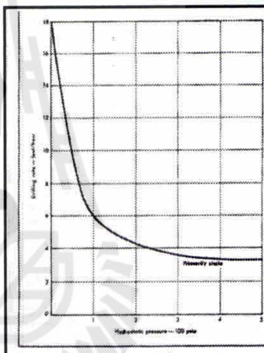


FIG. 2-6. Drilling rate vs. hydrostatic pressure

primarily because the hydrostatic pressure was less than the formation pore pressure.

Solids Content and Type Solids

It is difficult to separate the solids content effect on drilling rate from the mud weight effect. As the solids content increases the mud weight also

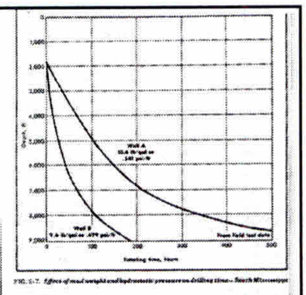


FIG. 2-7. Effect of mud weight and hydrostatic pressure on drilling time—South Mississippi

increases. Thus both effects are generally present. However, it is known that drilling rates with a 10 ppg saturated salt water will in the same environment be substantially higher than those with a 10 ppg mud. To confirm the effect of the solids content on drilling rate, refer to Figure 2-10.

Figure 2-10 represents the results of field tests where alternate slugs of a 9.2 ppg mud and fresh water were used as drilling fluids. The size of the slugs of each were selected to provide a constant hydrostatic pressure in the annulus. Drilling rates were measured as the water and mud passed through the bit. The drilling rates with water are shown as the 100 per cent drilling rate curves on Figure 2-10. The drilling rates measured when mud passed through the bit are shown as 60 per cent of those with water using jet bits and 40 per cent of those with water using conventional bits. These tests were conducted primarily in the West Texas area and confirm that the solids content of the mud affects drilling rate. Further proof of the effect of the solids content on drilling rate is shown in Figure 2-11, which is a

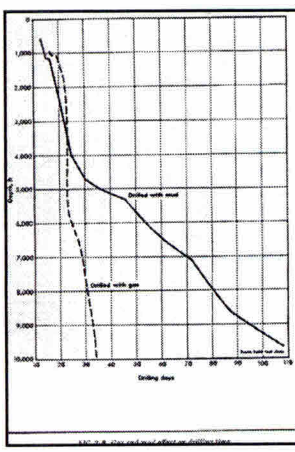


FIG. 2-8. Gas and mud effect on drilling time

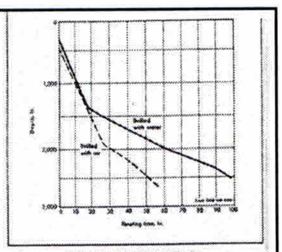


FIG. 2-9. Air and water effect on drilling time

In laboratory tests such as Figure 2-11 there was no change in hydrostatic pressure. It is noted that the drilling rate is eleven feet per hour with two per cent solids by volume and about three feet per hour with a solids content of 12 per cent by volume.

In addition to the solids content it has been noted that the solids type and the state of solids dispersion also affects the drilling rate. Figure 2-12 from work by Lummus[2] shows the effect of solids dispersion on drilling rate.

It is noted, particularly below a solids content of three per cent by volume, that the drilling was substantially higher with the non-dispersed mud in Figure 2-12. This same type results would be expected when comparing highly dispersible clay solids with non-dispersible solids such as sand and limestone.

Mud Viscosity, Laminar and Turbulent

The term viscosity was introduced to represent the thickness of a Newtonian fluid in laminar flow. In some way common usage expanded the original meaning to include the thickness of non-newtonian fluids, such as

a common practice in some areas, then running the test is an expensive exercise in futility.

The drilling man is interested in finding hydrocarbons as well as drilling cheaply and the formation evaluation man wants to drill cheaply as well as find hydrocarbons. The only conflict comes in the interpretation of requirements. While improvements in communication will help, the best method to improve is to study procedures and practices on the basis of results versus dollars spent.

COMPLETION COSTS

A company may or may not include completion costs in drilling costs, these costs are certainly a part of total well costs. No attempt will be made in this section to enter into a discussion on suggested completion practices; however, problems that happen during or after the well completion are often blamed on drilling practices and this point will be discussed.

For many years, practices were promoted that [illegible] increased drilling costs in the Rocky Mountains because [illegible] caused by running salt. [illegible] pletely, cementing between the casing and salt section [illegible] opposite the salt section has minimized the problem [illegible] drilling and thus fluid which were considered causes of the problem, were actually beneficial to minimizing this problem.

Very often a bad primary cement job is blamed on drilling practices, when during the cement job the casing is not moved or properly centered in the hole. As a result drilling costs are increased and completion costs remain the same.

SUMMARY

The secret to cost control is to consider the total well costs. This will include location, drilling, formation evaluation, casing and completion costs. Cost control in drilling starts with the rig selection after the well is planned. Too often operators begin a deep expensive well with an inadequate rig. Rigs should be examined carefully. Pumps are important relative to size and normal operating pressures followed by the rig operator. Careful attention should be focused on the drill string and the operating efficiency of the rig on other wells. It is clear that the success of any cost control program will be dependent on the rig.

Cost control on a minimum cost well is sold as a service by many organizations. In most cases some type of computerized operation is used and an accurate record of current and past operations is essential.

In general all of the factors which affect drilling rate should be considered and cost per foot determinations should be used on a continuous basis. It should be emphasized that all organizations may not agree with all the conclusions in this discussion. Also any cost control program has to be tempered by the potential hole problems.

In most cases, an increase in emphasis and supervision will result in reduced drilling costs. Expertise is an essential ingredient in the increased supervision. The high cost drilling operations create the necessity of having competent personnel at the rig during the drilling operations.

Formation evaluation practices should be studied carefully. Extensive coring and logging programs do not necessarily increase the ratio of successful wells to dry holes. These programs do reduce the number of wells drilled. Formation testing programs should be analyzed. It may be cheaper to set small casing than conduct multiple open-hole drill stem tests. Also be certain the tests results are used to make the right decisions.

Completion practices may be affected by drilling practices; however make sure that suggested changes that raise costs are not actually excuses for a dry hole.

A total cost control program between geologists, engineers and operating personnel is possible if they recognize the importance of being on the same team. Competition between these groups will result in face saving [illegible] cause for problems that in many cases are not [illegible] problem.

COST CONTROL

LOCATION

DRILLING

FORMATION EVALUATION

CASING

COMPLETION

Cost Control

[illegible]

REFERENCES

1. Eckel, John R., "How Mud and Hydraulics Affect Drilling Rate," The Oil and Gas Journal, June 17, 1968.
2. Lummus, J. L., and Field, L. J., "Non-Dispersed Mud: A New Drilling Concept," Petroleum Engineer, March, 1968.

Drilling Cost Analysis

The Drilling Engineer:

- Recommends drilling procedures that will safely drill and complete the well at the lowest cost possible
- Makes recommendations concerning **routine rig operations**:

7

The Drilling Engineer

- **Examples of routine rig operations**
  - drilling fluid treatment
  - pump operation
  - bit selection
  - handling problems during the drilling process

8

The Drilling Cost Equation:

$$C_f = \frac{C_b + C_r(t_b + t_c + t_t)}{\Delta D} \quad \frac{\$}{ft}$$ Eq. 1.16

C_f = drilling cost, $/ft

C_b = cost of bit, $/bit

C_r = fixed operating cost of rig, $/hr

t_b = total rotating time, hrs

t_c = total non-rotating time, hrs

t_t = total trip time (round trip), hrs

ΔD = footage drilled with bit, ft/bit

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Example 1.5

A recommended bit program is being prepared for a new well using bit performance records from nearby wells.

Drilling performance records for three bits are shown for a thick limestone formation at 9,000 ft.

Determine which bit gives the lowest drilling cost if the operating cost of the rig is $400/hr, the trip time is 7 hours, and connection time is 1 minute per connection.

10

Example 1.5 cont'd

Assume that each of the bits was operated at near the minimum cost per foot attainable for that bit.

Bit	Bit Cost ($)	Rotating Time (hours)	Connection Time (hours)	Mean Penetration Rate (ft/hr)
A	800	14.8	0.1	13.8
B	4,900	57.7	0.4	12.6
C	4,500	95.8	0.5	10.2

Which bit would you select?

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Solution:

The cost per foot drilled for each bit type can be computed using Eq. 1.16. For Bit A, the cost per foot is

$$C_f = \frac{C_b + C_r(t_b + t_c + t_t)}{\Delta D} \quad \frac{\$}{ft}$$

$$C_f = \frac{800 + 400(14.8 + 0.1 + 7)}{13.8(14.8)} = \$46.81/ft.$$

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Solution:

Similarly, for Bit B,

$$C_f = \frac{C_b + C_r(t_b + t_c + t_t)}{\Delta D} \quad \frac{\$}{ft}$$

$$C_f = \frac{4{,}900 + 400(57.7 + 0.4 + 7)}{12.6(57.7)} = \$42.56/ft.$$

Solution, cont'd

Finally, for Bit C,

$$C_f = \frac{C_b + C_r(t_b + t_c + t_t)}{\Delta D} \quad \frac{\$}{ft}$$

$$C_f = \frac{4{,}500 + 400(95.8 + 0.5 + 7)}{10.2(95.8)} = \$46.89/ft.$$

Solution, cont'd

Bit A: $46.81 /ft

Bit B: $42.56 /ft ⟵

Bit C: $46.89 /ft

The lowest drilling cost was obtained using **Bit B**. - Highest bit cost ...but - intermediate bit life and ROP...

1.10 Drilling Cost Analysis

The main function of the drilling engineer is to recommend drilling procedures that will result in the successful completion of the well as safely and inexpensively as possible. The drilling engineer must make recommendations concerning routine rig operations such as drilling fluid treatment, pump operation, bit selection, and any problems encountered in the drilling operation. In many cases, the use of a drilling cost equation can be useful in making these recommendations. The usual procedure is to break the drilling costs into (1) variable drilling costs and (2) fixed operating expenses that are independent of alternatives being evaluated.

1.10.1 Example Drilling Cost Formula. The most common application of a drilling cost formula is in evaluating the efficiency of a bit run. A large fraction of the time required to complete a well is spent either drilling or making a trip to replace the bit. The total time required to drill a given depth, ΔD, can be expressed as the sum of the total rotating time during the bit run, t_b, the nonrotating time during the bit run, t_c, and trip time, t_t. The drilling cost formula is

$$C_f = \frac{C_b + C_r(t_b + t_c + t_t)}{\Delta D}, \quad \ldots\ldots\ldots\ldots (1.16)$$

where C_f is drilled cost per unit depth, C_b is the cost of bit, and C_r is the fixed operating cost of the rig per unit time independent of the alternatives being evaluated.

Since this drilling cost function ignores risk factors, the results of the cost analysis sometimes must be tempered with engineering judgment. Reducing the cost of a bit run will not necessarily result in lower well costs if the risk of encountering drilling problems such as stuck pipe, hole deviation, hole washout, etc., is increased greatly.

Example 1.5. A recommended bit program is being prepared for a new well using bit performance records from nearby wells. Drilling performance records for three bits are shown for a thick limestone formation at 9,000 ft. Determine which bit gives the lowest drilling cost if the operating cost of the rig is $400/hr, the trip time is 7 hours, and connection time is 1 minute per connection. Assume that each of the bits was operated at near the minimum cost per foot attainable for that bit.

Bit	Bit Cost ($)	Rotating Time (hours)	Connection Time (hours)	Mean Penetration Rate (ft/hr)
A	800	14.8	0.1	13.8
B	4,900	57.7	0.4	12.6
C	4,500	95.8	0.5	10.2

Solution. The cost per foot drilled for each bit type can be computed using Eq. 1.16. For Bit A, the cost per foot is

$$C_f = \frac{800 + 400(14.8 + 0.1 + 7)}{13.8(14.8)} = \$46.81/ft.$$

Similarly, for Bit B,

$$C_f = \frac{4{,}900 + 400(57.7 + 0.4 + 7)}{12.6(57.7)} = \$42.56/ft.$$

Finally, for Bit C,

$$C_f = \frac{4{,}500 + 400(95.8 + 0.5 + 7)}{10.2(95.8)} = \$46.89/ft.$$

The lowest drilling cost was obtained using Bit B.

2. Criteria for selecting the best bit

$$C_f = \frac{C_b + C_r(t_b + t_c + t_t)}{\Delta D}$$

where

C_f --is drilled cost per unit depth

C_b --is the cost of the bit

C_r --is the fixed operating cost of the rig per unit time

t_b --total rotating time during the bit run

t_c --non rotating time during the bit run

t_t --trip time

Example

- Calculate the cost per foot for the given data of 3 bits: Rig rate= $400/hr, and trip time 1hr/1000'

Bit3	Bit cost, $	Depth out, FT	Footage, FT	Rot. Hr.
A	2500	9206	206	15
B	4950	9732	732	58
C	4950	9983	983	96

$$C = \frac{2500 + 400(15 + \frac{9206}{1000})}{206}$$

$$= \$59.13/ft$$

Bit	Bit cost, $	Footage, FT	Rot. Hr.	ROP, ft/hr	Cost/ft, $
A	2500	206	15	13.7	59.13
B	4950	732	58	12.6	43.76
C	4950	983	96	10.2	48.13

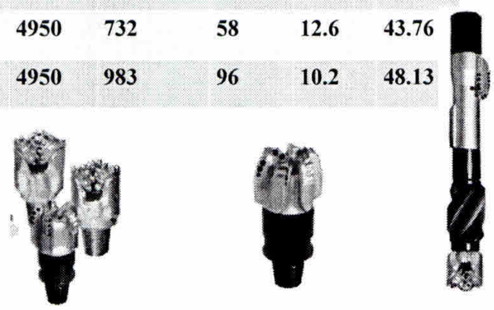

TABLE 1.7 – AVERAGE 1978 COSTS OF DRILLING AND EQUIPPING WELLS IN THE SOUTH LOUISIANA AREA

Depth Interval (ft)	Dry Holes: Number of Wells, n_i	Dry Holes: Mean Depth, D_i (ft)	Dry Holes: Cost, C_i ($)	Completed Wells: Number of Wells, n_i	Completed Wells: Mean Depth, D_i (ft)	Completed Wells: Cost, C_i ($)
0 to 1,249	1	1,213	64,289	0	–	–
1,250 to 2,499	1	1,542	65,921	9	1,832	201,416
2,499 to 3,749	8	3,015	128,294	20	3,138	212,374
3,750 to 4,999	11	4,348	199,397	20	4,347	257,341
5,000 to 7,499	43	6,268	278,087	47	6,097	419,097
7,500 to 9,999	147	8,954	426,336	117	9,070	614,510
10,000 to 12,499	228	11,255	664,817	165	11,280	950,971
12,500 to 14,999	125	13,414	1,269,210	110	13,659	1,614,422
15,000 to 17,499	54	16,133	2,091,662	49	16,036	2,359,144
17,500 to 19,999	21	18,521	3,052,213	17	18,411	3,832,504
20,000 and more	7	21,207	5,571,320	11	20,810	5,961,053

1.10.2 Drilling Cost Predictions. The drilling engineer frequently is called upon to predict the cost of a well at a given location. These predictions are required so that sound economic decisions can be made. In some cases, such as the evaluation of a given tract of land available for lease, only an approximate cost estimate is required. In other cases, such as in a proposal for drilling a new well, a more detailed cost estimate may be required.

Drilling cost depends primarily on well location and well depth. The location of the well will govern the cost of preparing the wellsite, moving the rig to the location, and the daily operating cost of the drilling operation. For example, an operator may find from experience that operating a rig on a given lease offshore Louisiana requires expenditures that will average about $30,000/day. Included in this daily operating cost are such things as rig rentals, crew boat rentals, work boat rentals, helicopter

rentals, well monitoring services, crew housing, routine maintenance of drilling equipment, drilling fluid treatment, rig supervision, etc. The depth of the well will govern the lithology that must be penetrated and, thus, the time required to complete the well.

An excellent source of historical drilling-cost data presented by area and well depth is the annual joint association survey on drilling costs published by API. Shown in Table 1.7 are data for the south Louisiana area taken from the 1978 joint association survey. Approximate drilling cost estimates can be based on historical data of this type.

Drilling costs tend to increase exponentially with depth. Thus, when curve-fitting drilling cost data, it is often convenient to assume a relationship between cost, C, and depth, D, given by

$$C = ae^{bD}, \qquad (1.17)$$

where the constants a and b depend primarily on the well location. Shown in Fig. 1.65a is a least-square curve fit of the south Louisiana completed well data given in Table 1.7 for a depth range of 7,500 ft to about 21,000 ft. For these data, a has a value of about 1×10^5 dollars and b has a value of 2×10^{-4} ft^{-1}. Shown in Fig. 1.65b is a more conventional cartesian representation of this same correlation.

When a more accurate drilling cost prediction is needed, a cost analysis based on a detailed well plan must be made. The cost of tangible well equipment (such as casing) and the cost of preparing the surface location usually can be predicted accurately. The cost per day of the drilling operations can be estimated from considerations of rig rental costs, other equipment rentals, transportation costs, rig supervision costs, and others. The time required to drill and complete the well is estimated on the basis of rig-up time, drilling time, trip time, casing placement time, formation evaluation and borehole survey time, completion time and trouble time. Trouble time includes time spent on hole problems such as stuck pipe, well control operations, formation fracture, etc. Major time expenditures always are required for drilling and tripping operations.

An estimate of drilling time can be based on historical penetration rate data from the area of

varies inversely with both compressive strength and shear strength of the rock. Also, rock strength tends to increase with depth of burial because of the higher confining pressure caused by the weight of the overburden. When major unconformities are not present in the subsurface lithology, the penetration rate usually decreases exponentially with depth. Under these conditions, the penetration rate can be related to depth, D, by

$$\frac{dD}{dt} = K e^{-2.303 a_2 D}, \qquad (1.18)$$

where K and a_2 are constants. The drilling time, t_d, required to drill to a given depth can be obtained by separating variables and integrating. Separating variables gives

$$K \int_0^{t_d} dt = \int_0^D e^{2.303 a_2 D} dD.$$

Integrating and solving for t_d yields

$$t_d = \frac{1}{2.303 a_2 K}\left(e^{2.303 a_2 D} - 1\right). \qquad (1.19)$$

As experience is gained in an area, more accurate predictions of drilling time can be obtained by plotting depth vs. drilling time from past drilling operations. Plots of this type also are used in evaluating new drilling procedures designed to reduce drilling time to a given depth.

Example 1.6. The bit records for a well drilled in the South China Sea are shown in Table 1.8. Make plots of depth vs. penetration rate and depth vs. rotating time for this area using semilog paper. Also, evaluate the use of Eq. 1.19 for predicting drilling time in this area.

Solution. The plots obtained using the bit records are shown in Fig. 1.66. The constants K and a_2 can be determined using the plot of depth vs. penetration rate on semilog paper. The value of $2.303a_2$ is 2.303 divided by the change in depth per log cycle:

$$2.303 a_2 = \frac{2.303}{6,770} = 0.00034.$$

The constant 2.303 is a convenient scaling factor since

Drilling Costs

- Tend to increase **exponentially** with depth. Thus, when curve-fitting drilling cost data, it is often convenient to assume a relationship between total well cost, C, and depth, D, given by

C = ae

$$C = ae^{bD} \qquad \text{.......................(1.17)}$$

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Drilling Costs, cont'd

$C = ae^{bD}$

Constants a and b depend primarily on the well location.

Shown on the next page is a least-squares curve fit of the south Louisiana completed well data given in Table 1.7.

Depth range of 7,500 ft to 21,000 ft.

For these data,

$a = 1 \times 10^5$ dollars

$b = 2 \times 10^{-4}$ ft^{-1}.

17

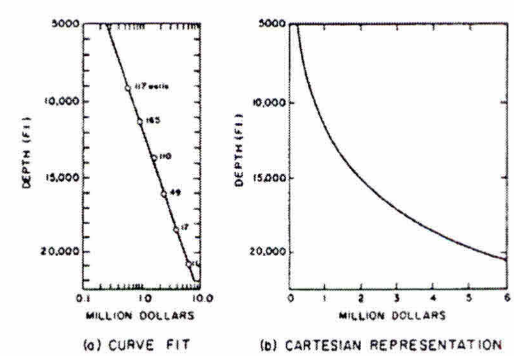

Fig. 1-65. Least-square curve fit of 1978 completed well costs for wells below 7,500 ft in the south Louisiana area.[18]

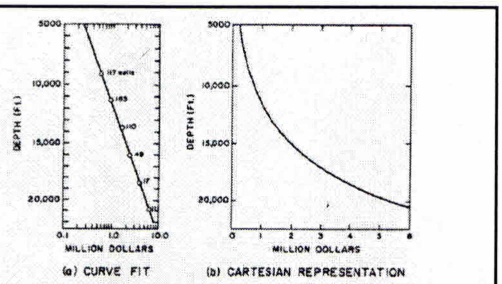

Fig. 1.65 – Least-square curve fit of 1978 completed well costs for wells below 7,500 ft in the south Louisiana area.

Penetration Rate

When major variations are not present in the subsurface lithology, the penetration rate usually decreases exponentially with depth. Under these conditions, the penetration rate can be related to depth, D, by

$$\frac{dD}{dt} = Ke^{-2.303\,a_2 D} ,........(1.18)$$

where K and a_2 are constants.

WHY?

19

Drilling Time

The drilling time, t_d, required to drill to a given depth can be obtained by separating variables and integrating. Separating variables gives

$$K\int_0^{t_d} dt = \int_0^D e^{2.303\,a_2 D}\,dD$$

Integrating and solving for t_d yields

$$t_d = \frac{1}{2.303a_2K}\left(e^{2.303a_2D} - 1\right).............(1.19)$$

20

varies inversely with both compressive strength and shear strength of the rock. Also, rock strength tends to increase with depth of burial because of the higher confining pressure caused by the weight of the overburden. When major unconformities are not present in the subsurface lithology, the penetration rate usually decreases exponentially with depth. Under these conditions, the penetration rate can be related to depth, *D*, by

$$\frac{dD}{dt} = K\,e^{-2.303a_2D}, \quad ....(1.18)$$

where *K* and a_2 are constants. The drilling time, t_d, required to drill to a given depth can be obtained by separating variables and integrating. Separating variables gives

$$K\int_o^{t_d} dt = \int_o^D e^{2.303a_2D}\,dD.$$

Integrating and solving for t_d yields

$$t_d = \frac{1}{2.303a_2K}\left(e^{2.303a_2D} - 1\right). \quad .... (1.19)$$

operations. Plots of this type also are used in evaluating new drilling procedures designed to reduce drilling time to a given depth.

Example 1.6. The bit records for a well drilled in the South China Sea are shown in Table 1.8. Make plots of depth vs. penetration rate and depth vs. rotating time for this area using semilog paper. Also, evaluate the use of Eq. 1.19 for predicting drilling time in this area.

Solution. The plots obtained using the bit records are shown in Fig. 1.66. The constants *K* and a_2 can be determined using the plot of depth vs. penetration rate on semilog paper. The value of $2.303a_2$ is 2.303 divided by the change in depth per log cycle:

$$2.303a_2 = \frac{2.303}{6{,}770} = 0.00034.$$

The constant 2.303 is a convenient scaling factor since

TABLE 1.8 – BIT RECORDS FROM SOUTH CHINA SEA AREA

Bit No.	Depth Out (ft)	Mean Depth (ft)	Bit Time (hours)	Total Drilling Time (hours)	Average Penetration Rate (ft/hr)	Hole Size (in.)
1	473	237	1.0	1.0	473	15.00
2	1,483	978	5.0	6.0	202	15.00
3	3,570	2,527	18.5	24.5	113	12.25
4	4,080	3,825	8.0	32.5	64	12.25
5	4,583	4,332	7.0	39.5	72	12.25
6	5,094	4,839	7.0	46.5	73	12.25
7	5,552	5,323	14.0	60.5	32	12.25
8	5,893	5,723	11.5	72.0	30	12.25
9	6,103	5,998	9.0	81.0	23	12.25
10	6,321	6,212	11.5	92.5	19	12.25
11	6,507	6,414	9.0	101.5	21	12.25
12	6,773	6,640	9.0	110.5	30	12.25
13	7,025	6,899	9.5	120.0	27	12.25
14	7,269	7,147	8.0	128.0	31	12.25
15	7,506	7,388	16.0	144.0	15	8.5
16	7,667	7,587	12.0	156.0	13	8.5
17	7,948	7,808	14.0	170.0	20	8.5
18	8,179	8,064	8.0	178.0	29	8.5
19	8,404	8,292	10.5	188.5	21	8.5
20	8,628	8,516	11.0	199.5	20	8.5
21	8,755	8,692	7.0	206.5	18	8.5
22	8,960	8,858	10.0	216.5	21	8.5
23	9,145	9,053	11.0	227.5	17	8.5

Formations with high strength require the use of a greater number of bits to drill a given depth interval. In some cases, the number of trips required to drill a well is too great to treat each trip individually with convenience as was done in Example 1.7. The time required per round trip is relatively constant over a 1,000-ft interval. Thus the total trip time required per 1,000 ft is approximately equal to the time per round trip times the number of trips per 1,000 ft. The number of bits required per 1,000 ft, N_b', at a given depth can be approximated by dividing the drilling time per 1,000 ft, t_d', by the average bit life for that depth interval:

$$N_b' = \frac{t_d'}{\bar{t}_b}.$$

The drilling time required to drill from D to $(D+1,000)$ can be obtained using Eq. 1.19.

$$t_d' = \frac{1}{2.303a_2K}[e^{2.303a_2(D+1,000)}-1] - \frac{1}{2.303a_2K}(e^{2.303a_2D}-1).$$

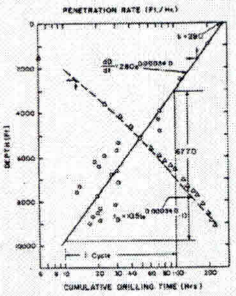

Fig. 1.66 – Example drilling-time plots for South China Sea area.

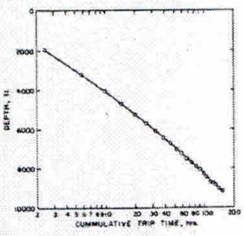

Fig. 1.67 – Example trip-time plot for South China Sea area.

TABLE 1.9 – EXAMPLE TRIP-TIME COMPUTATION FOR SOUTH CHINA SEA AREA

(1) Trip No.	(2) Depth, D_i (ft)	(3) Trip Time (hours)	(4) Cumulative Trip Time (hours)	(5) Depth, D (ft)	(6) Next Casing Depth (ft)
1	500	0.5	0.5	2,299	2,000
2	2,000	2.0	2.5	3,205	7,500
3	3,205	3.2	5.7	4,057	7,500
4	4,057	4.1	9.8	4,717	7,500
5	4,717	4.7	14.5	5,256	7,500
6	5,256	5.3	19.8	5,711	7,500
7	5,711	5.7	25.5	6,105	7,500
8	6,105	6.1	31.6	6,452	7,500
9	6,452	6.5	38.1	6,762	7,500
10	6,762	6.8	44.9	7,043	7,500
11	7,043	7.0	51.9	7,299	7,500
12	7,299	7.3	59.2	7,534	7,500
13	7,500	7.5	66.7	7,721	9,150
14	7,721	7.7	74.4	7,926	9,150
15	7,926	7.9	82.3	8,118	9,150
16	8,118	8.1	90.4	8,298	9,150
17	8,298	8.3	98.7	8,467	9,150
18	8,467	8.5	107.2	8,627	9,150
19	8,627	8.6	115.8	8,779	9,150
20	8,779	8.8	124.6	8,923	9,150
21	8,923	8.9	133.5	9,061	9,150
22	9,061	9.1	142.6	9,192	9,150
23	9,150	9.2	151.8		

semilog paper is based on common logarithms. The value of K is equal to the value of penetration rate at the surface. From depth vs. penetration rate plot, $K=280$. Substitution of these values of a_2 and K in Eq. 1.19 gives

$$t_d = -\frac{(e^{0.00034D}-1)}{(0.00034*280)} = 10.504(e^{0.00034D}-1)$$

$$t_d = 10.504\,(e^{0.00034D}-1).$$

The line represented by this equation also has been plotted on Fig. 1.66. Note that the line gives good agreement with the bit record data over the entire depth range.

A second major component of the time required to drill a well is the trip time. The time required for tripping operations depends primarily on the depth of the well, the rig being used, and the drilling practices followed. The time required to change a bit and resume drilling operations can be approximated using the relation

$$t_t = 2\left(\frac{t_s}{\bar{l}_s}\right)D, \quad \ldots\ldots\ldots\ldots\ldots\ldots (1.20)$$

where t_t is the trip time required to change bits and resume drilling operations, t_s is the average time required to handle one stand of the drillstring, and $\bar{l}_s$ is the average length of one stand of the drillstring. The time required to handle the drill collars is greater than for the rest of the drillstring, but this difference usually does not warrant the use of an additional term in Eq. 1.20. Historical data for the rig of interest are needed to determine t_s.

The previous analysis shows that the time required per trip increases linearly with depth. In addition, the footage drilled by a single bit tends to decrease with depth, causing the number of trips required to drill a given depth increment also to increase with depth. The footage drilled between trips can be estimated if the approximate bit life is known. Integrating Eq. 1.18 between D_i, the depth of the last trip, and D, the depth of the next trip, gives the following equation:

$$D = \frac{1}{2.303a_2}\ln(2.303a_2K t_b + e^{2.303a_2D_i}). \quad .\ (1.21)$$

The total bit rotating time, t_b, generally will vary with depth as the bit size and bit type are changed. Eqs. 1.20 and 1.21 can be used to estimate the total trip time required to drill to a given depth using estimated values of t_s, t_b, a_2 and K. As experience is gained in an area using a particular rig, more accurate predictions of trip time can be obtained by plotting depth vs. trip time data from past drilling operations.

Example 1.7. Construct an approximate depth vs. trip time plot for the South China Sea area if the rig can handle a 90-ft stand in an average time of 2.7 minutes. Assume an average bit life of 10.5 hours for the entire depth interval. Use the values of a_2 and K obtained in Example 1.6. Also, the casing program calls for casing set at 500, 2,000, and 7,500 ft. The planned well depth is 9,150 ft.

Solution. The time required per round trip at a given depth is given by Eq. 1.20:

$$t_t = 2\left(\frac{2.7/60}{90}\right)D = 0.001\,D.$$

The approximate depth of each trip can be obtained from the casing program and Eq. 1.21. The use of Eq. 1.21 gives

$$D = \frac{1}{0.00034}\ln\,(0.00034\,(280)\,(10.5) + e^{0.00034D_i})$$

$$= 2,941\,\ln\,(0.9996 + e^{0.00034D_i})$$

The first bit will drill to the first casing depth. Thus, the first trip will occur at 500 ft. Subsequent trips are predicted as shown in Table 1.9. Col. 2 is obtained by selecting the smaller of the two depths shown in Cols. 5 and 6. Col. 3 is obtained using Eq. 1.20, and Col. 4 is the cumulative obtained by summing Col. 3. Col. 5 is obtained using Eq. 1.21, and Col. 6 is obtained from the planned casing program. The results of Table 1.9 have been plotted in Fig. 1.67.

Example 1.7. Construct an approximate depth vs. trip time plot for the South China Sea area if the rig can handle a 90-ft stand in an average time of 2.7 minutes. Assume an average bit life of 10.5 hours for the entire depth interval. Use the values of a_2 and K obtained in Example 1.6. Also, the casing program calls for casing set at 500, 2,000, and 7,500 ft. The planned well depth is 9,150 ft.

Solution. The time required per round trip at a given depth is given by Eq. 1.20:

$$t_t = 2\left(\frac{2.7/60}{90}\right)D = 0.001\,D. \qquad t_t = 2\left(\frac{t_s}{l_s}\right)D,$$

The approximate depth of each trip can be obtained from the casing program and Eq. 1.21. The use of Eq. 1.21 gives

$$D = \frac{1}{0.00034}\ln\left[0.00034\,(280)\,(10.5) + e^{0.00034D_i}\right]$$

$$= 2{,}941\ln\left(0.9996 + e^{0.00034D_i}\right) \qquad D = \frac{1}{2.303a_2}\ln(2.303a_2Kt_b + e^{2.303a_2D_i}).$$

The first bit will drill to the first casing depth. Thus, the first trip will occur at 500 ft. Subsequent trips are

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$$= 2{,}941\ln\left(0.9996 + e^{0.00034D_i}\right)$$

$$t_t = 2\left(\frac{2.7/60}{90}\right)D = 0.001\,D.$$

Trip No	Depth,Di ft. D>Casing Di =Casing	Trip Time (hours) 0.001*Di	Cumulative Trip Time (hours)	Depth,D ft. D<Casing	Next Casing Depth ft.
1	500	0.5	0.5	2299	2000
2	2000	2	2.5	3205	7500
3	3205	3.2	5.7	4057	7500
4	4057	4.1	9.8	4717	7500
5	4717	4.7	14.5	5255	7500
6	5255	5.3	19.7	5710	7500
7	5710	5.7	25.4	6104	7500
8	6104	6.1	31.5	6451	7500
9	6451	6.5	38.0	6762	7500
10	6762	6.8	44.8	7043	7500
11	7043	7.0	51.8	7299	7500
12	7299	7.3	59.1	7534	7500
13	7500	7.5	66.6	7721	9150
14	7721	7.7	74.3	7926	9150
15	7926	7.9	82.3	8117	9150
16	8117	8.1	90.4	8297	9150
17	8297	8.3	98.7	8467	9150
18	8467	8.5	107.1	8627	9150
19	8627	8.6	115.8	8779	9150
20	8779	8.8	124.5	8924	9150
21	8924	8.9	133.5	9061	9150
22	9061	9.1	142.5	9193	9150
23	9150	9.2	151.7		9150

TABLE 1.9 – EXAMPLE TRIP-TIME COMPUTATION FOR SOUTH CHINA SEA AREA

This equation simplifies to

$$t_d' = \frac{e^{2.303a_2D}}{2.303a_2K}\left(e^{2.303a_2} - 1\right). \quad \ldots\ldots\ldots\ldots (1.22)$$

Multiplying the number of bits per 1,000 ft, N_b', by the time per round trip yields trip time per 1,000 ft.

Example 1.8. Compute the trip time requirements for the South China Sea area between 8,000 and 9,000 ft. Use the conditions stated in Example 1.7.

Solution. The average trip time can be estimated using Eq. 1.20 for a mean depth of 8,500 ft.

$$t_t = \frac{2(2.7/60)}{90}(8{,}500) = 8.5 \text{ hours.}$$

The drilling time required to drill from 8,000 to 9,000 ft is determined using Eq. 1.22.

$$t_d' = \frac{e^{0.00034(8{,}000)}}{(0.00034)280}\left(e^{0.34} - 1\right) = 64.6 \text{ hours.}$$

Thus, the number of bits required between 8,000 and 9,000 ft is

$$N_b' = \frac{t_d'}{t_b} = \frac{64.6}{10.5} = 6.15.$$

Multiplying the trip time per trip by the number of trips required yields

$$8.5(6.15) = 52.3 \text{ hours.}$$

This compares favorably with the trip time required between 7,926 and 8,923 ft computed in Example 1.7. From Table 1.9, the trip time per 1,000 ft is shown to be

$$133.5 - 82.3 = 51.2 \text{ hours.}$$

In addition to predicting the time requirements for drilling and tripping operations, time requirements for other planned drilling operations also must be estimated. These additional drilling operations usually can be broken into the general categories of (1) wellsite preparation, (2) rig movement and rigging up, (3) formation evaluation and borehole surveys, (4) casing placement, (5) well completion, and (6) drilling problems. The cost associated with wellsite preparation and moving the rig on location depends primarily on the terrain, the distance of the move, and the type of rig used. The cost of formation evaluation depends on the number and cost of the logs and tests scheduled, plus rig time required to condition the drilling fluid and run the logs and tests. The time required to run, cement, and test the casing depends primarily on the number of casing strings, casing depths, diameters, and weights per foot. These costs also must include the rig time required for running and cementing the casing strings, rigging up the surface equipment on each casing size, and perhaps changing the drillpipe or drill collar sizes to accommodate the new hole size. The cost of completing the well depends on the type of completion used, and this cost estimate is often made by the production engineer.

On many wells, a large fraction of the well cost may be because of unexpected drilling problems such as mud contamination, lost circulation, stuck drillstring, broken drillstring, ruptured casing, etc. These unforeseen costs cannot be predicted with any

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On many wells, a large fraction of the well cost may be because of unexpected drilling problems such as mud contamination, lost circulation, stuck drillstring, broken drillstring, ruptured casing, etc. These unforeseen costs cannot be predicted with any

degree of accuracy and in some cases are not included in an original cost estimate. Requests for additional funds then must be submitted whenever a significant problem is encountered. However, long-range economic decisions concerning a drilling program in a given area should include average well costs due to drilling problems.

In areas where formation strength is low, time spent drilling and tripping may account for only about one-half to one-third of the total time needed to finish the well. Shown in Table 1.10 is a detailed time breakdown for an offshore Louisiana well drilled to 10,000 ft using a small platform rig tender. Only about 36% of the time required to drill and complete this well was spent drilling and tripping to change bits. About 7% of the time was spent "fishing" parts of the drillstring from the hole.

TABLE 1.10 – EXAMPLE RIG TIME ANALYSIS FOR TENDERED RIG

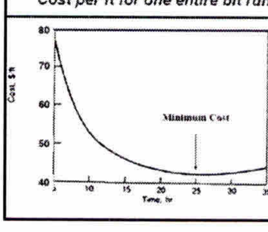
Drilling Operation		Total Required (hours)	Time Fraction
Drilling		351	0.17
Tripping		388	0.19
Rigging up		348	0.17
Formation evaluation and borehole surveys		103	0.05
Casing placement		199	0.10
Well completion		211	0.10
Drilling problems (total)		450	0.22
Mud conditioning	143		
Well control operations	12		
Fishing operations	152		
Severe weather	97		
Rig repairs	20		
Logistics	26		
Total		2,050	1.00

EXAMPLE - Cost per ft

t hr	R fph	D ft	Total Cost $	C_f $/ft
5	90	475	38,950	77.80
10	80	900	47,800	53.10
20	60	1,600	69,200	43.30
25	50	1,875	79,750	42.50
30	40	2,100	90,200	43.00
35	30	2,275	100,550	44.20
40	20	2,400	110,800	46.20

These cost data are plotted below.

Cost per ft for one entire bit run



A cursory analysis quickly shows that well costs are not a linear function of depth. A high order polynomial, such as:

$$\Phi_{well} = c_0 + c_1 z + c_2 z^2 + c_3 z^3 + ... \qquad (6\text{-}1)$$

where Φ_{well} is the completed well cost, z is the depth of the well, and c_i are fitted parameters, can be used to express well costs as a function of depth. However, it is not obvious what order polynomial would best fit the data, and any decent fit will require at least four parameters, if not more. By noting that an exponential function can be expanded as an infinite series of polynomial terms:

$$e^x = 1 + x + \frac{x^2}{2!} + \frac{x^3}{3!} + ... \qquad (6\text{-}2)$$

one might be able to describe the well-cost data as a function of depth using only a few parameters. As Figure 6.1 shows, the average costs of completed oil and gas wells for the depth intervals from 1,250 feet (380 m) to 19,999 feet (6,100 m) can be described as an exponential function of depth, that is:

$$\Phi_{well} = a \cdot \exp(b_1 \cdot \text{depth}) = a \cdot \exp(b_1 z) \qquad (6\text{-}3)$$

where only two fitted parameters, a and b_1, are needed. Thus, a plot of $\log_{10}$(well cost) vs. depth results in a straight line.

$$\log_{10}(\Phi_{well}) = \log_{10}(a) + b_2 z \qquad (6\text{-}4)$$

Although there is no fundamental economic reason for an exponential dependence, the "Oil and Gas Average" trend line in Figure 6.1 shows that a two-parameter exponential function adequately describes year 2004 JAS average completed well costs as a function of depth for the depth intervals considered. The correlation coefficient (R^2) value for the year 2004 JAS data, when fit to Eq. (6-4), was 0.968. This indicates a high degree of correlation between the log of the completed well costs and depth. Similar plots for each year of JAS report data from the years 1976-2003 also show high levels of correlation between the $\log_{10}$ of well costs and depth, with all years having an R^2 value of 0.984 or higher.

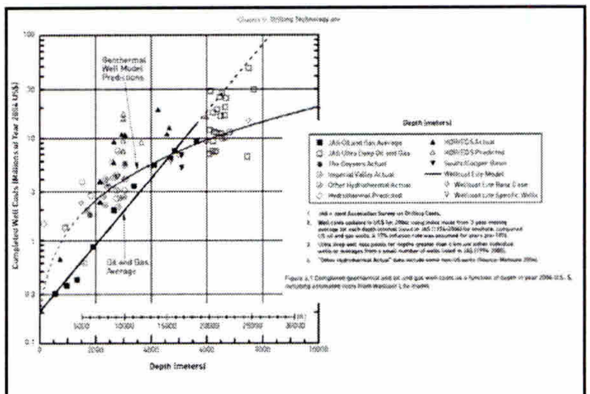


Figure 6.1 Completed geothermal and oil and gas well costs as a function of depth in year 2004 U.S. $, including estimated costs from Wellcost Lite model.

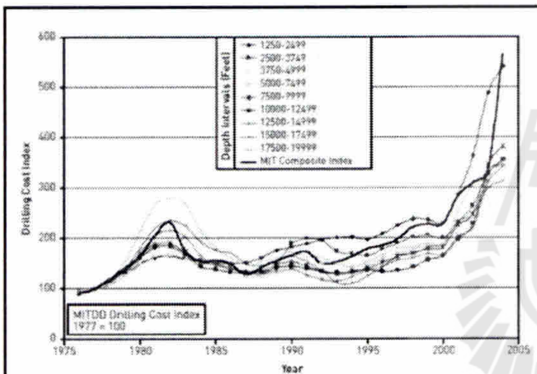


Figure 6.2 MITDD drilling cost index made using average cost per well for each depth interval from Joint Association Survey on Drilling Costs (1976-2004), with data smoothed using a three-year moving average (1977 = 100 for all depth intervals). Note: 1 ft = 0.3048 m.

Figure 6.6 MITDD drilling cost index compared to GDP deflator index for 1977-2004 (U.S. Office of Management and Budget, 2006). Note: 1 ft = 0.3048 m.

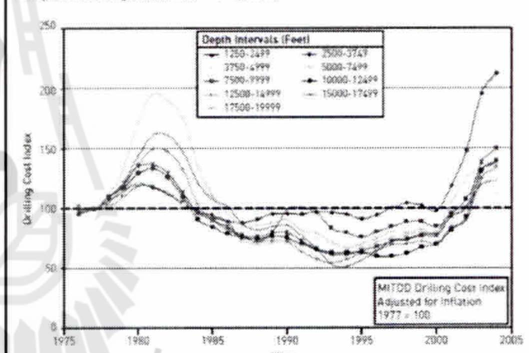


Figure 6.7 MITDD drilling cost index made using new method, adjusted for inflation to year 2004 U.S. $. Adjustment for inflation made using GDP Deflator index (1977 = 100). Note: 1 ft = 0.3048 m.

1.21 Assume that C_i represents the average cost for n_i wells drilled to a mean depth, D_i, and that C_i varies approximately exponentially with depth such that an expression

$$C = ae^{bD}$$

can be used to curve fit N observed values of n_i, C_i, and D_i. If we define a residual error, r_i, as

$$r_i = n_i \ln \frac{C_i}{C},$$

it is possible to determine the constants a and b using the N observed values of n_i, D_i, and C_i such that the sum of the residuals squared has a minimum value. Derive expressions for a and b that result in a minimum value of

$$\sum_{i=1}^{N} r_i^2.$$

1.22 Apply the expressions for a and b derived in Exercise 1.21 to obtain a least-square curve fit of the south Louisiana completed well cost data given in Table 1.7 for well depths below 7,500 ft.

1.23 Complete the following using the cost vs. depth data given in Table 1.7 for dry holes drilled in south Louisiana in 1978.

a. A plot of cost vs. depth on cartesian paper.

b. A plot of cost vs. depth on semilog paper.

c. Determine a set of constants a and b of Eq. 1.17 that allow a curve fit of these data. *Answer: \$65.513 and 0.000212.*

1.24 The following bit records were obtained on a well drilled in Maverick County, Texas.

Bit No.	Depth Out (ft)	Time (hours)	Bit Size (in.)
1	500	2.0	17.5
2	1,925	15.0	17.5
34	8,060	25.8	12.0
35	8,494	270.0	12.0
36	8,614	33.1	12.0
37	8,669	19.0	12.0
38	8,737	29.7	8.5
39	8,742	3.4	8.5
40	8,778	8.5	8.5
41	9,661	179.1	8.5
42	9,874	88.4	8.5
43	9,973	30.0	8.5
44	10,016	11.8	8.5
45	10,219	64.3	8.5
46	10,408	57.2	8.5
47	10,575	61.2	8.5
48	10,661	36.1	8.5

a. Plot a depth vs. rotating time curve for this well.

b. Evaluate the use of Eq. 1.19 in this area.

c. Assuming that the rig can pull thribbles at an average time per stand of 4 minutes, plot the trip time per trip vs. depth. *Answer: t_t = 0.00148 D.*

d. Using the bit records, make a plot of total trip time vs. depth.

e. Compare the performance of Bits 34 and 35. Assume a daily operating cost of \$24,000/D, a bit cost of \$3,000 for Bit 34, and a bit cost of \$12,000 for Bit 35. *Answer: \$565/ft and \$679/ft.*

1.25 Two rigs are available for drilling a well in southern California. One rig costs \$800/hr but can only pull doubles. The other rigs costs \$1,000/hr but can pull thribbles. In this area K is 200 ft/hr and $2.303a_2$ is 0.0004. The time required to pull one stand is about 4 minutes for both rigs. Considering only the cost of the tripping operations, which rig would be best for a well drilled to 7,000 ft? Assume an average bit life of 10 hours for all bits and casing setting depths of 500 and 2,000 ft. *Answer: Thribble rig (\$151,200 vs. \$181,400).*

References

HW. NO 4.1; 19.2, 19.3, 19.6

19.2 Refer to Figs. 19–7 and 19–8 and calculate the costs to build and maintain a 15.0-lb/gal lignosulfonate mud for 60 days. Compare it with an oil mud. Assume a 750-bbl system.

19.3 What are the cement pumping charges for a 15,000-ft well onshore and offshore?

19.4 Determine the cost to run 15,000 ft of 6-in. pipe.

19.5 A 60-ft sand zone will be perforated with 4 shots/ft. If the zone is at 20,000 ft, what will be the perforating charge?

19.6 Why is a 20,000-ft high pressure well more expensive than a normal pressure well at the same depth?

Due Date;Friday 15 AUGUST 2014

HW. NO 4.1; 19.2, 19.3, 19.6

6.00 3,153

Plot the pump pressure flow rate combinations possible at maximum hydraulic horsepower using cartesian coordinate paper. Repeat this using log-log

a. Capacity of the drillpipe in barrels. *Answer: 159.8 bbl.*

19.2 Refer to Figs. 19–7 and 19–8 and calculate the costs to build and maintain a 15.0-lb/gal lignosulfonate mud for 60 days. Compare it with an oil mud. Assume a 750-bbl system.

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hole. The ID of the casing in the hole is 10.05 in.

HW. NO 4.2; 1.18, 1.19, 1.24, 1.25

if one stand of ... the hole. *Answer:* ... *ft.*

In" Applied Drilling Engineering"

Adam T. Bourgoyne Jr.

... pit is 8 ft ... hole is filled ... *r: 2.5 in.* ... change in fluid level in a 3- ... 3-ft trip tank ... trip tank ... *r: 3.6 ft.* ... of calcium carbide in the drillstring when a connection is made. The calcium carbide reacts with the mud to form acetylene gas. The acetylene is detected by ... having an ID of 2.825 in. The pump is a double-

1.18 A recommended bit program is being prepared for a new well, using bit performance records from nearby wells. Drilling records for three bits are shown below for a thick shale section encountered at 12,000 ft. Determine which bit gives the lowest drilling cost if the hourly operating cost of the rig is $1,000/hr and the trip time is 10 hours. The connection time is included in the rotating time shown below.

Bit	Bit Cost ($)	Interval Drilled (ft)	Rotating Time (hours)
A	700	106	9
B	4,000	415	62
C	8,300	912	153

Answer: Bit B ($183.13/ft).

1.19 The penetration rates using gas, foam, and mud in an area are 10 ft/hr, 5 ft/hr, and 1 ft/hr, respectively. If gas is used, each water zone encountered must be sealed off. The cost of the plugging treatment is $2,000, and 25 hours of rig time are required to complete the sealing operation. The normal operating cost for air drilling is $200/hr. The use of foaming agents requires an additional $60/hr. The normal operating cost when using mud is $100/hr. Regardless of the drilling fluid used, the average bit cost is $1,000. The average bit life is 25 hours and the average trip time is 6 hours. Determine which drilling fluid yields the lowest drilling cost if one water zone is encountered per 1,000 ft drilled and if five water zones are encountered per 1,000 ft drilled. *Answer: gas is best for both assumptions ($35.80/ft and $63.80/ft).*

1.20 Pipe being recovered from an interval of borehole has a value of $30/ft. On the average, 20 hours of rig time must be expended to recover 200 ft of pipe. The cost per foot to sidetrack the well and redrill the junked interval of borehole would be ... Do the fishing operations appear ... approximately ... best alternative ($50/ft).

Due Date;Friday 15 AUGUST 2014

1.24 The following bit records were obtained on a well drilled in Maverick County, Texas.

Bit No.	Depth Out (ft)	Time (hours)	Bit Size (in.)
1	500	2.0	17.5
2	1,925	15.0	17.5
3	2,326	14.9	17.5
4	2,995	20.2	17.5
5	3,177	26.3	17.5
6	3,452	23.2	17.5
7	3,937	29.7	17.5
8	4,298	27.3	17.5
9	4,621	28.2	17.5
10	4,973	31.3	17.5
11	5,171	19.4	17.5
12	5,298	15.9	17.5
13	5,424	15.9	17.5
14	5,549	15.7	17.5
15	5,625	13.8	17.5
16	5,743	15.8	17.5
17	5,863	18.9	17.5
18	6,006	16.2	17.5
19	6,178	18.4	17.5
20	6,340	27.3	17.5
21	6,602	29.3	17.5
22	6,783	23.9	17.5
23	6,978	26.4	17.5
24	7,165	27.3	17.5
25	7,292	21.5	17.5
26	7,386	20.5	17.5
27	7,528	26.5	17.5
28	7,637	22.8	17.5
29	7,741	23.8	17.5
30	7,795	17.2	12.0
31	7,855	26.4	12.0
32	7,917	26.9	12.0
33	7,988	26.8	12.0
34	8,060	25.8	12.0
35	8,494	270.0	12.0
36	8,614	35.1	12.0
37	8,669	19.0	12.0
38	8,737	29.7	8.5
39	8,742	3.4	8.5
40	8,778	8.5	8.5
41	9,661	179.3	8.5
42	9,874	65.0	8.5
43	9,973	30.0	8.5
44	10,016	11.8	8.5
45	10,219	64.7	8.5
46	10,408	57.2	8.5
47	10,575	61.2	8.5
48	10,661	36.1	8.5

a. Plot a depth vs. rotating time curve for this well.

b. Evaluate the use of Eq. 1.19 in this area.

c. Assuming that the rig can pull thribbles at an average time per stand of 4 minutes, plot the trip time per trip vs. depth. *Answer:* $t_t = 0.00148\,D$.

d. Using the bit records, make a plot of total trip time vs. depth.

e. Compare the performance of Bits 34 and 35. Assume a daily operating cost of $24,000/D, a bit cost of $3,000 for Bit 34, and a bit cost of $12,000 for Bit 35. *Answer: $565/ft and $679/ft.*

Due Date;Friday 15 AUGUST 2014

1.25 Two rigs are available for drilling a well in southern California. One rig costs $800/hr but can only pull doubles. The other rigs costs $1,000/hr but can pull thribbles. In this area K is 200 ft/hr and $2.303a_2$ is 0.0004. The time required to pull one stand is about 4 minutes for both rigs. Considering only the cost of the tripping operations, which rig would be best for a well drilled to 7,000 ft? Assume an average bit life of 10 hours for all bits and casing setting depths of 500 and 2,000 ft. *Answer: Thribble rig ($151,200 vs. $181,400).*

HW. NO 4.3;

EXAMPLE 3:

Well depth = 10,000 ft. **12,000'**
Bit costs = $200.00 **$5,000**
Rig costs = $100.00 per hr. **$1000/hr**
Round trip time = ½ hr. per 1000 ft.
Bit weight = 40,000 pound
Rotary speed = 150 RPM
Bit wear, b = 1.5
Bit life = 10 hours

Due Date;Friday 15 AUGUST 2014

Determine the optimum bit weight

Solution:

Using Equation 4, $\frac{K'}{N} = (L)W^b = (10)(40,000)^{1.5}$

$$Wopt. = \left[\frac{(100)(10)(40,000)^{1.5}}{(1.5-1)[200+(100)(5)]}\right]^{1/1.5}$$

$$Wopt. = \left[\frac{(100)(10)}{(0.5)(700)}\right]^{0.667} 40,000 = 80,000 \text{ pounds}$$

To show the effect of b consider a change in the bit wear function from 1.5 to 2.0.

$$Wopt. = \left[\frac{(100)(10)}{700}\right]^{.5} 40,000 = 47,480 \text{ pounds}$$

To further emphasize the effect of b, consider a doubling of the rig operating cost from $100 to $200 per hour.

$$Wopt. = \left[\frac{(200)(10)}{(.5)(1200)}\right]^{.667} 40,000 = 90,400 \text{ pounds}$$

It is noted in Example 3 that an increase in the bit wear function of

---

COST CONTROL

$

- The object of any drilling operation is to drill a usable well at minimum cost
- In most drilling operations, faster is cost effective
- Minimize non-drilling operations

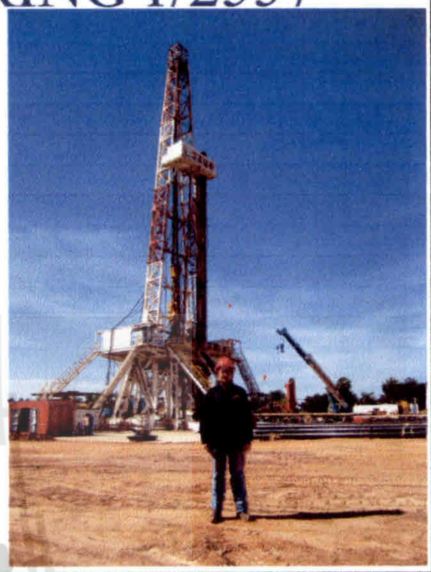
Factors Affecting Penetration Rate

- Bit weight will affect penetration rate
- Generally, if the bit weight is increased, penetration rate will increase if hydraulics are adequate
- Equation 5 gives the relationship of bit weight versus drilling rate

$$D_R = KW^d$$

ADVANCED DRILLING ENGINEERING 1/2557

Chapter5
Hole Problems.
(4 hrs.)



By
Kriangkrai Trisarn

534620 ADVANCED DRILLING ENGINEERING 4(4-0-8) @ 1/2557, 2014

Course Contents

1. How to Get Drilling Permission (2hrs.) Asso. Prof. KK
2. Introduction to Rotary Drilling (4 hrs.) Asso. Prof. KK
3. Well Planning and Proposal (2 hrs.) Asso. Prof. KK
4. Cost Estimation and Control (4 hrs.) Asso. Prof. KK
5. Hole Problems.(4 hrs.) Asso. Prof. KK
6. Drilling Fluids (4 hrs.) Asso. Prof. KK
7. Factors Affecting Rate of Penetration (4 hrs.) Asso. Prof. KK
8. Pressure Control (4 hrs.) Dr. Akkaphun
9. Pore Pressure and Pressure Gradient (4 hrs.) Dr. Akkaphun
10. Blowout Control Procedure and Equipment (4 hrs.) Dr. Akkaphun
11. Directional and Slimhole Drilling (4 hrs.) Dr. Akkaphun
12. Rotary Bit Design (2 hrs.) Dr. Akkaphun
13. New Technology Drilling (6 hrs.) Dr. Akkaphun

ADVANCED DRILLING ENGINEERING

CHAPTER 5

•HOLE PROBLEMS
•DRILLING PROBLEMS

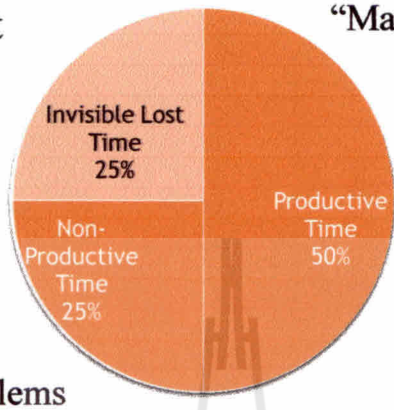
HOLE PROBLEMS

Avoid hole problems and stuck pipe if at all possible to reduce costs

Typical Drilling Time Breakdown

Inefficient

"Making Hole!



Drilling Problems

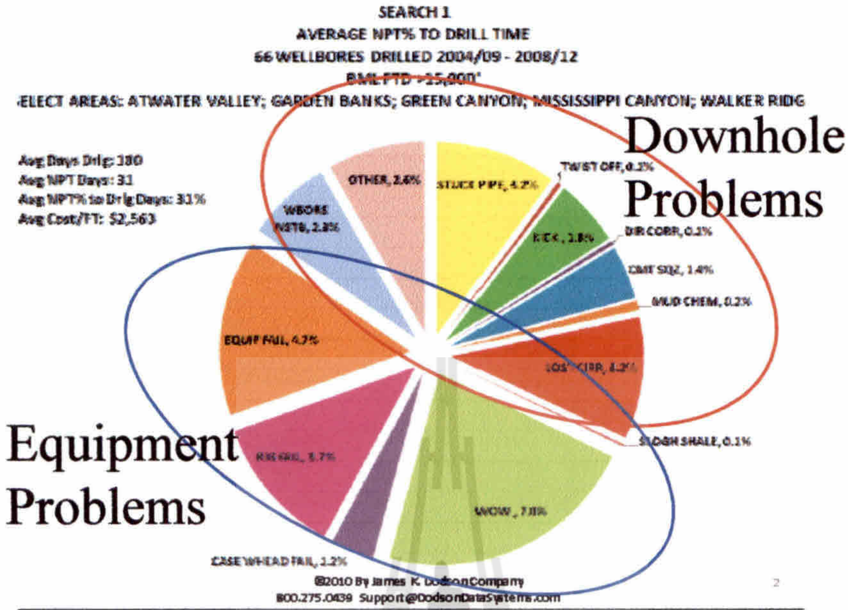
Impact on the Industry

- **Biggest Impact - HSE**
  - Many drilling problems are also associated with increased risk to personnel

Example: Stuck Pipe May Require Jarring which can lead to dropped objects

Example: Lost Circulation may lead to Lost of Well Control, resulting in potential Damage to the Environment, Fire and/or Harm to Personnel

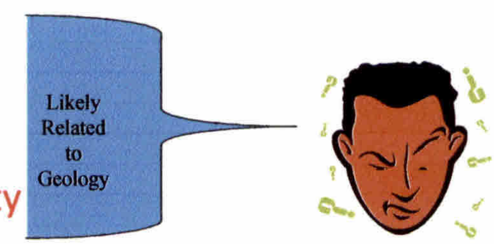
Sources of NPT – Deepwater Industry Example



Top Sources of Downhole Problems

1. **Downhole Equipment Failures**
2. **Downhole Cement Problems**

3. Stuck Pipe
4. Lost Circulation
5. Wellbore Stability
6. Well Control



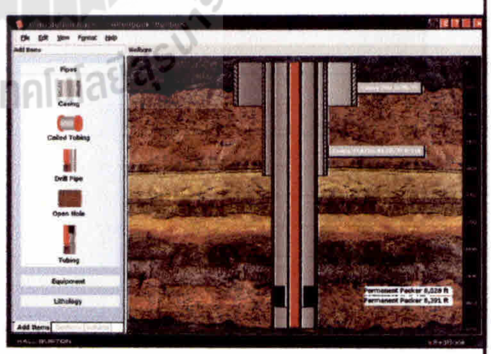
Downhole Equipment Failures

- A single equipment failure can
  - Compromise the integrity of the well
  - Cost Millions of Dollars to Repair
- Common Equipment Failures
  - Casing
  - Drillpipe
  - Downhole Motors
  - Downhole Measurement Tools
    - MWD
    - LWD

Vector Motors
www.nov.com

Downhole Cement Problems

- Cement Left in Pipe
  - Premature Setting
  - Surface Equipment Pump Failures
- Cement Not Setting Properly
  - Cement never sets – "Bad Shoe" or "No Shoe Test"
  - Cement allows for gas migration
  - Cement seeps away into faults or fractures – "Partial or Total Losses"



Picture from Halliburton website: generic example of a cemented wellbore

HOLE PROBLEMS

1 FORMATION RELATED PROBLEM

2 TIGHT HOLE PROBLEM

3 LOST CIRCULATION

4 HOLE CLEANING PROBLEM

•5.Problems Caused by Disturbed Geology

6.Pipe Stuck and MECHANICAL PROBLEMS

1 FORMATION RELATED PROBLEM

- SLOUGHING
- OVERPRESSUREED FORMATION
- UNCONSOLIDATED ZONES
- TECTONIC WEAKENING

Problems Caused by Shale Instability

Terms frequently used to describe troublesome shales are, sloughing shale, heaving shale, running shale, bentonitic shale, mud-making, plastic-flowing and pressured shale. Besides enlarged hole due to shale sloughing, other problems which occur include:

- Improper mud weight
- Hole cleaning difficulties
- Stuck pipe
- Bridges and fill on trips
- Increased mud volume and treating costs
- Poor cement jobs and increased cement requirements
- Well logging problems
- Limited sidewall core recovery
- Tight hole

Factors Causing Shale Instability

- Tectonically stressed shales
- Abnormally pressured shales
- Erosion due to high annular velocities
- Drill string whipping, knocking shale off the wall of the hole
- While tripping, the drill string dislodges shale, either by direct contact or swabbing action.
- Dissolving salt within the formation
- Mud filtrate or whole mud invasion of the formation is mechanical. The subsequent effect is chemical.
- Annular pressure losses in excess of 50 psi/1000 ft. This can cause wellbore erosion and instability even in laminar flow.

Shale Sloughing

- Sloughing shale
  - Four causes of sloughing shale
    - Water sensitive
    - Tectonically stressed
    - Over pressured
    - Combination of above

BOREHOLE PROBLEMS

I. WELLBORE INSTABILITY

A. Shale Problems (Chemical- Physical)

1- Indicators of problem shales

1. Sloughing shale.
2. Hole enlargement.
3. Bridges and fill on trips.
4. Stuck pipe and fishing difficulty.
5. Hole-cleaning problems.
6. High fluid-maintenance cost.
7. Solids-control problems.

3. Stabilizing shales through inhibition.

Table 1 lists the chemical and physical process used in stabilizing shale sections and typical fluids which employ these stabilization mechanisms.

Table 1. Shale Stabilization Mechanisms and Their Applications

Categories	Fluid Type	Stabilization Mechanism	Application
Electrolytes Fluids	utilizing sodium chloride, potassium systems, gypsum and lime muds, aluminum complex systems (ALPLEX ™)	Cation exchange process Li+, Na^+, K^+, Mg^{++}, Ca^{++}, Al^{+++} → Increasing replacement order	Soft, highly-dispersive hydratable shales, shales high in montmorillonite and large percentages of mixed layers with swelling tendencies.
Polymer	NEW-DRILL®, NEW-DRILL HP, NEW-DRILL PLUS, (hydrolyzed polycrylamides)	Encapsulation	

NOTE: Application of inhibitive fluids should be preceded by thorough analysis of mineralogy and dispersion testing.

(Continued) Table 1. Shale Stabilization Mechanisms and Their Applications

Categories	Fluid Type	Stabilization Mechanism	Application
Asphalts And Gilsonites	PROTECTOMAGIC®M, SHALE-BOND™	Plug and seal micro-fractures reducing filtrate invasion between bedding planes	Medium hard, moderately-dispersive shales with sloughing tendencies. Shale high in inter-layered clays. Sometimes high in Illite and Chlorite
Oil Muds	CARBO-DRILL℠ SYSTEMS	Oil external phase, balanced activity of water phase	Highly-dispersive and fractured shales with sloughing tendencies. Hard, brittle, indurated shales in which moderate dispersion exhibits severe sloughing.

NOTE: Application of inhibitive fluids should be preceded by thorough analysis of mineralogy and dispersion testing.

B. Mechanically-Induced Borehole Problems and Solutions

Many borehole problems encountered while drilling are the results of improper drilling practices.

Table 2 outlines typical borehole problems which are mechanically-induced, and recommended solutions.

C. Unconsolidated Formations (Sands, Gravels, etc.)

1. Indicators of Unconsolidated Formations

1. Rough drilling.
2. Hole fill, torque and drag on connections and trips.
3. Frequent packing-off and bridges at specific depths.
4. Large amounts of cavings and/or sloughing shale after bit trips.
5. Re-drilling of footage.
6. Mud loss.

2. *Remedial Procedures*

1. Increase low-shear viscosities to improve hole cleaning.
2. Increase mud weight, if possible.
3. Assure laminar flow to avoid mechanical erosion.
4. Combat loss of circulation with viscous pills containing LCM materials.
5. Use SILDRILL mud.
6. Utilize cement squeeze.
7. Case off hole.

D. Evaporite Deposits (Stringers and Massive Salt Sections)

1. *Associated Problems*

   1. Excessive washouts causing reduced hole cleaning and/or undermining (caving in) of the formation.
   2. Dissolved evaporite (salts) contaminate mud system.
   3. Directional problems (unwanted sidetracking).

2. *Indicators*

1. Salt in cuttings or increased chlorides without in- creased volume (no water flow).
2. Flocculation of freshwater muds.
3. Increased plastic viscosity.
4. Increase in total hardness (anhydrite).

3. *Remedial Procedure*

1. Change to oil mud with balanced water phase.
2. Convert to near-saturated salt system
3. Increase low-shear viscosity to improve hole cleaning
4. Dill evaporite deposits and run casing

BOREHOLE PROBLEMS

II. Loss Of Circulation

A. Causes

1- Fractured Formation

- Natural fractures may be indicated when losses occur during or immediately subsequent to rough drilling or sudden formation change.
- Induced fracture are indicated where losses occur while tripping pipe, breaking circulation, or raising mud weights. Causes include exceeding the fracture gradient with excessive mud weights or high surge pressures, and

Table 2. Mechanically-Induced Borehole Problems and Solutions

Problem	Cause	Indicators	Solutions
Mechanical Erosion	Turbulent flow rates. Drillstring Geometry. Inadequate Rheo- logical Properties.	Mixed sizes and shapes of cuttings, excessive lag,	Alter rheological properties or reduce pump output to ensure laminar o transitional flow. Reduce drillstring diameter.
Underbalanced Hydrostatic Pressures	Inadequate mud weight. Geopressured formations.	Gas cut mud, excessive splintered or concave cuttings, hole fill after trips.	Raise mud weight to balance formation pressure
Pipe Whip	Excessive rotary speeds. Drillstring not in tension	Cuttings-small mixed shapes of different types.	Slow rotary speed. Ensure drillstring is in tension
Swab or surge pressures	Excessive pipe running or pulling speeds. High gel strenghts, improper drillstring design	Loss of circulation, gas, oil, or water intrusions on trips. Large quantities of fill and debris after trips. Improper fluid displacement	Reduce pipe running or pulling speeds. Condition mud to reduce gel strengths.

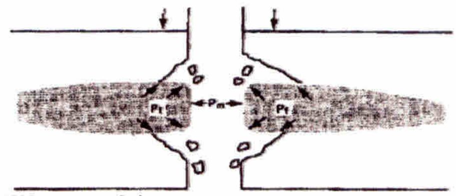
Shale Sloughing

- **Water sensitive**
  - Shale has highly reactive clays
  - Usually associated with younger and softer shale
  - Absorbs water
  - Use a more inhibited mud – depending upon how long the formation will be open

Shale Sloughing

- **Water sensitive**
  - Salt can be added to the mud – sodium, potassium, magnesium, calcium (potassium is most effective)
  - Some polymers will help to inhibit shales
  - Lignosulfonate muds used to tolerate higher solids content
  - Oil or synthetic based muds are the only muds that will truly inhibit the shales
  - Reduce API fluid loss?

Figure 1
Instability of Brittle Shales



Pressure of Mud (P_m) equal to or less than Pressure of Formation (P_f)

Hydration Induced Sloughing

Hydration Induced Sloughing

Two main types of hydration mechanisms which may induce sloughing have been identified. These are surface hydration and osmotic absorption. The degree of reaction caused by surface hydration is affected by several factors. These include:

- the type of clays present in the shale
- the ability of the shale to take in water
- the concentrations and types of salts present
- the accessibility of the water to the hydratable clays,
- the physical integrity of the formation after hydration, and
- the presence of residual loads, such as overpressure or tectonic stresses.

Due to the complex structural relationship between the shale platelets and clays, the severity of sloughing is often not directly related to the degree of hydratability of the clays. Many cases of severe sloughing occur in shales where the clays have a relatively low affinity for water, such as in the case of illite.

Osmotic absorption constitutes the other main source of hydration induced sloughing. Osmotic pressure is develops when two fluids of different salinity are separated by a semi-permeable membrane. Water transport occurs in a direction which tends to equalize the salinity of the two fluids. Fresh water muds have lower salinity than the pore fluid in most shales. A strong attraction for the drilling fluid water is therefore developed by the formation. This undesirable situation results in accelerated rates of shale sloughing, especially in formations with high pore fluid

2. Shale hydration (surface adsorption and osmotic adsorption) will result in two distinctly different problems.

a. Swelling -Expansion of clays due to intake of water. Indicators -Bit balling, mud rings or gumbo attacks, hole washout, elliptical well bores, fine solids buildup.

b. Dispersion -The disintegration of shale body due to water contact.

Indicators -Sloughing shale, bridges and fill on trips, hole-cleaning problems.

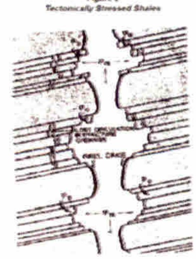
Shale Sloughing

- **Tectonically stressed**
  - Usually associated with heavy faulting near mountains and thrust faults
  - Drilling high angle wellbores
  - Increasing mud weight will stop it depending upon the stress imbalance and degree of water sensitivity
  - Formations are less stable when drilling at higher angles or horizontally

Tectonically Stressed Shales

Stressed shales occur in areas where diastrophic movement has occurred. (This is the process by which the earth's crust is reshaped, producing continents, oceans, mountains, etc.) The shales may incline considerably from the horizontal, having steeply dipping bedding planes. Forces may be acting upon the formation which, when relieved, cause the shale to fall into the hole (see Figure 2)

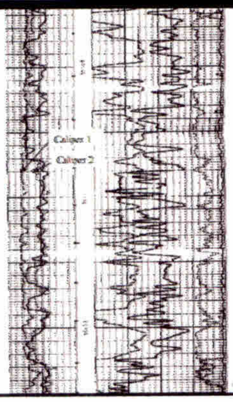
Figure 2
Tectonically Stressed Shales



The problem may be further aggravated if the bedding planes become wet with water or oil. The Atoka and Springer shales of the American mid-continent are classic examples of shales of this type.

Shale Sloughing

- Open hole log showing stress related sloughing with elliptical hole



(2) OVERPRESSURED FORMATION

Overpressured Formations

A formation is considered overpressured if the pore pressure is considerably greater than the hydrostatic pressure of a water column to the same depth. Overpressured zones usually contain pore pressures greater than hydrostatic pore pressures. The existence of abnormal pressures may be due to:

- aquifers
- formations charged by higher pressure zones
- uplifting of a normally pressured zone to a lesser depth
- faulting and structural disturbance
- compaction of matrix and transfer of overburden load to pore spaces

The high pressure zone may contain fresh water, salt water, gas, oil or other fluids within the pore spaces.

Overpressured formations of low permeability are detected while drilling by:

- increases in background and connection gas
- increased fill on bottom
- change in cuttings size and shape
- increases in torque and drag
- change in filtrate chlorides content
- increased flowline temperature
- decreases in shale bulk density

Some Causes of Abnormal Pressure

1. Incomplete compaction of sediments
   - Fluids in sediments have not escaped and are still helping to support the overburden.
2. Tectonic movements
   - Uplift
   - Faulting

Some Causes of Abnormal Pressure

3. Aquifers in Mountainous Regions
   - Aquifer recharge is at higher elevation than drilling rig location.
4. Charged shallow reservoirs due to nearby underground blowout.
5. Large structures...

Shale Sloughing

- **Over pressured shale**
  - Mud weight in wellbore is too low
  - Pressure differential exceeds the tensile strength of the shale
  - Fails in long, thin pieces
  - Increase mud weight

Hole Problems

- Sloughing caused by over pressured shale
- The shale has sloughed in long thin pieces

I.Well Kicks

It is the entering of the formation fluid to the wellbore.

- this occur when the formation pressure exceeds the hydrostatic pressure.
- A blowout is uncontrolled kick.

Well Kicks

- **Overbalance.**
- **Underbalance.**
- **Factors controlling the kicks severity:-**

1. permeability.

2. underbalance.

Reasons for Kicks

1. **Insufficient Mud Weight.**
2. **Swabbing.**
3. **Gas cut mud.**
4. **Failure to keep the hole full.**
5. **Lost circulation.**

1.Insufficient Mud Weight.

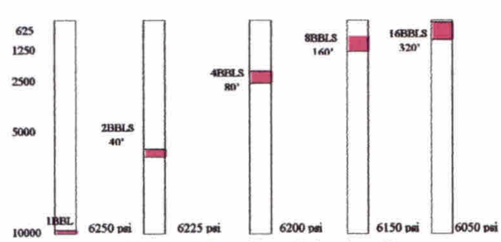
The formation pressure is higher than the hydrostatic pressure

2.Swabbing

A negative hydrostatic pressure causing reducing bottom hole pressure

- **The speed of the drill pipe pulling.**
- **Mud flow properties; yp, gel.**
- **Hole geometry.**
- **Balled up string.**

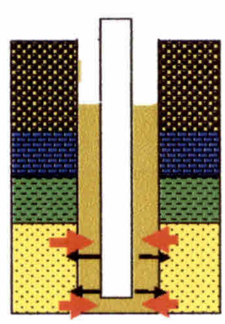
3.Gas cut mud



1 BBL Gas Influx without closing the well

4.Failure to keep the hole full.

5.LOST CIRCULATION



Indications of Kicks

- Changes in mud gas.
- Drilling breaks.
- Improper hole fillups in trips.
- Pump pressure decrease and pump strokes increase
- Flow out rate increase.
- Pit Volume Increase.
- String weight change.
- Well flowing with pumps off.

WELL CONTROL

Early kick recognition & prompt execution of correct shut-in procedures is the key to successful kick control.

Objectives

1. **Kell safely.**
2. **Minimize borehole stresses.**

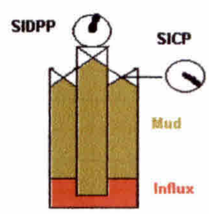
A. Shut-in Procedures

- Hard Shut-in:

the adjustable choke is closed before taking a kick.

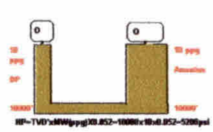
- Soft Shut-in:

the adjustable choke is opened before taking a kick.



In order to kill a well the bottom hole pressure must be maintained constant at a level greater than or equal to the formation pressure.

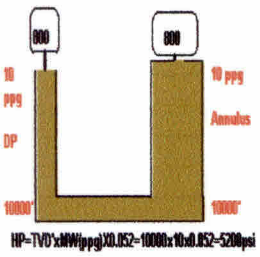
B. U – tube Theory



1. **No influx, no Imposed pressure.**
2. BHP = HP + IP + PL

BHP=5200+0+0=5200psi

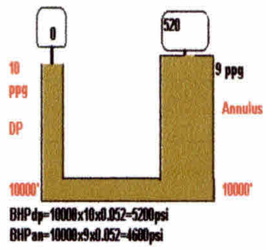
2. No Influx, with imposed pressure



FP=HP+IP+PL

=5200+800+0=6000psi

No influx, Unbalanced tube sides.

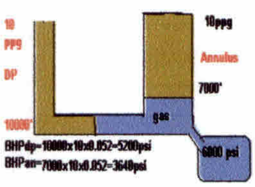


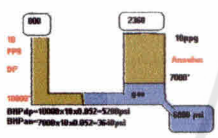
FP=HP+IP+PL

FPdp=5200+0+0=5200psi

FPan=4680+520+0=5200psi

4. Influx, Unbalanced tube sides.

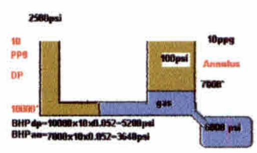




The drill pipe side is always used for calculation due to its homogeneity rather than the contaminated casing side

5.Balancing while circulation

- System PL = 2500psi
- Annulus PL = 100psi.
- MW = 10.0ppg
- Influx length=3000'
- Hole depth = 10000'.
- **Fm pressure=6000psi.**
- **What should be the imposed pressure on both sides while circulation?**



Answer

A. FP=BHPan=BHPdp

BHPan=HP+APL+IP

6000=3640+100+IP

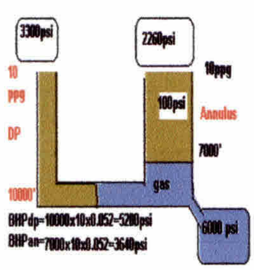
IPan=2260psi

B. BHPdp=HP+IP

6000=5200+IP

IP=800psi

Cir.P.=2500+800=3300psi



The pump rate at which the system pressure loss is recorded for purpose of well control is called:-

- ✓ Reduced circulating pressure,
- ✓ Kill rate,
- ✓ Reduced pump rate,
- ✓ Slow pump pressure,
- ✓ Slow pump rate.

Shut-in Pressure

The shut-in drill pipe pressure is the amount by which the formation pressures exceeds the hydrostatic head of the mud in drill pipe

Influx Gradient

Influx grad. = mud grad – (sicp-sidpp) / length of influx

- Gas 1-3 ppg
- Mix gas & water 3 -5 ppg
- Oil, water or mix. 5 -7 ppg

Kill Weight Mud

$$KWM = \frac{SIDPP}{0.052 \times TVD} + OMW$$

OMW: Original mud weight.

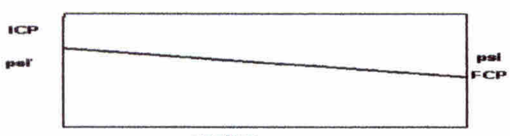
C. Killing Procedures

1. **Wait and Weight Method.**
2. **Driller's Method.**
3. **Concurrent Method.**

1.Wait and Weight Method.

The well is shut-in, the surface mud is weighted and the kill weight mud is pumped in one cycle.

- Initial circulating pressure=SIDPP+SPR
- Final circ. Pressure= SPRx (KWM/OMW)



2. The Driller Method.

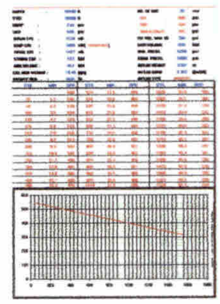
1.The influx is pumped out first,
2.The well is shut-in until the mud is weighted,
3.The kill weight mud is then pumped.

3. The Concurrent Method.

1. Pumping is begun immediately and the mud weight is raised while circulating the kick out.
2. It needs several cycles of circulation.

Kill Sheet

The kill sheet includes all the necessary data for killing the well including the drop down pressure against pumped strokes.



Kick Tolerance

((Is the maximum allowable pressure or its equivalent ppg that the weakest point in a wellbore can withstand))

- The weakest point is the casing shoe.
- No influx in the wellbore.
- Kick toleance= [Shoe depth * (FR – MW)]/Depth.

Hole Problems - Blowout (oil, gas or water)

Indication:

- Returns to Surface after Circulation is Stopped (KICK!)
- Well Out of Control - Big Problem!
- Lost Circulation . . .

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Hole Problems - Blowout (oil, gas or water)

[surface or underground]

Causes:

- Loss of Hydrostatic Head due to Lost Circulation
- Poor drilling Fluid
- Swabbing Effect while Pulling Drillpipe
- Insufficient Mud Weight

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Hole Problems - Blowout

Results:

- Possible Loss of Life and Property
- Legal and Financial Problems

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Hole Problems - Blowout

Preventive Measures:

- •Crew Education
- •Be Alert
- •Blowout Control Equipment on RIG including Pit Volume Indicators

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Hole Problems - Blowout

Remedial Action:

If on Bottom:

- Use proper Mud Weight
- Add Lost Circulation Materials

In Extreme Case of Blowout:

- May Have to Directionally Drill a Relief Well

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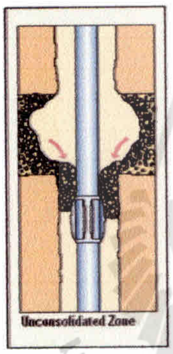
Shale Sloughing

(3) UNCONSOLIDATED ZONE

- **Unconsolidated formation**
  - ➢While drilling across an unconsolidated zone, loose sand and gravel may collapse and pack-off the wellbore



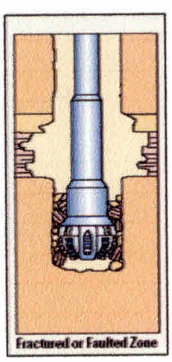
Shale Sloughing

- ➢Form a filter cake on the unconsolidated formation
- ➢Increase the viscosity of the drilling fluid to do a better job of cleaning the hole

Shale Sloughing

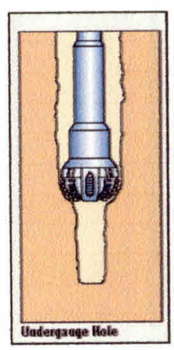
(4) TECTONIC WEAKENING

- **Fractured and faulted zones**
  - ➢Similar to boulders
  - ➢If the fractured material sloughs fast enough, it may stick the drill string
  - ➢Increase mud viscosity to clean the hole



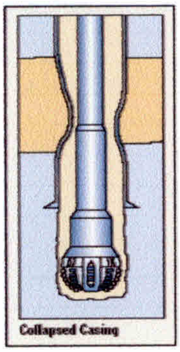
Shale Sloughing

- **Under gauge hole**
  - ➢Forcing the bit into an under gauge hole can cause the pipe to get stuck and/or damage the bit
  - ➢If an under gauge hole is encountered, ream the bit to bottom with lower bit weight



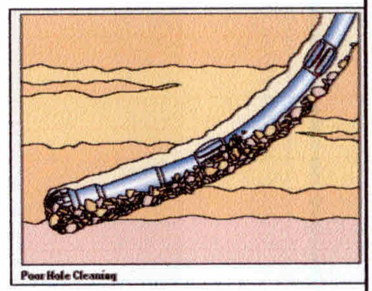
Shale Sloughing

- **Collapsed casing**
  - ➢Can be caused by under designed casing or casing wear while drilling
  - ➢Need to change the casing design



Shale Sloughing

- **Poor hole cleaning**
  - ➢If the hole is not cleaned efficiently, a buildup of cuttings can pack off and cause the drill string to get stuck

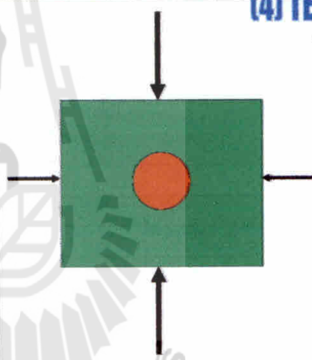


Shale Sloughing

- **Poor hole cleaning**
  - ➢Must do a better job of cleaning the hole which will be discussed in a separate chapter on Lifting Capacity

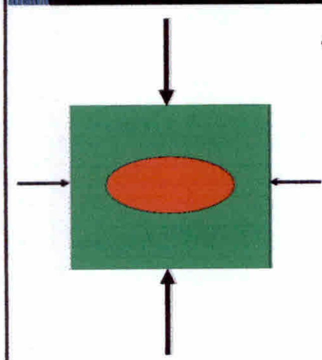
Shale Sloughing

(4) TECTONIC WEAKENING



- **Tectonically stressed**
  - ➢Large differences in horizontal stresses will cause sloughing
  - ➢Forms an elliptical hole when it sloughs

Shale Sloughing



- **Tectonically stressed**
  - ➢Large differences in horizontal stresses will cause sloughing
  - ➢Forms an elliptical hole when it sloughs

2 TIGHT HOLE PROBLEM

- GENERAL
- COAL SEAMS
- SWELLING CLAYS AND MUDSTONES
- PLASTIC AND ELASTIC ZONES
- FILTER CAKE BUILD UP

3 LOST CIRCULATION

- GENERAL
- EFFECTS of LOST CIRCULATION
- COMBATTING LOST CIRCULATION

BOREHOLE PROBLEMS

II. Loss Of Circulation

A. Causes

1- Fractured Formation

- **Natural fractures may be indicated when losses occur during or immediately subsequent to rough drilling or sudden formation change.**
- **Induced fracture are indicated where losses occur while tripping pipe, breaking circulation, or raising mud weights. Causes include exceeding the fracture gradient with excessive mud weights or high surge pressures, and equivalent circulating densities (ECD)**

2. Highly-Permeable Formations

- Formation types- Massive sands, pea gravel, shell beds, or reef deposits.
- Indicators- Continuous gradual seepage losses. Partial returns. (rate of loss is dependent on the degree of permeability)

3. Highly-porous Formation

- Formation types- sands, gravel beds, or reef deposits.
- Indicators- Partial loss of returns which may develop slowly and increase with penetration.

4. Cavernous and Vugular Formations

- Formation types-Limestone, dolomite, chalk, and other formation with secondary porosity.
- Indicators- Sudden and severe to complete loss of returns which may be accompanied by sudden erratic rates of penetration. Formation of this nature are generally predictable in areas with significant drilling histories.

B. Preventative Measures for LOC:

1. **Use of minimum fluid densities as dictated by formation pressures and borehole stability.**
2. **Evaluate area well data to determine proper mud weights and casing placement. Establish formation integrity with pressure test at the most recent casing depth.**
3. **Monitor and control rheologies to minimize swab/surge pressures, annular friction loss (ECD), and control pipe running speeds.**
4. **Maintain thermally-stable rheologies to avoid high temperature gelation. Breaking circulation in stages while tripping is advisable when gelation is evident. Utilize standpipe choke if available to break circulation with a gradual pressure increase.**

B. Preventative Measures for LOC ,Cont.:

5. Minimize annular restrictions

- **Optimize bit hydraulics and/or use of additives to minimize bit and drillstring balling.**
- **Control rates of penetration to avoid excessive solids loading in the annulus.**
- **Avoid excessive wall cake development by reducing filtration rates.**
- **Use of inhibitive fluids such as potassium-base and calcium-base fluids can provide protection against swelling and sticky shale.**

c. Remedial Procedures for Loss Circulation

1-seepage loss (permeable Formations)

1. **Treat system with fine lost-circulation-material (fine and coarse).**
2. **Accompany LCM treatments with additions of a viscosifier to improve particle-size distribution**
3. **Avoid excessive circulation rate and/or penetration rate to minimize ECD and solids loading of the annulus.**

2. *Partial Loss (Highly-Porous or Fractured Formations)*

1. **Treat system with various sizes of LCM. Mixtures of different shapes are often quite effective.**
2. **For severe losses, spot 50-100 bbl pill opposite the loss zone utilizing 30 to 40 lb_m/bbl of various types of LCM. Pull up into casing and allow 6 to 8 hours.**
3. **Squeeze the zone with an high-filtration slurry such as DIASEAL M (see Table 3). The addition of 10 to 20 lb_m/bbl of CHEK-LOSS will generally improve chances of success. When applying high-filtration slurries, squeeze slowly (1/2 to $1^1/_2$ lb_m/min) with pressure not exceeding 50 to 100 psi. Final squeeze pressure should not exceed 0.1 psi/ft of depth.**

3. Total Loss (Caverns, Vugs, or Induced Fractures)

1. **Cement loss zone. Neat or bentonite cement *for densities* 14.5 to 15.5 lb_m/gal. Gilsonite cement for densities. below 14.5 lb_m/gal.**
2. **Utilize soft plugs such as diesel oil-bentonite cement or diesel oil-bentonite gunk squeeze slurry (see Table 5).**
3. **Drill blind without returns until loss zone can be cased off.**
4. **Drill with air, stiff foam, or aerated mud.**

D. Formulation Tables for the Preparation and Use of Various Lost-Circulation Pills in Water-Based Systems

Table 3. Formulation for Preparing 1 bbl DIASEAL M, Weighted Slurry with Freshwater, Bay water, or Seawater

Density	DIASEAL M		MIL-BAR	Water
(lbm/gal)	(lbm)	Sacks	Sacks	bbl
9	50	1.00	0.0	0.87
10	50	10..	0.6	0.84
11	47	0.94	1.2	0.80
12	42	0.84	1.8	0.77
13	38	0.76	2.3	0.74
14	34	0.68	2.9	0.70
15	31	0.62	3.5	0.67
16	28	0.56	4.0	0.63
17	25	0.50	4.6	0.60
18	22	0.44	5.2	0.56
19	17	034	5.8	0.52

NOTE: When water-absorbing materials such as CHEK-LOSS are employed, observe the effect of LCM on viscosity prior to adding the full amount of DIASEAL M.

Example: 100 bbl of 14 lbm/gal DIASEAL slurry requires 68 sacks DIASEAL M, 290 sacks MIL-BAR, 70 bbl water, and CHEK-LOSS, if desired.

Table 4. Soft Plug Formulations (Total Loss of Circulation)

1. **Diesel oil-bentonite cement squeeze (100 bbl).**
   154 sacks (100 lb_m/sack) cement.
   154 sacks MILGEL.
   72 bbl diesel oil.
2. **Diesel oil-bentonite gunk squeeze.**
   4 sacks (100 lb_m/sack) MILGEL.
   1 bbl diesel oil (final volume 1.42 bbl).

A. Squeeze procedure (for 1 and 2).

- Locate loss zone (temperature or radioactive survey) and run in hole open ended.
- Mix slurry volume equivalent to or greater than hole volume. below loss zone.
- Precede slurry with 5 bbl of diesel oil and pump slurry to bit Follow slurry with 5 bbl diesel.
- When the slurry exits drillstring, close annular preventers and pump mud into annulus at 2 bbl/min while displacing the slurry from the drill pipe at 4 bbl/min.
- After displacing 1/2 the slurry from drillstring, reduce pump rates to 1 *bbl/min* on the annulus and 2 bbl/min on the drill pipe.
- After displacing 3/4 of the slurry from drillstring, attempt an "hesitation squeeze pressure" of 1 00 to 500 psi.
- Under-displace slurry leaving 1 bbl in drillstring, pullout of hole and allow 8 to 10 hours set time.

E. Loss of Circulation with Oil Muds

1. **Seepage loss** -Common problem in slightly-porous permeable formations due to low-colloid content of fluid.

Remedial procedures are:

a. Reduce HT-H P fluid loss with additions of CARBO- TROL

b. Utilize CHEK-LOSS or W.O. 30 with additions of 5 to 8 lb_m/bbl to active system

c. Utilize "slugging technique" in which a combination of CHEK-LOSS and W.O. 30 are mixed at 30 to 40 lb_m/bbl in a 20 to 50 bbl pill.

2.Partial losses (highly-porous or fractured formations) can be combated with additions of LCM to active sys- tem. Caution should be exercised to avoid water wetting of LCM material.

Remedial procedures include:

a. Spot pill using various sizes of LCM with a concentration of 30 to 40 lbm/bbl.

b. Go immediately to an high-filtration-type of squeeze such as DIASEAL (see Table 3).

c. Utilize an high-filtration diesel oil-bentonite squeeze as outlined in Table 5.

Table 5. High-Filtration Squeeze for Oil Muds Formulation 1 bbl of 18 lb_m/gal Slurry

MILGEL	300-400 lb_m
Diesel oil	0.6 bbl
CARBO-GEL®	3 lb_m
CARBO- TEC™	1 lb_m
CHEK-LOSS	10-15 lb_m
Barite	540 lb_m

Follow squeeze procedure as outlined in Table 4.

3. **Total losses** (caverns, vugs, or induced fractures) can be combated with the use of high-filtration squeezes as outlined above to avoid pumping costly fluid away.

Remedial procedures include:

a. Cement squeezes into loss zone.

b. Change out system to less costly water-based fluid until circulation is established and drilling can proceed or casing can be run.

Hole Problems - Lost Circulation

Indication:

- Flow out < Flow in (e.g 400 < 500)
- Drop in mud Return Rate
- Drop in Mud Pit Volume
- Blowout

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Hole Problems - Lost Circulation

Causes:

- High Formation Permeability (e.g. fractures)
- Low Formation Pore Pressure
- Poor Drilling Fluid Characteristics
- Induced Fracturing of Formation From Rapid Pipe Movement

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Hole Problems- Lost Circulation

Preventive Measures:

- Crew Education
- Good Mud Program
- Study Wells in Area

…to be prepared

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Hole Problems- Lost Circulation

Remedial Measures:

- Use Lost Circulation Material as Mud Additive (fibrous or granular)
- Drill Through Troublesome Interval and Case Off
- Decrease Mud Weight
- Decrease Circulation Rate

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1.LOST CIRCULATION

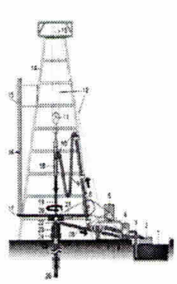
- □ **Below Surface Casing, Conductor**
- □ **Shallow Unconsolidated Formation**
- □ **Heavily fracture cavernous formation**
- □ **Weighted Mud**

Lost Circulation

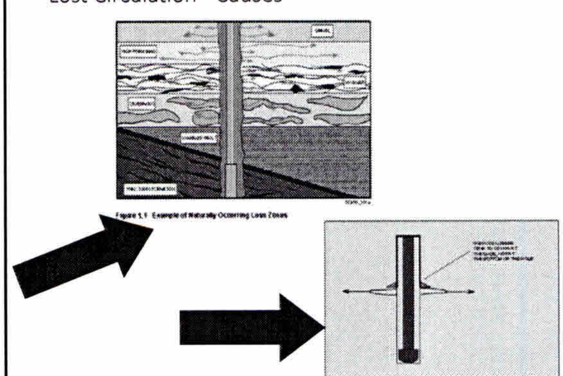
- **Lost circulation**
  - Lost circulation occurs when the effective hydrostatic (mud weight, friction losses and cuttings concentration) becomes greater than the formation pore pressure plus the resistance to flow of the fluid through the formation

Lost Circulation

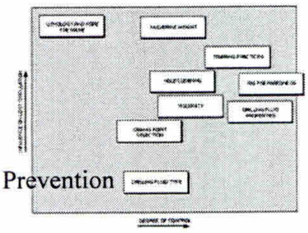
- Conventional drilling utilizes continuous fluid flow down the drillpipe to:
  - Remove cuttings
  - Maintain pressure
  - Cool the bit
- **Key indicator in understanding what is happening downhole**
- Circulation must be maintained at all times
- If the circulation is interrupted because fluid is flowing into the formation, that is called "Lost Circulation"



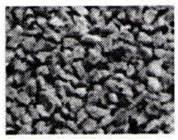
Lost Circulation - Causes

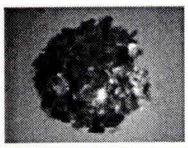


Lost Circulation - Solutions



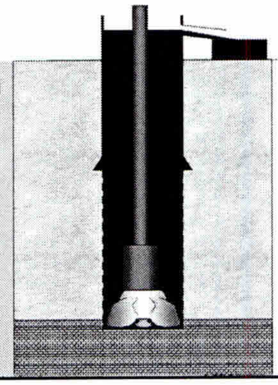
LCM





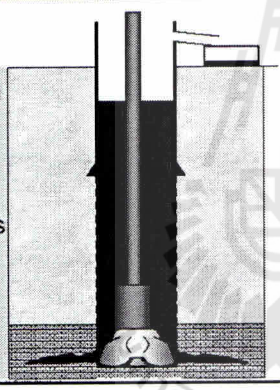
Hole Problems

- **Lost circulation**
  - ➢While drilling, all the fluid pumped into the drill string returns to the mud tank at the surface
  - ➢It is a closed system



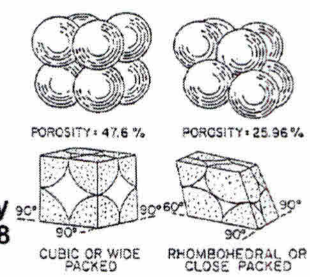
Hole Problems

- **Lost circulation**
  - ➢Lost circulation is when all or a portion of the circulating fluid is lost to the formation



Lost Circulation

- Can loose circulation into primary or secondary porosity
- Generally, primary porosity will range from 8 to 30% for reservoirs



Lost Circulation

- **Secondary porosity is porosity generated by altering the rocks such as the dolomitization of limestone or fracturing**
  - ➢Fractures
  - ➢Vugs
  - ➢Oolite

Lost Circulation

- **Permeability is a measure of the resistance to flow of a fluid through a rock**
  - ➢Measured in Darcys or millidarcys
  - ➢Most reservoirs have less than one Darcy of permeability and will not accept whole mud (with solids)

Hole Problems- Lost Circulation

Results:

- Costly Mud Makeup
- Loss of Production
- Fire
- Loss of Permit to Drill

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Hole Problems - Lost Circulation

Combating Lost Circulation

Remedial Measures:

- Use Lost Circulation Material as Mud Additive (fibrous or granular)
- Drill Through Troublesome Interval and Case Off
- Decrease Mud Weight
- Decrease Circulation Rate

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Hole Problems - Lost Circulation

Preventive Measures:

- Crew Education
- Good Mud Program
- Study Wells in Area

…to be prepared

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Lost Circulation

- **Lost circulation**
  - Shallow formations with high porosity and permeability that will accept whole mud
    - Shallow sands
    - Increase viscosity and/or add LCM
    - LCM - Lost Circulation Material - anything that is cheap and readily available

Lost Circulated

- Types of LCM that have been used
- Cellophane flakes, nut hulls (walnuts, peanuts, etc), mica, fibers, crawfish shells, calcium carbonate, tree bark, sawdust, manure, hay, carpet remnants, ground rubber (from old tires), diatomaceous earth, sweepings from cotton mills, cloth remnants, plastic pellets, sulfur, cottonseed hulls, quar gum, paper, etc

Lost Circulation

- Can often use LCM sweeps where the LCM is removed from the system using the shale shaker after one to two circulations
- Can also loose circulation due to excess penetration rate
  - Increased solids content of the mud will increase the circulating density (ECD) contributing to lost circulation when drilling fast in large diameter holes (exceeding the frac gradient)

Lost Circulation

- Lost circulation due to secondary porosity (deep or shallow)
  - Usually use LCM
    - Adding LCM requires bypassing the shale shaker unless just pumping a sweep
    - Bypassing the shale shaker increases mud density which will increase the possibility of lost circulation
    - LCM can seal natural fractures but does not prevent fracturing if the fracture gradient is exceeded

Lost Circulation

- Lost circulation due to secondary porosity (deep or shallow)
  - Usually use LCM
    - Pick up off bottom while mixing the LCM to prevent stuck pipe
    - Keep the pipe moving
    - Can drill ahead while spotting LCM to open up the entire loss zone (short distance)
    - Drilling ahead may be necessary prior to trying other methods to control lost circulation

OGCI PetroSkills

Lost Circulation

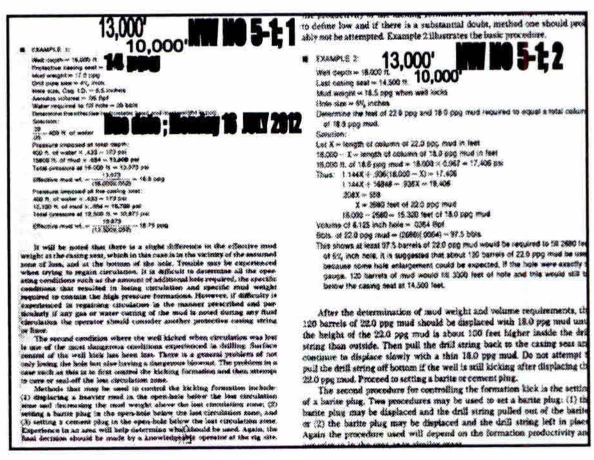
- **Operational guidelines for LCM pills**
  - LCM concentrations for spotting next to the loss zone should be in the range of 40 to 70 lb/bbl (100 to 200 kg/m^3)
  - The slurry should be able to cover the entire lost circulation zone with 20 to 40 barrels extra (3 to 6 m^3)

Lost Circulation

- The yield point of the mud should be larger than 20 (9) to prevent the LCM from settling or floating
- High fluid loss may help
- Nozzle plugging can be prevented by carefully selecting LCM sizes
- Nozzles larger than 15/32 inch (11.9 mm) will have no trouble passing LCM
- Common medium size LCM will pass through nozzles 9/32 inch (7.1 mm) in diameter and larger assuming the LCM is properly mixed

Lost Circulation

- Lost circulation due to secondary porosity (deep or shallow)
  - Drill without returns (blind drilling)
    - Drilling with no fluid returns to the surface
    - Cuttings go into the lost circulation zone
    - Uses large quantities of fluid
    - 250 gpm (0.94 m^3/min) equivalent to 7,000 bbls (1,130 m^3) in a 20 hour drilling day
    - Mixing that quantity of mud would be difficult
    - Usually use water
    - Sweep the hole with high viscosity pills



Lost Circulation Example

This Example shows how to determine the mud weight that can be supported by the formation and also the mud weight that will control the subsurface pressure.

- Well depth = 16,000 ft
- Protective casing seat = 12,500 ft
- Mud Weight = 17.0 lb/gal
- Drillpipe size = 4.5 in.
- Hole size, casing I.D. = 8.5 in.
- Annulus volume = 0.05 bbl/ft
- Water required to fill hole = 20 bbl

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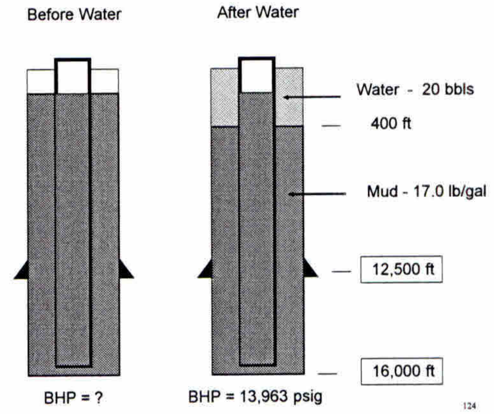

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Example - Solution

Determine: The effective hydrostatic head and mud weight in lb/gal.

Solution:

$$\frac{20\ \text{bbl}}{0.05\ \text{bbl/ft}} = 400\ \text{ft of water}$$

Water gradient = 0.052 * 8.33 = 0.433 psi/ft
Mud gradient = 0.052 * 17 = 0.884 psi/ft

125

Example 3.1

Pressure imposed at total depth:

400 ft of water x 0.433 psi/ft	= 173 psi
15,600 ft of mud x 0.884 psi/ft	= 13,790 psi
Total pressure at 16,000 ft	= 13,963 psi

$$\text{Effective mud weight} = \frac{13{,}963}{(16{,}000)(0.052)} = 16.78\ \text{lb/gal}$$

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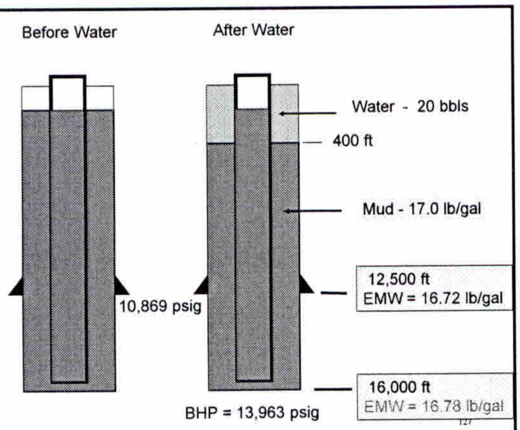

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4 HOLE CLEANING PROBLEM

- GENERAL
- HIGH DRILLING RATE
- RUBBER AND FRACTURE ZONES
- BOULDER AND GRAVEL ZONES
- EFFECT OF HOLE ENLARGEMENT

(1)GENERAL HOLE CLEANING PROBEMS

Hole Cleaning Problems

General

Hole cleaning problems occur when the size and shape of certain particles is such that they cannot be effectively removed by the annular flow. The particles presenting difficulties may be cuttings or cavings, or both.

When hole cleaning problems occur the chance of an annular packoff increases dramatically. An annular packoff occurs when sufficient solids accumulate around entire circumference of the drill pipe, drill collars, or stabilizers and restrict the circulation of drilling fluid. Once the ability to circulate has been lost the remaining (smaller) particles above the annular packoff will continue to settle and more solidly seal the annulus, usually resulting in a stuck drill string. If circulation cannot be reestablished and if jarring and working the drill string does not free the pipe, a fishing operation will usually be required.

(2)High Drilling Rate

High Drilling Rate

In areas where very high drilling rates are achieved, it is often difficult to clean all of the resulting solids out of the wellbore. Any slippage of the particles in the annulus at very high drilling rates will result in a high concentration of solids that may cause:

- lost circulation in certain areas due to the significantly increased mud density,
- greater chances of mechanical sticking and of differential sticking,
- plugged bit nozzles due to the hydrostatic imbalance and the resulting back flow on connections, and
- formation of mud rings, the collection of an annular pack of solids which form a stiff, solid mass that is difficult to remove from the annulus and that may eliminate the ability to circulate.

When hole cleaning problems associated with high drilling rate occur the following changes may be effected:

- reduce the rate of creation of cuttings by control drilling (limiting the maximum rate of penetration),

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- increasing the fluid viscosity (particularity the initial gel strength) to reduce the setting velocity of particles in the annulus,
- attempting to create smaller cuttings by using bits with greater numbers of smaller teeth, by reducing weight on bit, or by increasing RPM, and
- by increasing the circulation rate to limit the time that any given particle remains in the annulus.

(3)Rubble and Fracture Zones

Rubble and Fracture Zones

Hole cleaning problems are quite common when drilling zones have been well fractured and contain large amounts of loosened rubble. The types of particles that result from these zones are typically large, angular pieces that exhibit very high settling velocities in most fluids. As the range of flow rates and annular velocities possible are quite limited, the large particles encountered are almost always handled as follows:

- increase the initial gel strength and yield point considerably, and
- redrill to break into smaller sizes those particles that cannot be removed with the higher hole cleaning capability fluids.

Rubble and fracture zones often create very high peak bit torques as the fractures grab the edge of the bit or stabilizers. As these torques may release suddenly, care must be taken to ensure the drill string does not spin off.

(4)Boulder and Gravel Zones

Boulder and Gravel Zones

Similar to rubble resulting from fractured zones, boulder and gravel zones produce particles that have very high settling rates. Boulders and gravel in relatively consolidated zones require the cleaning of such large particles contained within the drilled hole volume of the zone. In unconsolidated zones, additional gravel and boulders often enter the wellbore in the form of sloughing and can therefore be much greater in total volume.

In either case, a large increase in drilling fluid viscosity is usually required to remove the bulk of the large particles present. The largest boulders must often be broken up into smaller pieces before they can be removed.

Also similar to drilling fractured zones is the high torque generated while drilling rubble and fracture zones. Peak torques are usually generated at the bit and therefore concern for spin-offs of the drill string are most prevalent in the lower portion of the drill collars.

Boulders

- **Boulders**
  - River beds
  - Volcanics
  - Glacial fill
  - Many times they are a problem in the surface hole
  - Can also be a problem deeper where the formation is highly fractured

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PetroSkills

Boulders

- **Indications**
  - Severe torque while drilling, sometimes the drill string rotation is stopped and the string stuck
  - Difficulty in pulling off bottom or pulling the first few stands
  - No difficulty in circulating
  - Free movement down with difficulty moving up
  - The tight spot is not in the same place but rather moves around

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PetroSkills

Boulders

- The only choice is to break up the boulder with movement of the drill string
- Can't get the mud viscosity high enough to circulate large rocks out of the hole

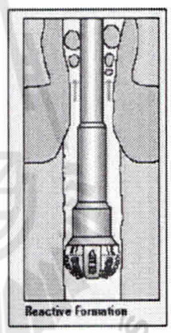
Squeezing Formations

- **Squeezing formations**
  - Salt can cause problems while drilling
  - Salt causes casing collapse during production
  - Design casing for 1 psi/ft (22.6 kPa/m) collapse
  - Drill with salt saturated mud or oil based mud

Squeezing Formations

- Marl
  - Increase mud weight
- Shale
  - More likely it is the buildup of gumbo on walls of hole
  - There is no conclusive evidence that the hole size in a shale section is reduced due to the shale moving
  - Should see a smaller hole on caliper log, but do not

Squeezing Formations



- Reactive formations will absorb water and swell
- The sticky formation can then stick to the walls of the hole and the drill string (Gumbo)
- Shale does not actually move into the wellbore

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(5)Effects of Hole Enlargement

Effects of Hole Enlargement

Whenever undrilled material enters the wellbore there is the chance that a hole larger than the drilled size will result. If the hole size exceeds the bit size by a significant degree, large annular flow area and therefore reductions in annular velocity occur. Two somewhat distinct types of hole enlargement are common. Their characteristics and ramifications on hole cleaning are described below:

a. Uniform Hole Enlargement

Uniform hole enlargement is often encountered where long sections of hydratable clays and shales exist that are sensitive to the washing action of the annular fluid flow. In these types of zones, the washout is usually somewhat greater nearer the surface as these zones have been exposed to the annular flow for a longer period of time. Uniform hole enlargement manifests itself primarily in reduced annular velocity which may or may not create a hole cleaning problem depending on degree of washout, circulation rate and mud properties. Once particles reach the large sections of the wellbore they generally travel the remainder of the distance out of the hole.

b. Localized Hole Enlargement

Most washed out holes exhibit some degree of nonuniform hole enlargement. In these cases the formation has for some reason enlarged in one or more relatively localized areas. If these areas are numerous and sudden the wellbore is said to be rugose.

5.Problems Caused by Disturbed Geology

- GENERAL
- DEVIATION
- TARGET CONTROL
- CROOKED HOLE

Problems Caused by Disturbed Geology (1)GENERAL

Problems

General

Disturbed geology discussed herein refers to the tectonic stresses and earth movements that cause faulting, fracturing, over thrusting and general complications within the subsurface structural geology. In addition, considerable dipping in the bedding planes occurs, with the formations lying at a few degrees to ninety degrees or more from its original horizontally deposited plane.

As well as the unstable hole conditions discussed earli such as tectonic weakening and rubble and fracture zones, th effects of disturbed geology manifest in the ability to dril a straight, vertical wellbore. The main effects on straigh drilling are discussed below.

(2)Deviation

Deviation

Deviation, or inclination from vertical, is of major concer in many areas of the world. The tendency of an area to buil angle (encounter deviation) is affected considerably by th type of formations present but more by the dip angle of th bedding planes present.

When significant dip angles are present, the bit tends to drill a wellbore that builds angle in a direction that returns the bit to a normal (perpendicular) orientation with the bedding planes. Thus when the dip is 20° in a southwesterly direction the bit tends to drill in a direction resulting in a wellbore of 20° deviation in a northeasterly direction. This effect is most strongly influenced by the formation's intrinsic ease of drilling being greater perpendicular to the bedding planes as opposed to parallel to the bedding planes. Of course the final hole direction and angle are influenced by many other factors such as degree of stabilization, bit angle relative to hole angle, weight on bit, type of bit, etc.

Problems that are anticipated due to deviation can be minimized by:

- use of a well stabilized bottom hole assembly
- weight on bit and RPM program
- placement of the surface location with respect to the bottom hole location
- use of specialized (deviation control) bits
- implementation of specialized drilling techniques that require lower weights on bit, such as air drilling or use of stratapax bits

(3)Target Control

Target Control

In areas where the wells are prone to considerable deviation, the difficulty in hitting the required subsurface target is greatly increased. It is quite common for larger, more realistic targets to be selected for these types of wells, rather than requiring several correction runs with kick subs and downhole motors to achieve the intersection of a very small target. Whenever target size is limited the additional costs required to ensure the target is intersected should be carefully weighed against the restricted target boundaries.

In many cases reduced bit weight is the usual method of limiting deviation to allow intersection of the target. This can often prove to be a very costly practice due to the low rates of penetration that occurs. It is often better to locate the rig a greater than expected distance from the bottom hole target and to use increased bit weight to allow the well to build sufficient angle to intersect the target.

(4)Crooked Hole

Crooked Hole

Crooked hole refers to wellbores that encounter not only deviation, but changes in deviation and direction, often abrupt, from the initial depth of deviation. In crooked hole areas the structural geology may have decreasing dip angles or even one or more reversals of the direction of dip. The wellbore may tend to build angle in one direction, then change direction or drop angle only or build angle and change direction again. The resulting crooked wellbore is the cause of several serious problems. These may include:

- extreme target control difficulties
- greatly increased drag and torque
- the formation of keyseats
- drill string failures
- inability to reach total depth objectives
- production problems

The mechanical problems that may be caused by crooked hole are discussed in greater detail in the following section.

6. Pipe Stuck andMECHANICAL PROBLEMS

- A STUCK DRILL STRINGS

-Differential Sticking

-Sticking Due to Solids

-Keyseat Sticking

- ABNORMAL DRAG AND TORQUE

-B. Hole Geometry

- WASHOUTS
- PARTED DRILL STRINGS
- PARTED DRILL PIPES
- DRILL COLLAR FAILURES
- DOWNHOLE TOOL FAILURES
- JUNK IN HOLE

II. Stuck pipe

Drilling string cannot be raised, lowered or rotate.

Hole Problems - Stuck Pipe (drill pipe, drill collars, casing)

Indication:

- Cannot Pick Up Pipe (Venezuela case)

Causes:

- Cave - ins
- Keyseat - Crooked Hole

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III. DRILLSTRING STICKING

A. Causes of Stuck Pipe

1. Differential pressure (wall sticking).

2. Mechanical related.

a. Key seating.
b. Formation-related (instability & tight holes).
c. Wellbore geometry (deviation & doglegs).
d. Inadequate hole cleaning.
e. Junk in hole.
f. Collapsed casing.
g. Cement related.

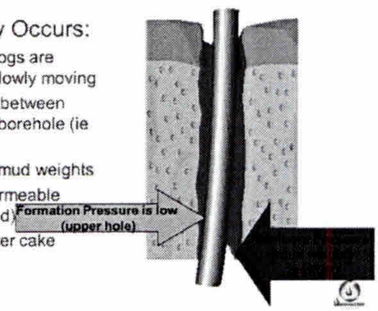
Stuck Pipe

1. Differential Sticking
   - Pressure-related
   - The pipe is "sucked" up against the formation due to a difference in pressure
2. Mechanical Sticking
   - A mechanical obstruction
   - Could be from the formation, wellbore geometry, or tool failure

Differential Sticking – A Pressure Problem

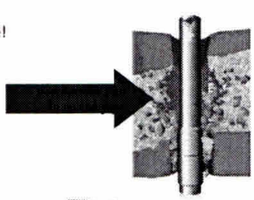
This Normally Occurs:

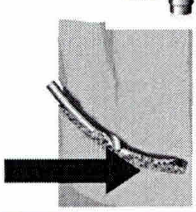
- when pipe/logs are stationary or slowly moving
- with contact between drillstring and borehole (ie at drill collars)
- with higher mud weights
- across a permeable formation (sand)
- in a thick filter cake



Mechanical Sticking – Dirty Wellbore

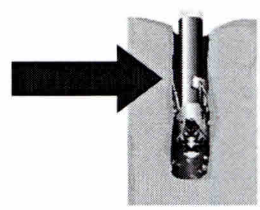
- Too many "solids" in the wellbore!
  - Indications:
    - higher pump pressure
    - fill on bottom
    - more "pull" required to move pipe
    - excessive cuttings on shakers
    - restricted circulation
- Why?
  - Unconsolidated Formations
  - Poor Hole Cleaning
- Prevention
  - maximise flow rates and rpm
  - Better mud properties
  - drill more slowly

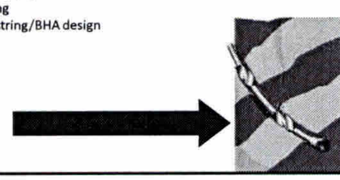




Mechanical Sticking – Obstructions

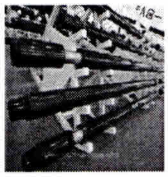
- Obstructions
  - Indications:
    - more "pull" required to move pipe
    - can still circulate
    - Increased torque
    - Unable to "make hole"
- Why?
  - Junk in the Wellbore
  - Hole Geometry
- Prevention
  - equipment QA/QC
  - housekeeping
  - correct drillstring/BHA design

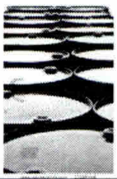




Stuck Pipe – How do we get free?

- Pull Harder (but don't break it)
- Jar on Pipe
- Cut Pipe and Fish
- Increase or decrease circulation
- Pump other types of fluids or chemicals





Stuck Pipe

- **Stuck pipe is a big problem in the drilling industry**
  - In the Netherlands, the stuck pipe incidents resulted in 5% of the drilling capital expenditure in 1993
  - Shell reported stuck pipe in 70% of its wells causing 80% of the lost time while drilling in Nigeria

Hole Problems - Stuck Pipe

Causes, cont'd:

- Differential Pressure Sticking
- Filter Cake
  - Deposited AFTER Circulation Stops
    - While Still on Bottom

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B. Preventative and Control Measures

1. Differential pressure sticking.

1. Control mud densities as low as practical.
2. Control filtration rate to produce a thin, compressible wallcake.
3. Control drilled solids as low as possible.
4. Control drill to avoid overloading annulus.
5. Utilize friction-reducing additives.

2. Mechanical related

a. Key seating.

1. Control hole deviation.
2. Assure drillstring is in tension.
3. Utilize string reamers and stabilizers.

b. Formation-related wellbore instability is generally associated with "tight hole" conditions. Improvement in hole conditions can be seen with optimization of fluid properties and the use of appropriate inhibitive additives and fluid systems.

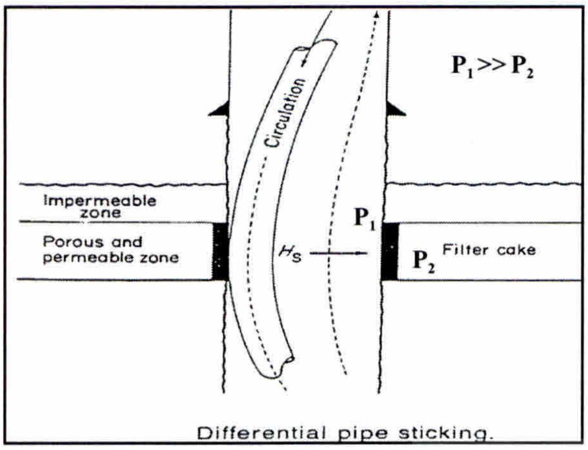
c. Inadequate hole cleaning can be improved by altering fluid rheologies and pump rates.

C. Remedial Procedures for Stuck Pipe

The "free-point" may be determined from electric logging or pipe stretch calculations.

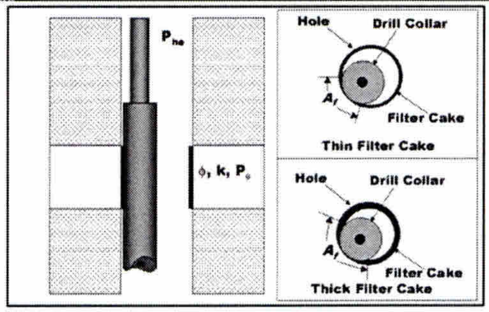
D. Spotting Fluids

- Drilling Fluids companies offers a variety of spotting fluids which are designed for use in every drilling environment.
- These fluids may be used in weighted or un-weighted form.
- The success of spotting fluids is time related.



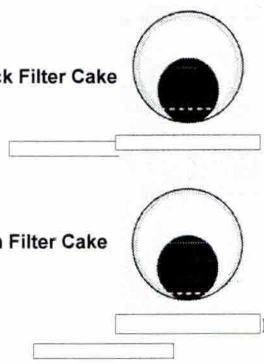
Differential pipe sticking.

Differential Pressure Sticking



$$F_s = fA_f\Delta P$$

1.5-26



$$F = \mu N$$

$$N = \Delta P A$$

$$F = \mu \Delta P A$$

How is filter cake formed?

Pipe Stuck in Wall Cake

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Hole Problems - Stuck Pipe

Results:

- Fishing Operations

  Back off, POH, RIG w/fishing string

- Loss of Hole

  or at least part of the hole

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D. Spotting Fluids

Table 7, 8, and 9 in notes example of spotting fluid materials and its mixing procedure.

Differential Pressure Sticking

- **Differential Pressure Sticking**
  - Across from a permeable formation
  - Stuck while the pipe was not moving
  - Can occur anywhere in the hole
  - Can circulate without a problem

Hole Problems - Stuck Pipe

Preventive Measures:

- Use Minimum Mud Weight Required to Control Formation Pressures.
- Use Special Drill Collars (spiral)
- Use Centralizers on Casing
- Periodically Establish Circulation while Running Casing or Drillpipe in Deep Hole

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Hole Problems - Stuck Pipe

Remedial Measures:

If Circulation Cannot Be Established:

- Cut Pipe or Unscrew Joint - and Fish

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1.5-22 Hole Problems – Stuck Pipe

Remedial Measures:

If Circulation Can Be Established:

- Erode Mud Filter Cake - at High Fluid Velocity (speed up pumps)
- Spot Special Fluid; Oil, Acid
- Reduce Mud Weight as Far as Possible
- Rotate Pipe - Keep Moving Pipe

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Hole Problems - Crooked Hole

Indication:

- Periodic Directional Surveys
- Stuck Drill String
- Casing Problems

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Hole Problems - Crooked Hole

Causes:

- Too much Weight on Bit
- Dipping Formation
- Anisotropic Formation
- Too Small Drill Collars
- No Stabilizers

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Hole Problems - Crooked Hole

Results:

- Uneven Spacing (on bottom)
- Legal Problems
- Production Problems
- Cementing Problems

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Hole Problems - Crooked Hole

Preventive Action:

- ➢Avoid Buckling of Drill Pipe by using sufficient number of drill collars
- ➢Use "Oversize" Drill Collars
- ➢Use Reamers and Stabilizers
- ➢Start the Hole Vertically

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Hole Problems - Crooked Hole

Remedial Action:

- ➢Plug Back and Sidetrack
- ➢Use Whipstock
- ➢Use Reamers in 3 Locations
-

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Differential Pressure Sticking

- **Getting unstuck**
  - ➢Pull or slack off (jar) the maximum immediately
  - ➢Spot oil or a proprietary product
  - ➢Reduce pressure by U-Tube
  - ➢Reduce pressure by pumping nitrogen
  - ➢Washover stuck pipe
  - ➢Sidetrack

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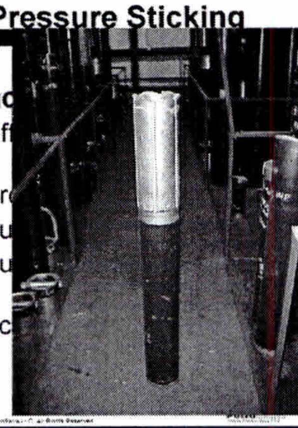
Differential Pressure Sticking

- **Getting unstuc**
  - ➢Pull or slack of immediately
  - ➢Spot oil or a pr
  - ➢Reduce pressu
  - ➢Reduce pressu nitrogen
  - ➢Washover stuc
  - ➢Sidetrack



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Differential Pressure Sticking

- **Prevention**
  - ➢Don't let the pipe sit without moving (keep the pipe moving)
  - ➢Use spiral drill collars
  - ➢Stabilize drill collars
  - ➢Replace drill collars with HWDP
  - ➢Reduce pressure differential
  - ➢Thin filter cake
  - ➢Add oil to mud (reduce friction coefficient)

Differential Pressure Sticking

- **Prevention**
  - ➢Don't let the pipe sit without the pipe moving)
  - ➢Use spiral drill collars
  - ➢Stabilize drill collars
  - ➢Replace drill collars with HV
  - ➢Reduce pressure differential
  - ➢Thin filter cake
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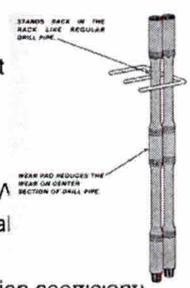

Differential Pressure Sticking

- **Prevention**
  - ➢Don't let the pipe sit without the pipe moving)
  - ➢Use spiral drill collars
  - ➢Stabilize drill collars
  - ➢Replace drill collars with HW
  - ➢Reduce pressure differential
  - ➢Thin filter cake
  - ➢Add oil to mud (reduce friction coen

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With water-base muds, the first prerequisite for low friction factors is a good bentonite content for the filter cake. Oil in almost any concentration is beneficial and special lubricants have been beneficial. Materials that are considered detrimental include most drill solids and barite.

In field applications, the operator should watch for wall sticking indications. Example 3 is one illustration of watching the problem:

■ EXAMPLE 3: 13,000' HW NO 5-1; 3 15 ppg mud

Problem sand at 12,000 feet
Pore pressure of sand = 8730 psi
Hydrostatic pressure of 14.8 ppg mud = 9250 psi
Force required to pull collars after stopping opposite the sand = 60,000 pounds
Maximum pull permitted on the drill string = 100,000 pounds
Determine the maximum permissable mud weight if no other changes are made.

Solution:

F = ΔPAf

60,000 = 520 Af

$$Af = \frac{60,000}{520}$$

$$F_s = fA_f\Delta P$$

$$\Delta P = \frac{(100,000)(520)}{60,000} = 867 \text{ psi}$$

Permissible hydrostatic pressure = 8730 + 867 = 9597 psi.

$$\text{Permissible mud weight} = \frac{9567}{(12,000)(.052)} = 15.4 \text{ ppg.}$$

Also the use of barite to increase mud weight will increase the friction factor thus to even reach a mud weight of 15.4 ppg the operator would have to change the drill string, thin the filter cake, or add a lubricant.

SLOUGHING HOLE

Hole sloughing is generally a problem associated with shale. Each drill

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Stuck Pipe

Many fishing jobs start with the drill pipe becoming stuck during a trip. Some of the causes of stuck pipe are.

(1)Foreign objects or *junk* in the hole
(2)Key-seating
(3)Sloughing formations (heaving shales, etc.)
(4)bit and drill collar balling
(5)Pressure differential sticking
(6)Cutting setting above the bit or drill collars

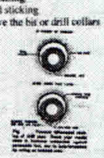


Fig. 7.26 Pressure differential sticking of drill pipe

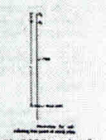


Fig.7.27 Procedure for calculating free point of stuck pipe

How to locate the stuck point

Recall Young's modulus for steel;

(7.5) $$E = \frac{\sigma}{\delta}$$

where E = 30 × 10⁶ psi → $E = 30 \times 10^6$ psi

σ = tensile stress or strain length per length

Also,

$$e = \delta \times 12L \quad \text{or} \quad \delta = \frac{e}{12L}$$

---

where e = inches of stretch measured
L = depth to stuck pipe

The stress causing the differential stretch e is

$$\sigma = \frac{F_2 - F_1}{A} = \frac{\Delta F}{A}$$

where F = force, lb
A = cross sectional area of steel in the drill pipe, in²

Substituting (1) and (2) in Eq. (7.5) And solving for L, we obtain

(7.6) $$L = \frac{EAe}{12\Delta F}$$

To save looking up or computing the area A it is more convenient to use the weight per foot of the pipe, which always known.

(3) $w = (A)(12)(0.283)$ or $A = w/(12)(0.283)$

where w = weight of drill pipe, lb/ft
0.283 = density of steel, lb/in³

substituting of (3) for A in Eq. (7.6) gives

(7.7) $$L = \frac{EAe}{12\Delta F} = 735 \times 10^3 \frac{we}{\Delta F}$$

HW NO 5-1; 4

5" wt. 21 lb/ft

Example 7.7

A string of 3 ½ in., 13.3 lb/ft. grade E drill pipe is stuck in a 10,000 ft hole. The driller obtains the following data as described previously:

13,000'

F_1 = 140,000 lb, which is greater than the weight of string.

F1=150,000 lb.

F_2 = 200,000 lb, which is less than the yield strength of the pipe

F2= 250,000 lb.

e = 4 ft e = 5' ft

Where is the pipe stuck

Solution:

Applying Eq. (7.7)

$$L = 735 \times 10^3 \frac{(13.3)(4)(12)}{\ldots} = 7,800 \text{ ft}$$

Stuck Pipe

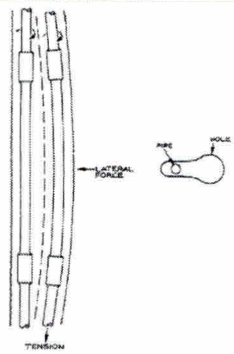
- **It is estimated that more than 65% of stuck pipe occurrences can be avoided with better planning and drilling crew training**
- **There is a need for better awareness of the problem and continued emphasis on prevention measures to achieve minimal stuck pipe incidents**

Keyseating

- **Keyseat**
  - ➢Occurs high in the hole
  - ➢Got stuck while pipe was moving
  - ➢If not stuck, may go down but not up past a point
  - ➢Can still circulate without difficulty
  - ➢Can occur in any formation

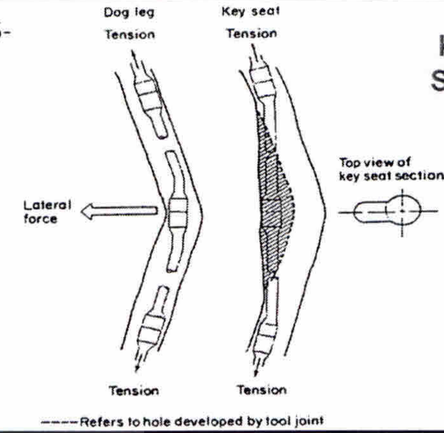
Keyseating

KEYSEAT FORMATION



1.5-

KEY SEAT

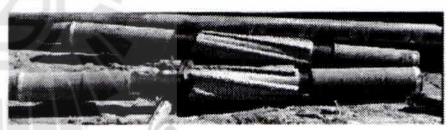


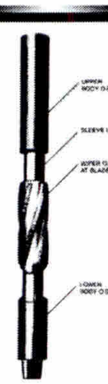
Keyseating

- **Getting out of the hole**
  - ➢Work pipe through the keyseat area – back ream
  - ➢If stuck, back off two or three joints above the stuck point
  - ➢Run jars and jar down
  - ➢Sidetrack
  - ➢If in acid soluble formation, spot acid

Keyseating

- **Can use a keyseat wiper at the top of the drill collars to aid in back reaming through the keyseat interval**





Keyseating

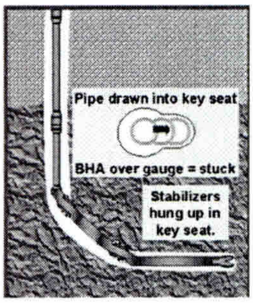
- **Prevent keyseat**
  - ➢Minimize dogleg severity – BHA design
  - ➢Reducing the number of drill collars – adding HWDP
  - ➢Drill with a downhole motor and minimize rotation of the drill string
  - ➢String ream potential keyseat

B. Wellbore Geometry

Hole diameter and / or angle relative to BHA geometry and / or stiffness will not allow passage of the drill string

1. Key seat
2. Microdoglegs
3. Ledges
4. Stiff assembly
5. Mobile formation
6. Under gauge hole

Key Seat



Causes:

1. Abrupt change in angle or direction in soft formations.
2. High string tension and pipe rotation wears a slot into the formation.
3. While POOH the drill collars jam into the slot.

Warning, indications, first action

Warning:

1. High angle doge leg in upper hole section.
2. Long drilling hours with no wiper trips through the dogleged section
3. Cyclic over pull at tool joint intervals on trips.

Indications:

1. Occurs only while POOH.
2. Sudden over pull as BHA reaches dogleg depth.
3. Unrestricted circulation.
4. Free string movement below key seat depth.

First Action, Preventive Action

First action:

- **Apply torque and jar down.**
- **Attempt to rotate with low over pull to work through dogleg.**

Preventive Action:

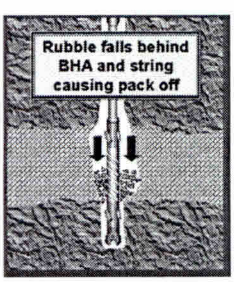
- **Minimize dog leg severity to 3deg/100' or less.**
- **Limit over pull through suspected intervals.**
- **Run string reamer or key seat wiper if suspected.**

C. Packing Off & Bridging

Formation cuttings cavings or medium to large pieces of hard formation, cement or junk settle around the drill string and pack off/bridging the annulus.

1. Settled cuttings
2. Shale instability +
3. Unconsolidated formations
4. Fractured formations
5. Cement related.
6. Junk.

Settled Cutting Straight Hole



Causes:

- **Low annular velocity and/or poor mud properties.**
- **When circulation is stopped, the cuttings fall back down the hole and pack off the drill string.**

Warning, indications, first action

Warning:

1. High ROP, low pump rate, little to no circulation time at connections.
2. Torque, drag and pump pressure increase.
3. Over pull off slips, pump surge to break circulation
4. Fill on bottom.

Indications:

1. Likely to occure on connections.
2. Possible during trips.
3. Circulation restricted or impossible.

First Action, Preventive Action

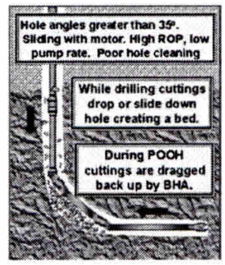
First action:

- **Applay low pump pressure (200-400psi).**
- **Apply torque and jar down.**
- **Circulate clean to avoid recurrence.**

Preventive Action:

- **Control ROP, maximize annular velocity.**
- **Maintain sufficient gel strength and YP.**
- **Circulate 5- 10 min before connections.**
- **Circulation clean before POOH.**

Settled Cutting Deviated Hole



Causes:

- **Drill cuttings settle on the low side forming a cutting bed.**
- **The cutting bed builds and slide down hole.**
- **While POOH the cuttings is dragged upward by the BHA**

Warning, indications, first action

Warning:

1. Hole angle > 35deg..
2. Drilling with a down hole motor.
3. High ROP, low GPM, increase torque, increase pump pressure.

Indications:

1. Likely to occure while POOH, possible while drilling.
2. Increase overpull on trips.
3. Circulating pressure restricted or impossible

First Action, Preventive Action

First action:

- Apply low pump pressure (100-400psi).
- Jar down & Apply torque with caution .
- Circulate clean to avoid recurrence.

Preventive Action:

- Record trend indicators for inadequate hole cleaning.
- Control ROP, maintain mud properties, maximize annular velocity, maximize string rotation.
- Circulation clean before POOH.
- Use low vis/high vis density sweeps.

Hole Problems - Junk in Hole

Indication:

- Bit Parts Missing
- Items from Surface Dropped into Hole
- Erratic Torque

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Hole Problems - Junk in Hole

Cause:

- Negligence of Crew

Result:

- Fishing Operation

200

Hole Problems - Junk in Hole

Preventive Measure:

- Crew Education

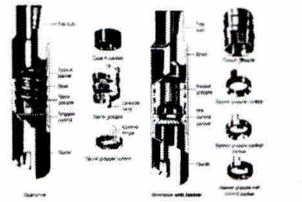
Remedial Measures:

- Run Junk Basket
- Run Basket with Collapsible Teeth ("Poor Boy" Basket)
- Run Magnet

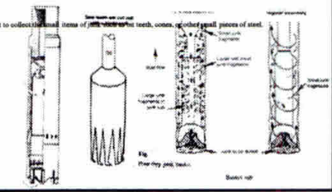
201

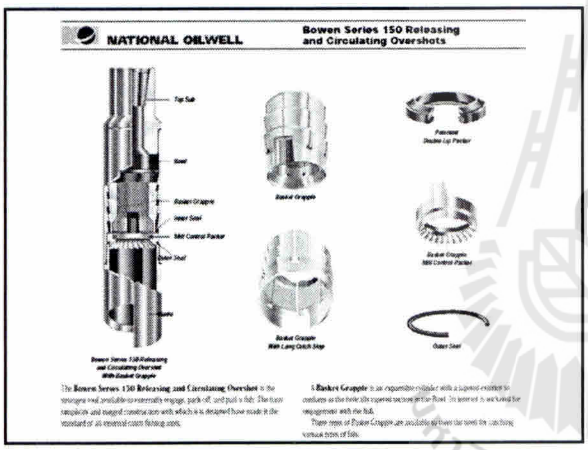
Fishing Tools

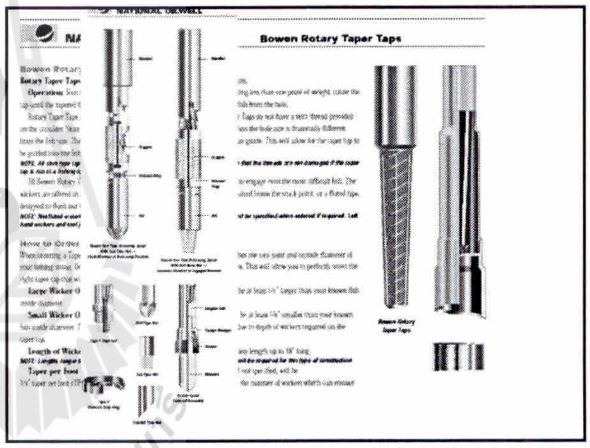
(1) Overshots: these are cylindrical bowl shaped tools whi
(2) Spears: these devices pass inside the fish, grasping int
(3) Washover pipe: this is a section of pipe ha
(4) Inside and outside cutters: outside cutters do the reverse.

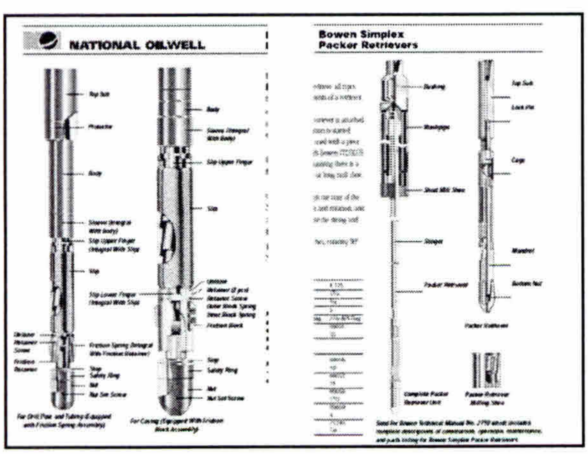


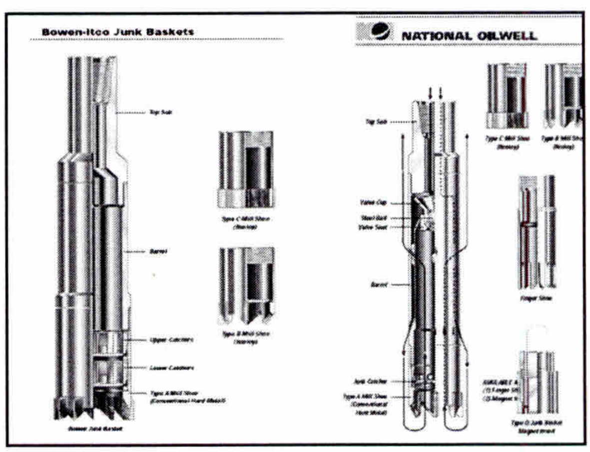
(5) Junk baskets: these tools run just above the bit to collect the small items of junk such as bit teeth, cones, or other small pieces of steel.

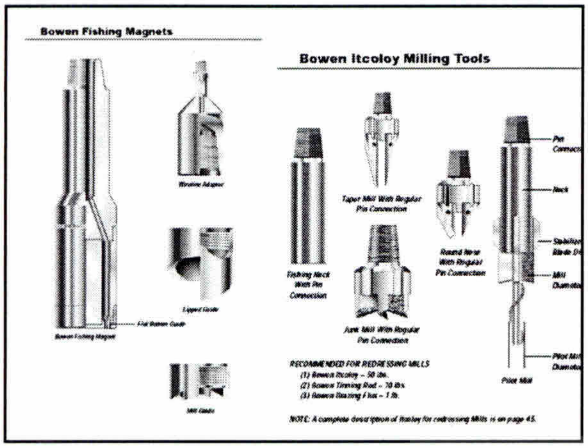


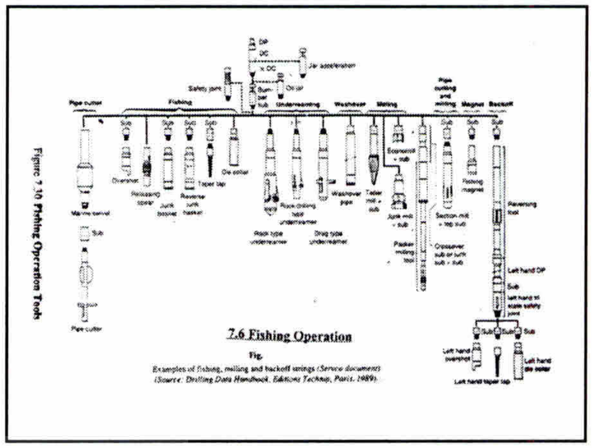












where e = inches of stretch measured

L = depth to stuck pipe

The stress causing the differential stretch e is

$$\sigma = \frac{F_2 - F_1}{A} = \frac{\Delta F}{A}$$

where F = force, lb

A = cross sectional area of steel in the drill pipe, in^2

Substituting (1) and (2) in Eq. (7.5) And solving for L, we obtain

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substituting of (3) for A in Eq. (7.6) gives

$$L = \frac{EAe}{12\Delta F} = 735 \times 10^3 \frac{we}{\Delta F} \quad (7.7)$$

HW NO 5-1; 4

5" wt. 21 lb/ft

Example 7.7

A string of 3 ½ in., 13.3 lb/ft. grade E drill pipe is stuct in a 10,000 ft hole. The driller obtains the following data as described previously: **13,000'**

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F_2 = 200,000 lb, which is less than the yield strength of the pipe **F2= 250,000 lb.**

e = 4 ft. **e = 5' ft**

Where is the pipe stuct

Solution:

Applying Eq. (7.7)

$$L = 735 \times 10^3 \frac{(13.3)(4)(12)}{60{,}000} = 7{,}800 \text{ ft}$$

1. The entrance of undrilled solids into the wellbore is usually referred to as ____.
2. A ____ ____ is sometimes used to catch pieces of metal as they are lifted off the bottom of the hole.
3. A formation is considered to be overpressured if ____ ____ is greater than ____ ____.
4. ____ is a loss of pressure integrity in the drill string.
5. List six ways overpressured formations can be detected while drilling:
   (a) ____
   (b) ____
   (c) ____
6. Name three types of mechanical wellbore situations that can result in sticking drill string:
   (a) ____
   (b) ____
   (c) ____
7. Formations that are unconsolidated can lead to a ____ ____ problem that could lead to a stuck drill string.
8. Name three methods that can reduce abnormal wellbore drag and torque:
   (a) ____
   (b) ____
   (c) ____
9. Name four symptoms of tight hole conditions:
   (a) ____
   (b) ____
   (c) ____
   (d) ____
10. List four methods that can be used to free the drill string when differential sticking occurs:
   (a) ____
   (b) ____
   (c) ____
   (d) ____
11. Name four causes of lost circulation:
   (a) ____
   (b) ____
   (c) ____
   (d) ____
12. List five things that can be done to minimize deviation:
   (a) ____
   (b) ____
   (c) ____
   (d) ____
   (e) ____

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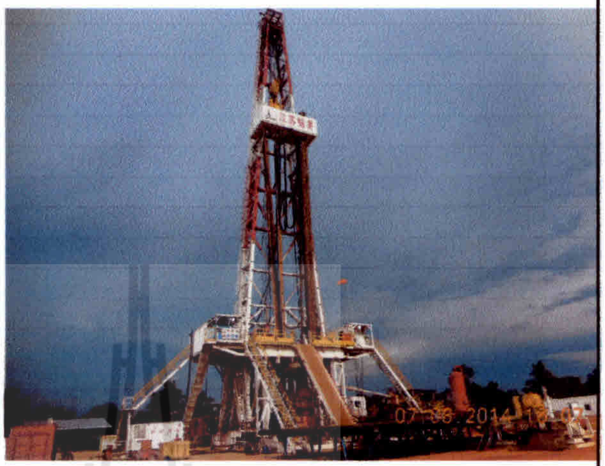
   (e) ____

ADVANCED DRILLING ENGINEERING

Chapter 6. Drilling Fluids (4 hrs.)



By Kriangkrai Trisarn

534620 ADVANCED DRILLING ENGINEERING 4(4-0-8) @ 1/2557, 2014

Course Contents

1. How to Get Drilling Permission (2hrs.) Asso. Prof. KK
2. Introduction to Rotary Drilling (4 hrs.) Asso. Prof. KK
3. Well Planning and Proposal (2 hrs.) Asso. Prof. KK
4. Cost Estimation and Control (4 hrs.) Asso. Prof. KK
5. Hole Problems.(4 hrs.) Asso. Prof. KK
6. Drilling Fluids (4 hrs.) Asso. Prof. KK
7. Factors Affecting Rate of Penetration (4 hrs.) Asso. Prof. KK
8. Pressure Control (4 hrs.) Dr. Akkaphun
9. Pore Pressure and Pressure Gradient (4 hrs.) Dr. Akkaphun
10. Blowout Control Procedure and Equipment (4 hrs.) Dr. Akkaphun
11. Directional and Slimhole Drilling (4 hrs.) Dr. Akkaphun
12. Rotary Bit Design (2 hrs.) Dr. Akkaphun
13. New Technology Drilling (6 hrs.) Dr. Akkaphun

ADVANCED DRILLING

DRILLING FLUID1

1. Mud System & Horse Power
2. Drilling Fluid Types
   - WATER-BASE MUD
   - OIL-BASE Drilling Fluids
   - AIR/GAS Drilling
3. MUD COMPROSITIONS
4. MUD PROPERTIES and Lab TESTs
5. Mud Calculation.

Rotary Drilling Rig & Components

1. Derricks, Masts and Substructure
2. Hoisting Equipment
3. Pipe Handling Equipment
4. Prime Movers
5. Power Transmission
6. Mud System
7. Instruments
8. Well Control Equipment

6) Mud System

Mud tanks

a) Duplex, double acting

b) Triplex, Single acting

Centrifugal pumps, auxiliary, for

Mud mixing and treating equipment

Solids separation equipment

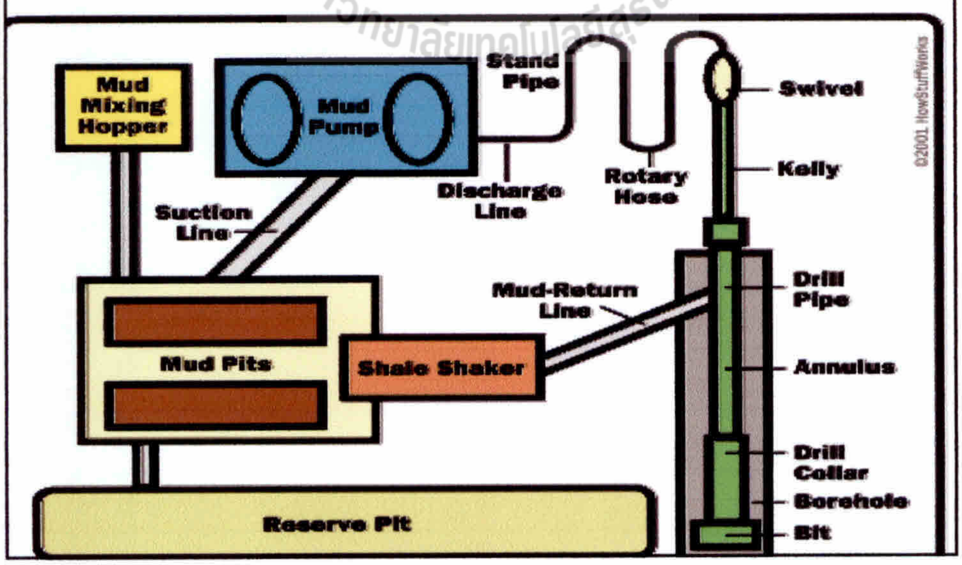
Mud-Gas separators

Bulk storage, bentonite, barytes & Cement

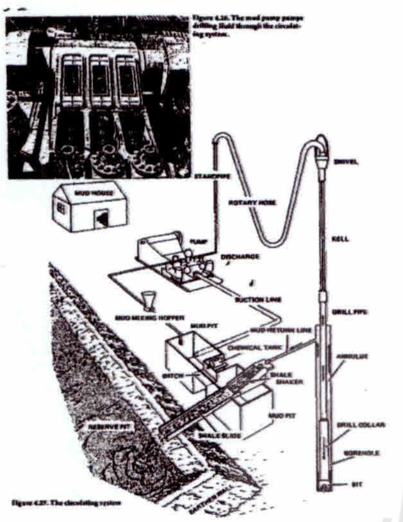
Mud guns, buttom jets

Lightning mixers (paddle-type)0

Mud System



Mud System & Horse Power



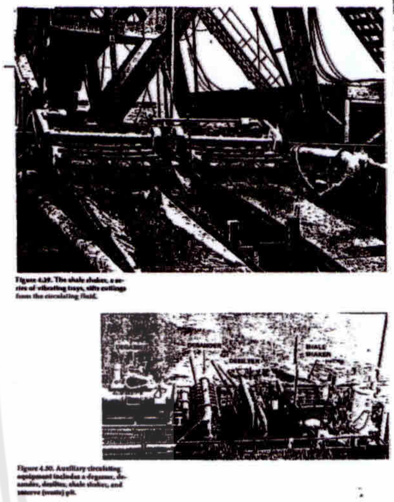
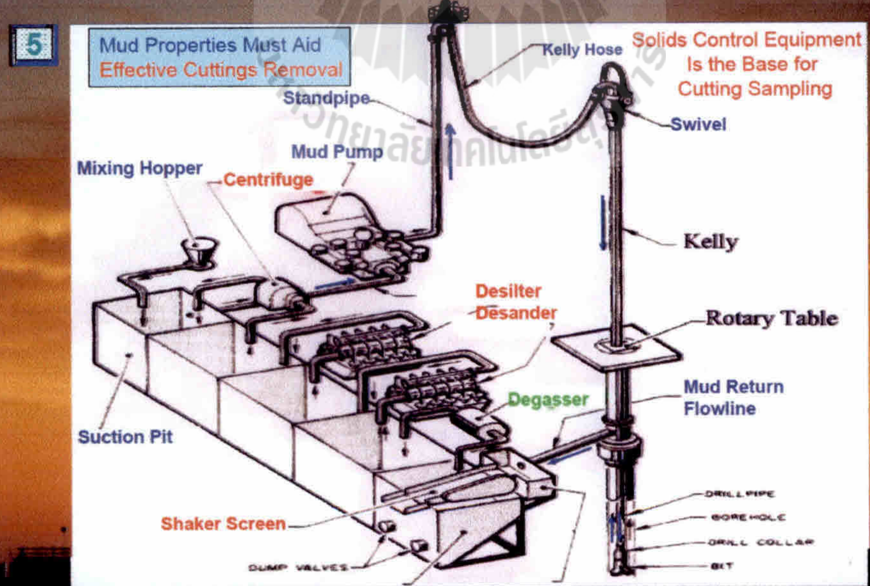


Fig. 3-23

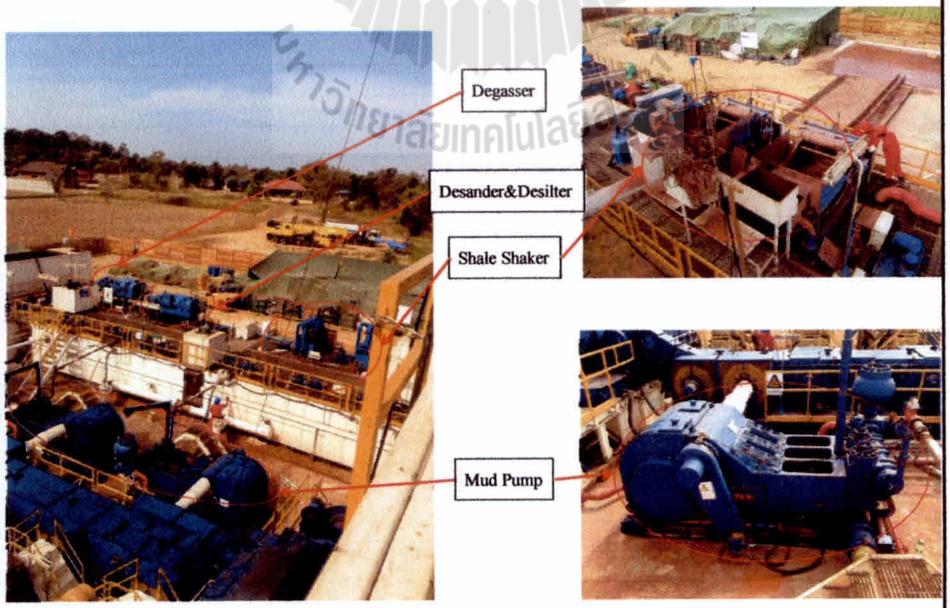
Mud Circulation System and Solids Control Equipment

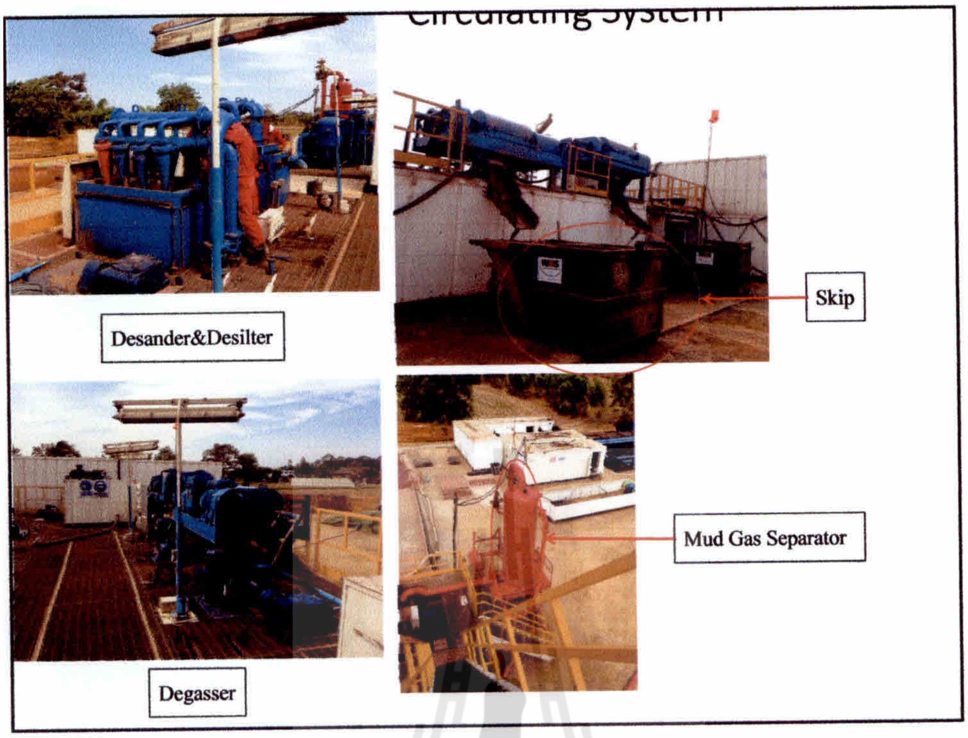


22 February 56 SINOPEC Rig 50765

YPT-2 : ตั้งอยู่ที่
อ.ชุมพลบุรี จ.สุรินทร์

Mud Circulating System




Desander&Desilter
Skip
Mud Gas Separator
Degasser


ExdIIBT4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Drilling Fluid

- **Historical perspective**
  - 1901 – The Spindletop well introduced rotary drilling methods and drilling fluid
  - 1920's – Barite was first used for density
  - Other additives and systems followed:
    - Bentonite
    - Polymers
    - Oil-based systems

OGCI

PetroSkills

Drilling Fluid History

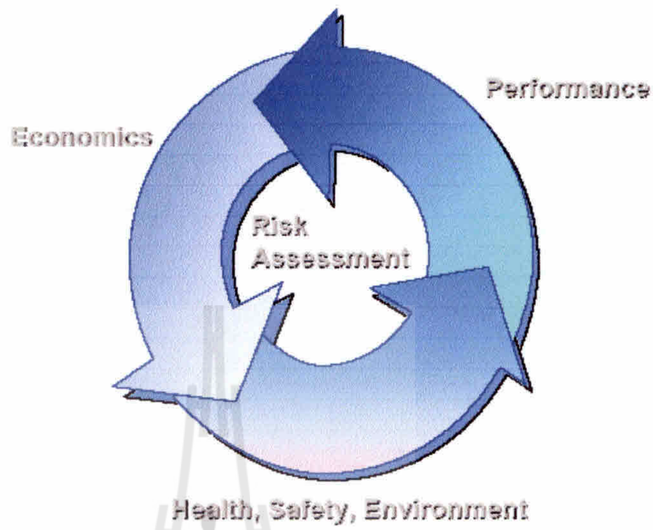
- Long time ago
  Chinese used water … 2-3 ft/day
  To
  - Soften the rocks
  - Remove the cuttings
- ค.ศ. 1901 – Capt. Anthony Lucas
  In Texas
- ค.ศ. 1901–1928 – First Development Period by Baroid
- 1921 Stroud – First "Drilling Fluid Engineer"
  Controlled Drilling Fluid Properties
- 1926 the use of Barite → BAROID®
- 1935 Baroid Registered AQUAGEL for … Filtration Control

Drilling Fluid

- Air, natural gas or nitrogen-based systems
- 1970's – Safety and environmental issues in addition to performance and cost
- 1990's – Synthetic based muds now called non-aqueous drilling fluids or NAF

Drilling Fluid

- **Major factors in drilling fluid selection**



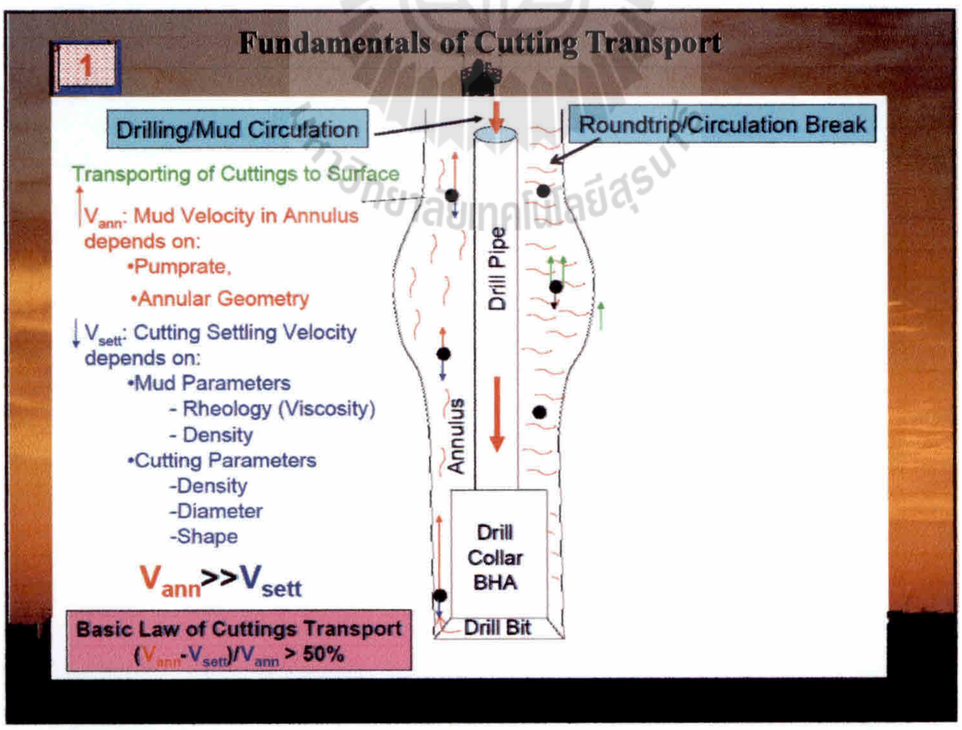
4.2 Functions of Drilling Fluid

The general functions of a drilling fluid are

1. To remove and transport cuttings from the bottom of the hole to the surface
2. To cool and lubricate the bits.
3. To suspend cuttings during times when circulation is stopped.
4. To control encountered subsurface pressure.
5. To wall the hole with an impermeable filter cake
6. To transmit fluid energy to the bit nozzles
7. To prevent caving of the formation
8. To support the weight of drill strings and casing.
9. To prevent corrosion fatigue of drill pipe.
10. To allow interpretation of electric logs

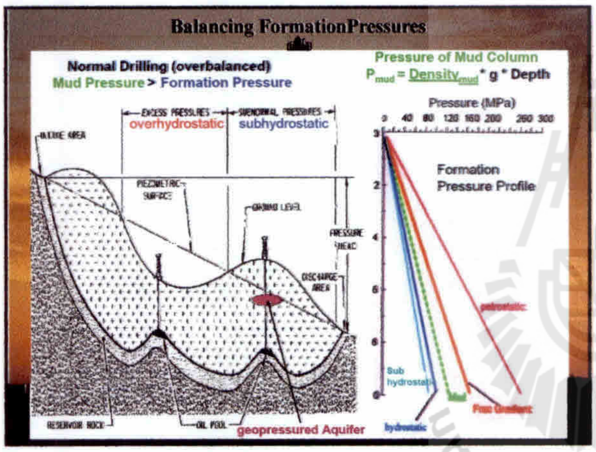
หน้าที่ของน้ำโคลน

1. พาเศษหินจากก้นหลุมขึ้นสู่พื้นผิวดิน
2. ควบคุมความดันก้นหลุมด้วยน้ำหนักของน้ำโคลน
3. หล่อลื่นหัวเจาะและก้านเจาะ
4. พยุงเศษหินไม่ให้ตกลงสู่ก้นหลุมในขณะหยุดปั๊มน้ำโคลน



Drilling Fluid

- Bottomhole cleaning is primarily performed by the hydraulics and not the mud
  - Mud additives generally reduce bottomhole cleaning
  - Bit balling is less of a problem with dispersed mud systems



Drilling Fluid

- Number two is to prevent blowouts
- Blowouts can be catastrophic with loss of life, equipment and environmental damage
- The most common additive for density is barite

Drilling Fluid

Weight Material	Specific Gravity	Average Density, ppg	Average kg/m³	Chemical Formula
Barite	4.2	35.0	4200	$BaSO_4$
Hematite	5.2	43.3	5200	$FeO\,Fe_2O_2$
Ilmenite	4.8	40.0	4800	$TiO_2\,FeO$

- Hematite and Ilmenite are not used very often in drilling fluids
- Only for very high density drilling fluids

หน้าที่ของน้ำโคลน

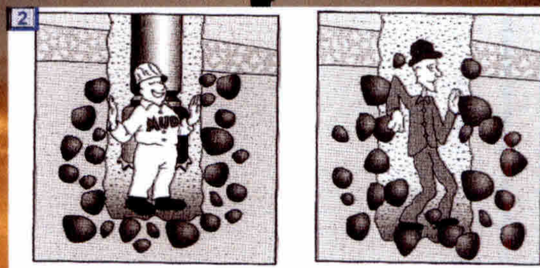
5. ฉาบผนังหลุมด้วยแผ่น Filter Cake ควบคุมการสูญเสียน้ำโคลน
6. เป็นตัวส่งผ่านพลังงานลงสู่หัวเจาะ
7. ป้องกันไม่ให้เกิดหลุมพัง
8. พยุงน้ำหนักของก้านเจาะและท่อกรุ

Functions Of Drilling Fluids

- Transmit hydraulic horsepower to
- the bit

HALLIBURTON
Fluid Systems

Support of the Borehole Wall – Balancing Formation Pressure



While Drilling Open Hole
Mud Column should act as „Hydraulic Casing"
Sufficient Mud Density
Good Filtration Properties

Insufficient Mud Density
Bad Filtration Properties
-Uncontrolled Fluid Entry
-Borehole Instabilities
-Differential Sticking

หน้าที่ของน้ำโคลน

9. ป้องกันการสึกกร่อนและความล้าของก้านเจาะ
10. ช่วยในการแปลความหมายการหยั่งธรณีหลุมเจาะ (Well Logging) เป็นสื่อไฟฟ้าให้วัดคุณสมบัติต่างๆ ของชั้นหินได้

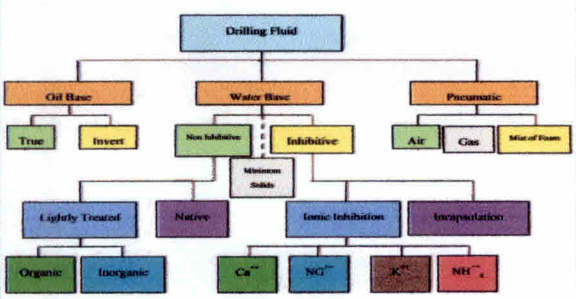
Functions Of Drilling Fluids

- Limit corrosion of tubular goods

HALLIBURTON
Fluid Systems

2.4.4 ชนิดของของ Drilling Fluid

การแบ่งชนิดของ Drilling Fluid ตามกายภาพของของไหล สามารถจัดได้เป็น 3 ประเภทใหญ่ ดังแสดงในรูปที่ 2.14 คือ



รูปที่ 2.14 ชนิดของ Drilling Fluid

Types of Drilling Fluid

- The three main categories of drilling fluids are:
- water-based muds (which can be dispersed and non-dispersed),
- non-aqueous muds, usually called oil-based mud,

and

- gaseous drilling fluid, in which a wide range of gases can be used.

A- Fresh water Base Mud

((is that mud with water as its continuous phase.))

1- Spud mud.
2- Low solids mud.
3- Lignite mud.
4- Lignite surfactant systems.
5- Lignosulfonate mud.
6- Lignite/ Lignosulfonate mud.

Types of Drilling Fluids

- **Water**
  - Water drills better than drilling fluids with solids
  - Low density, no solids, low viscosity
  - Not all formations can be drilled with water

Types of Drilling Fluids

- **Water based muds**
  - Clay for viscosity
  - Barite for density
  - Chemicals and polymers to get desired properties
  - Drill solids as a contaminant

B- Inhibited Mud

((Is that mud which repress the hydration and subsequent dispersion of clay into the mud))

1- Lime mud.
2- Low lime mud.
3- Gypsum mud.
4- Sea water mud.
5- Saturated salt water mud.
6- K-plus mud.

B- Inhibited Mud (continue)

Advantages over conventional water base mud:-

1- will Telerate a higher concentration of clays before developing high viscosity,
2- less drastic effects by contaminants such as cement, anhydrite, ..
3- can be raised to a higher mud weights before developing excessive viscosity,
4- less progressive gelling tendency.

Types of Drilling Fluids

ADVANTAGES	DISADVANTAGES
May be cheapest alternative in off-shore locations	May create disposal problem in some areas
Can result in better hole stability than fresh water counterpart	Usually requires more chemical treatment than fresh water mud
Salt saturated systems offer potential of highest possible densities	Often more expensive than equivalent fresh systems
Resistant to contamination by gypsum bearing zones	Poor filter cake properties
High solids tolerance (sometimes)	Corrosive
Reduces or prevents hole enlargements in salt zones	Difficult to maintain pH
May offer superior penetration rate due to low solids content at modest density	May interfere with open-hole logs
	May be more dense than needed

Types of Drilling Fluids

- High salinity levels in the water phase improve wellbore stability by creating osmotic pressures that dehydrate and harden reactive shales
- Usually try to balance the activity so that the water does not move from the mud to the formation or from the formation to the mud

KCL/polymer mud

- The basic components of potassium chloride (KCL)/polymer mud are:
  - Fresh water or sea water
  - KCL
  - Inhibiting polymer
  - Viscosity building polymer
  - Stabilized starch
  - Caustic soda or caustic potash

Low pH Polymer Water Base Mud (PHPA mud)

PHPA MUD

by admin on February 21, 2011

Oilfield Resume – Discover The Secret of Writing Perfect Resume for Oilfield Jobs

Partially-hydrolyzed polyacrylamide

Low pH Polymer Water Base Mud (Low pH/PHPA mud) is one of famous water based mud systems because there are partially-hydrolyzed polyacrylamide (PHPA) particles which function as protective colloid in the drilling mud. As you know that the water phase will act with shale formation causing wellbore problems as wellbore collapse, clay swelling, cutting build up, etc. With the PHPA in the system, it will help you prevent those serious wellbore problems because the PHPA will form bonding around the reactive shale. With this chemical mechanism, the formation solid cannot be dispersed into the water base mud.

Advantages/applications of PHPA mud

- Stabilize shale and clay formation
- Reduce bit balling
- Provide mud lubricity
- Flocculate drilled solid

General parameters to keep the PHPA mud in a good shape.

Fluid loss – Normally, 15 – 20 ml per 30 minutes with API filter press test is good range for the fluid loss of the PHPA mud. For instant, I personally used to drill wells with 20 ml fluid loss PHPA and before I come out of hole, I decreased the fluid loss to 5-8 ml which helped me run completion strings smoothly. You need to learn what the best practices are in your field in order to get the most optimized value for your operation.

Low Solids Fluids

- Systems in which the amount (volume) and type of solids are controlled.
- Total solids should not range higher than about 6% to 10% by volume.
- Clay solids to be 3% or less and exhibit a ratio of drilled solids to bentonite of less than 2:1.
- Low-solids systems typically use polymer additive as a viscosifier or bentonite extender and are non-dispersed.
- One primary advantage of low-solids systems is that they significantly improve drilling penetration rate.

C- Water Base Emulsion Mud

((Is that mud with oil & water being emulsified together)).

Advantages over conventional water base mud:-

1- Reduction of pipe torque & drag.

2- Increased ROP & bit life.

3- Reduction of bit balling.

4- Alleviation of differential sticking.

5- Better filtration control & production zone.

D- Oil Base & Synthetic Mud

((Is that mud with oil as its continuous phase with not more than 1 – 5% water)).

Advantages of oil base mud:-

1- protection of production horizon,

2- drill water sensitive formations; salt, clays..

3- allowing longer bit runs than water base mud of the same weight.

4- less viscosity problems in deep hot holes.

Types of Drilling Fluids

- Oil based muds can be formulated to weigh as little as 7.5 ppg (900 kg/m^3) with mostly oil
- Oil based muds are used to drill
  - Highly reactive shale and evaporite formations
  - Extended reach drilling for low friction coefficient
  - Deep, high pressure, high temperature H_2S wells

Types of Drilling Fluids

- Oil base muds are much more expensive per barrel
- Economics are a function of preventing hole problems, overall, it must save time on the rig to be cost effective
- Oil base muds are highly toxic and disposal costs must be considered in the economics

Types of Drilling Fluids

- Initially, crude oil was used but was later replaced by diesel
- Low-toxicity mineral oils can be used
- Oil/water ratios can range from 100:0 to 40:60
- Low water ratios (60:40 to 40:60) can have very high viscosities but they help minimize oil retained on cuttings

Types of Drilling Fluids

- Oil based muds are termed invert emulsion because the water phase is emulsified in the oil which means that oil is the continuous phase
- The emulsified water droplets contribute to viscosity which helps suspend weight material and reduce fluid loss

Types of Drilling Fluids

- Components of an oil based mud
  - Oil
  - Brine (usually calcium chloride)
  - Primary and supplementary emulsifiers (fatty acids are one)
  - Oil-wetting agent
  - Oil dispersible bentonite
  - Filtration control additives
  - Slaked lime

Types of Drilling Fluids

- Toxicity is the most serious drawback to oil based muds
- The characteristics that result in superior performance of oil based muds can also contaminate the environment

Types of Drilling Fluids

- A wide variety of refined mineral oils have been developed for use in low-toxicity oil based muds
- However, mineral oils are still considered toxic

Types of Drilling Fluids

- Synthetic based muds (SBM's) are an attempt to provide the performance of oil based muds without the toxicity and environmental problems
- Unit cost per barrel is higher than oil based muds

Types of Drilling Fluids

- Synthetics are highly refine oil or man made, hydrocarbon liquids
- The continuous phase of an SBM can be as much as 99% synthetic material
- First generation synthetics were esters, ethers, polyalphaolefins (PAO's), and acetals

Types of Drilling Fluids

- Second generation SBM's are isomerised olefins (IO's), linear alphaolefins (LAO's), linear alkylbenzenes (LAB's) and paraffin
- Second generation SBM's are characterized by lower costs and lower kinematic viscosities but slightly higher toxicity levels

Types of Drilling Fluids

- Air
  - Drills faster than any other drilling fluid
  - Can only be used in harder rock with lower production rates
  - No control of formation pressure

1. a continuous phase (liquid base)
2. a dispersed gel-forming phase such as colloidal solids and/or emulsified liquids which furnish the desired viscosity. Thixotropy, and wall cake.
3. Other inert dispersed solids such as weighting materials, sand, and cuttings.
4. Various chemical necessary to control properties within desired limits.

3.Composition of drilling fluids

Mud

is the mixture of

Clay dispersed gel-forming

And

Water Continuous phase

and

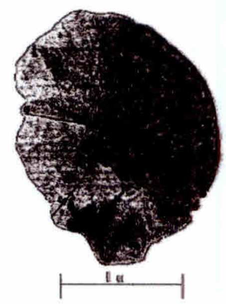
Additive

Solid Phase

- The solid phase of a drilling fluid consists of clays, drill solids, barite and LCM
- There are many different types of clays in the world but only three major groups are used in drilling fluids

Solid Phase

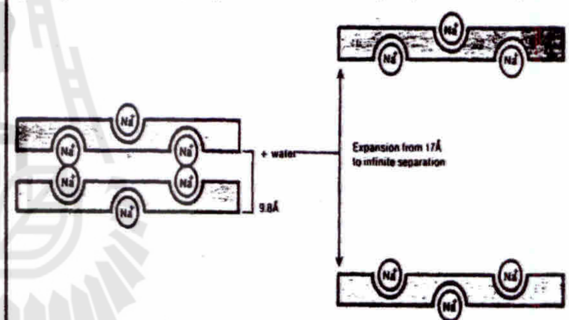
- Clays
  - Bentonite (gel)
  - Attapulgite (salt gel)
  - Sepiolite (high temperature)



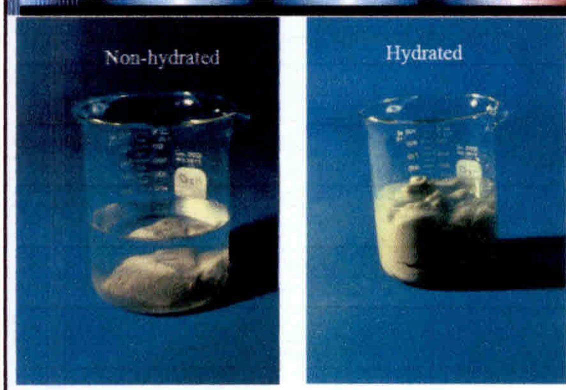
Solid Phase

- Bentonite particles are usually stacked plates like the pages of a book
- The space between the plates for non-hydrated bentonite is less than 10 angstroms
- When fully hydrated, the space between plates can be in excess of 40 angstroms

In drilling fluid, ***Montmorillonite*** is hydrated in fresh water while mixing. Water adsorbs between the platelets increasing the distance or spacing between them, they can be mechanically separated or dispersed .



Solid Phase



MOST IMPORTANT CLAY MINERAL FOR WATER BASE MUD :

- MONTMORILLONITE (SMECTITE)
- BENTONITE
- 3-LAYER HYDROUS ALUMINIUM SILICATE

- Good Viscosity
- Wall Building & Filtration Control
- Stability in High P, T ...

GENERAL FORMULA

$$Si_2O_3 \vdots AL_2(OH)_2O_4 \vdots Si_2O_3$$

BENTONITE :

$$Si_2O_3 \vdots AL_{1.6}Fe_{0.1}Mg_{0.3}(OH)_2O_4 \vdots Si_2O_3$$

WHY BENTONITE

- **Good Viscosity Building**
- **Good Wall Building and Fluid Control**
- **Good Stability in High P & T**

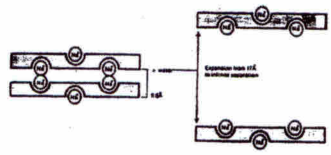
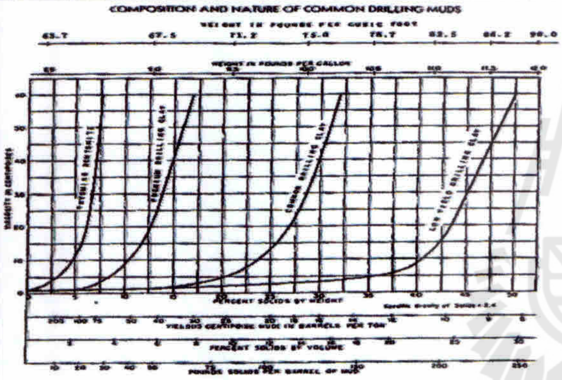


Fig.4.2 Hydration of Sodium Motmorillonite

COMPOSITION AND NATURE OF COMMON DRILLING MUDS



* A GOOD SALT CLAY IN SALT WATER APPROXIMATES THE BENTONITE YIELD CURVE IN FRESH WATER

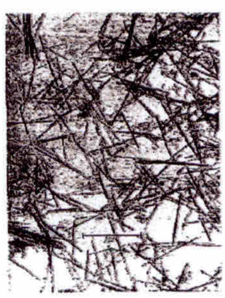
Fig. 6.12. Yield curves for typical clays.

Solid Phase

- The chemical binding of water between plates and solid to solid friction increase the viscosity of water
- Bentonite has good filter cake properties and can reduce fluid loss to 10 to 18 cc's if dispersed

Solid Phase

- **Attapulgite**
  - Does not yield or absorb water like bentonite
  - Viscosity comes from interference between particles
  - Has poor filter cake qualities



Solid Phase

- **Sepiolite is similar to attipulgite**
  - It is used mostly in high temperature wells such as geothermal wells

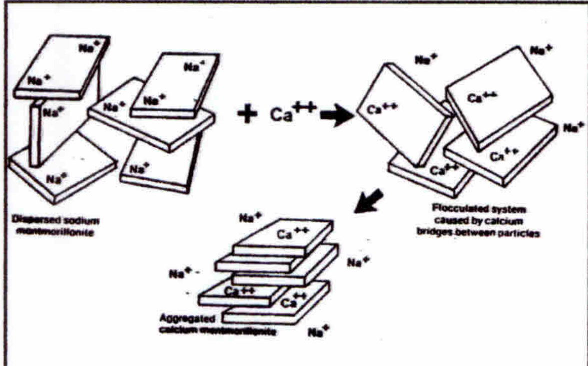


Fig.4.4 Diagram to show the initial flocculating effect of calcium as polyvalent ion bridge is formed between clay particles. This is followed by ion exchange reactions to form the aggregated calcium clay.

TABLE 5-1

Classification of principal clay minerals in sediments (excluding impure minerals and amorphous phases)

(After Degens, 1965, table 1, p. 16; courtesy of Prentice Hall, Inc.)

Layers	Population of octahedral sheet	Expansion	Group	Species	Crystallochemical formula	Space group	Structural schematic
Two-Sheet 1:1	Dioctahedral	Non-Swelling	Kaolinite	Kaolinite, Dickite, Nacrite	[illegible]	[illegible]	Kaolinite
		Non-Swelling and Swelling	Halloysite	Halloysite, Metahalloysite	[illegible]	Cm	Halloysite
	Trioctahedral	Non-Swelling	7Å-Chlorite (Septechlorite)	[illegible]	[illegible]	Cm	
Three-Sheet 2:1	Dioctahedral	Swelling	Montmorillonite (Smectite)	Montmorillonite, Beidellite, Nontronite	[illegible]	Monoclinic	
		Non-Swelling	Illite (Hydromica)	Many Varieties	[illegible]	C2/m or Cm	
	Trioctahedral	Swelling	Vermiculite	[illegible]	[illegible]	Cc	
Three-Sheet One-Sheet (2:2)	Trioctahedral	Non-Swelling	14Å-Chlorite (Normal Chlorite)	Many Varieties	[illegible]	Monoclinic	Illite, Montmorillonite Vermiculite, 14Å-Chlorite

* also trioctahedral varieties } less common
** also dioctahedral varieties }
— swelling chlorites are rare and intermediate forms between vermiculite and chlorite

CLASSIFICATION OF CLAY MINERALS

1. KAOLINITES
2. MONTMORILLONITES (SMECTITES)
3. ILLITES
4. CHLORITES
5. ATTAPULGITE
6. MIXED LAYER CLAYS

C'AYS[6,7] CLAYS

Nomenclature of Clays

Classes and names of clay minerals that are present in shales that are drilled will include the following:

1. Expandable (swelling) Clays:
   - a. Smectites:
     - Montmorillonite, Bentonite
     - Saponite,
     - Hectorite,
     - Beidellite.
   - b. Vermiculite.
2. Non-expandable (non-swelling) Clays:
   - Illite, 50% ของโลก.
   - Chlorite,
   - Kaolinite.

Additive	Function
BENTONITE	CUTTINGS REMOVAL
BARITE ($BaSO_4$)	PRESSURE CONTROL
MICA	LOST CIRCULATION CONTROL
SODA ASH (Na_2CO_3)	VISCOSITY CONTROL
POLYMER (CMC Sodium Carboxy Methyl Cellulose)	FLUID LOSS CONTROL
CAUSTIC SODA ($NaOH$)	PH CONTROL
LIME, GYPSUM ($Ca(OH)_2$, $CaSO_4 \cdot 2H_2O$)	SHALE HYDRATION CONTROL
Potassium Chloride (KCl)	Inhibit the swelling & dispersion of clays

4.8 Mud Additives

The following mud additives are among the most common types used in each of the following categories :

1.Weight Material

- barite(barium sulfate) S.G. = 4.2
- lead compounds(such as galena, lead sulfide) S.G. = 8
- calcium chloride
- iron oxide
- calcium carbonate

2.Viscosifiers

- bentonite
- polyanionic cellulose
- attapulgite clay(in salt water based mud)
- polysaccharides
- sodium carboxymethyl cellulose
- hydroxyethyl cellulose
- polyacrylates
- xanthan gums

3Alkalinity and pH Control
- caustics soda
- lime (calcium hydroxide)
- bicarbonate of soda
- phosphates
- potassium hydroxide(caustic potash)

4Thinners and Dispersants
- chrome lignosulfonates
- tannins
- lignite

5 Filtration Reducers
- carboxymethyl cellulose(CMC)
- polyanionic cellulose
- lignite
- chrome lignosulfonates
- bentonite

6 Alkalinity and pH Control
- caustics soda
- lime (calcium hydroxide)
- bicarbonate of soda
- phosphates
- potassium hydroxide(caustic potash)

7.Thinners and Dispersants
- chrome lignosulfonates
- tannins
- lignite

8.Filtration Reducers
- carboxymethyl cellulose(CMC)
- polyanionic cellulose
- lignite
- chrome lignosulfonates
- bentonite

9.Surfactants
- detergents
- amine and sulfonates

10.Shale inhibitors
- potassium lignite
- invert emulsion fluid
- potassium chloride
- sodium chloride
- diammonium phosphate
- ammonium sulfate
- sodium asphalt sulfonate

11.Lubricants
- graphite
- synthetic lubricants
- environmentally acceptable oils

12.Foaming Agents
- sodium asphalt sulfonate
- Detergent

GEO TECHNICAL ORDER

PLANNING MUD ENGG. POLICY

DECIDING FACTORS OF MUD ENGG. POLICY

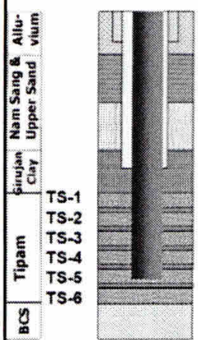
1. FORMATION PRESSURE
2. FORMATION TEMPERARURE
3. LITHOLOGY
4. CASING POLICY
5. HOLE PROFILE
6. MUD LOSS ZONES
7. ECONOMICS & ENVIRONMENTAL REGULATIONS
8. COMPANY SPECIFIC POLICY DECISION
9. AVAILABILITY OF MUD CHEMICALS AT SPECIFIC TIME & PLACE

MUD ENGG. POLICY

- High Viscous Gel : for Top hole section
- Non Dispersed mud / Gel Polymer : for Intermediate sections
- KCl-PHPA-Polyol system : for BCS & KOPILI
- Clay free / Barytes free – NDDF : for pay Zones

Non Dispersed Drilling Fluid

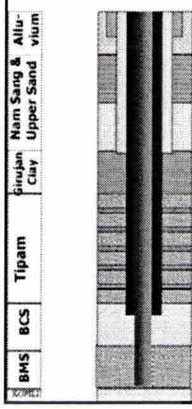
MUD POLICY FOR THREE CASING WELL



- HVG for drilling 17 ½" hole
- Non Dispersed / Gel-Polymer for 12 ¼" hole
- NDDF for drilling 8 ½" inclined section covering pay zone

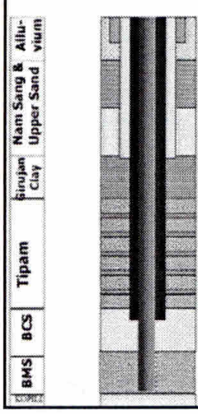
Non Dispersed Drilling Fluid

MUD POLICY FOR FOUR CASING WELL



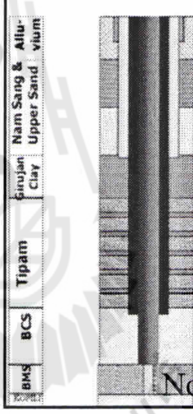
- HVG for 26" hole
- Non dispersed mud/ Gel-CMC for 17 ½" hole
- Gel-Polymer/ KCl-PHPA for 12 ¼" Girujan & Tipam
- KCl-PHPA-Polyol for BCS & BMS in 8 ½" final phase

MUD POLICY FOR FOUR CASING WELL



- HVG for 26" hole
- Non dispersed mud/ Gel-CMC for 17 ½" hole
- Gel-Polymer/ KCl-PHPA for 12 ¼" Girujan & Tipam
- KCl-PHPA-Polyol for BCS & BMS in 8 ½" final phase

MUD POLICY FOR FIVE CASING WELL



- HVG for 26" hole
- Non dispersed mud for 17 ½" hole
- Gel-Polymer/ KCl-PHPA for 12 ¼" Girujan & Tipam
- KCl-PHPA-Polyol for BCS in 8 ½" phase
- NDDF in 6" phase for pay zone

Non Dispersed Drilling Fluid

MUD CHEMICALS Product, Usage & MSDS

1. WATER

- Most important single substance involved in drilling fluid technology. It is major component (by volume) in mud.
- Unusual properties of water in comparison with other liquids - highest surface tension, dielectric constant, heat of fusion, heat of vaporization & the superior ability to dissolve a variety of substances.
- Dissociation of salts, acids & bases occurs in water.
- Reaction between water and clay surfaces and the effect of electrolytes dissolved in water on the clay-water interaction are primarily responsible for drilling mud properties.
- In some locations quality of water also decides mud composition or water must be treated to counteract some dissolved substances.

2. ALUMINIUM STEARATE

- White powder
- Used as de-foamer i.e. to reduce foaming action
- Insoluble in water
- Partially Soluble in Diesel & hence treated by making solution in diesel (2.5%)

3. BACTERICIDE

- To control Bio- Degradation of natural organic additives in polymer mud.
- Chemically it is an aldehyde or amine & acts as bacteria killer.
- Dose: 0.1% (1000ppm).
- Volatile & fumes are irritating.
- Avoid contact with skin.
- Care should be taken while handling it.

4. BENTONITE

- Minimum 85% montmorillonite): Sp.gr.-2.45-2.55. Occur as natural deposits.
- Classified as sodium bentonite or calcium bentonite depending on the dominant exchangeable cation.
- In terms of performance also classified as high yield & low yield bentonite.
- It is basic requirement of drilling fluid/mud (other than NDDF).
- To reduce water seepage or filtration in to permeable formation
- To increase hole cleaning capacity
- To form thin filter cake of low permeability.
- To promote hole stability in loose formations
- To avoid or overcome loss of circulation.
- Dose: (A) 3 to 7% depending up in mud system
- (B) 7 to 10% to stabilize caving formation.
- (C) 8 to 11% for loss of circulation.
- Suspension is prepared in fresh water as its hydration does not occur in salty water

5. BARITE($BaSO_4$)

- Grey powder(97% of material should pass through 200 mesh B.S.S. or equivalent) sieve; (90±5)% of material should pass through 300 mesh B.S.S. or equivalent) sieve), Sp. gr.- 4.2 4.25
- virtually insoluble in water & does not react with other component of mud. Calcium sulphate (Gypsum), present some times as impurity causes contamination in fresh water muds.
- Occurs naturally & is used to increase sp. gr. of mud to control formation pressure, caving & for pulling of dry pipe.
- Maximum sp.gr. achievable with barite is 2.2
- Dose: As per requirement of weight

OTHER WEIGHING MATERIALS

- Other weighing materials required to raise mud sp. gr. more than 2.2 are:
- Hematite, an Iron ore Fe_2O_3, self sp. gr.- 4.7
- Galena (PbS with self sp.gr.-7.4-7.7 & is used to prepare only very heavy muds because of high cost.

6. CAUSTIC SODA (NaOH)

- Used to increase pH of mud (Sp. gr.- 2.13)
- Should be added slowly to make water solution as making of its solution is exothermic reaction (heat is evolved).
- Solution should be added slowly in the mud to avoid sudden high pH in mud which will result in decomposition of polymers & unwanted sudden rise of viscosity in bentonite mud. Dose: 0.15%
- Avoid contact with skin, clothes, leather etc as It is corrosive in nature & hazardous for health.
- Do not get into contact with this on skin, eyes or cloth. If comes in contact, immediately wash with plenty of water for 15 minutes.
- Handle with Chemical goggles & chemical impervious gloves.

7. CAUSTIC POTASH (KOH)

- Used to increase pH of potassium treated muds & to solubilize lignite (Sp gr. - 2.04)
- Doses: 0.1 - 0.2% for normal mud treatment & 0.8% to solubilize lignite).
- Should added slowly to make water solution as making of its solution is exothermic reaction (heat is evolved).
- Solution should be added slowly in the mud to avoid sudden high pH in mud which will result in decomposition of polymers & unwanted sudden rise of viscosity in bentonite mud.
- Avoid contact with skin, clothes, leather etc. It is corrosive in nature & hazardous for health.
- Do not get into contact with this on skin, eyes or cloth. If comes in contact, immediately wash with plenty of water for 15 minutes. Handle with Chemical goggles & chemical impervious gloves.

8. CMC (Sodium carboxymethyl cellulose)

- The most widely used organic polymers are the semi-synthetic gums produced by chemical modification of cellulose. Of all the cellulose derivatives CMC was first to be used in mud.
- Water-dispersible, colourless, odorless, non toxic powder & does not ferment under normal conditions of use. Hence it is preferred to starch other than high-pH & salt saturated muds. It is of 2 types: 1) CMC-LVG; 2) CMC-HVG
- It is an anionic polymer & is adsorbed on clays. Used to **increase viscosity & reduce filtration loss**. Filtration is sharply reduced by low (**0.75-1.0%**) concentrations of CMC. Its suspensions are shear thinning; **have high apparent viscosity (AV) at low shear rate.** Like other polymers **AV decreases with rise in temperature**. The viscosity at 300° F (150°C) is about one-tenth that at 80°F (27°C). Its thermal degradation starts as temp. approaches 300° F(150°C). **Its effectiveness is decreases as salt concentration in mud increases.**
- Calcium containing muds are thinned by small addition of CMC. Like starch, CMC is coprecipitated along with calcium & magnesium by raising pH.
- **Dose: 0.75-1%**

9. COMMON SALT

- **Used to prepare brine during activation of well. (Used for inhibition i.e. to prevent swelling of clay in producing zone thus maintaining porosity & permeability.)**
- **Maximum sp. gr. of brine- 1.20**
- **Dose: 3% minimum for inhibition**

10. CORROSION INHIBITOR

- **To control corrosion of equipments (especially by KCl mud & brines)**
- **Dose: (a) Win Corr. Inhibitor- 100ppm**

11. CALCIUM CARBONATE (MCC)

- MCC is very fine powder & practically insoluble in water (Sp. gr. : 2.6-2.8)
- Used as bridging agent & weighting material in NDDF because the filter cake formed by it on productive formation can be removed easily. **Maximum sp. gr. achievable with Calcium Carbonate = 1.35**
- Min. Dose for wall cake formation : 5%

12. DRILLING DETERGENT

- To clean bit/stabillisers/tool joints during drilling of clay and increase ROP.
- Dose- 0.1-0.8%

13. E P LUBE

- As lubricant at deeper depths.
- Basically vegetable oil based lubricant. It makes a film of very high film strength between formation & string surface thus reduces friction.
- Film strength: 20000-25000psi in fresh water mud & up to 20000 psi in salt water muds.
- Dose: 0.4 to 0.6%

14. LIGNITE (Leonardite)

- It is mild dispersant
- Acts as thinner & F/L control agent, high temperature stability(up to 260°C)
- Deflocculant- reduces attraction between clay particles
- Dose- 5% (Solution with caustic soda / caustic potash(1:5) has to be prepared first

15. LIME STONE

- Used as weighing material .
- Basically it is impure form of Calcium carbonate.(sp.gr.-2.65)
- Max. sp. gr. can be achieved-1.35
- Dose: As per requirement of weight

16. LINSEED OIL

- It is vegetable oil & used as lubricant. It creates a film between two surfaces (i.e. between formation & string).
- Dose: 0.4 to 0.6%

17. MICA

- Loss circulation material.
- It is in form of flakes which plug the large gapes in the formation in case of mud loss.
- Dose: up to 5%/depending up on severity)

18. PAC (Poly anionic cellulose)

- The limitation of CMC in salt solution led to development of "polyanionic cellulosic polymer of high molecular weight"-PAC (Sp.gr. -1.5-1.6)
- Thickens salt solutions & is an environmentally acceptable polymer electrolyte
- Has shale inhibition qualities, pH of 1% solution is 5-8. Available in two forms:
- **(a) PAC (LVG):** Viscosifier & Filtration control. Temp. Stability-120°C
- **(b) PAC (RG):** Viscosifier & Filtration control. (Its polymer chains are longer than that of PAC(LVG). Temp. Stability-120°C
- Dose: 0.5-1%

19. PHPA

- Used for shale stabilization & inhibition by encapsulation of cutting in mud as well as forming a layer on the wall of open hole.
- It is long chain polymer.
- It is of two types having temperature stability of 110°C & 140°C.
- Dose: 0.2 to 0.5%

20. POLYOL (Poly glycol)

- Used for shale stabilization & lubrication.
- Clouding at a temperature above 78°C.
- Plugs formation pores & prevents formation invasion (by cloud formation) & thus imparts borehole stability.
- Thickens filtrate & act as lubricant at all temperatures.
- Dose: 3-5%

21. POTASSIUM CHLORIDE

- Used for shale stabilization & Brine preparation.
- Replaces Na^+ in bentonite (sodium montmorillonite) with K^+ thus preventing swelling of clays (in pay zones)
- Dose for mud – 3 to 8 % or as required.
- Dose for brine (minimum for inhibition)- 1%

22. RESINATED LIGNITE

- **It is a dispersant & used for filtration control & temperature stabilization of rheology.**
- **Stable at temperature up to 160° C**
- Dose: 1-2%

23. SULPHONATED ASPHALT

- Shale stabilizer (plugs micro fractures)
- Used in water based muds for **hole stabilization.**
- Adsorbed on shale & its beneficial effects are attributed to **plugging of microfractures** in the shale.
- Readily dispersible in water, & stabilizes emulsions of oil in water.
- **Temperature stable**, having a softening point of over 500 deg F (260 deg C).
- Reduces torque & drill pipe drag.
- **Dose – 1.5 to 3%.**

24. STARCH (PGS)

- **Viscosifier & Filtration control agent.** The first organic polymer used in mud. (Dose- 3%)
- Most economical substance for reducing **filtration of strongly-alkaline & salt saturated muds for shallow drilling**. 0.1% dose of biocide is required to reduce fermentation (bio degradation) of starch
- The ambient temperature affects the microbial decomposition rate; if ambience is cold or very hot, the rate is slow.
- Starch is degraded by heat & by agitation. With continued circulation in a hole at temperature of 200° F (93°C) and above, starch breaks down rapidly. The resulting product continues to affect viscosity but loses the sealing action of starch in filter cake. Consequently filtration rate & cake thickness are markedly greater under static bottom hole conditions than those indicated by tests at surface temperature. **Dose- 0.6 to 3.0%**

25. SODA ASH (Sodium Carbonate)

- Used for removal of calcium from muds & make up waters (Sp. gr.- 2.53)
- Used to increase pH in mud (especially in polymer muds).
- It is skin & eye irritant.
- If comes in contact wash with plenty of water.
- Doses-0.15-0.2%

26. SPOTTING FLUID

- **For freeing Stuck pipe by reducing interfacial tension between string & filter cake and eventually cracking the cake.**
- **Dose: 2.5 - 3% in diesel**
- **Should be allowed to soak for minimum 4-6hrs.**

27. XC POLYMER (Xanthan gum)

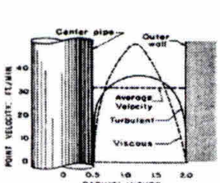
- Viscosifying Polymer in water & salt solutions
- Water-soluble polysaccharide produced by bacterial action (genus Xanthomonas) on carbohydrates.
- Displays exceptional shear-thinning properties.
- Cross-linking with chromic ion significantly increases viscosity.
- Doses: (a) NDDF - 0.5-0.8%
  (b) KCl-PHPA – 0.15 to 0.2%

ECONOMICS OF MUD ENGG.

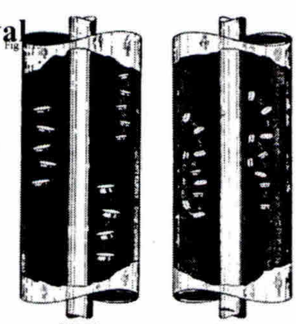
- CHEMICALS
- HANDLING EQUIPMENTS
- MUD TESTING LABORATORY
- MANPOWER
- ENVIRONMENT
- SAFETY
- LOGISTICS

5. Mud Calculation

Cutting Removal



Comparison of viscous and turbulent velocity distributions in annulus. After Williams and Bruce, courtesy AIME.



Turbulent Laminar

Flattish cutting rise behavior in turbulent and laminar flow. After Williams and Bruce, courtesy AIME.

Pigott has applied Stoke's law:

(4.8)

for spherical particles $$v_{ls} = \frac{148 d_c^2 (\rho_s - \rho_m)}{\mu}$$

and

(4.9)

for flat cutting $$v_{ls} = \frac{57.5 d_c^2 (\rho_s - \rho_m)}{\mu}$$

where v_{sl} = maximum (or terminal) ***slip velocity*** of the cutting in laminar flow, d_c = cutting diameter, in.

ρ_m, ρ_s = mud and cutting density, respectively, lb/gal

μ = mud viscosity, cp (normally used as the 600 rpm value)

148 and 57.5 = dimensional constants which also include drag coefficients (flat cuttings fall about 40% as fast as sphere)

Turbulent slip velocities are obtained from alternations of Rittinger's equation. Williams and Bruce have used

(4.10) $$v_c = 170\sqrt{\frac{d_c(\rho_s - \rho_m)}{\rho_m}}$$ for spheres

(4.11)

for flat cutting $$v_c = 133\sqrt{\frac{t_c}{d_c}}\sqrt{\frac{d_c(\rho_s - \rho_m)}{\rho_m}}$$

where v_c = uncorrected cutting slip velocity in turbulent flow, ft/min

t_c/d_c = thickness to diameter ratio of cutting

The value of v_c must be corrected for wall effect, or the fact that the cutting itself detracts from the annular area. This is accom

(4.12)

$$v_{ts} = \frac{v_c}{1 + d_c / d_a}$$

where v_{ts} = turbulent slip velocity of cutting, ft/min

d_a = hydraulically equivalent diameter of annulus (hole diameter – pipe diameter), in.

Example 4.1

(a)What is the slip velocity of 0.50 in. diameter sphere laminar flow conditions in a 30 cp, 10 lb/gal mud? Assume ρ_s = 21.7 lb/gal

Solution

Using Eq. (4.8) $v_{s\ell} = \dfrac{148(0.5)^2(21.7-10)}{30} = 14.4$ ft/min

(b) What would the maximum falling rate be for the system in turbulent flow? Ignore wall effect.

Solution

Using Eq. (4.10) $v_c = 170\sqrt{\dfrac{(0.5)(21.7-10)}{10}} = 130$ ft/min

(.c) What is the turbulent slip velocity corrected for wall effect? Hole size = 8 in.; drill pipe = 4 ½ inches.

Solution

Using Eq. (4.12) $v_{s\ell} = \dfrac{130}{1+\dfrac{0.5}{3.5}} = 104$ ft/min

It is generally considered that 80 to 150 ft/min annular mud velocity is sufficient to clean the hole under the various condition.

4.12 Drilling Mud calculations

Control of Encountered Subsurface Pressure

(4.13)

$$p_m = \frac{\rho_m}{8.33} \times 0.433D = 0.052\rho_m D$$

where p_m = static pressure exerted by mud column at depth D, psig.

ρ_m = mud density, lb/gallon

D = depth, ft

(i) $V_s + V_{m1} = V_{m2}$

(4.15) $\rho_s V_s + \rho_{m1} V_{m1} = \rho_{m2} V_{m2}$

Where V_s = *volume of solid*

V_{m1} = volume of initial mud (or any liquid)

V_{m2} = *final volume of mixture*

ρ_s = ***density of solid***

ρ_{m1} = density of initial mud

ρ_{m2} = density of final mud

If solving for V_s

(4.16) $V_s = Vm2(\rho_{m1} - \rho_{m2})/(\rho_s - \rho_{m2})$

If solving for $\rho_s V_s$

(4.17) $$\rho_s V_s = \frac{\rho_s V_{m2}(\rho_{m2} - \rho_{m1})}{\rho_s - \rho_{m1}}$$

Example 4.2

For laboratory purposes, it is desired to mix one liter of bontonite-fresh water mud having a viscosity of 30 cp.

(a)What will be the resulting mud density?

(b)How much of each material to be used?

Solution :

(a) From Fig 4.16, solid content = 3.0% by volume. By using alter forms of Eq. (4.16)

$$0.03 = \frac{\rho_{m2} - \rho_{m1}}{\rho_s - \rho_{m1}} = \frac{\rho_{m2} - 1.0}{2.5 - 1.0}$$

From which

ρ_{m2} = *1.045 gm / cc* = ***8.7 lb/gal***

(b)

$$V_s = \frac{1000(1.045 - 1.0)}{2.5 - 1.0} = 30 \text{ cc} = 2.5 \times 30 = 75 \text{ gm}$$

Also $V_{m1} = V_{m2} - V_s$ = 1000 - 30 = 970 cc water

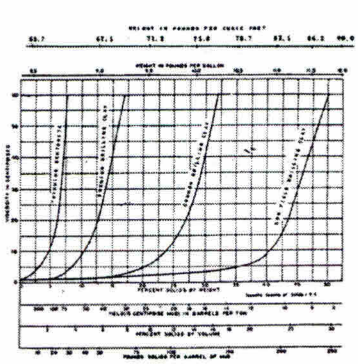


Fig. 4.16 **Yield curves for typical clays.**

For certain types of problems it is convenient to express Eq. (4.16) in different form. Suppose that the quantity of solids (V_s) necessary to increase (or decrease) the density of an initial mud is desired. Then:

(4.16a)
$$V_s = \frac{(V_{m1} + V_s)(\rho_{m2} - \rho_{m1})}{\rho_s - \rho_{m1}}$$

where $V_{m1} + V_s = V_{m2}$ (volumes additive)

Solving for V_s gives

(4.18)
$$V_s = \frac{V_{m1}(\rho_{m2} - \rho_{m1})}{\rho_s - \rho_{m2}}$$

Example 4.3

(a) How much weighting material ($BaSO_4$, the mineral barite, sg.gr. = 4.3) should be added to the mud of Ex. 4.2 to increase its density to 10 lb/gal? (b) What will the result volume be?

Solution

(a) $V_s = \frac{1000(10-8.7)}{35.8-10} = 50.4$ cc or $4.3 \times 50.4 = 217$ gm

$$V_{m2} = 1000 + 50.4 = 1050 \text{ cc}$$

For increasing mud weights by adding barite or bentonite, the number of sacks of barite(S_B) or bentonite (S_C) necessary to increase the density of 100 bbl of mud from ρ_{m1} to ρ_{m2} can be calculated by applying these two basic equations. Barite is sold in **100 lb sacks**. Such a sack contains **100/(4.3)(62.4) = 0.373 cu ft, or 0.373/ 5.61 = 0.0665 barrels** of net material. Therefore **1 barrel(net) of barite = 1/ 0.0665 ≅ *15 sacks*.** ***In the same manner, knowing bentonite(clay) has sp.gr. of 2.5 and is sold in 100 lb sacks. When put these values in the two basic equations, the other forms of formula will be obtained as follows.***

(4.18a)

$$\frac{S_B}{15} = \frac{100(\rho_{m2}-\rho_{m1})}{35.8-\rho_{m2}} \quad \text{or} \quad S_B = \frac{1500(\rho_{m2}-\rho_{m1})}{35.8-\rho_{m2}}$$

$$S_c = \frac{875(\rho_{m2}-\rho_{m1})}{20.8-\rho_{m2}}$$

Example 4.4

(a) How many sacks of barite are necessary to increase the density of 1000 bbl of mud from 10 to 14 lb/gal?

(b) What will be the final volume?

Solution

(a) Using Eq. (4.18a)

$$\frac{S_B}{15} = \frac{1500(14-10)}{35.8-14} = 275\frac{\text{sacks}}{100\text{ bbl}} = 2750\frac{\text{sacks}}{1000\text{ bbl}}$$

(b)

$$V_{m2} = 1000 + \frac{2750}{15} = 1180 \text{ bbl}$$

In order to lighten (decrease) the mud density by adding water, barrels of water (V_w) necessary to reduce density of V_{m1} barrels initial mud from ρ_{m1} to ρ_{m2} can be obtained.

(4.20)

$$V_w = \frac{V_{m1}(\rho_{m1}-\rho_{m2})}{\rho_{m2}-8.33}$$

muds tend to settle but are remixed easily by pumping or stirring. However, it must be noted that certain species of asbestos are regarded as carcinogenic and are not used.

2.3.12 Density Control Additives. Barium sulfate is the primary additive used to increase the density of clay/water muds. Densities ranging from 9 to 19 lbm/gal can be obtained using mixtures of barium sulfate, clay, and water. The specific gravity of pure barium sulfate is 4.5, but the commercial grade used in drilling fluids (API barite) has an average specific gravity of about 4.2.

Recently, alternative density-control agents such as hematite (Fe_2O_3) with specific gravity ranging from 4.9 to 5.3 and ilmenite ($FeO \cdot TiO_2$), with specific gravity ranging from 4.5 to 5.11 have been introduced. These materials are heavier and about twice as hard as conventional barite. The increased densities of these materials will decrease the weight/volume requirements in the mud. Since they are harder than for barite, the particle-size attrition rate will be significantly less than barite. However, the increased hardness raises the question of how abrasive these materials would be in the circulating system.

Galena (PbS), a dense mineral having a specific gravity of 7.5, can be used for special drilling problems that require a mud density greater than 19 lbm/gal. However, the formation pore pressure never requires a mud weight in excess of 19 lbm/gal during normal drilling operations since this is the average weight of the minerals and fluids present in the earth's crust. The hardness of galena is about the same as for barite.

The ideal mixing calculations presented in Sec. 2.2

$$V_2 = V_1 \frac{(\rho_B-\rho_1)}{(\rho_B-\rho_2)} \text{. . . . . (2.18)}$$

Example 2.16. It is desired to increase the density of 200 bbl of 11-lbm/gal mud to 11.5 lbm/gal using API barite. The final volume is not limited. Compute the weight of API barite required.

Solution. From Table 2.7 the density of API barite is 35.0 lbm/gal. Using Eq. 2.18, the final volume V_2 is given by

$$V_2 = V_1 \frac{(\rho_B-\rho_1)}{(\rho_B-\rho_2)} = 200\frac{(35.0-11.0)}{(35.0-11.5)} = 204.255 \text{ bbl.}$$

Using Eq. 2.17, the weight of API barite required is given by

$$m_B = (V_2 - V_1)\rho_B = (204.255 - 200)(42)(35) = 6{,}255 \text{ lbm.}$$

The addition of large amounts of API barite to the drilling fluid can cause the drilling fluid to become quite viscous. The finely divided API barite has an extremely large surface area and can adsorb a significant amount of free water in the drilling fluid. This problem can be overcome by adding water with the weight material to make up for the water adsorbed on the surface of the finely divided particles. However, this solution has the disadvantage of requiring additional weight material to achieve a given increase in mud density because the additional water tends to lower the density of the mixture. Thus,

average weight of the minerals and fluids present in the earth's crust. The hardness of galena is about the same as for barite.

The ideal mixing calculations presented in Sec. 2.2 accurately describe the addition of weight material to clay/water muds. These calculations allow the determination of the amount of mud and weight material required to obtain a specific volume of mud having a specified density. When excess storage capacity is not available, the density increase will require discarding a portion of the mud. In this case, the proper volume of old mud should be discarded before adding weight material. For ideal mixing the volume of mud, V_1, and weight material, V_B, must sum to the desired new volume, V_2:

$$V_2 = V_1 + V_B = V_1 + \frac{m_B}{\rho_B}.$$

Likewise, the total mass of mud and weight material must sum to the desired density-volume product:

$$\rho_2 V_2 = \rho_1 V_1 + m_B.$$

Solving these simultaneous equations for unknowns V_1 and m_B yields

$$V_1 = V_2 \frac{(\rho_B-\rho_2)}{(\rho_B-\rho_1)} \text{, ... (2.16)}$$

and

$$m_B = (V_2 - V_1)\rho_B \text{. . . . . (2.17)}$$

When the final volume of mud is not limited, the final volume can be calculated from the initial volume by rearranging Eq. 2.16:

sorbed on the surface of the finely divided particles. However, this solution has the disadvantage of requiring additional weight material to achieve a given increase in mud density because the additional water tends to lower the density of the mixture. Thus, it is often desirable to add only the minimum water required to wet the surface of the weight material. The addition of approximately 1 gal of water per 100 lbm of API barite is usually sufficient to prevent an unacceptable increase in fluid viscosity. Including a required water volume per unit mass of barite, V_{wB}, in the expression for total volume yields

$$V_2 = V_1 + V_B + V_w = V_1 + \frac{m_B}{\rho_B} + m_B V_{wB}.$$

Likewise, including the mass of water in the mass balance expression gives

$$\rho_2 V_2 = \rho_1 V_1 + m_B + \rho_w m_B V_{wB}.$$

Solving these simultaneous equations for unknowns V_1 and m_B yields

$$V_1 = V_2 \left[\frac{\rho_B\left(\frac{1+\rho_w V_{wB}}{1+\rho_B V_{wB}}\right) - \rho_2}{\rho_B\left(\frac{1+\rho_w V_{wB}}{1+\rho_B V_{wB}}\right) - \rho_1} \right] \text{, ... (2.19)}$$

and

$$m_B = \frac{\rho_B}{1+\rho_B V_{wB}}(V_2 - V_1) \text{, ... (2.20)}$$

Example 2.17. It is desired to increase the density

of 800 bbl of 12-lbm/gal mud to 14 lbm/gal. One gallon of water will be added with each 100-lbm sack of API barite to prevent excessive thickening of the mud. A final mud volume of 800 bbl is desired. Compute the volume of old mud that should be discarded and the mass of API barite to be added.

Solution. The water requirement for barite, V_{wB}, is 0.01 gal/lbm. The initial volume of 12-lbm/gal mud needed can be computed using Eq. 2.19. For a final volume of 800 bbl, V_1 is given by

$$V_1 = 800 \left\{ \frac{35.0\left[\frac{1+8.33(0.01)}{1+35.0(0.01)}\right] - 14.0}{35.0\left[\frac{1+8.33(0.01)}{1+35.0(0.01)}\right] - 12.0} \right\}$$

$= 700.53$ bbl.

Thus, 99.47 bbl of mud should be discarded before adding any API barite. Using Eq. 2.20, the mass of API barite needed is given by

$$m_B = \frac{35.0}{1+35.0(0.01)}(800 - 700.53)(42)$$

$= 108{,}312$ lbm.

The volume of water to be added with the barite is

$0.01\, m_B = 1{,}083$ gal or 25.79 bbl.

Considerable savings can be achieved in mud treatment costs for a weighted mud system if (1) the total mud volume is held as low as possible and (2)

$$V_w = \frac{(\rho_B-\rho_2)V_2 - (\rho_B-\rho_1)V_1}{(\rho_B-\rho_w)} \text{, ... (2.22)}$$

and

$$m_B = (V_2 - V_1 - V_w)\,\rho_B \text{ . . . . (2.23)}$$

Example 2.18. After cementing casing in the well, it is desirable to increase the density of the 9.5-lbm/gal mud to 14 lbm/gal before resuming drilling operations. It also is desired to reduce the volume fraction of low-specific-gravity solids from 0.05 to 0.03 by dilution with water. The present mud volume is 1,000 bbl, but a final mud volume of 800 bbl is considered adequate. Compute the amount of original mud that should be discarded and the amount of water and API barite that should be added.

Solution. The initial volume of 9.5-lbm/gal mud needed can be computed using Eq. 2.21. For a final volume of 800 bbl, V_1 is given by

$$V_1 = 800\frac{0.03}{0.05} = 480 \text{ bbl.}$$

Thus, 520 bbl of the initial 1,000 bbl should be discarded before adding any water or barium sulfate. Using Eq. 2.22, the volume of water needed is

$$V_w = \frac{(35.0-14.0)\,800 - (35.0-9.5)\,480}{(35.0-8.33)}$$

$= 171$ bbl.

treatment costs for a weighted mud system if (1) the total mud volume is held as low as possible and (2) the initial conversion from an unweighted system to a weighted system is done with the low-specific-gravity solids at the minimum possible concentration. The reduction in solids concentration by dilution is much less expensive before the conversion is made because the mud discarded during dilution does not contain any API barite. When mud dilution just precedes weighting operations, the proper volume of old mud, V_1, dilution water, V_w, and mass of weight material, m_B, that should be combined to obtain a desired volume of new mud, V_2, can be determined using the ideal mixing calculations. For ideal mixing, the total new volume is given by

$$V_2 = V_1 + V_w + \frac{m_B}{\rho_B}$$

Similarly, a mass balance on the mixing procedure requires

$$\rho_2 V_2 = \rho_1 V_1 + \rho_w V_w + m_B.$$

A third equation can be obtained by performing a volume balance on the low-specific-gravity solids. The volume of low-specific-gravity solids can be expressed in terms of the present volume fraction, f_{c1} and the desired new volume fraction, f_{c2}:

$$f_{c2} V_2 = f_{c1} V_1$$

Solving these three equations simultaneously yields

$$V_1 = V_2 \frac{f_{c2}}{f_{c1}} \text{, ... (2.21)}$$

$$(35.0-8.33)$$

$= 171$ bbl.

Using Eq. 2.23, the mass of API barite needed is given by

$$m_B = (800 - 480 - 171)(42)(35.0) = 219{,}000 \text{ lbm.}$$

2.3.13 Solids Control for Weighted Muds. The addition of solids for increasing density lowers the amount of inert formation solids that can be tolerated. The ideal composition of a weighted clay/water mud is (1) water, (2) active clay, and (3) inert weight material. Thus, every possible effort should be made to remove the undesirable low-gravity solids by screening before their particle size is reduced within the size range of the API barite particles. Hydrocyclones cannot be used alone on weighted systems because their cut point falls in the particle-size range of the API barite as shown in Fig. 2.26. However, they sometimes are used in conjunction with a shaker screen to increase the flow rate capacity of the solids removal equipment. A series arrangement of a hydrocyclone and a shaker screen is called a *mud cleaner*. It is suited best for muds of moderate density (below 15 lbm/gal). The fine solids that pass through the screen can be handled by dilution and deflocculation.

At higher densities, the mud cleaners are much less efficient. Much of the coarse solids in the mud remain in the liquid stream exiting the top of the unit and, thus, bypass the screen. Also, dilution requires

6) Mud System

Mud tanks

a) Duplex, double acting

b) Triplex, Single acting

Centrifugal pumps, auxiliary, for

Mud mixing and treating equipment

Solids separation equipment

Mud-Gas separators

Bulk storage, bentonite, barytes & Cement

Mud guns, buttom jets

Lightning mixers (paddle-type)0

Mud System & Horse Power

Mud Pump

Two types of mud pump are normally used in mud system as follows :

1)Duplex double acting slush pump

2)Triplex single acting pump.

Pump are commonly rate hydraulic horsepower as defined by

$$HP. \quad \frac{qp}{1714} \; for\, e = 100\,\%$$

Mud Pump

1)Duplex Double Acting Slush Pump

2)Triplex Single Acting Pump

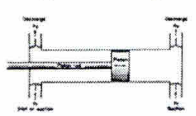
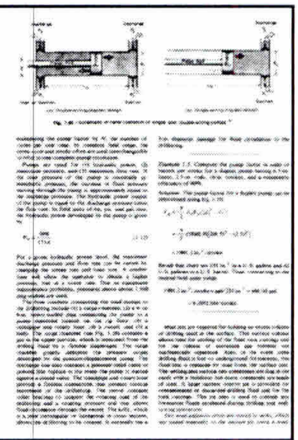


Fig.3.24 Schematic valve operation for double acting slush pump

$$Q = \left[2\left(\frac{\pi D^2}{4}\right)S + 2\left(\frac{\pi D^2}{4} - \frac{\pi d^2}{4}\right)S\right]N \times \frac{1}{231} \times e$$

$$\boldsymbol{Q = 0.00679SN(2D^2-d^2)e \text{ gal/min}}$$

Horse Power = (Q x P)/(1714 x E)



Example 4.5

A mud engineer finds from pilot tests that 2.0 gm of CMC is required to obtain the desired water loss reduction for a one liter mud sample.

(a) How much CMC should be added to the actual 1000 barrel system?

(b) What will be the cycle time for a duplex mud pump system ?,Given ; pump liners = 7.5 in. diam., stroke length = 16 in., piston rod diam. = 2.25 in., and N = 40 spm.

Solution :

(a) CMC needed = (350/1000) x 2.0 x 1000 = 700 lb

(b) Recalling the Eq.(3.32) For a duplex double acting system mud pumps.

$$q = 0.00679\, S\, N\, (2\, D^2 - d^2)e = V_m /\ t_c$$

Where q = pump discharge rate, gal/min

S = stroke length, in. N = complete strokes per minute

D = piston (liner) diameter, in.

d = piston rod diameter, in.

e = pump volume efficiency, commonly used as 90%

V_m = system volume, bbl

t_c = cycle time, min

$$tc = \frac{6190V_m}{SN(2D^2 - d^2)e}$$

$$= \frac{(6190)(1000)}{(16)(40)[((2)(7.5)^2 - (2.25)^2)](0.90)} = 100\text{min}$$

If 20 sacks of material were needed, they could be added at the rate of 20/100 = 1/5 (one sack/five min.)

4.13 Oil based muds

1.Advantages

Oil muds have shown special economic advantages when used

1.To drill troublesome shales with minimum mud weight.

2.To drill deep holes

3.To drill hot holes

4.To drill and core pay zones

5.To drill evaporite containing formations.

6.As a directional drilling fluid.

7.As a slim hole drilling fluid.

8.Drilling through formations containing hydrogen sulfide (H_2S) and carbon dioxide (CO_2)

9.As a perforating and completion fluid.

10.As a spotting fluid to free stuck pipe

11.As a packer fluid.

12.As a workover fluid.

13.For corrosion control.

14.As a casing.

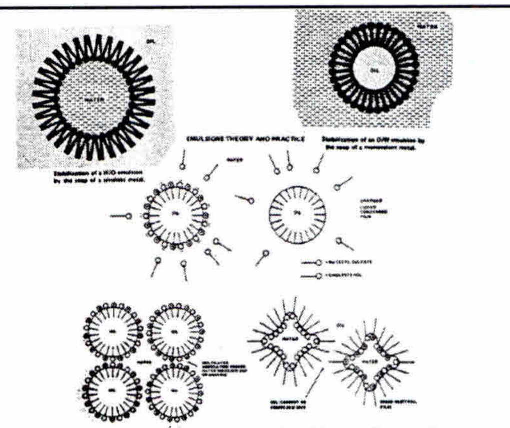
Emulsion: Theory and Practice

There are two types of emulsions, which are the mixer between oil and water by using emulsion technology, namely **oil- in-water** and water-in-oil, are generally applied in oil-based muds.

Preparation

The example for initial preparation of the oil based mud should be performed in the following manner :

1. 1. Add all of the oil.
2. 2. INVERMUL (Emulsifier for stable water-in-oil)
3. 3. Lime ($Ca(OH)2$) (For alkalinity control).
4. DURATONE HT(For stabilizer and fluid loss control),
5. Water.
6. GENTONE II (Bentonite for gel and viscosity)
7. EZ MUL (stabilizer)
8. BAOID (Barite)
9. Calcium Chloride (for stable emulsion and increasing chemical activity)



•Fig 4.17 Emulsions Theory and Practice

Air-drilling system consists of equipment as follows:

1.Compressors.
2.Boosters.
3.Mist pumps
4.Chemical pumps.
5.Rotation kelly packer or annular BOP).
6.Pipes and Blow line.
7.Meters and measurement apparatus
8.Location layout and aerated mud system are shown in the following figures.

figures.

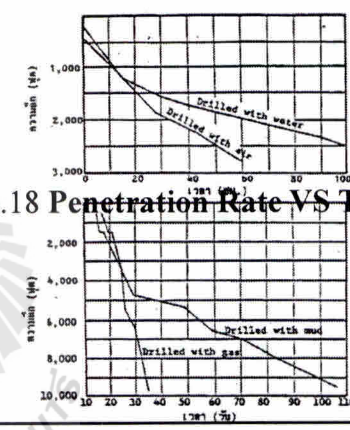


Fig. 4.18 **Penetration Rate VS Time Plot**

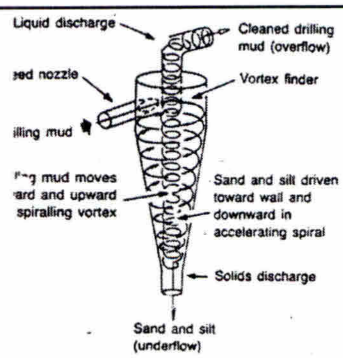
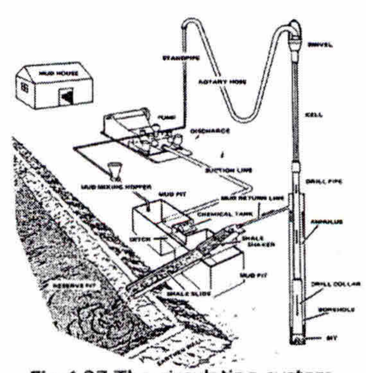


Figure 3-58

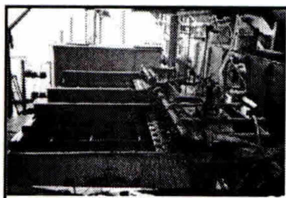
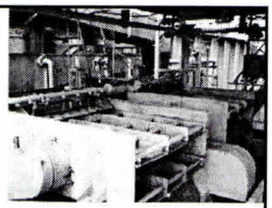
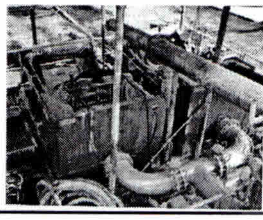
cyclone (Courtesy of SWECO)

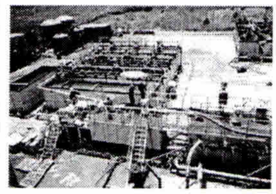
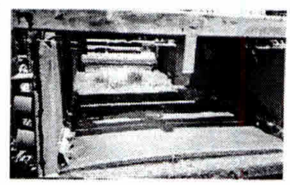
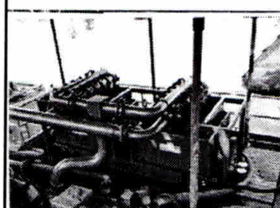
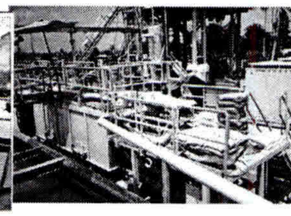
$\Delta p_t = \Delta p_s + \Delta p_p + \Delta p_c + \Delta p_b + \Delta p_{ac} + \Delta p_{ap}$



$HP_t = \frac{q\Delta pt}{1714}$

Fig 4.27 The circulating system

HW NO 6-1; CHAPTER 4: 6, 8,10, 13, AND 18

DRILLING ENGHINEERING TEXT

cartesian coordinate paper. Repeat this using log-log paper.

1.14 A drillstring is composed of 9,000 ft of 5-in. 19.5-lbm/ft drillpipe and 1,000 ft of drill collars having a 3.0-in. ID. Compute these items:

a. Capacity of the drillpipe in barrels. *Answer: 159.8 bbl.*

b. Capacity of the drill collars in barrels. *Answer: 8.7 bbl.*

c. Number of pump cycles required to pump surface mud to the bit. The pump is a duplex double-acting pump with 6-in. liners, 2.5-in. rods, 16-in. strokes, and operates at a volumetric efficiency of 85%. *Answer: 1,164 cycles.*

d. Displacement of the drillpipe in bbl/ft. *Answer: 0.0065 bbl/ft* (neglects tool joints).

e. Displacement of the drill collars in bbl/ft. The OD of the collars is 8.0 in. *Answer: 0.0534 bbl/ft.*

f. Loss in fluid level in the well if 10 stands (thribbles) of drillpipe are pulled without filling the hole. The ID of the casing in the hole is 10.05 in. *Answer: 64 ft.*

g. Loss in fluid level in the well if one stand of drill collars is pulled without filling the hole. *Answer: 108 ft.*

h. Change in fluid level in the pit if the pit is 8 ft wide and 20 ft long, assuming that the hole is filled after pulling 10 stands of drillpipe. *Answer: 2.5 in.*

i. Change in fluid level in a 3- × 3-ft trip tank assuming that the hole is filled from the trip tank after pulling 10 stands of drillpipe. *Answer: 3.6 ft.*

1.15 The mud logger places a sample of calcium carbide in the drillstring when a connection is made. The calcium carbide reacts with the mud to form acetylene gas. The acetylene is detected by a gas detector at the shale shaker after pumping 4,300 strokes. The drillstring is composed of 9,500 ft of 5-in., 19.5-lbm/ft drillpipe and 500 ft of drill collars having an ID of 2.875 in. The pump is a double-

below for a thick shale section encountered at 12,000 ft. Determine which bit gives the lowest drilling cost if the hourly operating cost of the rig is $1,000/hr and the trip time is 10 hours. The connection time is included in the rotating time shown below.

Bit	Bit Cost ($)	Interval Drilled (ft)	Rotating Time (hours)
A	700	106	9
B	4,000	415	62
C	8,000	912	153

Answer: Bit B ($183.13/ft).

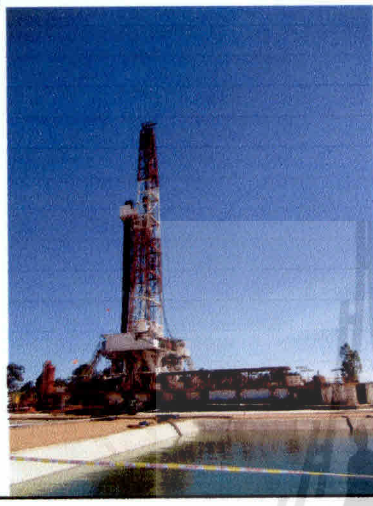
1.19 The penetration rates using gas, foam, and mud in an area are 10 ft/hr, 5 ft/hr, and 1 ft/hr, respectively. If gas is used, each water zone encountered must be sealed off. The cost of the plugging treatment is $2,000, and 25 hours of rig time are required to complete the sealing operation. The normal operating cost for air drilling is $200/hr. The use of foaming agents requires an additional $60/hr. The normal operating cost when using mud is $160/hr. Regardless of the drilling fluid used, the average bit cost is $1,000. The average bit life is 25 hours and the average trip time is 6 hours. Determine which drilling fluid yields the lowest drilling cost if one water zone is encountered per 1,000 ft drilled and if five water zones are encountered per 1,000 ft drilled. *Answer: gas is best for both assumptions ($35.80/ft and $63.80/ft).*

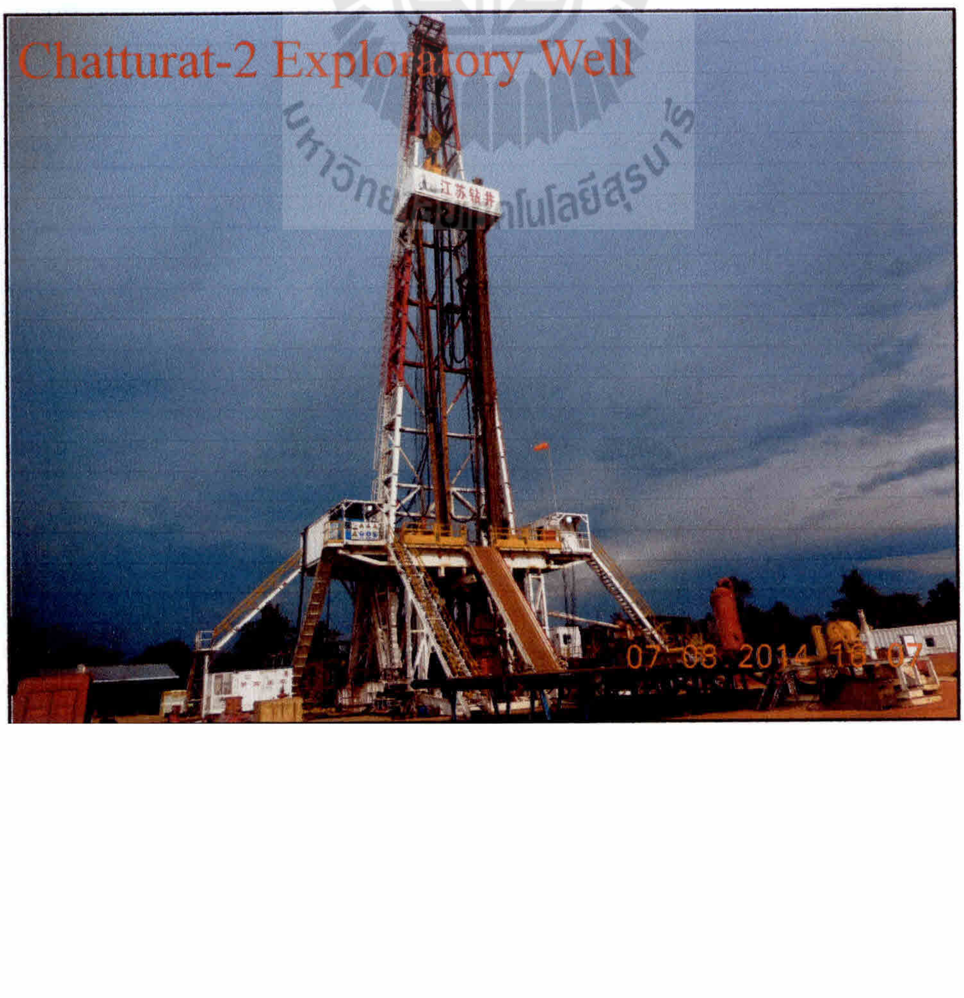
1.20 Pipe being recovered from an interval of borehole has a value of $30/ft. On the average, 20 hours of rig time must be expended to recover 200 ft of pipe. The cost per foot to sidetrack the well and redrill the junked interval of borehole would be about $150/ft. Do the fishing operations appear profitable if the average operating cost is $500/hr and the cost of abandoning the junked hole would be approximately $5/ft? *Answer: fishing is the best alternative ($50/ft).*

HW NO 6-2; SPE - CHAPTER 2: 2.23, 2.27,

DUE DATE: Friday 1 29 August 2014

Advanced Drilling Engineering
1/2557
Chapter7.FACTORS EFFECTING RATE OF PENETRATION



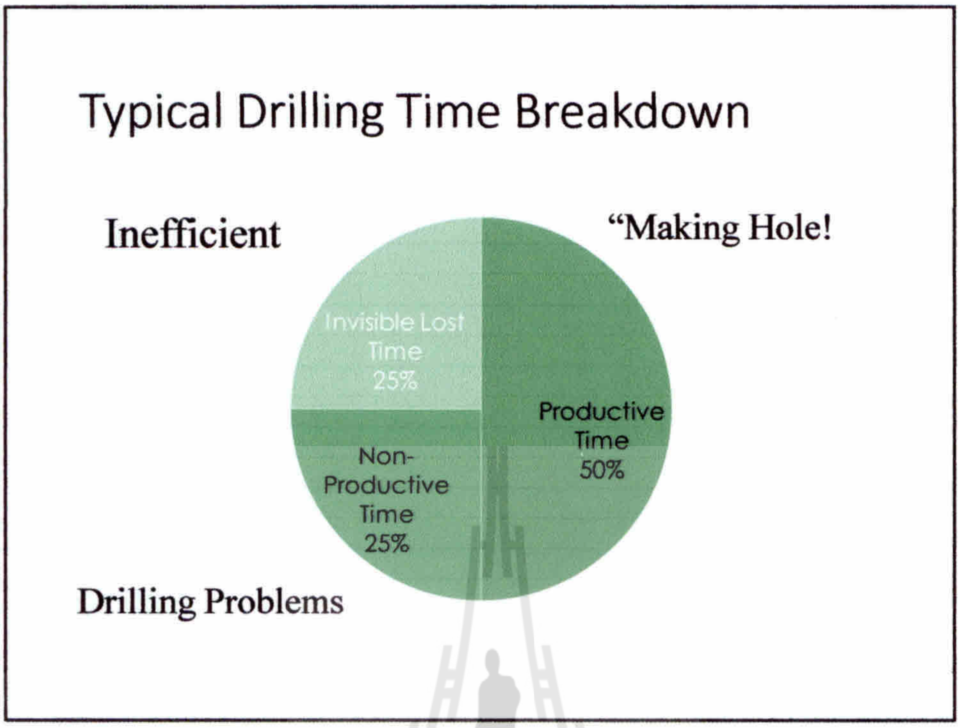


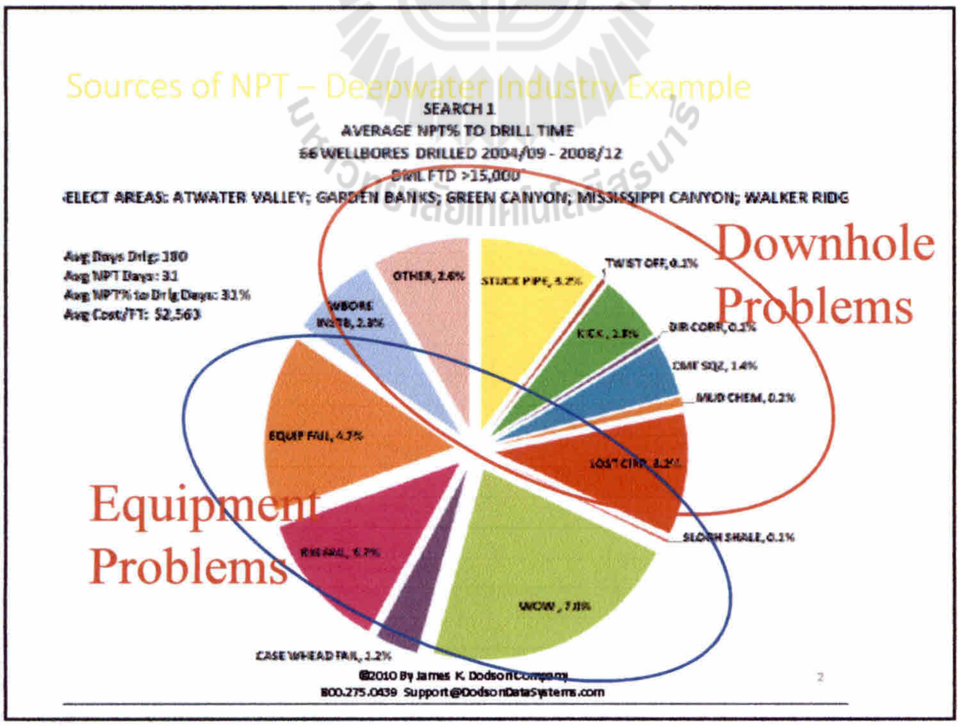
534620 ADVANCED DRILLING ENGINEERING
4(4-0-8) @ 1/2557, 2014

Course Contents

1. How to Get Drilling Permission (2hrs.) Asso. Prof. KK
2. Introduction to Rotary Drilling (4 hrs.) Asso. Prof. KK
3. Well Planning and Proposal (2 hrs.) Asso. Prof. KK
4. Cost Estimation and Control (4 hrs.) Asso. Prof. KK
5. Hole Problems.(4 hrs.) Asso. Prof. KK
6. Drilling Fluids (4 hrs.) Asso. Prof. KK
7. Factors Affecting Rate of Penetration (4 hrs.) Asso. Prof. KK
8. Pressure Control (4 hrs.) Dr. Akkaphun
9. Pore Pressure and Pressure Gradient (4 hrs.) Dr. Akkaphun
10. Blowout Control Procedure and Equipment (4 hrs.) Dr. Akkaphun
11. Directional and Slimhole Drilling (4 hrs.) Dr. Akkaphun
12. Rotary Bit Design (2 hrs.) Dr. Akkaphun
13. New Technology Drilling (6 hrs.) Dr. Akkaphun

Factors Effecting Rate of Penetration


Typical Drilling Time Breakdown
Inefficient
"Making Hole!
Invisible Lost Time 25%
Productive Time 50%
Non-Productive Time 25%
Drilling Problems


Sources of NPT – Deepwater Industry Example
SEARCH 1
AVERAGE NPT% TO DRILL TIME
66 WELLBORES DRILLED 2004/09 - 2008/12
ELECT AREAS: ATWATER VALLEY; GARDEN BANKS; GREEN CANYON; MISSISSIPPI CANYON; WALKER RIDG
Avg Days Drlg: 180
Avg NPT Days: 31
Avg NPT% to Drlg Days: 31%
Avg Cost/FT: $2,563
Downhole Problems
Equipment Problems
OTHER, 2.6%
TWIST OFF, 0.1%
DIR CORR, 0.1%
CMT SQZ, 1.4%
MUD CHEM, 0.2%
WBORE INSTB, 2.3%
EQUIP FAIL, 4.7%
CASE WHEAD FAIL, 1.2%
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2

✖What are the factor affecting rate of penetration?

✖ □□Rock type, porosity, and strength
□□Bottomhole and bit-face cleaning and differential pressure at bit-rock interface
□□Bit diameter, type, condition, and jet configuration
□□Weight on bit and rotary speed

Chapter 7

Factors Affecting Rate of Penetration

1. **Personnel efficiency**
2. **Rig efficiency**
3. **Formation characteristics**
4. **Mechanical factors**
5. **Mud properties**
6. **Hydraulic factors-essentially bottom hole cleaning**

1.2 Rate of Penetration V.S. Factors

		ROCK & FLUID PROPERTIES
ROP. VARIES	INVERSELY	-COMPRESSIVE STRENGTH -HARDNESS OR ABRASIVENESS -CONEFINEING PRESSURE -PLASSTIC -STICKINESS OR BALLING -MUD DENSITY, VISCOSITY -SOLID CONTENT -FILER CAKE
ROP varies	DIRECTLY	Δ POROSITY Δ PERMEABILITY Δ SURFACE TENSION Δ MECHANICALWOB, RPM, BIT TYPE Δ HYDRAULIC FACTOR

6.3 Formation Characteristics

1. Compressive Strength
   - bit+wt. จะต้องชนะ Com.str. ของหิน

   Scraping or Crushing Acting

2. Abra-siveness
   - bit ที่ต้องมี gauge protection พิเศษ

3. Overburn Pressure
   - P. มากหินแข็ง ยิ่งลึก ยิ่งแข็ง Deeper → higher Pressure
   - High Pressure-hard rock-difficult to drill

4. Porosity & Permeability

   φ, K สูง เจาะเร็ว high Porosity & Permeability

   \- Easy to drill

5. Pore Pressure

   สัมพันธ์กับ Mud wt. ซึ่งทำให้เกิด "Overbalance"

   Overbalance มาก หินแตกช้า "Chip Hold Down"

   High Pore Pressure →more difficult to drill

6. Stickiness of "balling tendency "

   Bit balling ถ้า Bottle hole cleaning

   If not sufficient cleaning → decrease ROP

   Add center nozzle at bit →improve ROP

7. Elasticity – Brittle or Plastic

   ถ้าสูงหินจะยุบตัวแทนที่จะแตกต้องให้ long teeth

   The high →resists to break →used long teeth bit.

6.4 Mechanical Factors

6.4.1 Weight On Bit

$$R_p = a + bW$$

6.4.2 Rotary Speed

$$R_p = f(N)^n \qquad n < 1$$

(6.6) $R_p = f\ WN$ for soft Rock

$= f\ W^{1.2}N^{0.5}$ for hard Rock

(6.7) $wN = K$

where

Rp	=	Rate of Penetration , ft/hr.
W	=	Weight on bit
w	=	$\frac{W}{d} = \frac{\text{weight on bit}}{\text{bit dia meter}}$
a, b	=	Intercept and slope
N	=	Rotary speed, rpm
F	=	Some function
K	≅	5×10^5 lb-rpm/in

Factors Affecting Penetration Rate

- Bit type and formation hardness
- Bit weight and rotary speed
- Bottomhole cleaning or hydraulics
- Mud properties
- Auxiliary practices

Factors that affect Penetration Rate

Variables:

- Type of Drill bit
- Bit weight
- Rotary speed
- Bottom-hole cleaning
- Mud properties

Fixed Factors:

- Rock hardness
- Formation pore pressure

28

Bit Selection is based on

- Past bit records
- Geologic predictions of lithology
- Drilling costs in $/bit...
- **Drilling cost in $/ft**

29

Bit Weight and Rotary Speed

- Increasing bit weight and rotary speed boosts drilling rate
- These increases accelerate bit wear
- Field tests show that drilling rate increases more or less in direct proportion to bit weight

30

Factors Affecting Penetration Rate

- Bit type will affect penetration rate
  - Bit selection will be covered later in the book
- Formation hardness
  - Can we do anything about formation hardness?
  - NO!

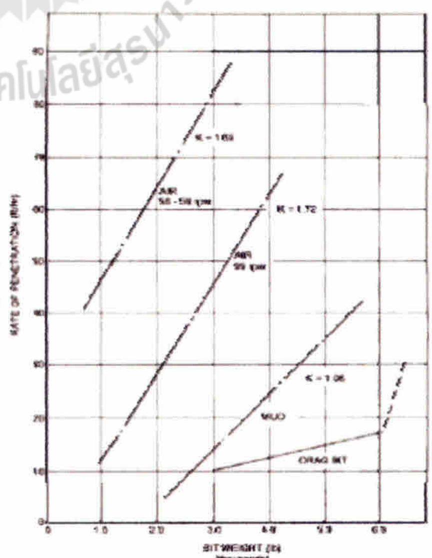
Factors Affecting Penetration Rate

- Bit weight will affect penetration rate
- Generally, if the bit weight is increased, penetration rate will increase if hydraulics are adequate
- Equation 5 gives the relationship of bit weight versus drilling rate

$$D_R = KW^d$$

Factors Affecting Penetration Rate

- The exponent "d" is usually close to 1.0 at the higher bit weights, which means that drilling rate is proportional to bit weight
- Straight line on graph
- It may be exponential at the lower bit weights



FACTORS AFFECTING PENETRATION RATE

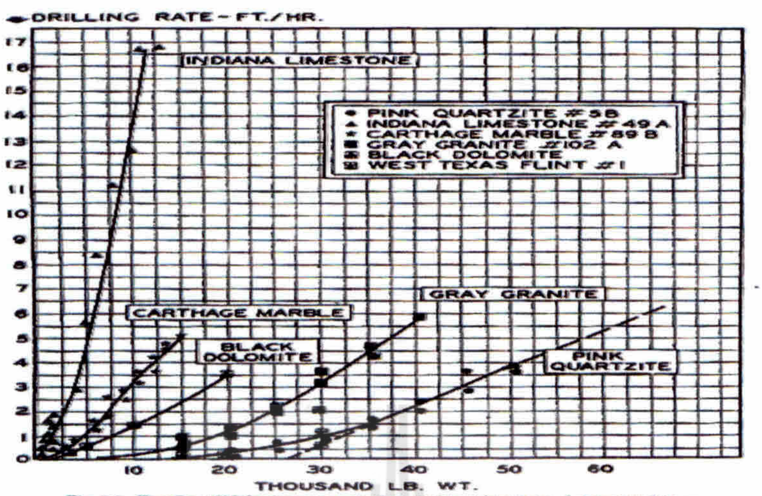


Fig. 8.8. The effect of bit loading on penetration rate for various rocks. Laboratory data — atmospheric pressure. Courtesy Hughes Tool Company.[19]

Again, the true relationship may be obscured by the hole cleaning variable. A satisfactory nozzle velocity at 100 rpm may not be adequate at 200 rpm, since at the latter speed a cutting has only half as much time to clear bottom prior to the next tooth impact.

The Battelle Institute study[8-1] set forth a formula for a rate of advance predicting linearity between R_p and N. It was assumed that each tooth impact removes essentially the same amount of rock. Fundamentally, this would seem logical; however, available data do not confirm this analysis for rotary (roller Turbodrill data to be cited later confirms rotating speeds up to 750 rpm.[17]

Combined Effect of W and N

An empirical combination of Eq. 8.1 dicates:

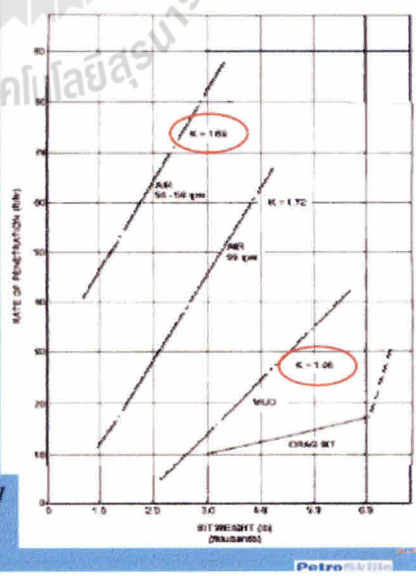
(8.3) $$R_p = e + fWN^{1/2}$$

where e, f = constants for a given set of

Factors Affecting Penetration Rate

- The slope K is not a constant
- Function of
  - Hole size
  - Drilling fluid
  - Formation
  - Bit type

$$D_R = KW^d$$

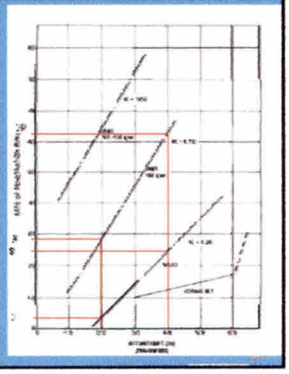


OGCI

PetroSkills

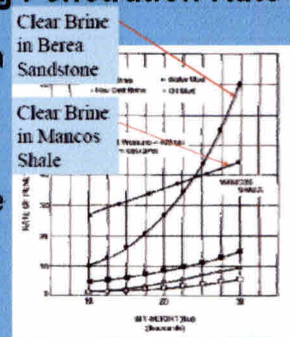
Factors Affecting Penetration Rate

- Double bit weight in mud from 2000 to 4000 lbs/in
- Double bit weight in air from 2000 to 4000 lbs/in

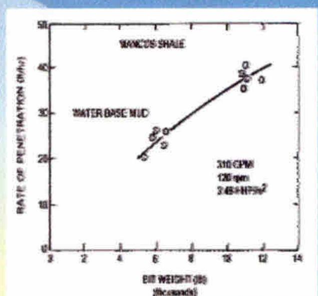


Factors Affecting Penetration Rate

- Laboratory data showing how fluid type will affect penetration rate

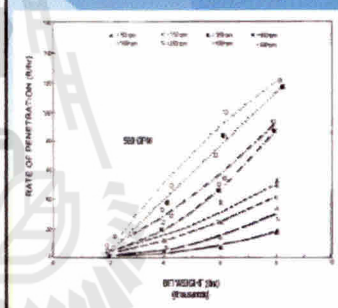


Factors Affecting Penetration Rate



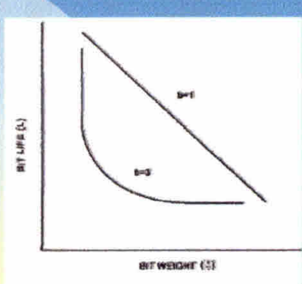
- PDC bit performance
  - Slope is less than one in the lab (one in the field)
  - Drag bits drill differently than roller cone bits

Factors Affecting Penetration Rate



- Performance of PDC bit at various rpm
- Slope increases as the rpm increases

Factors Affecting Penetration Rate



- Bit life is a function of the bit weight

$$L \propto \frac{1}{W^n N}$$

- With modern roller cone bits, bit life is difficult to predict and does not follow the equation

Factors Affecting Penetration Rate

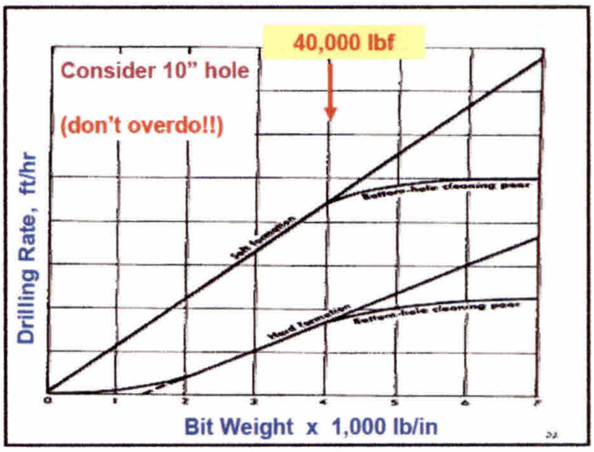
- Bit life
  - Bit life is a function of the seal
  - Seal life is a function of the conditions in the wellbore
  - Journal or friction bearings are even harder to predict
  - Once the seal fails in a journal bearing, the bearing does not last long

Factors Affecting Penetration Rate

- Rotary speed
  - Generally, as rpm is increased, penetration rate will increase

$$D_R \propto N^a$$

  - It is a function of the exponent "a" which varies from 0.5 to 1.0 in field data



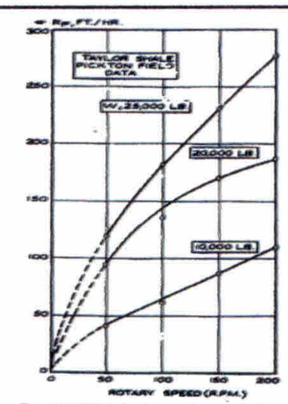
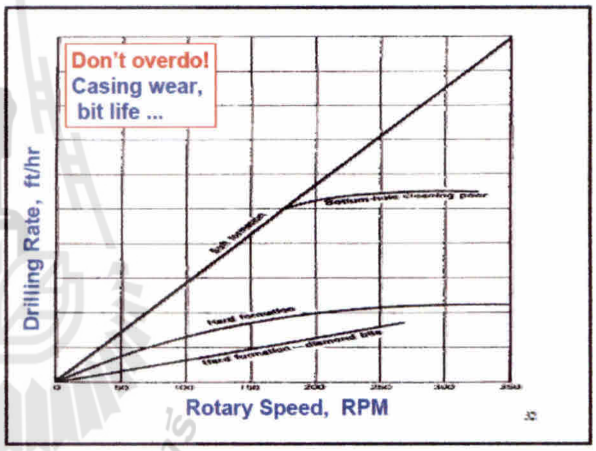
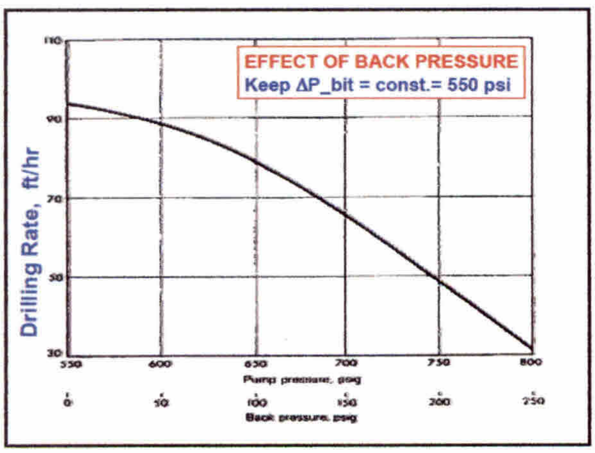


Fig. 8.10. Effect of rotary speed on penetration rate at various bit weights. Replotted from data of Bielstein and Cannon,[13] courtesy API.





$R_p = a + bW$

$R_p = f(N)^n \quad n < 1$

$R_p = \alpha + f W N^{1/2}$

$= f W N^{1/2}$

$= f \frac{W}{d} N^n = f w N^{1/2}$

$= f' W^m N^{1/2}$

$R_p = f W N$ for soft rock

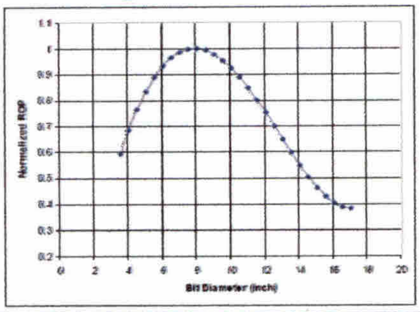
$= f W^{1.4} N^{0.5}$ for hard rock

Critical Rotary Speed $N_c = \frac{258,000}{L}$

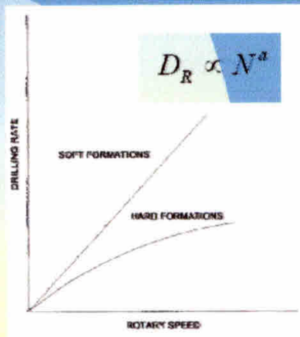
Harmonic Vibration $4N_c, 9N_c$ etc.

Factors Affecting Penetration Rate

Effecting of Bit Diameters

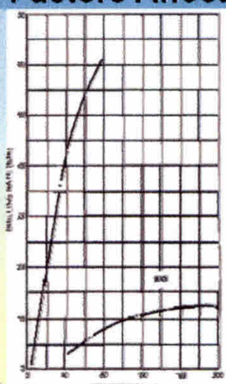


Factors Affecting Penetration Rate



- In soft formations the exponent "a" is closer to one
- In harder formations, the exponent "a" decreases to as little as 0.5

Factors Affecting Penetration Rate



- Field data in the Atoka shale show the exponent "a" is less than one
- Also depends upon the type of fluid used

Factors Affecting Penetration Rate

- In harder formations, it is usually better to increase bit weight rather than rotary speed
- In soft formations, rotary speed can be an alternative to bit weight
- PDC bits do well with increased rotary speed

COST PER FOOT

- Example Problem 2-1 shows how to calculate the cost per foot
  - Bit # 4
  - Rig cost = $2,000 per hour
  - Bit cost = $4,000
  - Rotating time = 100 hrs
  - Footage = 3000 feet (914 m)
  - Depth = 10,000 feet (3048 m)
  - Trip time = 2 hr per 1000 feet (305 m)
  - Rotary speed = 100 rpm

COST PER FOOT

- Calculate the cost per foot

$$C_T = \frac{C_B + C_r(t+T)}{F}$$

$$C_T = \frac{\$4000 + \$2000\left[100 + \left(\frac{2hr}{1000} x10000\right)\right]}{3000ft}$$

C_T = $81.33 /ft (266.83 /m)

COST PER FOOT

- Example Problem 2-2 shows how to calculate the cost per foot
  - Bit # 5
  - Rig cost = $2,000 per hour
  - Bit cost = $4,000
  - Rotating time = 63 hrs
  - Footage = 1300 feet (396 m)
  - Depth = 11,300 feet (3444 m)
  - Trip time = 2 hr per 1000 feet (305 m)

COST PER FOOT

- Calculate the cost per foot

$$C_T = \frac{C_B + C_r(t+T)}{F}$$

$$C_T = \frac{4000 + 2000\left[63 + \left(\frac{2}{1000} x 11300\right)\right]}{1300}$$

C_T = $134.77 /ft (442.16 /m)

COST PER FOOT

- Calculate the cumulative cost per foot

$$C_T = \frac{C_B + C_r(t+T)}{F}$$

$$C_{TC} = \frac{(4000 + 4000) + 2000\left[(63 + 100) + \left[\left(\frac{2}{1000}\right)(10000 + 11300)\right]\right]}{3000 + 1300}$$

C_{TC} = $97.49 /ft (319.85 /m)

CLASS PROBLEM

- Calculate cost per meter for each
- Insert bits
  - Number or bits = 2
  - Cost per bit = $7,000
  - Cost of rig = $625/hr
  - Rotating hours = 180
  - Total time for two trips = 21 hrs
  - Footage = 1375m
  - ROP = 7.64 m/hr
- PDC bit and motor
  - Number or bits = 1
  - Cost per bit = $25,000
  - Cost of rig = $625/hr
  - Cost of motor = $300/hr included in trip time
  - Rotating hours = 130
  - Trip time = 12 hrs
  - Footage =1375m
  - ROP = 10.58 m/hr

Class Problem

- Insert Bits
  - Cost of two bits = 7000 x 2 = 14,000
  - Cost per meter calculation

$$C_T = \frac{C_B + C_r(t+T)}{F}$$

$$C_T = \frac{14000 + 625(180 + 21)}{1375} = \$101.55 /m$$

Class Problem

- PDC bit and motor
  - Assume the motor cost is included in the trip time
  - Cost per meter calculation

$$C_T = \frac{C_B + C_r(t+T)}{F}$$

$$C_T = \frac{25000 + (625 + 300)(130 + 12)}{1375} = \$113.71/m$$

Class Problem

- PDC bit and motor
  - Assume the motor cost is not included in the trip time
  - Cost per meter calculation

$$C_T = \frac{C_B + C_r(t+T)}{F}$$

$$C_T = \frac{25000 + (625+300)(130) + (625)(12)}{1375} = \$111.09\ /m$$

Class Problem

- Insert bits assuming the rig rate is 48,000 per day or 2000 per hour
  - Cost of two bits = 7000 x 2 = 14,000
  - Cost per meter calculation

$$C_T = \frac{C_B + C_r(t+T)}{F}$$

$$C_T = \frac{14000 + 2000(180+21)}{1375} = \$302.55\ /m$$

Class Problem

- PDC bit and motor assuming the rig rate is 48,000 per day or 2000 per hour
  - Assume the motor cost is included in the trip time
  - Cost per meter calculation

$$C_T = \frac{C_B + C_r(t+T)}{F}$$

$$C_T = \frac{25000 + (2000+300)(130+12)}{1375} = \$255.71\ /m$$

Factors Affecting Penetration Rate

- Example 2-3
  - Determine the cost per foot for bit #4 in Example 2-1 if the rpm is reduced to 50 rpm from 100 rpm and the bit life is doubled.
  - Assuming the exponent "*a*" is 0.5

$$D_{R50} = \left(\frac{50}{100}\right)^{0.5} \times 30fph = 21.2\ \text{fph (6.5 mph)}$$

Factors Affecting Penetration Rate

- Example 2-3
  - The footage drilled at 100 rpm was 3000 feet (914 m)
  - The footage drilled at 50 rpm would be:

$$F = 21.2\ fph \times 200\ \text{hours} = 4243\ \text{feet (1293 m)}$$

Factors Affecting Penetration Rate

- Example 2-3
  - The cost per foot would be:

$$C_T = \frac{4000 + 2000\left[200 + \left(\frac{2}{1000} \times 10000\right)\right]}{4243} = \$104.65\ /ft\ (343.34\ /m)$$

  - As compared to \$81.33/ft (266.83/m)
  - Even though the bit lasts longer, the cost per foot increases

Factors Affecting Penetration Rate

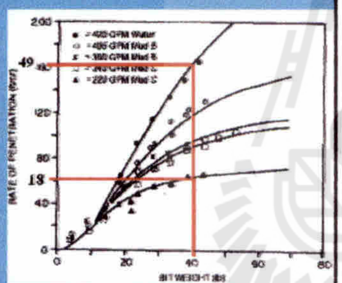
- Generally, it is better to drill faster as long as the rig cost does not increase too much
- The more expensive the hourly operating cost, C_r, the more money you can spend to make it drill faster

Factors Affecting Penetration Rate

- Bottom hole cleaning or hydraulics
  - Bottom hole cleaning is defined as cleaning the cuttings from the bottom of the hole (below the bit)
  - It is not concerned with hole cleaning in the annulus
- Penetration rate is a function of bit weight and rotary speed if bottom hole cleaning is adequate

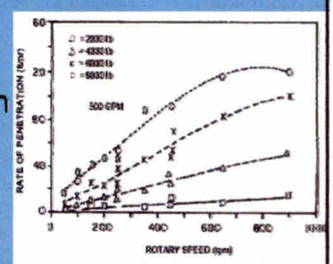
Factors Affecting Penetration Rate

- Inadequate bottom hole cleaning is termed "hydraulic flounder" or "hydraulic founder"



Factors Affecting Penetration Rate

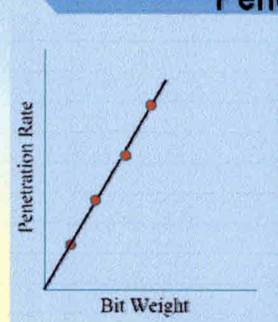
- "Hydraulic flounder" can also occur with rotary speed



Factors Affecting Penetration Rate

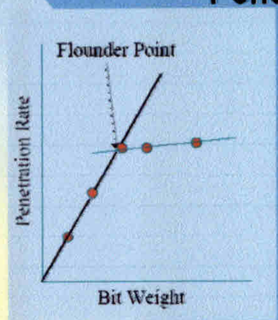
- Bottom hole cleaning is a function of the hydraulics and is often measured in hydraulic horsepower per square inch or HHP/in^2
- Softer formations require more hydraulics than harder formations

Factors Affecting Penetration Rate



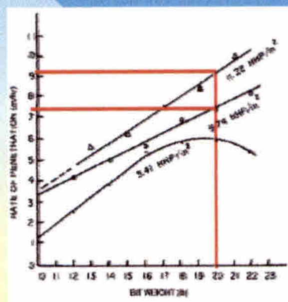
- Drill off test can be used to determine if hydraulics are adequate

Factors Affecting Penetration Rate



- Drill off test can be used to determine if hydraulics are adequate

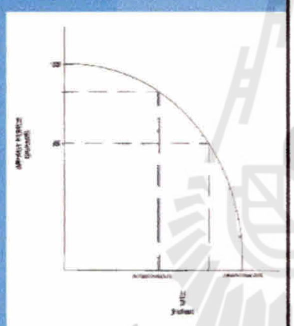
Factors Affecting Penetration Rate



- In softer formations, hydraulics may even help the bit drill faster
- Note the increase in ROP with increased HHP

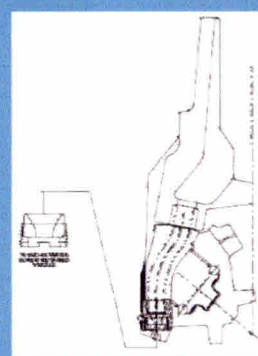
Factors Affecting Penetration Rate

- Extended nozzle bits can be used to increase penetration rate by using hydraulics to erode the formation

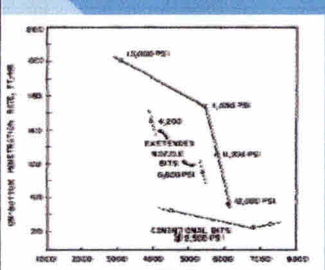


Factors Affecting Penetration Rate

- Extended nozzle bits can be used to increase penetration rate by using hydraulics to erode the formation in softer formations



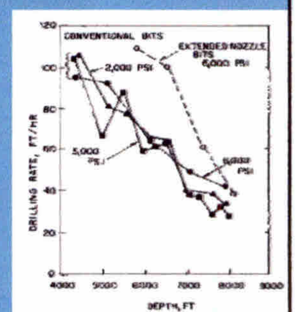
Factors Affecting Penetration Rate



- As long as the formation can be eroded, extended nozzle bits may drill faster
- By 6000 feet (1800 m), the higher pressures no longer drilled significantly faster

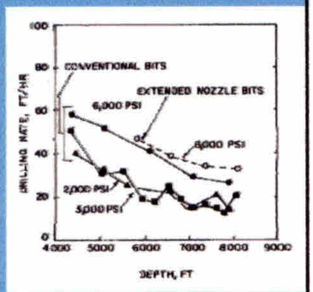
Factors Affecting Penetration Rate

- Conventional bits at 6000 psi (41,400 kPa) did not drill any faster than 2000 psi (13,800 kPa) in sandstone
- Below 8000 ft (2400 m) , there is no improvement with extended nozzle bits in this well



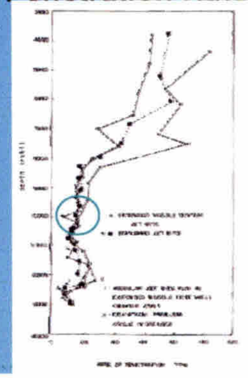
Factors Affecting Penetration Rate

- Conventional bits at 6000 psi (41,400 kPa) did drill faster than 2000 psi (13,800 kPa) while drilling shale in this well



Factors Affecting Penetration Rate

- Extended nozzles increased penetration rate down to 10,000 feet (3000 m) in this well



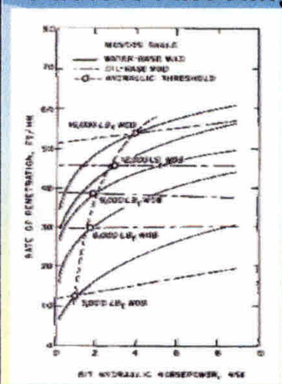
Factors Affecting Penetration Rate

- Extended nozzles can break off leaving junk in the hole
- The nozzles do not clean the cutting structure of the bit as well as conventional nozzles
- Bit balling can be a problem

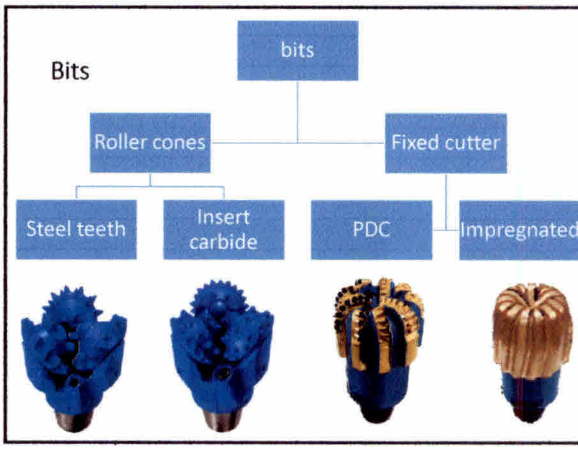
Factors Affecting Penetration Rate

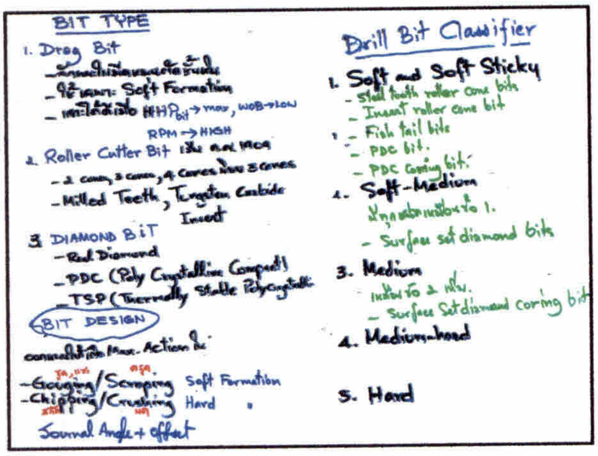
- Hydraulics and PDC bits
  - Hydraulics may be more important with PDC bits than with roller cone bits to clean the cutting structure
  - Originally all PDC bits had three jets similar to roller cone bits
  - PDC bits ball up easier and require jets to clean all the cutters

Factors Affecting Penetration Rate



- Hydraulic threshold for PDC bits while drilling with water based mud
- Minimum hydraulics are required to prevent bit balling

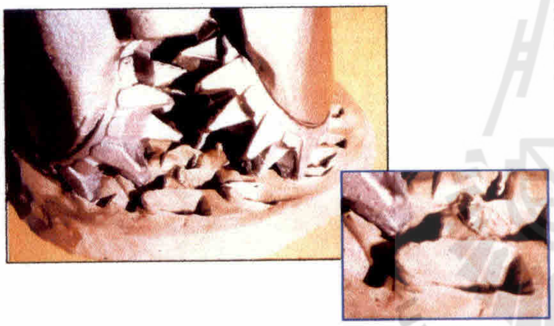




Cutting action

- ▶Soft Formation : Gouging-Scraping
  - ▶Most Aggressive Cutting Action
  - ▶Typically high ROP applications
- ▶Hard Formation : Chipping-Crushing
  - ▶Most Durable Cutting Action
  - ▶Typically low ROP applications

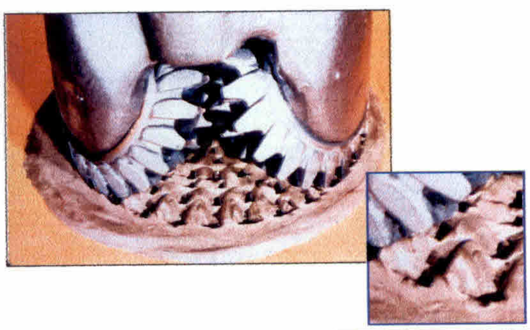
Gouging-Scraping Example



Gouging-Scraping

□Like.....using a shovel in the garden

Chipping-Crushing Example

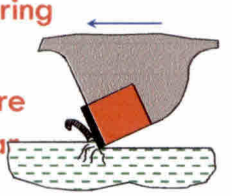


Chipping-Crushing

□Like.....using a hammer and chisel

PDC Mechanics

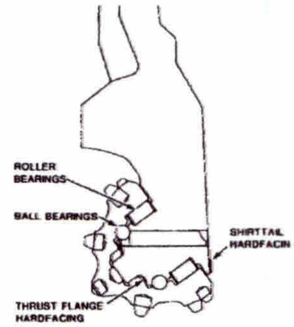
- PDC Bits drill by shearing the rock
- Rocks typically fracture more easily with shear loading (less energy, WOB)
- Most efficient cutting action



Polycrystalline Diamond Compact

Drill Bits

- Had roller bearings in the cones
- No seal in the bearings and used mud as lubricant
- Solids in the mud caused rapid bearing failure
- Most bearings lasted less than 24 hours



Comparison chart of 3-cutter roc. bits + Insert roller cone bits

Security sealed bearing	Type	Security	Hughes	Reed	Smith
S33S	soft formation	S3S	OSC-3A	YT3A	DS
		S3	OSC-3	YT3	DT
S33		S3T		YT3T	
		S4	OSC-16	YT1A	DG
S44		S4T	CIC	TY1T	
		S6	OSC	YTL	K2
M44N	medium	M4N	OWV	YSI	V2
M44		M4L	OWC	YM	T2
		H7	V7	YH	
H77	hard	H7T	W7C		L4
		H7U	W7R2	YHW2	W4
H77S		H7SG	WD7		
H77C		HC	WR	YBVC	WC
*S88	insert bits		J44	SCM	3
**M88		M8	X-55R	YC5G	4
H88		H8	RG7	YC4G	5-6-7
H100		H10	RG2B	YC2G	9

*S88 for S44—M44 drilling.
**M88 for M44N—H77 drilling.

PDC drill bit LX401 G412
Code M433

Mud Properties

- Mud weight
- Mud type
- Solids content
- Other mud properties
  - Viscosity
  - Filtration Rate

The Effect of Drilling Fluid Properties

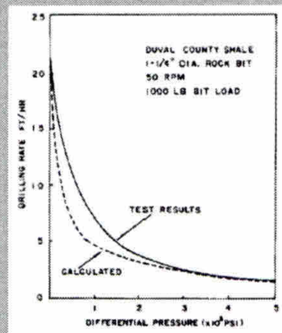
1. Mud Density สูง เจาะช้า
2. Solid Content สูง เจาะช้า
3. Viscosity + Gel Strength
   สูง เจาะช้า เพราะ ΔP มากลด จะลด ΔP_b
4. Filtration Loss สูง เจาะช้า
   - เพราะ Bit จะ Filter cake ก่อน rock
   - cuttings trapped in the partly filter needed longer time to clean up
5. Oil Content สูง เจาะเร็ว
6. Surface Tension ลด จะเจาะเร็วขึ้น
   - Emulsifying agent
     Surfactant

MUD PROPERTIES

- Mud weight
  - It is the overbalance between hydrostatic imposed by the mud weight and formation pressure that affects penetration rate
  - As mud weight increases, penetration rate will decrease if the formation pressure remains constant

MUD PROPERTIES

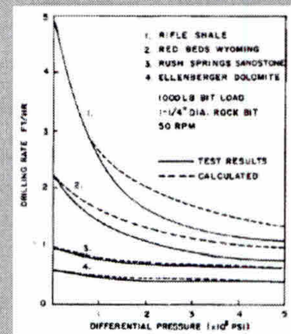
- As the amount of over balance increases, the drilling rate decreases

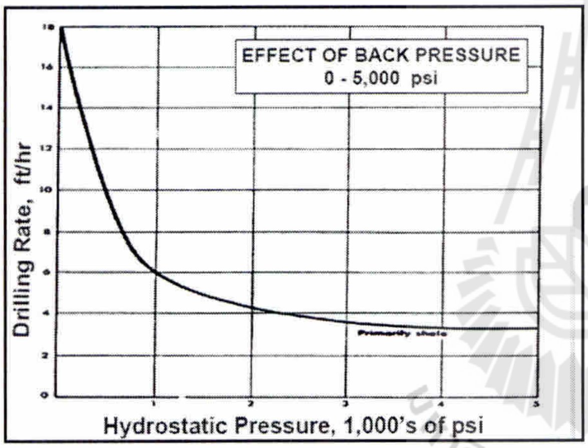


OGCI

MUD PROPERTIES

- Penetration rate is less affected by the over balance in harder formations





6.5 The Effect of Drilling Fluid Properties on Penetration Rate.

The effect of mud density has already been covered since it governs the pressure imposed on the hole bottom. This is probably the main factor contributing to the success of air drilling is such areas as depicted by Figure 6.3 The effect of mud density is probably not completely expressed in terms of the pressure exerted by the mud column. Rather, it should be considered in terms of the pressure differential between the interstitial fluid pressure in the rock and the imposed pressure.

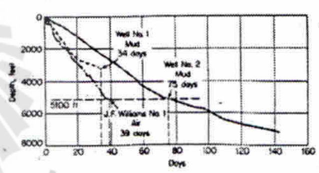


Fig. 6.3 Relative drilling times of air vs. mud drilled wells in Atoka County, Oklahoma. After Adams,[26] courtesy API.

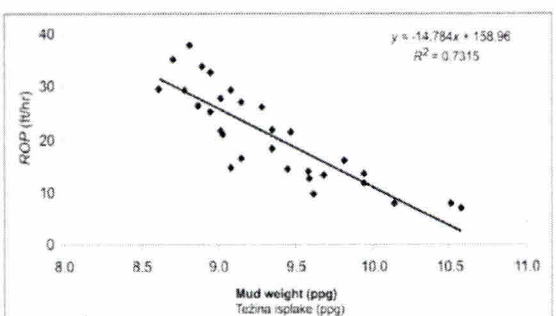
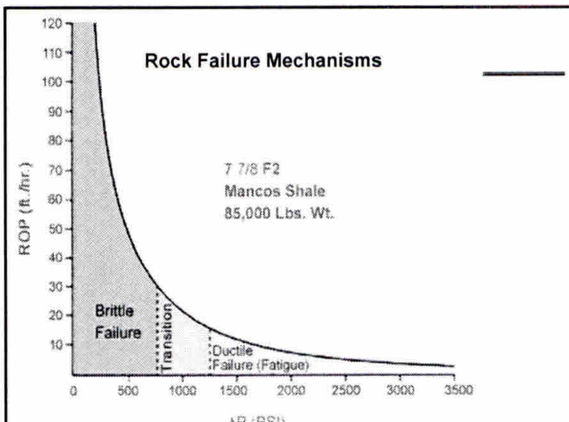
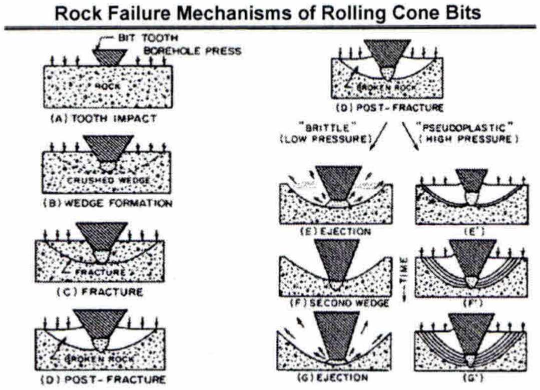


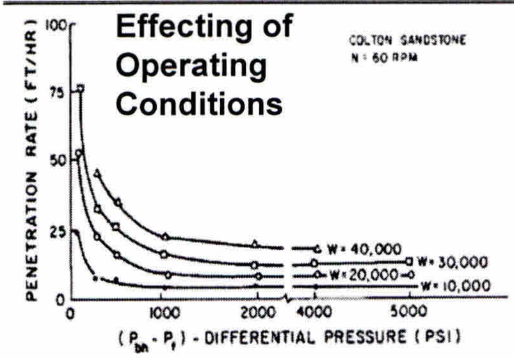
Fig. 7. Effect of mud weight on penetration rate
Sl. 7. Djelovanje težine isplake na brzinu bušenja

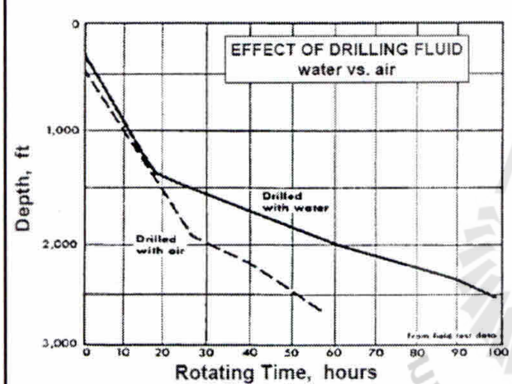


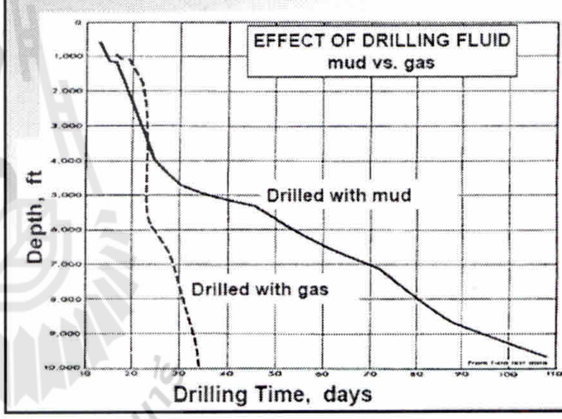
Rock Failure Mechanisms of Rolling Cone Bits



Factors Affecting Penetration Rate

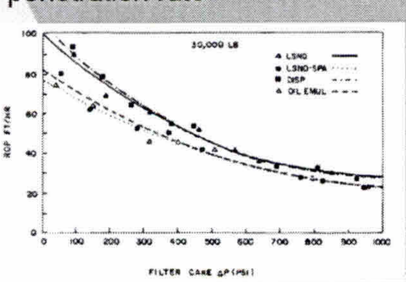






MUD PROPERTIES

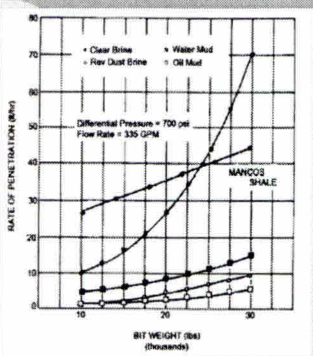
- Effect of filter cake differential on penetration rate



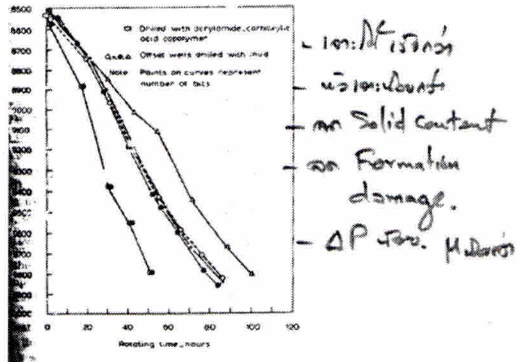
MUD PROPERTIES

- The mud type makes a difference in penetration rate
  - Air drills fastest
  - Water drills faster than mud
  - Water is a good drilling fluid but not a very good hole cleaning fluid

MUD PROPERTIES



- As the solids content increases, the penetration rate decreases



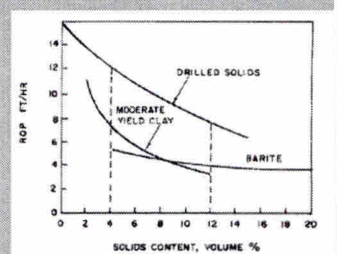
11-9. Effect of treatment with acrylamide-carboxylic acid copolymer on drilling rates Midland County, Texas. (After Gallus et al., 1958, p. 74, fig. 9; courtesy of the Society Petroleum Engineers of AIME.)

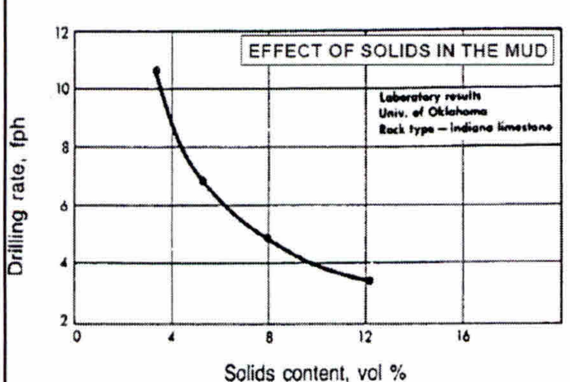
MUD PROPERTIES

- Solids
  - Once solids are introduced into the system, the activity, size and numbers of solids will affect the drilling rate
  - Solids also contribute to mud weight so penetration rate will decrease due to higher hydrostatic pressure

MUD PROPERTIES

- The more reactive the solids, the more affect they have on penetration rate





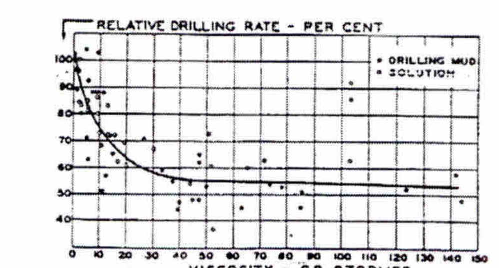


Fig. 6.4 Laboratory data showing effect of viscosity on drilling rate. After Eckel, courtesy API.

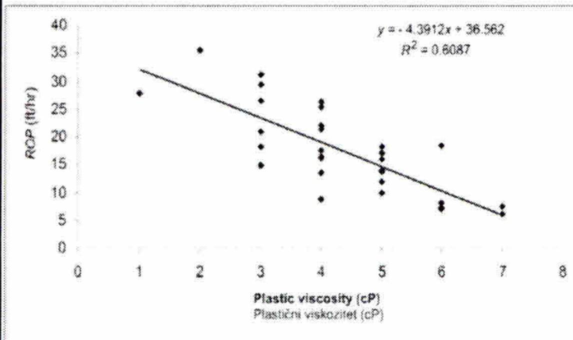


Fig. 1. Observed penetration rate vs. plastic viscosity
Sl. 1. Uočena brzina bušenja u ovisnosti o plastičnom viskozitetu

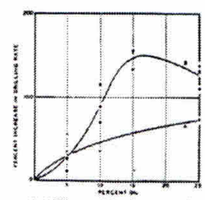


Fig.6.5 Increase in drilling rate VS. oil concentration. Curve (A) is for a Vicksburg shale; curve (B) is for a Miocene shale(laboratory data). After Cunningham and Goins,[31] courtesy Petroleum Engineering drilling

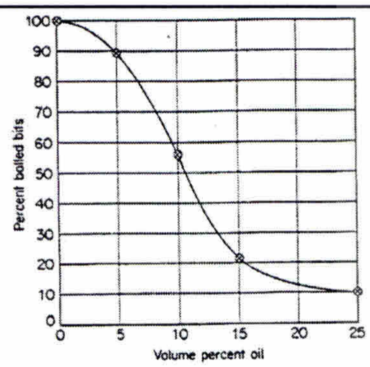
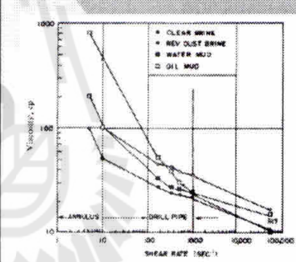


Fig.6.6 Effect of oil content on the incidence of balled bits in laboratory drilling of Miocene shale. After Cunningham and Goins,[31] courtesy Petroleum Engineering .

MUD PROPERTIES

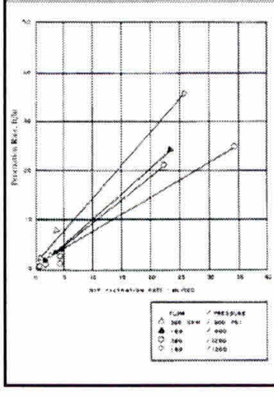


- At the bit, the shear rates are very high so the viscosity is relatively low
- Some drilling fluids shear thinner than others

MUD PROPERTIES

- Viscosity
  - ◆Viscosity is usually increased by the addition of solids in the mud
  - ◆Higher solids content and viscosity will decrease penetration rate
  - ◆It is difficult to isolate any one mud property

MUD PROPERTIES



- As the filtration rate decreases, the penetration rate decreases
- It is harder to equalize the pressure below the rock chips when filtration rate is reduced

MUD PROPERTIES

- In general, the more mud you have in the hole, the slower the well will drill
- After air, water is the best drilling fluid
- Unfortunately, all wells cannot be drilled with air or water

CLASS PROBLEM

- Calculate cost per meter for each
- Insert bits
  - Number or bits = 2
  - Cost per bit = $7,000
  - Cost of rig = $625/hr
  - Rotating hours = 180
  - Total time for two trips = 21 hrs
  - Footage = 1375m
  - ROP = 7.64 m/hr

PDC bit and motor
  - Number or bits = 1
  - Cost per bit = $25,000
  - Cost of rig = $625/hr
  - Cost of motor = $300/hr included in trip time
  - Rotating hours = 130
  - Trip time = 12 hrs
  - Footage =1375m
  - ROP = 10.58 m/hr

Class Problem

- Insert Bits
  - Cost of two bits = 7000 x 2 = 14,000
  - Cost per meter calculation

$$C_T = \frac{C_B + C_r(t+T)}{F}$$

$$C_T = \frac{14000 + 625(180+21)}{1375} = \$101.55\ /m$$

Class Problem

- PDC bit and motor
  - Assume the motor cost is included in the trip time
  - Cost per meter calculation

$$C_T = \frac{C_B + C_r(t+T)}{F}$$

$$C_T = \frac{25000 + (625+300)(130+12)}{1375} = \$113.71\ /m$$

Class Problem

- PDC bit and motor
  - Assume the motor cost is not included in the trip time
  - Cost per meter calculation

$$C_T = \frac{C_B + C_r(t+T)}{F}$$

$$C_T = \frac{25000 + (625+300)(130) + (625)(12)}{1375} = \$111.09\ /m$$

Class Problem

- Insert bits assuming the rig rate is 48,000 per day or 2000 per hour
  - Cost of two bits = 7000 x 2 = 14,000
  - Cost per meter calculation

$$C_T = \frac{C_B + C_r(t+T)}{F}$$

$$C_T = \frac{14000 + 2000(180+21)}{1375} = \$302.55\ /m$$

Class Problem

- PDC bit and motor assuming the rig rate is 48,000 per day or 2000 per hour
  - Assume the motor cost is included in the trip time
  - Cost per meter calculation

$$C_T = \frac{C_B + C_r(t+T)}{F}$$

$$C_T = \frac{25000 + (2000+300)(130+12)}{1375} = \$255.71/m$$

6.6 Hydraulic Factors

1) Rate of penetration is directly proportional to nozzle velocity (at constant circulation rate)
2) Rate of penetration is directly proportional to circulation volume (at constant nozzle velocity)

$$HP_B = HP_T - HP_s$$

where HP_B = bit horsepower
HP_T = total pump horsepower
HP_s = system horsepower exclusive of bit

Since

$$HP_t = \frac{q\Delta pt}{1714}, \quad q\Delta p_t = \text{constant}$$

4) $\Delta p_s = K_1 q^{1.86}$.

∴

(5) $HP_s = \frac{K_1 q^{2.86}}{1714}$ Also, $HP_t = (q \times \Delta p_t)/1714$

Substituting Eqs. (5) into Eq. (1), we arrive at an expression for bit horsepower:

$$HP_B = (q \times \Delta p_t)/1714 - \frac{K_1 q^{2.86}}{1714}$$

Differentiating (7) with respect to q, noting that Δp_t = constant, and solving for maximum Δp_B wich is the desired operating condition:

(6.10) $\Delta p_s = 0.35\,\Delta p_t$ or (6.10a) $\Delta p_B = 0.65\,\Delta p_t$

Example 8.1

Constant HP, minimum q
Hole size = $8\frac{3}{4}$ in.
Drill pipe = $4\frac{1}{2}$ in., 16.6 lb, IF.
Drill collars = 500 ft long, $6\frac{3}{4}$ in. o.d., $2\frac{3}{4}$ in. bore
Bit = 3 cone, jet type, rolling cutter rock bit
Pump capacity = 400 HP (output)
Required annular velocity = 150 ft/min (from experience)

Calculate (1) Operating conditions for utilization of 400 HP, (2) Nozzle size at 6,000 ft depth, (3) Nozzle size at 11,500 ft depth.

Solution:

In lieu of more specific data we will assume the mud properties of the Hughes charts in Chapter 7.

(1) $q = 2.45(d_h^2 - d_p^2)\bar{v}_a$
$= 2.45[(8.75)^2 - (4.5)^2](150/60)$
$= 350$ gal/min

Since

$$HP = \frac{q\Delta p_t}{1714}$$

$$\Delta p_t = \frac{(1714)(400)}{350} = 1960 \text{ psi}$$

These are then the imposed operating limits for circulating volume and pressure.

(2) Calculating hydraulic losses,

Δp_s = 20 psi (Figure 7.3, #3)
Δp_p = 220 psi (Figure 7.5, #7)
Δp_c = 100 psi (Figure 7.7, $2\frac{3}{4}$ in.)
Δp_{ac} = 26 psi (Figure 7.11, $6\frac{3}{4}$ in.)
Δp_{ap} = 55 psi (Figure 7.11, $4\frac{1}{2}$ in.)
Δp_s = 421 psi
Δp_b = 1960 − 421 = 1540 psi

From Figure 7.9,

A_N = 0.260 in.^{2} = total area of 3 nozzles;

hence

$$d_N = \left(\frac{4A_N}{3\pi}\right)^{1/2} = 0.332 \text{ in.}$$

The nearest larger stock nozzle size would normally be selected.

3) At 11,500 ft,

Δp_s = 20 psi (same as above)
Δp_p = 440 psi (twice)
Δp_c = 100 psi (same as above)
Δp_{ac} = 26 psi (same as above)
Δp_{ap} = 110 psi (twice)
Δp_s = 696 psi
Δp_b = 1960 − 696 = 1264

Hence,

A_N = 0.290 in.^{2}
d_N = 0.351

Hydraulic Horse Power at bit

$HP_b = HP_t - HP_{se}$; $HP_t = \frac{q\Delta P_t}{1714 \times E_f}$

if ΔP_{se} = Pressure Losses in System Exclude bit
Assume Turbulent, + annular losses are small

$\Delta P_{se} = K_1 q^{1.86}$ (ans Prob. 7.24)

$HP_{se} = \frac{q\Delta P_{se}}{1714} = \frac{K_1 q^{2.86}}{1714}$

$HP_t = \frac{q\Delta P_t}{1714}$

∴ $HP_B = \frac{q\Delta P_t}{1714} - \frac{K_1 q^{2.86}}{1714}$

let ΔP_t constant, diff. by dq

Max $\frac{dHP_B}{dq} = \frac{\Delta P_t}{1714} - \frac{2.86\, q^{1.86} K_1}{1714} = 0$

$2.86\, K_1 q^{1.86} = \Delta P_t = 2.86\,\Delta P_{se}$

$\Delta P_{se} = 0.35\,\Delta P_t$

∴ $\Delta P_b = 0.65\,\Delta P_t$

$\Delta P_{se} = K_1 q^{1.86} = 0.35\,\Delta P_t$

$q = 0.57\left(\frac{\Delta P_t}{K_1}\right)^{\frac{1}{1.86}}$

Optimum q; $q_o = 0.57\left(\frac{\Delta P_t}{K_1}\right)^{0.54}$

From $\Delta P_b = \frac{\rho q_o^2}{7430\, C^2 d_e^4}$

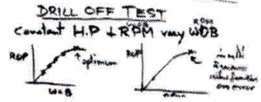
sub. $\Delta P_b = 0.65\,\Delta P_t$, $C = 0.95$

∴ $d_e = 0.123\, q_o^{1/2}\left(\frac{\rho}{\Delta P_t}\right)^{1/4}$

$\Delta P_s = C \cdot Q^n$

DRILL OFF TEST

Constant H.P + RPM vary WOB



130 $\Delta P = \frac{K\mu\text{-}\rho\, q\, L}{d^{4.86}}$ FACTORS AFFECTING PENETRATION RATE [Chap. 8

Note that nozzle size is relatively insensitive to depth changes under these conditions.

We now consider a second approach in which total pressure loss, Δp_t, is held constant at some maximum value as dictated by pump and/or surface connection ratings. The flow rate q will be treated as a restrained variable free to vary above some minimum value, i.e., $q \geq q_{min}$; where q_{min} depends on the necessary annular velocity and hole-pipe clearance.

Assuming turbulent flow and that annular losses are relatively small, we may write:

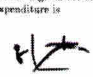
(4) $\Delta p_s = K_1 q^{1.86}$

where K_1 is dependent on pipe length, size, tool joint, and mud properties, but is constant for a given set of operating conditions. The power expenditure is

$$HP_s = \frac{q\Delta p_s}{1714}$$

∴

(5) $HP_s = \frac{K_1 q^{2.86}}{1714}$



Also,

(6) $HP_t = \frac{q\Delta p_t}{1714}$

Substituting Eqs. (5) and (6) into Eq. (1), we arrive at an expression for bit horsepower:

(7) $HP_b = \frac{q\Delta p_t}{1714} - \frac{K_1 q^{2.86}}{1714}$

Differentiating (7) with respect to q, noting that Δp_t = constant, and solving for maximum Δp_B which is the desired operating condition:

Substituting $\Delta p_b = 0.65\,\Delta p_t$, $C = 0.95$, and solving for d_e

(8.12) $d_e = 0.123\, q_o^{1/2}\left(\frac{\rho}{\Delta p_t}\right)^{1/4}$

Example 8.2 Constant Pressure Operation

Let us rework Example 8.1 assuming the same pipe sizes, etc., and a depth of 6000 ft. This time we will let Δp_t = 2000 psig and q vary, according to our recent discussion. Immediately we see that Δp_s = 700, and Δp_b = 1300 psig.

Solution:

$$q_o = 0.57\left(\frac{2000}{K_1}\right)^{0.54}$$

To determine K_1 we must consider both the drill pipe and drill collar section.

It can be shown (see Problem 6b) that

$$\Delta p_p + \Delta p_c = \Delta p_p\left[1 + \frac{L_c}{L_p}\left(\frac{d_p}{d_c}\right)^{4.86}\right]$$

where L_c, L_p = length of drill collars and pipe, respectively, ft
d_c, d_p = internal diameters of same, in.

Since

$\Delta p_p = \frac{0.58q^{1.86}L}{1000d^{4.86}}$ = turbulent pressure loss inside pipe, psi, according to Hughes charts (see Problem 6)

It can be shown (see Problem 6b)

$$K_1 = \frac{0.58L_p}{1000d_p^{4.86}}\left[1 + \frac{L_c}{L_p}\left(\frac{d_p}{d_c}\right)^{4.86}\right]$$

Substitution of values yields

stant at some maximum
nd/or surface connection
will be treated as a re-
above some minimum
depends on the acces-
-pipe clearance.
that annular losses are

$q^{1.86}$

length, size, tool joint,
stant for a given set of
er expenditure is

to Eq. (1), we arrive at

$\frac{K_1 q^{1.86}}{1714}$

to q, noting that Δp_t =
mum Δp_p which is the

Example 8.2 Constant Pressure Operation

Let us rework Example 8.1 assuming the same pipe sizes, etc., and a depth of 6000 ft. This time we will let Δp_t = 2000 psig and q vary, according to our recent discussion. Immediately we see that Δp_b = 700, and Δp_a = 1300 psig.

Solution:

$$q_s = 0.37\left(\frac{2000}{K_1}\right)^{1.86}$$

To determine K_1 we must consider both the drill pipe and drill collar section.

It can be shown (see Problem 6b) that

$$\Delta p_p + \Delta p_c = \Delta p_p\left[1 + \frac{L_c}{L_p}\left(\frac{d_p}{d_c}\right)^{4.86}\right]$$

where L_c, L_p = length of drill collars and pipe, respectively, ft
d_c, d_p = internal diameters of same, in.

Since

$$\Delta p_p = \frac{0.58 q^{1.86} L}{1000 d^{4.86}}$$ = turbulent pressure loss inside pipe, psi, according to Hughes charts (see Problem 6)

It can be shown (see Problem 6b)

$$K_1 = \frac{0.58 L_p}{1000 d_p^{4.86}}\left[1 + \frac{L_c}{L_p}\left(\frac{d_p}{d_c}\right)^{4.86}\right]$$

Substitution of values yields

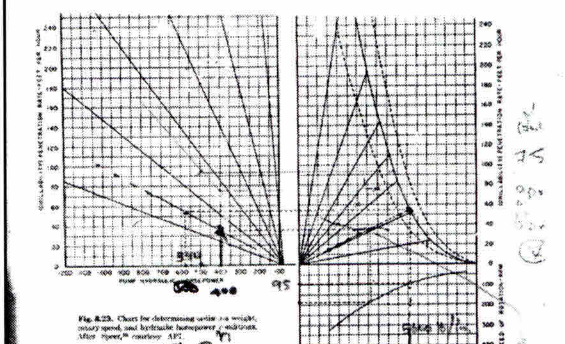


Fig. 8.23. Chart for determining optimum weight, rotary speed, and hydraulic horsepower conditions. After Speer, courtesy API.

$\Delta P_s = C\, q_i^n$

1. Pump 400 HP. 2. $4\frac{1}{2}$ in DP 3. $9\frac{7}{8}$ in hole 4. $3 \times \frac{1}{2}$ in bit 5. drillability

Depending on the situation, rig equipment, etc., either ... data. This method is illustrated by Example 8.3 which is solved graphically with Figure 8.23.

Example 6.3 (After Speer[22])

A certain rig is available to drill a 1,000-ft homogeneous shale section. It is desired to determine: (a) optimum operating conditions for the available rig; and (b) the equipment required to drill the shale section most economically. The given parameters are as follows:

1. 400 HP pump
2. $4\frac{1}{2}$-in. drill pipe
3. $9\frac{7}{8}$-in. hole
4. three $\frac{1}{2}$-in. bit nozzles

When the shale section is drilled, short-duration tests of weight vs. Penetration rate are made (1) to establish a drillability index for the formation and (2) to determine at what weight the bit begins to ball up with the available pump (a tentative index must first be established to select an appropriate rotary speed). These test values are plotted on the weight vs. Penetration rate chart (upper righthand section) and an appropriate curve is drawn through them.

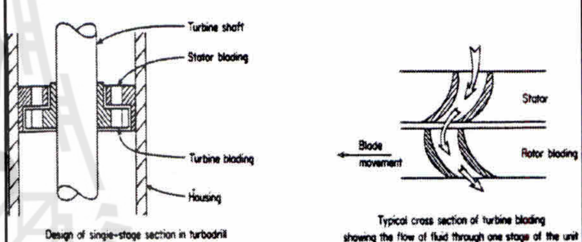


Fig. 6.10 Elementary diagram of turbine component. After LeVelle,44 courtesy Petroleum Engineering.

Fig.6.11 Cutaway view of the French (Neyrpic) turbodrill. After O'Connor,[45] courtesy *The Monitor*.

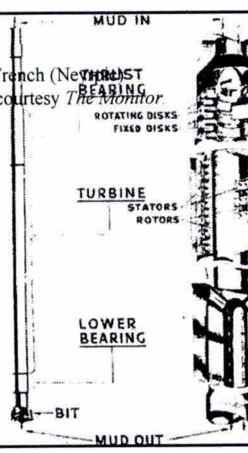
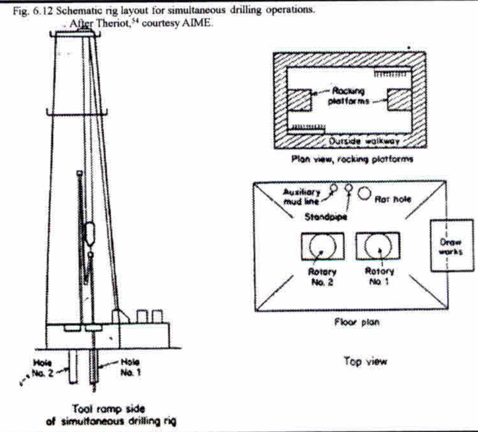


Fig. 6.12 Schematic rig layout for simultaneous drilling operations. After Theriot,[14] courtesy AIME.



Eq. 8.15:
(6.15)

$$C_R = \frac{C_R\left(t_{mt} + \frac{D}{\bar{R}_p}\right) + C_B + C_A + C_C + C_M}{D}$$

where C_F = average direct drilling and completion cost/ft

C_R = rig operating cost, $/hr

t_{mt} = maintenance and trip time, hr

D = depth interval

C_B = bit costs

C_A = auxiliary equipment costs, such as turbodrill, etc.

C_M = mud costs

C_C = completion costs, including casing, cementing, etc.

$\bar{R}_p$ = average *on bottom* penetration rate, ft/hr

Eq.(6.16) $W_{opt} = \left[\frac{C_f K}{(b-1)(C_B + C_R T)}\right]^{1/b}$

EXAMPLE 6.4

Well depth = 10,000 ft.
Bit costs = $200.00
Rig costs = $100.000 per hr.
Round trip time = 1.2 hr. Per 1000 ft.
Bit weight = 40,000 pound
Rotary speed = 150 RPM
Bit wear, b = 1.5
Bit life = 10 hours

Determine the optimum bit w[illegible]

$W_{opt} = \left[\frac{(200 \times 10)}{(0.5 \times 1200)}\right]^{0.667}$ 40,000=94,400 pounds

Solution :

Using Equation 4, [illegible]

Wopt. = [illegible]

Wopt. = [illegible] 40,000=80,000 pounds

To show the effect b consider a change in the bit wear function from 1.5 to 2.0

Wopt. = [illegible] 40,000=47,480 pounds

To further the emphasize the effect of b , consider a doubling of the rig operating cost from $100 to $200 per hour.

Bit	Bit cost ($)	Rotating Time (hours)	Connection Time (hours)	Mean Penetration Rate (ft/hr)
A	800	14.8	0.1	13.8
B	4,900	57.7	0.4	12.6
C	4,500	95.8	0.5	10.2

Solution. The cost per foot drilled for each bit type can be computed using Eq. 6.17 For bit A, the cost per foot is

$$C_f = \frac{800 + 400(14.8 + 0.1 + 7)}{(13.8)(14.8)} = \$46.81/\text{ft}$$

similarly, for Bit B,

$$C_f = \frac{4{,}900 + 400(57.7 + 0.4 + 7)}{(12.6)(57.7)} = \$42.56/\text{ft}$$

Finally, for Bit C,

$$C_f = \frac{4{,}500 + 400(95.8 + 0.5 + 7)}{(10.2)(95.8)} = \$46.89/\text{ft}$$

The lowest drilling cost was obtained using Bit B.

AIR DRILLING

[illegible]

Advantages

1. [illegible] 8–10 [illegible]
2. [illegible] 3–4 [illegible]
3. [illegible]
4. [illegible]
5. [illegible] flow check [illegible]
6. [illegible] Lost circulation
7. [illegible]

Disadvantages

1. [illegible] Mist or foam drilling
2. [illegible]
3. [illegible]
4. [illegible] "Aerated Mud Drilling"
5. [illegible]
6. [illegible]

อุปกรณ์ที่ใช้ใน AIR DRILLING

[illegible] Rotary System [illegible]

1. Air Compressors
2. Boosters
3. Mist pump
4. Chemical Pump
5. Rotating Kelly Packer
6. Pipe & Blow line
7. [illegible] P, V_{air}, T [illegible]

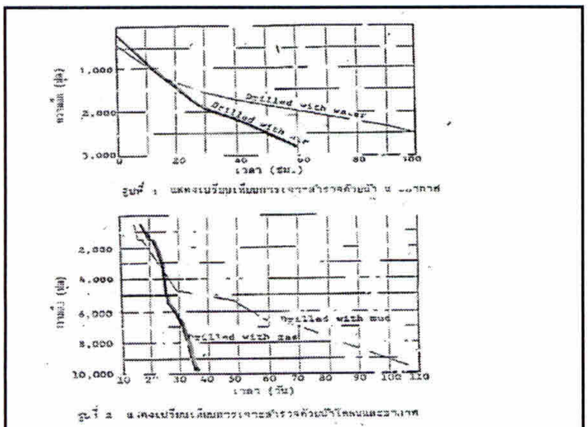
[illegible]

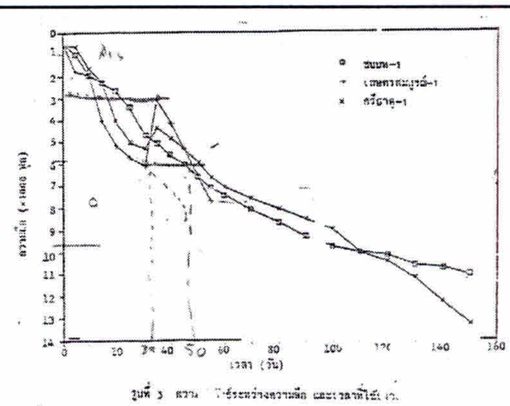
1. S-W Texas [illegible] 10000' [illegible] Air [illegible]
2. [illegible]

[illegible] 76

[illegible] 7704 [illegible] Air [illegible] 1 [illegible] 24

[illegible] 13316 [illegible]





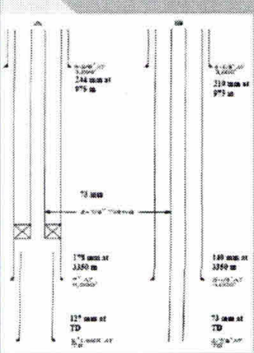
การเปรียบเทียบการใช้น้ำโคลนและอากาศ เจาะสำรวจปิโตรเลียมเป็น Drilling Fluid.

น้ำโคลน	อากาศ
1. นิยมใช้ทั่วไป	1. ใช้ได้ผลดีเฉพาะกรณีที่เหมาะสม
2. เทคนิคได้พัฒนามานานไม่ยุ่งยากมากนัก	2. ใช้เทคนิคที่ยุ่งยากมากขึ้น
3. ปลอดภัยและควบคุมความดันจากปิโตรเลียมได้ดี	3. ต้องระวังอันตรายจากการระเบิด และติดไฟ
4. อุปสรรคที่เกิดจากก้านเจาะมีน้อยกว่า	4. เจาะได้เร็วกว่าและใช้หัวเจาะน้อยกว่า
5. เศษหินใหญ่กว่าสามารถวิเคราะห์ได้ดีกว่า	5. เวลาการขจัดเศษหินเร็วกว่า
	6. ถ้าประสบผลสำเร็จจะประหยัดทั้งเวลาและค่าใช้จ่าย

Auxiliary Practices

- Short trips and wiper trips
- Reaming connections
- Trip time
- Rig selection
- Bottomhole assembly
  - Stabilizers
  - Shock subs
  - Jars
  - Motors

Auxiliary Practices



- Casing strings must be economically justified, running the casing must save money
- The bigger the casing, the more expensive
- Must look at total cost including future operating costs

Maximize Penetration Rate

- Select the proper bit
- Increase bit weight increases penetration rate
- Increased rpm increases penetration rate
- More HHP/in² increases penetration rate
- Increased mud weight decreases penetration rate
- Increased solids content decreases penetration rate
- Higher viscosity (especially at higher shear rates) decreases penetration rate
- Decreased fluid loss decreases penetration rate

Summary

- Efficiency in drilling must be a team effort
  - Involve top management to the roughneck
  - Good new ideas must be given an opportunity to be successful
  - Use experience and sound engineering

Summary

- Drilling faster minimizes cost
- Stay out of trouble
- Keep an open mind and don't be afraid to try something new
- Look at every aspect of the drilling operation
- Honestly evaluate changes in the drilling program
- Keep it as simple as possible

m = the slope of the line.

If we express overbalance in terms of equivalent circulating mud density ρ_c and pore pressure gradient g_p, we obtain

$(p_{bh}-p_f)=0.052\,D(\rho_c-g_p)$.

Substituting this expression for overbalance in Eq. 5.18a gives

$\log(R/R_0) = -0.052\,mD(\rho_c-g_p)$

$= 0.052\,mD(g_p-\rho_c)$.

density or pore pressure gradient to changes in penetration rate.

Example 5.6. The slope of the shale line in Fig. 5.42 has a value of −0.000666. Evaluate the coefficient a_4 for this value of m and estimate the change in penetration rate in this shale at 12,000 ft to be expected if the mud density is increased from 12 to 13 lbm/gal. The current penetration rate in shale is 20 ft/hr.

Solution. The coefficient a_4 is given by

$a_4 = 0.052(0.000666) = 35\times10^{-6}$.

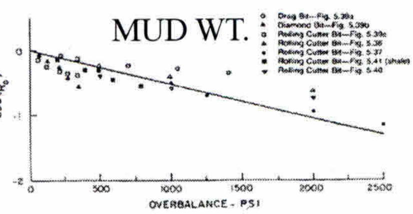


Fig. 5.42—Exponential relation between penetration rate and overbalance for rolling cutter bits.

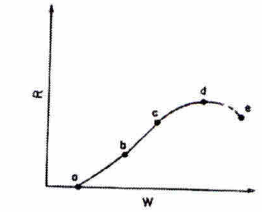


Fig. 5.43—Typical response of penetration rate to increasing bit weight.

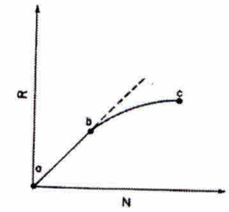


Fig. 5.44—Typical response of penetration rate to increasing rotary speed.

Eq. 5.18b can be rearranged using the definition of a common logarithm in terms of the initial penetration rate R_1 and mud density ρ_1 to give

$$R_1 = R_0\times10^{a_4D(g_p-\rho_1)} = R_0e^{2.303a_4D(g_p-\rho_1)}.$$

Similarly, for the final penetration rate R_2 and mud density ρ_2, we obtain

$$R_2 = R_0\times10^{a_4D(g_p-\rho_2)} = R_0e^{2.303a_4D(g_p-\rho_2)}.$$

Dividing the equation for R_2 by the equation for R_1 gives

of bit weight (Segment de). This type of behavior often is called *bit floundering*. The poor response of penetration rate at high values of bit weight usually is attributed to less efficient bottomhole cleaning at higher rates of cuttings generation or to a complete penetration of the cutting element into the hole bottom.

A typical plot of penetration rate vs. rotary speed obtained with all other drilling variables held constant is shown in Fig. 5.44. Penetration rate usually increases linearly with rotary speed at low values of rotary speed. At higher values of rotary speed, the response of penetration rate to increasing rotary speed diminishes. The poor

Similarly, for the final penetration rate R_2 and mud density ρ_2, we obtain

$$R_2 = R_0\times10^{a_4D(g_p-\rho_2)} = R_0e^{2.303a_4D(g_p-\rho_2)}.$$

Dividing the equation for R_2 by the equation for R_1 gives

$$\frac{R_2}{R_1} = e^{2.303a_4D(\rho_1-\rho_2)}.$$

Solving for the final penetration rate R_2 yields

$$R_2 = R_1\times e^{2.303a_4D(\rho_1-\rho_2)}$$

$$= 20\left[e^{2.303(35\times10^{-6})(12{,}000)(12-13)}\right] = 7.60 \text{ ft/hr}.$$

5.7.4 Operating Conditions

The effect of bit weight and rotary speed on penetration rate has been studied by numerous authors both in the laboratory and in the field. Typically, a plot of penetration rate vs. bit weight obtained experimentally with all other drilling variables held constant has the characteristic shape shown in Fig. 5.43. No significant penetration rate is obtained until the threshold bit weight is applied (Point a). Penetration rate then increases rapidly with increasing values of bit weight for moderate values of bit weight (Segment ab). A linear curve is often observed at moderate bit weights (Segment bc). However, at higher values of bit weight, subsequent increase in bit weight causes only slight improvements in penetration rate (Segment cd). In some cases, a decrease in penetration rate is observed at extremely high values

A typical plot of penetration rate vs. rotary speed obtained with all other drilling variables held constant is shown in Fig. 5.44. Penetration rate usually increases linearly with rotary speed at low values of rotary speed. At higher values of rotary speed, the response of penetration rate to increasing rotary speed diminishes. The poor response of penetration rate at high values of rotary speed usually is also attributed to less efficient bottomhole cleaning.

Maurer[25] developed a theoretical equation for rolling cutter bits relating penetration rate to bit weight, rotary speed, bit size, and rock strength. The equation was derived from the following observation made in single-tooth impact experiments.

1. The crater volume is proportional to the square of the depth of cutter penetration.
2. The depth of cutter penetration is inversely proportional to the rock strength.

For these conditions, the penetration rate R is given by

$$R = \frac{K}{S^2}\left[\frac{W}{d_b}-\left(\frac{W}{d_b}\right)_t\right]^2 N, \quad \text{(5.19)}$$

where

K = constant of proportionality,
S = compressive strength of the rock,
W = bit weight,
W_t = threshold bit weight,
d_b = bit diameter, and
N = rotary speed.

This theoretical relation assumes perfect bottomhole cleaning and incomplete bit tooth penetration.

The theoretical equation of Maurer can be verified using experimental data obtained at relatively low bit

Figs. 5.43 and 5.44. At moderate values of bit weight, a weight exponent usually is observed to be closer to a value of one than the value of two predicted by Eq. 5.19. At higher values of bit weight, a weight exponent of less than one usually is indicated. Bingham[18] suggested the following drilling equation on the basis of considerable laboratory and field data.

$$R = K\left(\frac{W}{d_b}\right)^{a_5} N, \quad \text{(5.20)}$$

where K is the constant of proportionality that includes the effect of rock strength, and a_5 is the bit weight exponent.

In this equation the threshold bit weight was assumed to be negligible and the bit weight exponent must be determined experimentally for the prevailing conditions. However, a constant rotary speed exponent of one was used in the Bingham equation even though some of his data showed behavior similar to that described by Segment be in Fig. 5.44.

More recently, several authors have proposed the determination of both a bit weight exponent and a rotary speed exponent using data representative of the prevailing conditions. Young[13] has pioneered the development of a computerized drilling control system in which both the bit weight and rotary speed could be varied systematically when a new formation type was encountered and the bit weight and rotary speed exponent automatically computed from the observed penetration rate response. Values of the bit weight exponent obtained from field data range from 0.6 to 2.0, while

Solving this expression for ΔL gives

$$\Delta L = \frac{L}{EA_s}\Delta W.$$

The average penetration rate observed for the change in bit weight ΔW can be obtained by dividing this equation by the time interval Δt required to drill off ΔW.

$$R = \frac{\Delta W}{\Delta t} = \frac{L}{EA_s}\frac{\Delta W}{\Delta t}. \qquad R = \frac{\Delta L}{\Delta t} = \frac{L}{EA_s}\frac{\Delta W}{\Delta t}$$

Range 2 drillpipe has tool joint upsets over about 5% of its length that have a much greater cross-sectional area than the pipe body and essentially do not contribute to the length change observed. Replacing L by $0.95L$ gives

$$R = 0.95\frac{L}{EA_s}\frac{\Delta W}{\Delta t}. \quad \text{(5.22)}$$

The length ch… can be ignore… $R = \frac{\Delta L}{\Delta t} = 0.95\frac{L}{EA_s}\frac{\Delta W}{\Delta t}$

Care must b… of the bit at the initial bit weight of the test before performing the drilloff test. The following procedure was adapted from a Chevron U.S.A.[26] recommended practice.

1. Select a depth to run the drilloff test where a section of uniform lithology (usually shale) is expected.

…ematically when a new formation type was encountered and the bit weight and rotary speed exponent automatically computed from the observed penetration rate response. Values of the bit weight exponent obtained from field data range from 0.6 to 2.0, while values of the rotary speed exponent range from 0.4 to 0.9.

Frequent changes in lithology with depth can make it difficult to evaluate the bit weight and rotary speed exponents from a series of penetration rate measurements made at various bit weights and rotary speeds. In many cases, the lithology may change before the tests are completed. To overcome this problem, a *drilloff test* can be performed. A drilloff test consists of applying a large weight to the bit and then locking the brake and monitoring the decrease in bit weight with time while maintaining a constant rotary speed. Hook's law of elasticity then can be applied to compute the amount the drillstring has stretched as the weight on the bit decreased and the hook load increased. In this manner, the response in penetration rate to changing bit weight can be determined over a very short depth interval.

Hook's law states that the change in stress is directly proportional to the change …

Hook's law

$$\Delta\delta = E\Delta\epsilon$$

$$\Delta\sigma = E\Delta\epsilon. \quad \text{(5.21)}$$

For the case of axial tension in a drillstring, the stress change is equal to the change in bit weight (axial tension) divided by the cross-sectional area of the drillpipe. The change in strain is equal to the change in drillpipe length per unit length. Thus, Hook's law becomes

$$\frac{\Delta W}{A_s} = E\frac{\Delta L}{L} \qquad \Delta\delta = \frac{\Delta W}{A} \qquad \Delta\epsilon = \frac{\Delta L}{L}$$

adapted from a Chevron U.S.A.[26] recommended practice.

1. Select a depth to run the drilloff test where a section of uniform lithology (usually shale) is expected.
2. While drilling with the bit weight currently in use, lock the brake and determine the time required to drill off 10% of this weight. This is called the characteristic time.
3. Increase the bit weight to the initial value of the drilloff test. This initial value should be at least a 20% increase in bit weight over the bit weight currently in use.
4. Drill at this bit weight long enough to establish the new bottomhole pattern of the bit. The time allowed is usually one characteristic time per 10% increase in bit weight—e.g., a time interval of twice the characteristic time would be used for a 20% increase in bit weight.
5. Lock the brake and maintain a constant rotary speed. Record the time each time the bit weight falls off 4,000 lbf. If the weight indicator is fluctuating, use the midpoint of the fluctuations as the bit weight. Continue the test until at least 50% of the initial bit weight has been drilled off.
6. Make a plot of Δt vs. W or R vs. W using log-log graph paper. A straight-line plot should result having a slope equal to the bit weight exponent. Deviation from straight-line behavior may occur at high bit weights if bit floundering occurs or is impending.
7. If time permits, repeat the test at a different rotary speed. If bit floundering (nonlinear behavior at high bit weights) was observed in the initial test, use a lower rotary speed in the second test. If no bit floundering occurred in the initial test, use a higher rotary speed in the second test.

The rotary speed exponent can be obtained using penetration rates obtained at two different rotary speeds but at the same bit weight.

Example 5.7. Using the following drilloff test data evaluate the bit weight exponent and rotary speed exponent. The length of drillpipe at the time of the test was 10,000 ft, and the drillpipe has a cross-sectional area of 5.275 sq in. Young's modulus for steel is 30×10^6. Assume that the threshold bit weight is zero.

Test No. 1 (rotary speed = 150 rpm)

Δw=4klb

Bit Weight (1,000 lbm)	Elapsed Time (seconds)
76	0
[illegible]	52
[illegible]	105
[illegible]	160
60	218
56	281
52	352
48	432
44	522
40	626
36	746

Test No. 2 (rotary speed = 100 rpm)

Bit Weight (1,000 lbm)	Elapsed Time (seconds)
76	0
72	54
68	114
64	180
60	253
56	334
52	424
48	525
44	641
40	773

Solution. The penetration rate can be evaluated using Eq. 5.21:

$$R = 0.95\frac{L}{EA_s}\frac{\Delta W}{\Delta t}$$

$$= 0.95\frac{10{,}000}{30(10)^6\,5.275}\frac{4{,}000}{\Delta t} = \frac{0.24}{\Delta t}$$

If we express R in units of feet per hour and Δt in seconds, this expression becomes

$$R = \frac{0.24}{\Delta t}\left(\frac{3{,}600 \text{ seconds}}{1 \text{ hour}}\right) = \frac{864}{\Delta t}$$

The drilloff test data have been evaluated using this expression in Table 5.10.

A plot of penetration rate vs. average bit weight can be constructed on log-log paper from the results of the drilloff test analysis. This has been done in Fig. 5.45. Graphical evaluation of the slope of the straight-line portion of either line on Fig. 5.45 yields a value of 1.6. Thus, the observed bit weight exponent is approximately 1.6 for values of bit weight below the flounder region. The rotary speed exponent can be evaluated from the spacing between the lines in the parallel region.

For example, a penetration rate of 13.7 ft/hr is observed for a bit weight of 58,000 lbf and a rotary speed of 150 rpm. Reducing the rotary speed to 100 rpm resulted in a penetration rate of 10.7 ft/hr at the same bit weight. Thus, we have

$$R = KN^{a_6}$$

$$13.7 = K(150)^{a_6},$$

TABLE 5.10—EXAMPLE DRILLOFF TEST ANALYSIS

		N = 150			N = 100		
Bit Weight (1,000 lbf)	Average Bit Weight (1,000 lbf)	Elapsed Time (seconds)	Δt (seconds)	R (ft/hr)	Elapsed Time (seconds)	Δt (seconds)	R (ft/hr)
76		0			0		
	74		52	16.6		54	16.6
72		52			54		
	70		53	16.6		60	14.4
68		105			114		
	66		55	15.7		66	13.1
64		160			180		
	62		58	14.9		73	11.8
60		218			253		
	58		63	13.7		81	10.7
56		281			334		
	54		71	12.2		90	9.6
52		352			424		
	50		80	10.8		101	8.6
48		432			525		
	46		90	9.6		116	7.4
44		522			641		
	42		104	8.3		132	6.5
40		626			773		
	38		120	7.2			
36		746					

Example 5.7. Using the following drilloff test data, evaluate the bit weight exponent and rotary speed exponent. The length of drillpipe at the time of the test was 10,000 ft, and the drillpipe has a cross-sectional area of 5.275 sq in. Young's modulus for steel is 30×10^6. Assume that the threshold bit weight is zero.

Solution. The penetration rate can be evaluated using Eq. 5.21:

$$R = 0.95\,\frac{L}{EA_s}\,\frac{\Delta W}{\Delta t}$$

5.275 sq in. Young's modulus for steel is 30×10^6. Assume that the threshold bit weight is zero.

Test No. 1 (rotary speed = 150 rpm)

Bit Weight (1,000 lbm)	Elapsed Time (seconds)
76	0
72	52
68	105
64	160
60	218
56	281
52	352
48	432
44	522
40	626
36	746

Test No. 2 (rotary speed = 100 rpm)

Bit Weight (1,000 lbm)	Elapsed Time (seconds)
76	0
72	54
68	114
64	180
60	253
56	334
52	424
48	525
44	641
40	773

$$= 0.95\,\frac{10{,}000}{30(10)^6 5.275}\,\frac{4{,}000}{\Delta t} = \frac{0.24}{\Delta t}$$

If we express R in units of feet per hour and Δt in seconds, this expression becomes

$$R = \frac{0.24}{\Delta t}\left(\frac{3{,}600\ \text{seconds}}{1\ \text{hour}}\right) = \frac{864}{\Delta t}.$$

The drilloff test data have been evaluated using this expression in Table 5.10.

A plot of penetration rate vs. average bit weight can be constructed on log-log paper from the results of the drilloff test analysis. This has been done in Fig. 5.45. Graphical evaluation of the slope of the straight-line portion of either line on Fig. 5.45 yields a value of 1.6. Thus, the observed bit weight exponent is approximately 1.6 for values of bit weight below the flounder region. The rotary speed exponent can be evaluated from the spacing between the lines in the parallel region.

For example, a penetration rate of 13.7 ft/hr is observed for a bit weight of 58,000 lbf and a rotary speed of 150 rpm. Reducing the rotary speed to 100 rpm resulted in a penetration rate of 10.7 ft/hr at the same bit weight. Thus, we have

$$R = KN^{a_6},$$

$$13.7 = K(150)^{a_6},$$

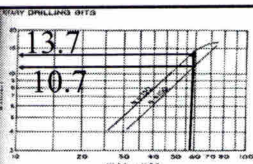


Fig. 5.45—Example drilloff test analysis.

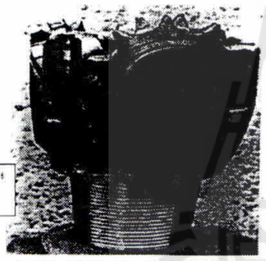


Fig. 5.46—Cutaway view of extended-nozzle bit.[27]

$$\frac{13.7}{10.7} = \left(\frac{150}{100}\right)^{a_6}$$

and

$$10.7 = K(100)^{a_6},$$

[illegible] K is the constant of proportionality, and a_6 is the [illegible] speed exponent.

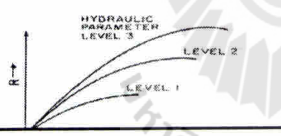
Dividing the top equation by the bottom equation gives

$$\frac{13.7}{10.7} = \left(\frac{150}{100}\right)^{a_6}.$$

Taking the logarithm of both sides and solving for a_6 yields

$$a_6 = \frac{\log(13.7/10.7)}{\log(150/100)} = 0.6.$$

In this example, a good straight-line fit was obtained below the flounder region assuming the threshold bit weight was zero. When the threshold bit weight is not zero, it may be necessary to subtract the threshold bit weight from the bit-weight column before plotting the data. If the threshold bit weight is not known, it can be determined by trial and error as the value that gives the [illegible]



$$\frac{13.7}{10.7} = \left(\frac{150}{100}\right)^{a_6}.$$

Taking the logarithm of both sides and solving for a_6 yields

$$a_6 = \frac{\log(13.7/10.7)}{\log(150/100)} = 0.6.$$

In this example, a good straight-line fit was obtained below the flounder region assuming the threshold bit weight was zero. When the threshold bit weight is not zero, it may be necessary to subtract the threshold bit weight from the bit-weight column before plotting the data. If the threshold bit weight is not known, it can be determined by trial and error as the value that gives the best straight-line fit.

5.7.5 Bit Tooth Wear

Most bits tend to drill slower as the bit run progresses because of tooth wear. The tooth length of milled tooth rolling cutter bits is reduced continually by abrasion and chipping. As previously discussed in Section 5.3, the teeth are altered by hardfacing or by case-hardening process to promote a self-sharpening type of tooth wear. However, while this tends to keep the tooth pointed, it does not compensate for the reduced tooth length. The teeth of tungsten carbide insert-type rolling cutter bits fail by breaking rather than by abrasion. Often, the entire tooth is lost when breakage occurs. Reductions in penetration rate due to bit wear usually are not as severe for insert bits as for milled tooth bits unless a large

Fig. 5.46—Cutaway view of extended-nozzle bit.[27]

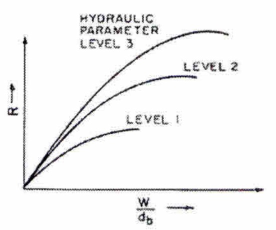


Fig. 5.47—Expected relationship between bit hydraulics and penetration rate.

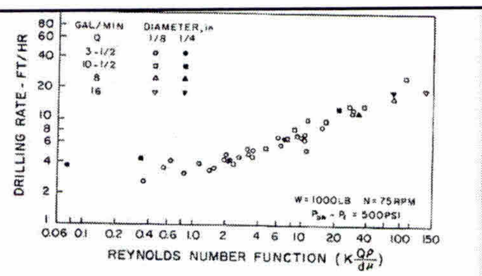
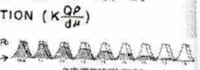


Fig. 5.48—Penetration rates as a function of bit R[illegible]



number of teeth are broken during the bit run. Diamond bits also fail from tooth breakage or loss of diamonds from [illegible]

New bit h=0

Several studies have published mathematical models for computing the effect of tooth wear on penetration rate for rolling-cutter bits. Galle and Woods[11] published the following model in 1963.

$$R \propto \left(\frac{1}{\ldots}\right)^{a_7} \quad (5.23)$$

new bit is zero. Thus, for the relation given as Eq. 5.24 we have

$$R = Ke^{-a_7 h},$$

$$20 = Ke^{-a_7(0)},$$

and

following model in 1963.

$$R \propto \left(\frac{1}{0.928125h^2 + 6h + 1}\right)^{a_7} \quad (5.23)$$

where h is the fractional tooth height that has been worn away, and a_7 is an exponent.

H=bit wear fraction

[illegible] self-sharpening wear of milled tooth bits, the primary bit type discussed in the publication. In a more recent work, Bourgoyne and Young[15] suggested a similar but less complex relationship given by

$$R \propto e^{-a_7 h} \quad (5.24)$$

Bourgoyne and Young suggested that the exponent a_7 be determined based on the observed decline of penetration rate with tooth wear for previous bits run under similar conditions.

Example 5.8. An initial penetration rate of 20 ft/hr was observed in shale at the beginning of a bit run. The previous bit was identical to the current bit and was operated under the same conditions of bit weight, rotary speed, mud density, etc. However, a drilling rate of 12 ft/hr was observed in the same shale formation just before pulling the bit. If the previous bit was graded T-6, compute the approximate value of a_7.

Solution. The value of h for the previous bit just before the end of the bit run is 6/8 or 0.75. The value of h for the

and

$$12 = Ke^{-a_7(0.75)}$$

Dividing the first equation by the second yields

$$\frac{20}{12} = e^{0.75a_7}$$

Taking the natural logarithm of both sides and solving for a_7 gives

$$a_7 = \frac{\ln(20/12)}{0.75} = 0.68.$$

5.7.6 Bit Hydraulics

The introduction of the jet-type rolling cutter bits in [illegible] showed that significant improvements in penetration rate could be achieved through an improved jetting action at the bit. The improved jetting action promoted better cleaning of the bit teeth as well as the hole bottom. [illegible] evidence has been presented[28] that the jetting action is most effective when using extended-nozzle bits, where the discharge ends of the jets are brought closer to the bottom of the hole (Fig. 5.46). A center jet [illegible] used with extended-nozzle bits to prevent [illegible] soft formations.

As discussed previously in Chap. 4, there is considerable uncertainty as to the best hydraulic parameter to use in characterizing the effect of hydraulics on penetration rate. Bit hydraulic horsepower, jet impact force, and nozzle velocity all are [illegible]

The constants a_1 through a_8 can be computed using prior drilling data obtained in the area when detailed drilling data are available. The drilling model can be used both for drilling optimization calculations and for the detection of changes in formation pore pressure.

The function f_1 primarily represents the effects of formation strength and bit type on penetration rate. However, it also includes the effect of drilling variables such as mud type, solids content, etc., which are not included in the drilling model. The exponential expression for f_1 is useful when applying a multiple regression technique presented by Bourgoyne and Young[15] for computing the values of a_1 through a_8 from prior drilling data obtained in the area. The coefficient "2.303" allows the constant a_1 to be defined easily in terms of the common logarithm of an observed penetration rate. The utility of this will be demonstrated in Chap. 6, which includes a discussion of the determination of formation pore pressure from drilling data.

The functions f_2 and f_3 model the effect of compaction on penetration rate. The function f_2 accounts for the rock strength increase due to normal compaction with depth, and the function f_3 models the effect of undercompaction experienced in abnormally pressured formations. Note that the $(f_2 f_3)$ product is equal to 1.0 for a pore pressure gradient equivalent to 9.0 lbm/gal and a depth of 10,000 ft.

The function f_4 models the effect of overbalance on penetration rate. This function has a value of 1.0 for zero

The function f_8 models the effect of bit hydraulics on penetration rate. Jet impact force was chosen as the hydraulic parameter of interest, with a normalized value of 1.0 for f_8 at 1,000 lbf.

However, as shown in Fig. 5.50, the choice of impact force is arbitrary. Similar results could be obtained with bit hydraulic horsepower or nozzle Reynolds number as the hydraulic parameter affecting penetration rate. Typical values for a_8 range from 0.3 to 0.6.

In practice, it is prudent to select the best available values of a_2 through a_8 for the formation types and depth interval of interest. However, the value of f_1 varies with the strength of the formation being drilled. The term f_1 is expressed in the same units as penetration rate and commonly is called the drillability of the formation. The drillability is numerically equal to the penetration rate that would be observed in the given formation type (under normal compaction) when operating with a new bit at zero overbalance, a bit weight of 4,000 lbf/in., a rotary speed of 60 rpm, and a depth of 10,000 ft. The drillability of the various formations can be computed using drilling data obtained from previous wells in the area.

Example 5.10. A 9.875-in. milled tooth bit operated at 40,000 lbf/in. and 80 rpm is drilling in a shale formation at a depth of 12,000 ft at a penetration rate of 15 ft/hr. The formation pore pressure gradient is equivalent to a 12.0 lbm/gal mud, and the equivalent mud density on bottom is 12.5 lbm/gal. The computed jet impact force beneath the bit is 1,200 lbf, and the computed fractional tooth wear is 0.3. Compute the ...

F1 roc strength

F2 F3 compaction

F4 overbalane

---

pore pressure gradient equivalent to 9.0 lbm/gal and a depth of 10,000 ft.

The function f_4 models the effect of overbalance on penetration rate. This function has a value of 1.0 for zero overbalance—i.e., when the formation pore pressure is equal to the bottomhole pressure in the well.

The functions f_5 and f_6 model the effect of bit weight and rotary speed on penetration rate. Note that f_5 has a value of 1.0 when (W/d_b) has a value of 4,000 lbf/in. of bit diameter and f_6 has a value of 1.0 for a rotary speed of 60 rpm. This was chosen so that the $f_5 f_6$ product would ... The threshold bit weight is often quite small and can be neglected in areas such as the U.S. gulf coast where the formations are relatively soft. In more competent formations, the threshold bit weight can be estimated from drilloff tests terminated at very low bit weights. The function of f_5 has an upper limit corresponding to the bit flounder point, which must be established from drilloff tests. The constants a_5 and a_6 also can be determined from drilloff tests as in Example 5.7. Reported values of a_5 range from 0.5 to 2.0, and reported values of a_6 range from 0.4 to 1.0.

The function f_7 models the effect of tooth wear on penetration rate. The value of a_7 can be estimated from penetration rate measurements taken in similar formations at similar bit operating conditions at the beginning and end of a bit run as shown previously in Example 5.8. The term f_7 has a value of 1.0 for zero tooth wear. When tungsten carbide insert bits are used and operated at moderate bit weights and rotary speeds, tooth wear is often insignificant and this term can be neglected. Typical values of a_7 for milled tooth bits range from 0.3 to 1.5.

12.0 lbm/gal mud, and the equivalent mud density on bottom is 12.5 lbm/gal. The computed jet impact force beneath the bit is 1,200 lbf, and the computed fractional tooth wear is 0.3. Compute the apparent formation drillability f_1 using a threshold bit weight of zero and the following values of a_2 through a_8.

a_2	a_3	a_4	a_5	a_6	a_7	a_8
0.00007	0.000005	0.00003	1.0	0.5	0.5	0.5

Solution. The functional relations f_2 through f_8 are given by Eqs. 5.28a through 5.28h. The multiplier f_2 accounts for the normal decrease in penetration rate with depth from a reference depth of 10,000 ft.

$$f_2 = e^{2.303a_2(10,000-D)} = e^{2.303(0.00007)(10,000-12,000)} = 0.724.$$

The multiplier f_3 accounts for the increase in penetration rate due to undercompaction.

$$f_3 = e^{2.303a_3D^{0.69}(g_p-9)} = e^{2.303(0.000005)(12,000)^{0.69}(12-9)} = 1.023.$$

The multiplier f_4 accounts for the change in penetration rate with overbalance assuming a reference overbalance of zero.

$$f_4 = e^{2.303a_4D(g_p-\rho)} = e^{2.303(0.00003)(12,000)(12.0-12.5)} = 0.6606.$$

F4 overbalane

F5f6bt wt and rotary speed

$$R = (f_1)(f_2)(f_3)(f_4)\ldots(f_n), \quad\ldots\ldots\ldots\ldots (5.28a)$$

$f_1 = e^{2.303a_1} = K$ (5.28b) F1 formation drillability factor

$f_2 = e^{2.303a_2(10,000-D)}$ (5.28c) F2 compaction depth factor

$f_3 = e^{2.303a_3D^{0.69}(g_p-9.0)}$ (5.28d) f3 compaction

$f_4 = e^{2.303a_4D(g_p-\rho_c)}$ (5.28e) F4 overbalane

$$f_5 = \left[\frac{\left(\frac{W}{d_b}\right) - \left(\frac{W}{d_b}\right)_t}{4 - \left(\frac{W}{d_b}\right)_t}\right]^{a_5}$$ (5.28f) F5 bit wt. factor, W=klb/in

f6 N=rotary speed

$f_6 = \left(\frac{N}{60}\right)^{a_6}$ (5.28g) N reference =60rpm

$f_7 = e^{-a_7h}$ F7 bit wear factor

$f_8 = \left(\frac{F_j}{1{,}000}\right)^{a_8}$ (5.28h) Fj=jet impact, Fj reference=1000 lbf

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Example 5.10. A 9.875-in. milled tooth bit operated at 40,000 lbf/in. and 80 rpm is drilling in a shale formation at a depth of 12,000 ft at a penetration rate of 15 ft/hr. The formation pore pressure gradient is equivalent to a 12.0 lbm/gal mud, and the equivalent mud density on bottom is 12.5 lbm/gal. The computed jet impact force beneath the bit is 1,200 lbf, and the computed fractional tooth wear is 0.3. Compute the apparent formation drillability f_1 using a threshold bit weight of zero and the following values of a_2 through a_8.

a_2	a_3	a_4	a_5	a_6	a_7	a_8
0.00007	0.000005	0.00003	1.0	0.5	0.5	0.5

Solution. The functional relations f_2 through f_8 are given by Eqs. 5.28a through 5.28h. The multiplier f_2 accounts

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Solution. The functional relations f_2 through f_8 are given by Eqs. 5.28a through 5.28h. The multiplier f_2 accounts for the normal decrease in penetration rate with depth from a reference depth of 10,000 ft.

Reference Depth = 10000ft.

$$f_2 = e^{2.303a_2(10,000-D)} = e^{2.303(0.00007)(10,000-12,000)} = 0.724.$$

D=depth = 12000ft.

The multiplier f_3 accounts for the increase in penetration rate due to undercompaction.

$g_p = pore-pressure, ppg = 12\,ppg$

$$f_3 = e^{2.303a_3D^{0.69}(g_p-9)} = e^{2.303(0.000005)(12,000)^{0.69}(12-9)} = 1.023.$$

The multiplier f_4 accounts for the change in penetration rate with overbalance assuming a reference overbalance of zero.

$g_p = pore-pressure, ppg = 12\,ppg$
$\rho_c = mud-density = 12.5\,ppg$

$$f_4 = e^{2.303a_4D(g_p-\rho)} = e^{2.303(0.00003)(12,000)(12.0-12.5)} = 0.6606.$$

The multiplier f_5 accounts for the change in penetration with bit weight assuming a reference bit weight of 4,000 lbf/in.

$$f_5 = \left[\frac{\left(\frac{W}{d_b}\right) - \left(\frac{W}{d_b}\right)_t}{4 - \left(\frac{W}{d_b}\right)_t}\right]^{a_5}$$

Threashold จุดเต้นเป็น0

W=wt. on bit klb/in=40 klb/in.

$$= \left[\frac{\left(\frac{40}{9.875}\right)}{4}\right]^{1.0} = 1.013.$$

The multiplier f_6 accounts for the change in penetration rate with rotary speed assuming a reference rotary speed of 60 rpm.

N = Rotary speed=80 rpm

$$f_6 = \left(\frac{N}{60}\right)^{a_6} = \left(\frac{80}{60}\right)^{0.5} = 1.155$$ N reference=60 rpm

The multiplier f_7 accounts for the change in penetration rate with tooth dullness using zero tooth wear as a reference.

F7 bit wear factor,h=0.3
New bit h=0

$$f_7 = e^{-a_7 h} = e^{-0.5(0.3)} = 0.861.$$

The multiplier f_8 accounts for the change in penetration rate with jet impact force using an impact force of 1,000 lbf as a reference.

Fj=jet impact=1200lbf
, F reference=1000 lbf

$$f_8 = \left(\frac{F_j}{1{,}000}\right)^{a_8} = \left(\frac{1{,}200}{1{,}000}\right)^{0.5} = 1.095.$$

Substitution of the computed values of f_2 to f_8 into Eq. 5.28 and solving for the formation drillability yields

$$R = f_1 \cdot f_2 \cdot f_3 \cdot \ldots \cdot f_8,$$

$$15 = f_1(0.724)(1.023)(0.6606)(1.013) \cdot (1.155)(0.861)(1.095),$$

and

$$f_1 = \frac{15}{0.540} = 27.8 \text{ ft/hr}.$$

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$$R = K\left(\frac{W}{d_b}\right) N \ldots\ldots (5.28)$$

The multiplier f_5 accounts for the change in penetration rate with bit weight assuming a reference bit weight of 4,000 lbf/in.

$$f_5 = \left[\frac{\left(\frac{W}{d_b}\right) - \left(\frac{W}{d_b}\right)_t}{4 - \left(\frac{W}{d_b}\right)_t}\right]^{a_5}$$

Threashold จุดต้นเป็น0

$$= \left[\frac{\left(\frac{40}{9.875}\right)}{4}\right]^{1.0} = 1.013.$$

The multiplier f_6 accounts for the change in penetration rate with rotary speed assuming a reference rotary speed of 60 rpm.

Reference60rpm

$$f_6 = \left(\frac{N}{60}\right)^{a_6} = \left(\frac{80}{60}\right)^{0.5} = 1.155.$$

The multiplier f_7 accounts for the change in penetration rate with tooth dullness using zero tooth wear as a reference.

h0.3

$$f_7 = e^{-a_7 h} = e^{-0.5(0.3)} = 0.861.$$

count. If we define a composite drilling variable J_1 using

$$J_1 = f_1 \cdot f_2 \cdot f_3 \cdot f_4 \cdot f_5 \cdot f_6 \cdot f_8, \ldots\ldots (5.29)$$

Eq. 5.28 can be expressed by

$$R = \frac{dD}{dt} = J_1 f_7 = J_1 e^{-a_7 h}.$$

Separating variables in this equation yields

$$dD = J_1 e^{-a_7 h} dt. \ldots\ldots (5.30)$$

The evaluation of this integral requires a relation between time t and tooth wear h. Recall that Eqs. 5.10 and 5.11 give

$$dt = J_2 \tau_H (1 + H_2 h)\, dh.$$

Substituting this expression into Eq. 5.30, we obtain

$$dD = J_1 J_2 \tau_H e^{-a_7 h}(1 + H_2 h)\, dh. \ldots\ldots (5.31a)$$

Finally, integration of this equation leads to the following expression of bit footage in terms of the final tooth wear observed.

$$\Delta D = J_1 J_2 \tau_H \left[\frac{1 - e^{-a_7 h_f}}{\ldots}\right.$$

TABLE 5.7—COMPARISON OF EQUATIONS FOR MODELING THE EFFECT OF TOOTH HEIGHT ON TOOTH WEAR RATE

Bit Weight (lbf) per inch (W/d_b)	Relative Wear Rate $\left[\frac{dh}{dt}/\left(\frac{dh}{dt}\right)_4\right]$ Eq. 5.6a	Eq. 5.7b
1	0.4	0.7
2	0.6	0.8
3	0.8	0.9
4	1.0	1.0
5	1.3	1.2
6	1.8	1.5

TABLE 5.8—RECOMMENDED TOOTH-WEAR PARAMETERS FOR ROLLING-CUTTER BITS

Bit Class	H_1	H_2	$(W/d)_{max}$
1–1 to 1–2	1.90	7	7.0
1–3 to 1–4	1.84	6	8.0
2–1 to 2–2	1.80	5	8.5
2–3	1.76	4	9.0
3–1	1.70	3	10.0
3–2	1.65	2	10.0
3–3	1.60	2	10.0
4–1	1.50	2	10.0

temperatures. The flow velocities must also be maintained high enough to prevent clogging of fluid passages with rock cuttings. The design of the fluid distribution passages in a diamond or PCD drag bit is extremely important and varies considerably among the various bits available. However, the manufacturer will generally specify the total flow area (TFA) of the fluid distribution system for each bit. In addition, the bit manufacturer will specify a recommended drilling-fluid flow rate or pressure drop across the bit face.

Mathematical models for estimating the effect of hydraulics on the rate of cutter wear have not yet been employed. The development of such models would be extremely difficult because of the wide variety of bit designs available. It is generally assumed that as long as the flow is present to clean and to cool the cutters, the effect of hydraulics on cutter wear rate can be ignored.

5.4.5 Tooth Wear Equation

A composite tooth wear equation can be obtained by combining the relations approximating the effect of tooth geometry, bit weight, and rotary speed on the rate of

The tooth wear rate formula given by Eq. 5.10 has been normalized so that the abrasiveness constant τ_H is numerically equal to the time in hours required to completely dull the bit teeth of the given bit type when operated at a constant bit weight of 4,000 lbf/in. and a constant rotary speed of 60 rpm. The average formation abrasiveness encountered during a bit run can be evaluated using Eq. 5.10 and the final tooth wear h_f observed after pulling the bit. If we define a tooth wear parameter J_2 using

$$J_2 = \left[\frac{\left(\frac{W}{d_b}\right)_m - \left(\frac{W}{d_b}\right)}{\left(\frac{W}{d_b}\right)_m - 4}\right]\left(\frac{60}{N}\right)^{H_1}\left(\frac{1}{1 + H_2/2}\right) \ldots\ldots (5.11)$$

Eq. 5.10 can be expressed by

designs available. It is generally assumed that as long as the flow is present to clean and to cool the cutters, the effect of hydraulics on cutter wear rate can be ignored.

5.4.5 Tooth Wear Equation

A composite tooth wear equation can be obtained by combining the relations approximating the effect of tooth geometry, bit weight, and rotary speed on the rate of tooth wear.[15] Thus, the instantaneous rate of tooth wear is given by

$$\frac{dh}{dt} = \frac{1}{\tau_H}\left(\frac{N}{60}\right)^{H_1}\left[\frac{\left(\frac{W}{d_b}\right)_m - 4}{\left(\frac{W}{d_b}\right)_m - \left(\frac{W}{d_b}\right)}\right]$$

$$\cdot\left(\frac{1 + H_2/2}{1 + H_2 h}\right), \ldots\ldots (5.10)$$

where

h = fractional tooth height that has been worn away,
t = time, hours
$H_1, H_2, (W/d_b)_m$ = constants,
W = bit weight, 1,000-lbf units,
N = rotary speed, rpm, and
τ_H = formation abrasiveness constant, hours.

The rock bit classification scheme shown in Table 5.3 can be used to characterize the many bit types available from the four major bit manufacturing companies. Recommended values of H_1, H_2, and $W/(d_b)_m$ are shown in Table 5.8 for the various rolling-cutter rock bit classes.

$$\ldots\left(\frac{W}{d_b}\right)_m - 4 \ldots 1 + H_2/2 \ldots (5.11)$$

Eq. 5.10 can be expressed by

$$\int_0^{t_b} dt = J_2 \tau_H \int_0^{h_f} (1 + H_2 h)\, dh. \ldots\ldots (5.12a)$$

Integration of this equation yields

$$t_b = J_2 \tau_H (h_f + H_2 h_f^2/2). \ldots\ldots (5.12b)$$

Solving for the abrasiveness constant τ_H gives

$$\tau_H = \frac{t_b}{J_2(h_f + H_2 h_f^2/2)}. \ldots\ldots (5.13)$$

Although Eqs. 5.10 through 5.15 were developed for use in modeling the loss of tooth height of a milled tooth bit, they have also been applied with some degree of success to describe the loss of insert teeth by breakage. Insert bits are generally operated at lower rotary speeds than milled-tooth bits to reduce impact loading on the brittle tungsten carbide inserts. In hard formations, rotary speeds above about 50 rpm may quickly shatter the insert.[16]

Example 5.3. An 8.5-in. Class 1-3-1 bit drilled from a depth of 8,179 to 8,404 ft in 10.5 hours. The average bit weight and rotary speed used for the bit run was 45,000 lbf and 90 rpm, respectively. When the bit was pulled, it was graded T-5, B-4, G-I. Compute the average formation abrasiveness for this depth interval. Also estimate the time required to dull the teeth completely using the same bit weight and rotary speed.

Solution. Using Table 5.8 we obtain $H_1 = 1.84$, $H_2 = 6$, and $(W/d_b)_m = 8.0$. Using Eq. 5.11 we obtain

$$J_2 = \frac{8.0 - 45/8.5}{8.0 - 4.0}\left(\frac{60}{90}\right)^{1.84}$$

$$\cdot\frac{1}{1 + 6/2} = 0.08.$$

Solving Eq. 5.13 for the abrasiveness constant using a final fractional tooth dullness of ⅝ or 0.625(T-5) gives

$$\tau_H = \frac{10.5 \text{ hours}}{0.080[0.625 + 6(0.625)^2/2]}$$

$$= 73.0 \text{ hours}.$$

The time required to dull the teeth completely ($hf = 1.0$) can be obtained from Eq. 5.12:

$$t_b = 0.08(73.0)\left[1 + 6(1)^2/2\right] = 23.4 \text{ hours}.$$

TABLE 5.9—RECOMMENDED BEARING WEAR EXPONENT FOR ROLLING-CUTTER BITS

Bearing Type	Drilling Fluid Type	B_1	B_2
Nonsealed	barite mud	1.0	1.0
	sulfide mud	1.0	1.0
	water	1.0	1.2
	clay/water mud	1.0	1.5
	oil-base mud	1.0	2.0
Sealed roller bearings	—	0.70	0.85
Sealed journal bearings	—	1.6	1.00

Lummus[17] has indicated that too high a jet velocity can be detrimental to bearing life. Erosion of bit metal can occur, which leads to failure of the bearing grease seals. In the example discussed by Lummus, this phenomenon was important for bit hydraulic horsepower values above 4.5 hp/sq in. of hole bottom. However, a general model for predicting the effect of hydraulics on bearing wear was not presented.

A bearing wear formula[15] frequently used to estimate bearing life is given by

$$\frac{db}{dt} = \frac{1}{\tau_B}\left(\frac{N}{60}\right)^{B_1}\left(\frac{W}{4d_b}\right)^{B_2}, \ldots\ldots (5.14)$$

where

b = fractional bearing life that has been

5.5 Factors Affecting Bearing Wear

The prediction of bearing wear is much more difficult than the prediction of tooth wear. Like tooth wear, the instantaneous rate of bearing wear depends on the current condition of the bit. After the bearing surfaces become damaged, the rate of bearing wear increases greatly. However, since the bearing surfaces cannot be examined readily during the dull bit evaluation, a linear rate of bearing wear usually is assumed. Also, bearing manufacturers have found that for a given applied force, the bearing life can be expressed in terms of total revolutions as long as the rotary speed is low enough to prevent an excessive temperature increase. Thus, bit bearing life usually is assumed to vary linearly with rotary speed.

The three main types of bearing assemblies used in rolling cutter bits are (1) nonsealed roller, (2) sealed roller, and (3) sealed journal. The price of the bit is lowest for the nonsealed roller and highest for the sealed journal.

The effect of bit weight on bearing life depends on the number and type of bearings used and whether or not the bearings are sealed. When the bearings are not sealed, bearing lubrication is accomplished with the drilling fluid, and the mud properties also affect bearing life.

The hydraulic action of the drilling fluid at the bit is also thought to have some effect on bearing life. As flow rate increases, the ability of the fluid to cool the bearings also increases. However, it is generally believed that flow rates sufficient to lift cuttings will also be sufficient to prevent excessive temperature buildup in the bearings.

b = fractional bearing life that has been consumed,
t = time, hours,
N = rotary speed, rpm,
W = bit weight, 1,000 lbf,
d_b = bit diameter, inches,
B_1, B_2 = bearing wear exponents, and
τ_B = bearing constant, hours.

Recommended values of the bearing wear exponent are given in Table 5.9. Note that the bearing wear formula given by Eq. 5.14 is normalized so that the bearing constant, τ_B, is numerically equal to the life of bearings if the bit is operated at 4,000 lbf/in. and 60 rpm. The bearing constant can be evaluated using Eq. 5.14 and the results of a dull bit evaluation. If we define a bearing wear parameter J_3 using

$$J_3 = \left(\frac{60}{N}\right)^{B_1}\left(\frac{4d_b}{W}\right)^{B_2} \ldots\ldots (5.15)$$

Eq. 5.14 can be expressed by

$$\int_0^{t_b} dt = J_3 \tau_B \int_0^{b_f} db,$$

where b_f is the final bearing wear observed after pulling the bit. Integration of this equation yields

$$t_b = J_3 \tau_B b_f. \ldots\ldots (5.16)$$

…multiplier f_8 accounts for the change in penetration …with jet impact force using an impact force of 1,000 … a reference.

$$f_8 = \left(\frac{F_j}{1{,}000}\right)^{a_8} = \left(\frac{1{,}200}{1{,}000}\right)^{0.5} = 1.095.$$

…tution of the computed values of f_2 to f_8 into Eq. … and solving for the formation drillability yields

$$R = f_1 \cdot f_2 \cdot f_3 \cdot \ldots \cdot f_8,$$

$$15 = f_1(0.724)(1.023)(0.6606)(1.013)$$

$$\cdot(1.155)(0.861)(1.095),$$

…

$$f_1 = \frac{15}{0.540} = 27.8 \text{ ft/hr.}$$

…Example 5.10, detailed drilling data were available … given point in time. This requires the use of a …well monitoring and data recording system. In …instances, data of this quality are not available and …average drillability for an entire bit run must be com…ed. For bits that show a significant tooth wear over …life of the bit, the change in the tooth wear function …with time over the life of the bit must be taken into ac-

$$+\frac{H_2(1-e^{-a_7h_f}-a_7h_fe^{-a_7h_f})}{a_7^2}\Bigg]. \quad (5.31b)$$

This equation can be used to determine the footage corresponding to a given final tooth wear h_f and composite drilling parameter J_1. Conversely, it also can be used to compute an apparent or average value of J_1 for an observed footage ΔD and final tooth wear h_f. The formation drillability then can be computed from J_1 using Eq. 5.29.

In some cases, it is desirable to compute the footage drilled after a given time interval t_b of bit operation. To use Eq. 5.31 for this purpose, it is necessary to know the tooth dullness at the drilling time of interest. Recall that the time required to obtain a given tooth wear is given by Eq. 5.12b. Expressing this equation in terms of h_f, we obtain

$$\left(\frac{H_2J_2\tau_H}{2}\right)h_f^2+(J_2\tau_H)h_f-t_b=0$$

Solving this quadratic for h_f gives

$$h_f=\sqrt{\left(\frac{1}{H_2}\right)^2+\left(\frac{2t_b}{H_2J_2\tau_H}\right)}-\left(\frac{1}{H_2}\right) \quad \ldots (5.32)$$

Example 5.11. Compute the average formation drillability for the bit run described in Example 5.3. Assume the

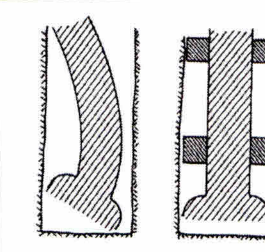


Fig. 5.52—Need for bit stabilizers.

average jet impact force was 1,000 lbf, the formation drilled was shale with a normal formation pressure gradient (equivalent to a 9.0 lbm/gal fluid), and the equivalent circulating density was 9.5 lbm/gal. Also, use the threshold bit weight and constants a_2 through a_8 given in Example 5.10.

Solution. Recall from Example 5.3 that H_2 had a value of 6, J_2 had a value of 0.080, and τ_H had a value of 73.0 hours. Also, the bit drilled from a depth of 8,179 to

The multipliers f_2 through f_6 and f_8 can be obtained …ing Eqs. 5.28c through 5.28g and 5.28i.

$$f_2 = e^{2.303a_2(10{,}000-D)}$$

$$= e^{2.303(0.00007)(10{,}000-8{,}292)} = 1.32.$$

$$f_3 = e^{2.303a_3D^{0.69}(g_p-\rho_c)} = 1.0 \text{ for } g_p = 9.0.$$

$$f_4 = e^{2.303a_4D(g_p-\rho_c)}$$

$$= e^{2.303(0.00003)(8{,}292)(9.0-9.5)} = 0.751$$

$$f_5 = \left[\frac{\left(\frac{W}{d_b}\right)-\left(\frac{W}{d_b}\right)_t}{4-\left(\frac{W}{d_b}\right)_t}\right]^{a_5}$$

$$= \left[\frac{\left(\frac{45}{8.5}\right)-0}{4-0}\right]^{1.0} = 1.32.$$

$$f_6 = \left(\frac{N}{60}\right)^{a_6} = \left(\frac{90}{60}\right)^{0.5} = 1.225.$$

8,404 ft in 10.5 hours and was graded as T-5 (h_f = ⅝ or 0.625). The constant a_7 given in Example 5.10 had a value of 0.5. Substitution of these data into Eq. 5.31 yields

$$\Delta D = J_1J_2\tau_H\left[\frac{1-e^{-a_7h_f}}{a_7}\right.$$

$$\left.+\frac{H_2(1-e^{-a_7h_f}-a_7h_fe^{-a_7h_f})}{a_7^2}\right],$$

and

$$(8{,}404-8{,}179) = J_1(0.08)(73.0)$$

$$\times\left\{\frac{1-e^{-0.5(0.625)}}{0.5}\right.$$

$$\left.+\frac{6\left[1-e^{-0.5(0.625)}-0.5(0.625)e^{-0.5(0.625)}\right]}{(0.5)^2}\right\}.$$

Solving this equation for J_1 gives

J_1 = 25.8 ft/hr.

The mean depth of the bit run is

$$\bar{D} = \frac{8{,}179+8{,}404}{2} = 8{,}292$$

$$f_8 = \left(\frac{F_j}{1{,}000}\right)^{a_8} = 1.0 \text{ for } F_j = 1{,}000.$$

Substituting these values of f_2 through f_6 and f_8 into Eq. 5.29 gives

$$J_1 = f_1 \cdot f_2 \cdot f_3 \cdot f_4 \cdot f_5 \cdot f_6 \cdot f_8.$$

$$25.8 = f_1(1.32)(1.0)(0.751)(1.32)(1.225)(1.0).$$

Solving this equation for the formation drillability, we obtain f_1 = 16.1 ft/hr.

5.8 Bit Operation

In addition to selecting the best bit for the job, the drilling engineer must see that the bit selected is operated as efficiently as possible. Items of primary concern include (1) selection of bottomhole assembly, (2) prevention of accidental bit damage, (3) selection of bit weight and rotary speed, and (4) bit run termination.

Proper attention to all of these items must be given to approach a minimum-cost drilling operation.

5.8.1 Bottomhole Assembly

The bottomhole assembly used above the bit often has a significant effect on bit performance. The length of drill collars used should be adequate to prevent the development of bending moments in the drillpipe for the largest bit weight used. This can be accomplished through use of Eq. 4.25b as described in Chap. 4. Also, stabilizers should be used above the bit in the string of drill collars to prevent bending of the lower portion of the drill collars. A severe wobbling bit action results … the bit a…

…ed if the drill collars above the bit are not held in a …ntric position in the borehole (Fig. 5.52). This can …se (1) severe shock loading on teeth, bearings, and …the seals of rolling cutter bits, (2) shock loading on …nd or PCD cutters and uneven fluid distribution …ith diamond bits, (3) a below-gauge borehole …eter, and (4) a crooked borehole.

The use of stabilizers having a diameter near the hole …can reduce the severity of these problems greatly. …cal shock absorbing devices called *shock subs* also …be used above the bit to dampen the shock loads fur… The additional cost of shock subs is justified more …ly for the more expensive journal bearing bits, which …e the potential of extremely long bit runs if the grease …al and bearing surfaces are not damaged.

TABLE 5.11—EXAMPLE COST-PER-FOOT TABLE[19]

Rotary Speed (rpm)	Bit Weight per Inch of Bit Diameter (1,000 lbf/in.)					
	2.0	3.0	4.0	5.0	6.0	7.0
20	$167.83	$103.51	$73.67	$56.88	$46.67	$42.82
40	114.94	71.45	51.48	40.61	34.92	38.55
60	95.19	59.84	43.84	35.56	32.36	42.65
80	85.77	54.81	40.77	34.08	32.80	49.76
100	81.15	52.37	39.85	34.30	34.70	58.52
120	79.25	51.83	40.17	35.51	37.48	68.36
140	79.07	52.38	41.29	37.37	40.86	79.01
160	80.08	53.68	42.96	39.69	44.68	90.29
180	81.97	55.54	45.06	42.37	48.85	102.11
200	84.52	57.83	47.48	45.32	53.29	114.39

5.8.2 Prevention of Accidental Bit Damage

…idental bit damage before placing the bit in service at …bottom of the hole can reduce the life of the bit great… The bit should be tightened in the drillstring to the …ommended torque using a special *breaker plate* …gned for the bit type in use. Care also should be …en to see that the jet nozzles are installed properly us…ing a shroud to minimize fluid erosion of the nozzle …ges.

The bit is especially susceptible to damage during the …ping operations. The presence of tight spots observed …ile pulling the previous bit out of the hole should be …ed in writing so that slower pipe velocities can be …ed at these points when running the new bit to bottom. …ight spots may be especially noticeable when running a …stabilized bottomhole assembly after a bit that was …nd to have significant gauge wear. When reaming …necessary, low bit weights should be used. The bit …ings are not designed for the inward thrust present …ing reaming operations. It is also possible to catch a …cone on an irregular ledge in the borehole wall while …ping back to bottom. Plastic bit guides can be in…ed beneath the bit to minimize the risk of this type of …age.

After the new bit reaches bottom, it should be "broken …properly using a low bit weight and rotary speed for …first foot or two drilled. This allows any microscopic …gularities in the bearing surfaces to be smoothed and …ws the bottomhole pattern of the new cutters to be …blished in the rock. The bit weight and rotary speed …en can be increased slowly to the desired values. Also, …always is important to establish drilling fluid circula…n before resuming drilling operations. Heat buildup …quickly damage the bit when fluid circulation stops …ing drilling operations.

5.8.3 Selection of Bit Weight and Rotary Speed

…cussed in the previous sections, the weight applied …the bit and the rotational speed of the drillstring have a …an effect on both the penetration rate and the life of … In addition, these parameters can be varied easi… Thus, the determination of the best bit weight and …y speed for a given bit run is one of the routine prob…s faced by the drilling engineer. In selecting the bit …ht and rotary speed to be used in drilling a given for…tion, consideration must be given to these items: (1) …effect of the selected operating conditions on the cost per foot for the bit run in question and on subsequent bit runs, (2) the effect of the selected operating conditions on crooked hole problems, (3) the maximum desired penetration rate for the fluid circulating rates and mud processing rates available and for efficient kick detection, and (4) equipment limitations on the available bit weight and rotary speed.

In many instances, a wide range of bit weights and rotary speeds can be selected without creating crooked hole problems or exceeding equipment limitations. Also, penetration rates that can be achieved are usually less than the maximum desirable penetration rate in the deeper portions of the well. Under these conditions, the drilling engineer is free to select the bit weight and rotary speed that will result in the minimum cost per foot.

Several published methods for computing the optimum bit-weight/rotary-speed combinations for achieving minimum drilling costs are available.[11-17] All of these methods require the use of mathematical models to define the effect of bit weight and rotary speed on penetration rate and bit wear. Methods are available for computing both the best *variable* bit-weight/rotary-speed schedule and the best *constant* bit weight and rotary speed for the entire bit run. Galle and Woods[11] have reported that the simpler constant weight/speed methods result in only slightly higher costs per foot than the methods allowing the bit weights and rotary speeds to vary as the bit dulls or encounters different formation characteristics. Reed[14] indicated a difference of less than 3% in cost per foot between the variable and constant weight/speed schedules for the cases studied.

One straightforward technique that can be used to determine the best constant weight/speed schedule is to generate a cost-per-foot table. The cost per foot for various assumed bit weights and rotary speeds can be computed using the penetration rate and bit wear models and the results tabulated as shown in Table 5.11. The best combination of bit weight and rotary speed, the best bit weight for a given rotary speed, or the best rotary speed for a given desired bit weight then can be read from the table. The use of the best bit weight for a given rotary speed may be desirable when the rotary speed selection is limited by the rotary power transmission system. The best rotary speed for a given bit weight may be desirable when the bit weight is limited because of hole deviation problems.

Various algorithms can be used to evaluate the cost-per-foot table. When desired, a foot-by-foot analysis of the bit run can be made taking into account formation of different drillabilities that may be encountered during the bit run. However, when the use of a single average formation drillability is possible, the integrated forms of the penetration rate and tooth wear models can be used. This greatly reduces the number of calculation steps involved. For example, if the Bourgoyne-Young penetration rate and bit wear models are used, the following procedure could be used.

1. Assume a bit weight and rotary speed.
2. Compute the time required to wear out the bit teeth using Eqs. 5.11 and 5.12.
3. Compute the time required to wear out the bearings using Eqs. 5.15 and 5.16.
4. Using the smaller of the two computed times, compute the footage that would be drilled using Eqs. 5.29 and 5.31.
5. Compute the cost per foot using Eq. 1.16.

The procedure will give the cost per foot associated with complete bit wear. For a few cases where penetration rate decreases rapidly with tooth dullness, the minimum cost per foot can occur before complete bit wear. This situation can be determined by repeating Steps 4 and 5 using a drilling time slightly less than the bit life. If this results in a lower cost per foot, successively lower drilling times should be assumed until the optimum drilling time is determined.

Example 5.12. A Class 1-3 bit will be used to drill a formation at 7,000 ft having a drillability of 20 ft/hr. The abrasiveness constant τ_H has a value of 15.7 hours, the bearing constant τ_B has a value of 22 hours, and the bearing exponents B_1 and B_2 are equal to 1.0. The for…

$$= 0.250\left(2-\frac{W}{4d_b}\right)\left(\frac{60}{N}\right)^{1.84}.$$

For $(W/d) = 4$ and $N = 60$, J_2 has a value of 0.250. … …ing a final tooth dullness of 1.0, Eq. 5.12b gives

$$t_b = J_2\tau_H\left[1+6(1)^2/2\right] = 4\tau_HJ_2.$$

Substituting the values of τ_H and J_2 into this equation yields

$$t_b = 4(15.7)(0.25)\left(2-\frac{W}{4d_b}\right)\left(\frac{60}{N}\right)^{1.84}$$

$$= 15.7\left(2-\frac{W}{4d_b}\right)\left(\frac{60}{N}\right)^{1.84}$$

For $(W/d_b) = 4$ and $N = 60$, the time required to reach tooth dullness of 1.0 predicted by this equation is 15.7 hours.

The bearing life can be computed using Eqs. 5.15 and 5.16.

$$J_3 = \left(\frac{60}{N}\right)\left(\frac{4d_b}{W}\right)^{1.0}.$$

$$t_b = J_3\tau_B(b_f) = J_3(22)(1.0)$$

$$= 22\left(\frac{4d_b}{W}\right)\left(\frac{60}{N}\right).$$

For $(W/d_b) = 4$ and $N = 60$, the time required to completely wear the bearings predicted by this equation is 2…

abrasiveness constant τ_H has a value of 15.7 hours, the bearing constant τ_B has a value of 22 hours, and the bearing exponents B_1 and B_2 are equal to 1.0. The formation pore pressure gradient is equivalent to a 9.0-lbm/gal fluid, and the mud density is 10.0 lbm/gal. The bit costs \$400, the operating cost of the drilling operation is \$500/hr, the time required to trip for a new bit is 6.5 hours, and 3 minutes are required to make a connection. Using a threshold $(W/d_b)_t$ of 0.5 and the values of a_2 through a_8 as given, compute the cost per foot that would be observed for $(W/d_b) = 4.0$, $N = 60$ rpm, and a jet impact force of 900 lbf.

a_2	a_3	a_4	a_5	a_6	a_7	a_8
0.000087	0.000005	0.000017	1.2	0.6	0.9	0.4

Solution. Using Table 5.8 for a Class 1-3 bit, we obtain $H_1 = 1.84$, $H_2 = 6$, and $(W/d_b)_m = 8.0$. The value of J_2 as a function of bit weight and rotary speed is given by Eq. 5.11.

$$J_2 = \left[\frac{\left(\frac{W}{d_b}\right)_m - \frac{W}{d_b}}{\left(\frac{W}{d_b}\right) - 4}\right]\left(\frac{60}{N}\right)^{H_1}\left(\frac{1}{1+\frac{H_2}{2}}\right)$$

$$= \left[\frac{8-\left(\frac{W}{d_b}\right)}{4}\right]\left(\frac{60}{N}\right)^{1.84}\left(\frac{1}{1+6/2}\right)$$

For $(W/d_b) = 4$ and $N = 60$, the time required to completely wear the bearings predicted by this equation is 2 hours. Evaluation of the multipliers f_1 to f_4 and f_8 yields the following.

$$f_1 = 20.0.$$

$$f_2 = e^{2.303a_2(10{,}000-D)}$$

$$= e^{2.303(0.000087)(10{,}000-7{,}000)}$$

$$= 1.83.$$

$$f_3 = e^{2.303a_3D^{0.69}(g_p-9.0)}$$

$$= 1.0 \text{ for } g_p = 9.0.$$

$$f_4 = e^{2.303a_4D(g_p-\rho_c)}$$

$$= e^{2.303(0.000017)(7{,}000)(9-10)}$$

$$= 0.76.$$

$$f_8 = \left(\frac{F_j}{1{,}000}\right)^{a_8} = \left(\frac{900}{1{,}000}\right)^{0.4} = 0.959$$

Substitution of these values into Eq. 5.29 gives

$$J_1 = f_1 \cdot f_2 \cdot f_3 \cdot f_4 \cdot f_5 \cdot f_6 \cdot f_8$$

$$= (20)(1.83)(1.0)(0.76)f_5 \cdot f_6(0.959)$$

$$= 26.7f_5 \cdot f_6.$$

For $(W/d_b) = 4$ and $N = 60$, both the weight function and the rotary function f_6 have a value of 1.0; thus, J_1 has a value of 26.7.

The footage drilled before tooth failure at 15.7 hours is given by Eq. 5.31.

$$\Delta D = J_1J_2\tau_H\left[\frac{1-e^{-a_7h_f}}{a_7} + \frac{H_2\left(1-e^{-a_7h_f}-a_7h_fe^{-a_7h_f}\right)}{a_7^2}\right].$$

Since the bit teeth will fail first, the final tooth dullness is known to be 1.0. When the bearings fail first, it is necessary to compute h_f for the known value of t_b using Eq. 5.32. Solving the above equation for ΔD, we obtain

$$\Delta D = (26.7)(0.250)(15.7)$$

$$\times\left[\frac{1-e^{-0.9}}{0.9} + \frac{6(1-e^{-0.9}-0.9e^{-0.9})}{(0.9)^2}\right]$$

$$= 246 \text{ ft.}$$

This footage corresponds to approximately 8 joints of pipe at 3 minutes per connection. The total connection time is

$$t_c = \frac{3}{60}(8) = 0.4 \text{ hours.}$$

The cost per foot for the bit run is given by Eq. 1.16.

$$C_f = \frac{C_b + C_r(t_b + t_c + t_t)}{\Delta D}$$

$$= \frac{400 + 500(15.7+0.4+6.5)}{246} = \$47.56/\text{ft}.$$

This is the predicted cost per foot that corresponds to ending the bit run just before bit failure and is usually the minimum cost per foot for the bit weight and rotary speed assumed. However, to ensure that this is true, the cost per foot corresponding to a slightly shorter bit life should be checked. For example, if the bit was pulled after 15 hours, the final tooth dullness, as computed from Eq. 5.32, is given by

$$h_f = \sqrt{\left(\frac{1}{H_2}\right)^2 + \left(\frac{2t_b}{H_2J_2\tau_H}\right)} - \frac{1}{H_2}$$

$$= \sqrt{\left(\frac{1}{6}\right)^2 + \frac{2(15)}{6(0.25)(15.7)}} - \frac{1}{6} = 0.974$$

The footage drilled for this value of h_f would be

$$\Delta D = (26.7)(0.25)(15.7)$$

$$\times\left\{\frac{1-e^{-0.9(0.974)}}{0.9} + \left[6(1-e^{-0.9(0.974)}\right.\right.$$

$$\left.\left. -0.9(0.974)e^{-0.9(0.974)}\right]/(0.9)^2\right\} = 238 \text{ ft.}$$

The cost per foot after 15 hours of drilling time is given by

$$C_f = \frac{400+500(15+0.4+6.5)}{238}$$

$$= \$47.69/\text{ft}.$$

Note that this cost per foot is slightly greater than the cost per foot corresponding to the maximum possible bit life.

Relatively simple analytical expressions for the best constant bit weight and rotary speed were derived by Bourgoyne and Young[15] for the case in which tooth wear limits bit life. Eq. 1.16, the cost-per-foot equation, can be rearranged to give

$$C_f = \frac{C_r}{\Delta D}\left(\frac{C_b}{C_r} + t_t + t_c + t_b\right).$$

Substituting Eq. 5.12a for t_b and Eq. 5.31a for ΔD in this cost-per-foot formula yields

$$C_f = \frac{C_r}{\int_0^{h_f} e^{-a_7h}(1+H_2h)\,dh}\left[\frac{C_b}{C_r} + t_t + t_c \over J_1J_2\tau_H} + \frac{\int_0^{h_f}(1+H_2h)\,dh}{J_1}\right].$$

Taking $(\partial C_f)/[\partial(W/d)] = 0$ and solving yields

$$\left(\frac{C_b}{C_r}+t_t+t_c\right)\left\{a_5 - \left[\frac{\frac{W}{d_b}-\left(\frac{W}{d_b}\right)_t}{\left(\frac{W}{d_b}\right)_{max}-\left(\frac{W}{d_b}\right)}\right]\right\}$$

$$+ a_5J_2\tau_H\int(1+H_2h)\,dh = 0. \quad \ldots\ldots (5.33a)$$

Taking $(\partial C_f)/(\partial N) = 0$ and solving yields

$$\left(\frac{C_b}{C_r}+t_t+t_c\right)\left(1-\frac{H_1}{a_6}\right) + J_2\tau_H\int(1+H_2h)\,dh$$

$$= 0. \quad \ldots\ldots (5.33b)$$

Solving these two equations simultaneously for (W/d_b) gives the following expression for optimum bit weight.

$$\left(\frac{W}{d_b}\right)_{opt} = \frac{a_5H_1\left(\frac{W}{d_b}\right)_{max} + a_6\left(\frac{W}{d_b}\right)_t}{a_5H_1 + a_6}. \quad \ldots\ldots (5.34)$$

If the optimum bit weight predicted by this equation is greater than the flounder bit weight, then the flounder bit weight must be used for the optimum. The optimum bit life is obtained by solving either Eq. 5.33a or Eq. 5.33b for $J_2\tau_H\int(1+H_2h)\,dh$.

$$t_b = \left(\frac{C_b}{C_r}+t_t+t_c\right)\left(\frac{H_1}{a_6}-1\right). \quad \ldots\ldots (5.35)$$

The optimum rotary speed N_{opt} is obtained using the known value of t_b in Eq. 5.12b and solving for J_2. N_{opt} then can be obtained from J_2 using Eq. 5.11. This leads to the following expression for N_{opt}.

$$N_{opt} = 60\left[\frac{\tau_H}{t_b}\,\frac{\left(\frac{W}{d_b}\right)_{max}-\left(\frac{W}{d_b}\right)_{opt}}{\left(\frac{W}{d_b}\right)_{max}-4}\right]^{1/H_1} \quad \ldots\ldots (5.36)$$

Unfortunately, for the case where bit life is limited by bearing wear or penetration rate, such simple expressions for the optimum conditions have not been found and the construction of a cost-per-foot table is the best approach. This type of calculation is most easily accomplished using a digital computer.

Example 5.13. Compute the optimum bit weight and rotary speed for the bit run described in Example 5.12. Bit floundering was observed to occur for bit weights above 6,700 lbf/in. at 60 rpm.

Solution. The optimum bit weight is computed using Eq. 5.34

$$\left(\frac{W}{d_b}\right)_{opt} = \frac{a_5H_1\left(\frac{W}{d_b}\right)_{max} + a_6\left(\frac{W}{d_b}\right)_t}{a_5H_1 + a_6}$$

$$= \frac{1.2(1.84)(8.0)+0.6(0.5)}{1.2(1.84)+0.6} = 6.4$$

Thus, the optimum bit weight is 6,400 lbf/in. of bit diameter. The optimum bit life is computed using Eq. 5.35.

$$t_b = \left(\frac{C_b}{C_r}+t_t+t_c\right)\left(\frac{H_1}{a_6}-1\right).$$

Assuming a total trip time and connection time of about 7 hours, we obtain

$$t_b = \left(\frac{400}{500}+7\right)\left(\frac{1.84}{0.6}-1\right) = 16.1 \text{ hours.}$$

The optimum rotary speed can be calculated using Eq. 5.36.

$$N_{opt} = 60\left[\frac{\tau_H}{t_b}\,\frac{\left(\frac{W}{d_b}\right)_{max}-\left(\frac{W}{d_b}\right)_{opt}}{\left(\frac{W}{d_b}\right)_{max}-4}\right]^{1/H_1}$$

$$= 60\left[\frac{15.7}{16.1}\,\frac{8-6.4}{8-4}\right]^{1/1.84} = 36 \text{ rpm.}$$

Since the computed optimum weight is below the flounder point, the use of 1.2 for a_5 is justified. If the computed optimum bit weight is above the flounder point, the weight at which floundering occurs should be used for the optimum bit weight.

Significant cost savings have been reported from the field use of mathematical methods for obtaining the optimum bit weight and rotary speed. However, these techniques should not be applied without engineering supervision on location. In many instances, the assumptions made in the bearing wear, tooth wear, and penetration rate equations yield inaccurate results and the computed optimums are not valid. When engineering supervision is present in the field, the progress of each bit run can be monitored to ensure that the deviation between the computed and observed results is acceptable. The bit manufacturers constantly are evaluating the performance of their bits in the various areas of drilling activity and can furnish guidelines for the driller when engineering supervision is not available. For example, the normal range of bit weights and rotary speeds recommended by one bit manufacturer for journal-bearing, insert-tooth rolling-cutter bits is shown in Table 5.12. Using these guidelines, the driller can experiment using his own judgment and dull bit evaluation.

Exercises

5.1 List the two main types of bits in use today. Also list two subclassifications of each basic bit type and discuss the conditions considered ideal for the application of each subclassification given.

5.2 Discuss how cone offset, tooth height, and number of teeth differ between soft- and hard-formation rolling cutter bits.

5.3 List five basic mechanisms of rock removal that are employed in the design of bits.

5.4 Discuss the primary mechanism of rock removal used in the design of drag bits.

5.5 Discuss the primary mechanism of rock removal used in the design of hard-formation rolling cutter bits.

HW NO 7; CHAPTER 6: 4, 6, AND 7 in DRILLING ENGINEERING TEXT and 5.22, 5.24, and 5.28 in SPE TEXT

DUE DATE: Friday 5 September 2014

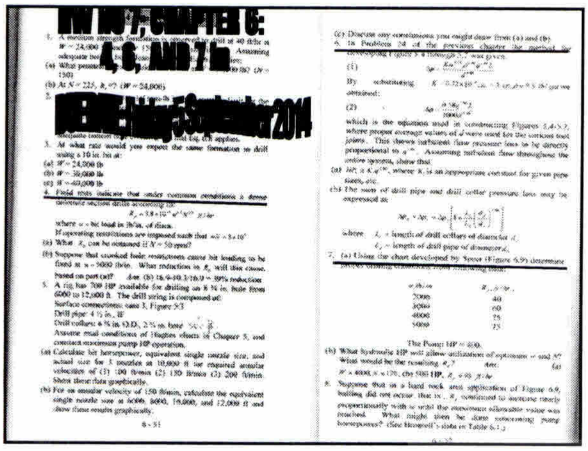
1. A medium strength formation is observed to drill at 40 ft/hr at $W = 24{,}000$ lb and $N = 150$ rpm. Bit size is 8 in. Assuming adequate bottom hole cleaning and that Eq. 6.4 applies:
(a) What penetration rate could be obtained at $W = 36{,}000$ lb? ($N = 150$)
(b) At $N = 225$, $R_s = ?$ ($W = 24{,}000$)

2. Assume that $WN = 3.6\times10^6$ rpm-lb is the operating limit for the conditions of Problem 1. Plot the rate of penetration vs W and N for the range $12{,}000 \le W \le 60{,}000$ and $60 \le N \le 300$. Show these plots on both cartesian and log-log paper. Assume adequate bottom hole cleaning and that Eq. 6.4 applies.

3. At what rate would you expect the same formation to drill using a 10 in. bit at:
(a) $W = 24{,}000$ lb
(b) $W = 30{,}000$ lb
(c) $W = 40{,}000$ lb

4. Field tests indicate that under common conditions a dense dolomite section drills according to:
$R_s = 3.8\times10^{-5}w^{1.5}N^{0.5}$ ft/hr
where w = bit load in lb/in. of diam.
If operating restrictions are imposed such that $wN = 5\times10^5$
(a) What R_s can be obtained if $N = 50$ rpm?
(b) Suppose that crooked hole restrictions cause bit loading to be fixed at $w = 5000$ lb/in. What reduction in R_s will this cause, based on part (a)? Ans: (b) 16.9-10.3/16.9 = 39% reduction.

5. A rig has 700 HP available for drilling an 8¾ in. hole from 6000 to 12,000 ft. The drill string is composed of:
Surface connections: case 3, Figure 5.7
Drill pipe: 4½ in., IF
Drill collars: 6¾ in. O.D., 2¼ in. bore [illegible]
Assume mud conditions of Hughes charts in Chapter 5, and constant maximum pump HP operation.
(a) Calculate bit horsepower, equivalent single nozzle size, and actual size for 3 nozzles at 10,000 ft for required annular velocities of (1) 100 ft/min (2) 150 ft/min (3) 200 ft/min. Show these data graphically.
(b) For an annular velocity of 150 ft/min, calculate the equivalent single nozzle size at 6000, 8000, 10,000, and 12,000 ft and show these results graphically.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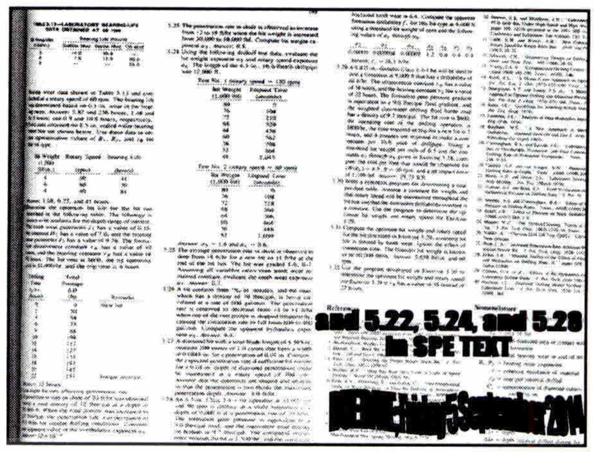
and 5.22, 5.24, and 5.28
in SPE TEXT