Drilling & Geology
Resource presentation for exercises related to Storvola & Festningen

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Festningen Exercise

• Solve an exercise that is focusing on elements to be considered when constructing a drilling program

• Can also be found on the resource CD
Festningen exercise

• Exercise handed out to each group in advance
• Work with it during the excursion and afterwards.
• Two groups will be selected to present and go through the assignment for discussion (powerpoint presentation)
Festningen Exercise

• In the field you should have focus on:
  • Which type of layers do we have and what is the sequence? (i.e. draw the stratigraphic column)

• For each layer, you should consider:
  – What type of bit would I use here and how will the ROP be (high or low)?
  – Is there potential for stuck pipe here?
  – Potential for lost circulation?
  – Layers/structures that can cause problems for directional drilling?
Drilling & Geology

![Diagram showing different geological layers and types of traps](image)

**Principal Types of Geologic Traps:**
- Fault
- Anticlinal
- Stratigraphic
- Domal

**Legend:**
- Clays
- Limestone
- Shale
- Salt
- Sandstone containing:
  - Natural Gas
  - Crude Oil
  - Water
Drilling Rigs

Semi Sub
West Alpha - Seadrill

Jack up
West Ariel / Seadrill

Drillship
West Alpha - Seadrill

Consults www.seadrill.com for an overview/animations

West Phoenix – Dual ramrigg. Seadrill

Condeep type. www.statoil.com
Riser, BOP, Choke and Killline

Figuur 1: Skisse av fast platform (produksjonseplatform) og fyltbare platform. Merk ulik placering av BOP og bomhodet, som i begge tilfelle står rett under BOP.

Figuur 2: Skisse av utstyr på pumpedeck og boretårn. Renseanlegg for returnert børebølger er ikke vist i detalj. Motorer som driver slampumpe, rotationsbord og hestespill er helst ikke vist. BOP står skiltisk på bomhodet.
Some drilling surface equipment

Riser tensioners, Petrobras.

Active heave compensator – www.akersolutions.com

TopDrive – www.nov.com

Riser – www.akersolutions.com

Iron roughneck www.akersolutions.com

Styreskinne/Lagring av rør
Drillstring components

BHA – Bottomhole assembly:
DC – Drill collars
HWDP – Heavy wall drillpipes
Jar – to release stuck pipe
MWD – Measurement while drilling
LWD – Logging while drilling
Motor or
Rotary steerable assembly (with logs integrated)
Underreamer
Holeopener
Stabilisers
+
+

The BHA composition will vary depending on which hole section to be drilled.

Some important drilling parameters:
• WOB – Weight on bit
• Torque
• RPM
• Flowrate
• ROP – rate of penetration

Example – Underreamer - www.halliburton.com

Bit.

www.nov.com
Drilling bits

Depending on the formation type, hardness and abrasiveness – a proper bit has to be selected to optimise ROP etc. Consult the homepages of the different vendors to see which bit that is most appropriate.
Some vendors

• National Oilwell (Reed Hycalog drillbits)
  – www.nov.com
• BakerHughes (Hughes Christensen)
  – www.bakerhughesdirect.com
• Smith
  – (www.smith.com)
• Varel
  – www.varelintl.com
• Halliburton
  – www.halliburton.com
ROP – rate of penetration

- ROP tells us how fast we drill.
  - (1 m/hour – very slow, 60 m/hour – quite good)
- Low ROP -> Expensive operations.
- ROP will depend on formation hardness & bit choice
- Bit change (wear, failure etc) is time consuming & costs money
- Important to choose the right bit for the formation to ensure
  - As high ROP as possible
  - Avoid wearing out the bits too early.
Formation hardness

• The choice of an appropriate bit will depend on formation hardness & abrasiveness
  – Soft/Medium soft formation
    • Shale, clay, limestone, sands.
  – Medium hard/hard formation
    • Hard limestone, sandstone, dolomite
  – Hard and abrasive formations
    • Granites, basalts, quartzite and chert
• Check www.adriatech.com for appropriate rock bits for the different formation types.
Drillbit types

- Roller cone
  - Tricone

- Fixed cutter bits – PDC
  - polydiamond crystalline

[www.nov.com](http://www.nov.com) - Rockforce
Drillbit types

- Diamond bit
  - Hard formations
  - Very expensive

- Drill out bicenter bits
  - Hole enlargement
Drillbit types

• Coring bits (take sealed samples of formation to surface)

• Milling tools (special bits are required for making hole in a steel casing when performing a sidetrack)
Roller cone bits

- Cones
  - Bearings
- Cutting structure
  - Insert (tungsten carbide) bits
  - Milled tooth
- Jet nozzles (x 3)
  - Remove cuttings
  - Jet impact force
  - Defines TFA (total flow area)
- Gauge inserts (protect gauge of bit)
Workprinciple

• When the drillpipe rotates the three cones will roll on the "formation" and crush the rock.

• A certain WOB (weight on bit) is applied
8-1/2" FH40ODV
(215.9 MM)
Product ID: 005218041 IADC 617X

The dual material elastomers in the patented Bullet™ seal provide superior protection for the bearing and enable the bits to attain the ultimate in reliability.

Spinodal™ 2 bearing with silver plated components ensures longer runs at higher ROP. This proprietary material offers maximum wear resistance and withstands extreme load forces for longer periods than conventional bearing materials.

Diamond enhanced heel inserts maintain gauge in abrasive, hard formation drilling and significantly increase cone durability. This feature extends bit life and ensures that a full gauge hole is drilled.

V-Flo™ directs nozzles to the leading side of the following bit cone to maximize cleaning. The resulting upward spiral flow enhances bottom hole cleaning, prevents bit balling and allows the bit to drill at maximum ROP.

Note focus on bearings (generally a weak point)
Note focus on gauge protection
Note focus on hydraulics
Note operating param

Design Specifications

<table>
<thead>
<tr>
<th>Bearing Type</th>
<th>Spinodal™ 2 Bearing w/Silver Plated Components</th>
</tr>
</thead>
<tbody>
<tr>
<td>Seal Type</td>
<td>Dual Material Bullet Seals</td>
</tr>
<tr>
<td>Bit Connection Type</td>
<td>4-1/2&quot; API Reg.</td>
</tr>
<tr>
<td>Journal Angle (°)</td>
<td>34</td>
</tr>
<tr>
<td>Offset (inches)</td>
<td>.188</td>
</tr>
<tr>
<td>Rows</td>
<td>Total: 14 inner: 11 Gauge: 3</td>
</tr>
<tr>
<td>Inserts/Teeth</td>
<td>Total: 157 inner: 106 Gauge: 51</td>
</tr>
</tbody>
</table>

Operating Parameters

<table>
<thead>
<tr>
<th>Weight on Bit</th>
<th>30,000 To 50,000 (lbs)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>13,635 To 24,998 (daN)</td>
</tr>
<tr>
<td></td>
<td>14 To 25 (Tonnes)</td>
</tr>
<tr>
<td>Rotary Speed (RPM)</td>
<td>200 To 50</td>
</tr>
</tbody>
</table>

The operating parameters listed here are general parameters, please contact your local Smith Bits representative for precise recommendations for your individual well.
Gauge protection

- Must ensure that the bit really drills the correct hole size
- Undergauge (due to wear) can lead to a stuck pipe situation when re-entering the well with a new bit.
- Wear resistant, durable shapes or diamond inserts on the heel row.
Cutting structure

- **Soft formation**
  - Long cutters
  - More scattered

- **Hard formation**
  - Short and butt cutters

- **Weak point is that the cutters will be worn**
  - Reduced ROP
  - Increase WOB will help temporarily but wear the teeth even more
  - Trip and install new bit
Bearsings

• Different types
  – Ball and roller bearing
  – Journal bearing (friction bearing)
  – Sealed and non sealed bearings
  – Lubrication (grease reservoir inside bit body supplies the bearings if the bearing is sealed)
Jet nozzles

• Usually three (sometimes a center nozzle in addition)
• Flow velocity (around 100 m/s) – remove cuttings/clean
• Nozzle diameters will impact flow velocity/pressure loss across bit
• Low flowspeed will impact ROP
• Nozzle diameters e.g. 20/32”
Roller cone application areas

• Steel tooth
  – Top hole, Soft formations
• Tungsten carbid inserts
  – Medium to very hard formations
  – Formations where PDC does not work
  – Drill out shoe (cement)
• Rate of penetration – Medium, Slow
• Steerability – Good
• More trips to change bit due to wear compared to using PDC bits.
Some issues to be aware of

- Cones can be lost (fishing operations)
- The cutters will be worn down
- Bearings is a weak point
- Gauge wear
- Bit balling (bit packed with formation)
PDC bits

• Body (tungsten carbide)
• Waterways (junk slot)
• Nozzles (3-8)
• Cutters (position and backracking angle will affect aggressiveness)
• Cutter blades (form and number can vary)
• No bearings (opposed to roller cone)
• Many different designs (pending on application area)
Work principle

PDC cuts rock

The cutter is placed with a certain angle (backrake) which affects how aggressive the bit will be. (cutter orientation)
PDC Cutters

- PDC is formed by polycrystalline diamond layer with tungsten carbide substrate
- Different types (special technologies)
- PDC cutters are self-sharpening
- PDC cutters deteriorate quickly at temperatures above 700 C. – Proper cooling by mud/hydraulics is very important (number of nozzles and positions).
- More cutter blades give better cooling and less wear on each cutter blade

www.pioneer-polydiamond.com
Application areas

- Soft to medium hard formations (not applicable in very hard & abrasive formations)
- Shales are easier to drill (ROP) than limestone/sandstone and PDC bits usually drills twice as fast in shale compared to roller cone
- Lower sections (12 ¼” hole ->)
- Steerable and rotary applications (motor & RSS)
- High ROP (opposed to roller cones)
- More expensive
- More robust (fewer trips compared to roller cone)
- Steerability depends on design
  - Aggressives of cutters
  - Backrake of cutters
  - Blade count
  - etc
Bit stability – important in design

• Unwanted vibrations
  – Axial (Bit bounce)
  – Lateral (Whirl)
  – Torsional – twist about its axis (Stick slip)

• Can destroy the bits quite fast and wear them down
Vibration roller cone

- Axial vibration - Yes
  - Due to the three cones
- Torsional vibrations – No
- Lateral vibration - Yes
  - Can cause rapid damage to teeth
Vibration PDC

- Axial vibration – No
- Torsional vibration – Yes
  - The shearing action of PDC causes a torsional force 3-4 times higher than for roller cone
  - Stick slip
- Lateral vibration- Yes
  - Quite common
  - Can lead to severe damage to bit and drillstring
  - Different designs to overcome this (anti whirl etc)

A challenge for PDC bits
Vibration - PDC

• To reduce vibrations and increase the stability of the bit is a very important part of the bit design process.

• When using PDC bit in a very hard formation (e.g. hard abrasive sandstone), the bit can easily be destroyed by vibrations (SPE 79797).
What affects the steerability of a bit

- High Torque sensitivity to WOB implies that small changes in WOB will easily change the direction in a way that is not wanted.
- Roller cones are much less aggressive than PDC bits -> easier to steer (basic design).
- However, PDC design has been continuously improved to increase the steerability.
- E.g. non aggressive cutters in the face of the bit will reduce torque sensitivity to WOB changes. Important for PDC bit steerability.

![Diagram showing WOB vs Torque for PDC and Roller cones](image-url)
Hybrid Bits (recent technology)

• Combination of roller cone and PDC bit design (use the best of both)
• Hard and interbedded formations - handles changes from soft to hard rock
• Less vibrations
• Increased ROP potential
• Chert drilling

Kymera Hybrid bit
Baker Hughes Tools
Natural Diamond Bits

- Applicable for hard formations (e.g. where roller cone is too slow or har too short lifetime)
- Not applicable for chert and pyrite (will break into pieces and may destroy the diamonds)
- Not applicable for very hard broken formations (may break the diamonds)

www.nov.com
Directional Drilling – Why?

• Avoid salt dome structures
  – Drilling through salt can cause large washouts, lost circ and corrosion

• Faults
  – Formation
  – In general, crossing faults -> right angle is better to avoid sliding
  – The same is true for hard formation layers
Directional Drilling – Why?

- Drilling of many wells from one platform
- Multilaterals
- Sidetracking
- Relief well (usually two)
Directional Drilling – Why?

- Drain several layers

- Horizontal drilling (Troll) – exploit a thin oil layer (10 m)

- Fractured formations (e.g. carbonates) have vertical fractures -> Horizontal wells are good for drainage
Directional drilling equipment

• Motor
  – Combined with MWD/LWD
  – Angle set at surface
  – Only the motor rotates when building angle (not pipe)
Directional drilling equipment

- Rotary steerable assemblies
  - Possibility to rotate while changing direction
  - MWD, LWD fully integrated
  - Real time communication with surface (i.e. possibility to change direction while drilling depending on information gained)

Autotrak – www.bakerhughesdirect.com

Geopilot - www.halliburton.com

Powerdrive – www.slb.com

Check the homepages for most recent technology developments
Casing program, Why?

- Stabilise formation
- Control pressures (avoid losses)
- Protect formation
- Isolate zones (avoid hydrocarbons migrating to surface)
- Avoid communication between zones
- Why is it smart to set the casing shoe in shale and not sandstone?

The two upper casings are typically cemented to seabed. Otherwise a 200 meter overlap is common.
Casing program, why?

• Install equipment/completion
• Reduce well friction
• Isolate sones
  – Avoid contamination
  – Avoid unwanted production
    • Coning
    • Shut off gas/water bearing formation
  – Possibility to control production from different layers.
## Typical casing sizes

<table>
<thead>
<tr>
<th>Navn</th>
<th>Drilled hole size</th>
<th>Casing Size</th>
<th>Alt</th>
<th>Example of depths (from seabed)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conductor</td>
<td>36”</td>
<td>30”</td>
<td></td>
<td>50-100 m</td>
</tr>
<tr>
<td>Surface casing</td>
<td>26”</td>
<td>20”</td>
<td>18 5/8”</td>
<td>300-1200 m</td>
</tr>
<tr>
<td>Run BOP on riser</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Intermediate casing</td>
<td>17 ½”</td>
<td>13 3/8”</td>
<td>16”</td>
<td>1300-2000 m</td>
</tr>
<tr>
<td>Production casing</td>
<td>12 ¼”</td>
<td>9 5/8”</td>
<td>10 ¾”</td>
<td>2500 – 4500 m</td>
</tr>
<tr>
<td>Production liner</td>
<td>8 ½”</td>
<td>7”</td>
<td>5 ½”</td>
<td></td>
</tr>
</tbody>
</table>
Pore pressure figure (most important figure in all drilling programs)

Depth TVD

Fracture pressure

Pore pressure

Pressure in sg (1.0 sg = 1000 kg/m3)

SPE Bergen – 2005, Gullfaks
Pore pressure + lithology is required to make the casing program.
Well pressures

- If $P_{\text{well}} < P_{\text{pore}}$ - > Potential kick
- If $P_{\text{well}} > P_{\text{frac}}$ - > Potential losses
- i.e $P_{\text{pore}} < P_{\text{well}} < P_{\text{frac}}$

- $P_{\text{well}} \text{ (bar)} = d \times 0.0981 \times H_{\text{tvd}}$
  - $d$ – density of mud i sg ( e.g 1500 kg/m3 =1.5sg)
  - $H_{\text{tvd}}$ – True vertical depth of well
Purpose of casing

• Avoid losses
  – The chosen mudweight (red line) will fracture the formation at around 1500 meters. It means that we must set a casing before drilling the next hole section.
Purpose of casing

- Stabilise well/protect formation – Avoid stuck pipe incidents
  - Plastic formation, swelling clay
  - Avoid loose (fractured formation falling into well)
  - Avoid key seating
Selection of correct mudweight

Ensure that there is a margin which takes into account:

- Swab effects
- Riser margin
- Temperature effects

The mudweight must be large enough to avoid a kick

Mudweight in sg (must be between pore grad and frac grad). We must set casings when the new mudweight can create losses

Max mudweight is limited by ECD (well pressure when circulating) and ev. surge pressures.
Kick & well control

- **Kick** - unwanted inflow of gas, oil or water, if not controlled -> Blowout

- **Reasons:**
  - Uncertainty in pore pressure
  - Wrong mudweight
  - Swab (during tripping or heave effects)
  - Lost circulation (mud disappear) caused by too high well pressures causing fractures or drilling into caves.
  - Insufficient refill of well while tripping out.
Well kill

• After the kick has been detected.
  – Close BOP
  – Monitor shut in pressures
  – Open choke and circulate the kick out through chokeline to separator/flare
    • Drillers method (kill mud after the kick has been circ out)
    • Wait and weight (circulate kill mud immediately)
  – Bullheading
    • Last option method – reverse kill by pumping/forcing kick back into formation
    • Reasons (H₂S, unacceptable large kick volumes that can break down the formations on its way up)
BOP - Barrier

- NORSOK D10 provides an overview of the required barriers (two) which are required during well operations.
- BOP is classified as a secondary barrier.
Chokeline, Killine, Choke

• If a kick is to be circulated out of the well it will be circulated out through the chokeline and the choke is used to control the well pressures in order to avoid new influxes.

• A killine is a similar line as chokeline to pump fluids into the well (or it can be used as a ”secondary chokeline”)

Chokeline ID : 3”
Separator

• The kick must be separated from the drilling fluid and the gas has to be “flared”.
• Typical 5-10 MMscf/day capacity

Poor boy degasser
www.oilfieldgnsolidscontrol.com
HPHT wells

- Formation temp > 150 C, Pwell > 690 bar.
- Large kick volumes
- Easier to get kick
- Kick can hide in oil based mud (flash later).
- More strict routines is implemented
  - Always circulate across choke if uncertain.

Choice of type of mud

• OBM (oil based mud)
  – Advantage:
    • Often more compatible with the reservoir
    • Less risk for fracturing the well at the last casing shoe in case of a kick (HPHT)
    • Reduce problem with swelling clay, thinner mud filter cake - reduced risk for getting stuck.

  – Disadvantage
    • HSE, environment, more expensive
    • Can be difficult to detect kicks in HPHT wells (the gas influx will hide in the mud) -> Special HPHT procedures are introduced in drilling to reduce the problem.
Choice of type of mud

• WBM (water based mud)
  – Often used in the upper sections
  – Advantage:
    • Cheaper, less HSE issues, more environmental friendly
    • Easier to detect kicks in HPHT wells (High pressure, high temperature wells)
  – Disadvantage:
    • Swelling Clay/Shale
    • Less lubrication
    • Thicker mudcake /easier to get differential stuck
Geology related drilling problems

• Stuck pipe is one of the more severe events that can occur during drilling and can lead to large costs
  – Fishing operation
  – In worst case, a sidetrack is the final solution.

• Three main causes
  – Mechanical related
  – Formation related
  – Differential sticking (pressure related)
Mechanical

- Key seating
- Poor hole cleaning
- Undergauge
- Wellbore geometry
  - Formation layers, change in hardness
- Collapsed casing
- Junk
Formation related

- Unconsolidated formations (e.g. sand)
- Boulders
- Fractured formations (e.g. around a fault)
- Mobile formations (e.g. salt)
Formation related - Shale

• Shale can cause some special problems:
  – Geo pressured shale (over pressured shale)
    • Requires a higher mudweight to control it.
  – Reactive shale (water from mud inhibits the shale and it swells) – lack of inhibition
Lost circulation

- Can result in a reduced mudlevel in the well which again can cause a kick.

- Reasons:
  - Naturally fractured formations (Karst, dolomite, limestone)
    - Maybe UBO must be used to drill this type of prospect
  - Too high ECD -> Fracture pressure exceeded
    - Reduce pump rate and mudweight
  - Surges
    - Avoid tripping to fast
    - Break mud gel before initiating circulation.
Lost circulation

• LCM – Lost circulation material pills are pumped (marbles etc ) to try to plug the fractures.

• Note that a lost circulation incident can have some very negative consequences
  – Increase Kick probability
  – Reduced cuttings transport -> possible stuck pipe
  – Reduced fracture pressure next time
  – Possible collapse of well
Lost circulation

• Important to identify potential loss circulation zones in advance.
  – Seismic, geology
• Isolate potential low pressure zones with casings
• Control ECD, cuttings transport
• Avoid pressure surges
• Have equipment ready for injecting LCM into well.