Dual Gradient Well Control System

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IADC Dual Gradient Drilling Workshop
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Different System - Learning the Terminology

- CUB
- Dynamic Shut-in
- DSV
- SRD Bypass
- SMD
- Lff
- TOM
- SRD
- MLP
- SWTT
- MWpp
- ▲ M/W
## Nearly ALL Drilling Operations Procedures Change with Dual Gradient Drilling

<table>
<thead>
<tr>
<th>Drilling Operations</th>
<th>Unchanged</th>
<th>Changed w/DGD</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Circulation</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>2. Drilling ahead</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>3. Connections</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>4. Tripping</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>5. Displacing drilling fluids</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>6. Lost circulation treatment</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>7. Wireline logging</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>8. Running casing</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>9. Running liner</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>10. Cementing casing</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>11. Cementing liner</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>12. Balanced plug</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>13. High pressure squeeze</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>14. Stuck pipe procedures</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>15. Use and installation of packers</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>Well Control Operations</td>
<td>Unchanged</td>
<td>Changed w/DGD</td>
</tr>
<tr>
<td>-----------------------------------------------------</td>
<td>-----------</td>
<td>---------------</td>
</tr>
<tr>
<td>1. Kick detection</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>2. Basic well control with DSV (Driller's Kill)</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>3. Basic well control w/o DSV: NO shut-in</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>4. Basic well control w/o DSV: WITH shut-in</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>5. Kick detection during tripping</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>6. Shut-in while tripping</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>7. Trapped pressure management</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>8. Volumetric well control</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>9. Lubrication kill</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>10. Stripping</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>11. Bullheading</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>12. Shut-in while running casing</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>13. Test casing seat</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>14. Dynamic kill</td>
<td></td>
<td>✓</td>
</tr>
</tbody>
</table>
DGD As Safe or MORE Safe Than Conventional

**Dual Gradient Drilling**
- Closed system
  - Kick detection is FAST!
  - Lower Casing Pressure
  - Less Gas
- Riser margin can be restored!
- Greater useable kick margin
  - Less lost returns
  - Greater kick control success
  - Fewer Underground Blowouts

**Conventional Drilling**
- Kick detection based on flowline or pits
- No riser margin available
- Riser inventory lost in emergency disconnect
- Kick margin is low
- Lost returns common
  - Kick control difficult
<table>
<thead>
<tr>
<th>Method</th>
<th>In DGD?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Flow Rate Increase</td>
<td>Better</td>
</tr>
<tr>
<td>Pit Gain</td>
<td>As good as ever</td>
</tr>
<tr>
<td>Flow Check</td>
<td>w/DSV-Good…w/o DSV –Requires Fingerprint</td>
</tr>
<tr>
<td>Improper trip fill</td>
<td>As good as conventional</td>
</tr>
<tr>
<td>Indirect Signs</td>
<td>Some are different</td>
</tr>
<tr>
<td>▪ Drilling Break</td>
<td>w/DSV-OK…w/o DSV- Fingerprint</td>
</tr>
<tr>
<td>▪ DPP &amp; Speed</td>
<td>About the same as conventional</td>
</tr>
<tr>
<td>▪ Mud changes</td>
<td>Similar, but appear earlier</td>
</tr>
<tr>
<td>Unique DGD Signs</td>
<td>(Comment)</td>
</tr>
<tr>
<td>▪ Flow on C.U.B</td>
<td>Purpose-built process</td>
</tr>
<tr>
<td>▪ Abnormal U-tube</td>
<td>Good, but hard to catch early</td>
</tr>
<tr>
<td>▪ MLP Rate Increase</td>
<td>VERY GOOD</td>
</tr>
</tbody>
</table>
Differences in DGD Well Control

- U-tube is always present
  - We have a new way to read SIDPP
- We *probably* will kill at higher circulating rates
- *May* have higher gas flow rates
- *May* not fully shut-in before killing
- Most wells would self kill if open to C&K Line
- The kick *MUST* be pumped to the surface
- We almost always have a riser margin
DGD Well Control vs Conventional

- Useful kick tolerance
- Wellbore integrity
- Reduced ballooning?
- Rapid kick detection
- We smash gas with the pump, kick volumes MAY be less

- Potentially faster kick recovery
  - We can pump faster when the time is right
- Math is a little harder
- More moving parts and more to learn about and watch

We Smash Gas Faster
BHP vs. Kick Volume

![Graph showing BHP vs. Kick Volume comparison between DGD and Conventional methods.](Image)
Primary Well Control is UNCHANGED

- NO changes to BOPE are made
- Static pressure across the BOPE is inherently lower or much lower than conventional
  - Conventional wells differential is MW – SW = up to 5000 psi
  - DGD differential is SW – SW = Nothing
  - This reduction applies to well control as well
- We are almost always dead with seawater at the mud line
- Even in a kick we can make the BOP differential ZERO
  - We fill the riser above the BOP with mud
Well Control For DGD

- **We can:**
  - Do ALL traditional well control procedures

- **We do:**
  - Provide two independent means for measuring SIDPP and SICP
  - Accomplish ALL well control procedures
    - With and Without the DSV
  - Provide for control of well pressures even if the MLP fails
    - The BOP is STILL the primary well control device
Keep BHP Constant

- **THE PRIME DIRECTIVE IS STILL TO KEEP THE BOTTOM HOLE PRESSURE CONSTANT**

- This is done while the well is
  - Circulating
  - or Static

- All contributing pressures in the well must be accounted for because
  - Circulating rates can be higher than in conventional well control
Basic Well Control Requirements
(nothing new here)

- Be prepared, have a good battle plan and make sure all the troops know their jobs
- Prevent kicks first
- Detect kicks early, keep them small and pressures
- Shut-in quickly, ask why later
- Be prepared, have a good game plan and make sure all the players know their jobs
- Measure and verify pressures and volumes
- Organize and execute the plan
- Clear the influx from the well safely
- Circulate kill weight mud
- Clean-up and drill some more
Preplanning is Paramount

Use of a Simulator

- Provides normal operation parameter predictions
- Useful design tool
- Very powerful friction pressure calculator
- Being modified and improved for future real time use
Simulator Output Montage

- SPP and MRL/KLP
- MLP Pressure and Volume
- Kick Volume
- Casing shoe and BHP
- GPM and Gas Discharge
- Choke opening
- MLP inlet and outlet pressure
- Pressure at top of kick
- Kick influx rate
- Kick position
  - Kick height
  - Kill pump schedule
We Proved all of This In Our Test Well
We Drilled a Well & Tested Well Control
Driller’s Control Screen
All Important Objectives Met

• Manage Bottom Hole Pressure at All Times
  – Constant inlet pressure mode (Drill)
  – Constant rate mode (Kick or Kill)
• Cuttings to Surface
• Verify Dual Gradient Operation Procedures
• All Equipment Operated as Designed
• Personnel adapted quickly, training paid off
• 90% of Field Test Objectives met
  • Including multiple induced kicks to test ability to discern a kick
We did it right the first time we tried it. Any questions?