Extended Reach Drilling

- Discussion of the State of the Art, Present Limitations, Completion, Fishing and Workover Tools & Techniques and Critical Safety Issues

Steve Walls
Definitions of ERD

- Throw ratio > 2:1
  - HD/TVD
- ER Projects typically break into four groups:
  - Ultra Long ERD
  - Very Shallow ERD
  - Deepwater ERD
  - Small Rig ERD
General Limitations

- Traditional Challenges have been mostly overcome
- Remaining Ones are Toughest
  - ECD
  - Ultra Deep Casing Runs
  - Practices
    - Design
    - Implementation
ERD Performance

- ERD: Just reaching the objective
- Time & Cost Performance
- New Benchmarks
  - Fit-for-Purpose Solutions
- ERD Solutions: Alternatives
  - Subsea Tiebacks
  - Another Platform
  - Increased Footprint
Ultra-Long ERD Wells

- Where are these wells being drilled?
  - US: GoM, California, ANS
  - West Africa, Canada, North Sea
  - China, Australia, New Zealand
  - SE Asia: Thailand, Malaysia, Indonesia
  - Russia
  - Argentina, Venezuela
Ultra-ERD Characterization

- Throw Ratios up to 6:1
- Build/hold to 80°
- Negative weight: ½ of the HD
- Special techniques: logs, casing
- Nuclear drilling
  - TDS-4 minimum, XT conn
  - 3 or 4 1600-hp pumps
  - 5.5”, 5.875” drill strings
What Does It Take?

- Extensive Planning: 9-12 mo/well
- Lead Times (Drill Pipe 1 year)
- Rig Availability & Modifications
  - HP, HT, space, setback loads
- Training for THAT well
  - Office & Operations teams
Available Technologies

- Casing Flotation
- Downhole Adjustable Stabilizers
- Rotary Steerable Systems
- Walking PDC bits
- Mechanical torque/drag reducers
- Wireline tractors
- Hole condition monitoring systems
- HT top drives and tubulars
ERD Performance

- **Case History: Real Learnings**
- **1992:** 15980’ MD
  - Drlg: 400 hrs  
  - NPT: 175 hrs
- **1994:** 16018’ MD
  - Drlg: 250 hrs  
  - NPT: 50 hrs
- **1996:** 16400’ MD
  - Drlg: 260 hrs  
  - NPT: <10 hrs
CH 2: Best Performance

- Pre-1993
  - 16,000’ MD: 70 days
CH 2: Best Performance

- **Pre-1993**
  - 16,000’ MD: 70 days

- **1993-1994**
  - 16,500’ MD: 50 days
CH 2: Best Performance

- **Pre-1993**
  - 16,000’ MD: 70 days

- **1993-1994**
  - 16,500’ MD: 50 days

- **1995-1996**
  - 16,500’ MD: 35 days
  - 20,500’ MD: 55 days
Operational Training

- Before Training
  - 14,500’ MD: 60 days
  - 16,000’ MD: 95 days
  - 17,800’ MD: 108 days

- Project-Specific Training
  - 21,000’ MD: 110 days
  - 22,000’ MD: 108 days
  - 25,000’ MD: 140 days
  - 24,000’ MD: 93 days
Deepwater ERD

- Same considerations as Shallow
  - ECD is primary limit
- Present wells
  - Comfortably within 2.5:1 ratio
  - 15,000’ step-outs, 6000’ TVD
  - Primarily from SPARs
- Deepest WD to date: 5400’
- Record: 6000’ TVD, 21,000’ step-out (WD was 1200’)

15,000’ step-outs, 6000’ TVD
Primarily from SPARs
Deepest WD to date: 5400’
Record: 6000’ TVD, 21,000’ step-out (WD was 1200’)
Small Rig ERD

- Typical: ERD Rig  Small Rig
- DW: 2000 hp  <1500 hp
- MP: 4000+ hp  2-3000 hp
- Circ: 7500psi  4000 psi
- TD: 60k ft.lbs  28k ft.lbs
- Mud: >3000 bbl  1000 bbl
- Setback: Plenty  Not Enough
Finesse Drilling

- Offshore California: 1999
- Small “workover” rig
- 5” drill pipe
- Portable top drive
- 2 850-hp mud pumps
- 750-bbl active mud system
- Not enough setback or casing storage
Project Concerns

- Setback Limits
  - Space and fingerboard size
  - Weight on sub and jacket
- Pipe stretch exceeded head room
- Pipe Rack Storage
  - Casing run off the boat
  - Managing multiple strings
  - Simultaneous setback limits
## Operational Limits

- **Catheads, Iron Roughnecks (HT)**
- **Rig Power**
  - Impossible to backream at TD
  - Max: Pumps, Top drive, Lifting
- **Design Limits: Overpulls gone**
- **Mud systems: shipped whole mud**
- **Solids handling, small volume**
- **Circ: Flowrate, pressure limits**
Project Results

- Record California Well
- 19,555’ MD
- 79° Tangent section, drop @ TD
- 3°/100’ build
- 16,000+’ HD
- 8,000’+ TVD
Completion Techniques

- Pre-Drilling Consideration
  - Well: designed for the completion AND future interventions
- Tubular logging, perforations
- 8500’ slotted horizontal liner
- Wireline, CT tractors
- Intelligent completions, particularly for multiple pay sections
Interventions

- Three Main Technologies
  - Jointed Tubing
  - Live Workovers (Snubbing)
  - Coiled Tubing Units
- Wireline Options typically limited
  - Wheeled Tools, Tractors
- Primarily are System Failures
  - Corrosion, Sand Control, failed packers (Annular pressure)
Fishing Considerations

- Wellbore friction constraints due to tortuosity, wellbore stability
- Jar placement is of prime importance in ERD wells
- Computer program placement instead of rules of thumb
- Required at the start: Risk Management Analysis
  - Sidetrack Planning Team
  - Are the Take Points Firm?
Jar Placement

- Longitudinal Stress Wave Theory
  - Foundation of Jarring Programs
  - Impact and Impulse
- Stress Wave Reflection
- Jars need to be optimized for both down-hits and up-hits, depending on the anticipated problems
- Two-piece jars can be useful
General Fishing Rules

- DLS > 15°/100’: don’t operate jars in this environment due to stresses
- Jars below build/turn section: As much as 50% of the axial load can be lost due to wellbore contact
- Jars above build/turn section: Stress wave reflections are less, resulting in lower impulse.
- Anticipate (experience)
Intelligent Wells

- Fundamental: downhole process control
  - Realtime (or near-RT) surveillance, interpretation and actuation
  - Accomplished through downhole measurement and remotely controlled zones (versus surface)
- “Dumb” wells: provide no data or control except through CT, wireline or jointed tubing interventions
Converging Technology

- Smart wells Just In Time
  - ERD-ML, Horiz Drlg achievements
  - Fewer but larger tubulars
  - Sand control & stim improvements
    - 50 bpm @ 15000 psi frac-pacs
  - Pre-completion of multiple pays
    - Draining multiple reservoirs
  - Co-mingled production
ABB Smart Well Concept
Baker In-Force System
Schlumberger IRIS (Intelligent Remote Implementation System)
Project Optimization

Reservoir monitoring and control
Sensor type and location
Flow control equipment and location

Simulation and optimization algorithm

Shared-earth model

Project goals and constraints:
- Maximize recovery
- Maximize net present value
- Flow rate
- Pressure
- Water cut
Future Intelligence

- ADMARC system being tested
Critical Safety Issues

- Consider the Operations
- HP Circulating Systems
- Multiple handling of Tubulars
- Exposures to exotic fluids
- SBM BMP: compliance systems
- Storm planning, ops disruptions
- Rushed planning implications
Summary

- Viable ERD projects are now being undertaken from small rigs, in deepwater & with very long HDs.
- Current technologies answer most of the limitations of ERD. Those limitations which remain are very significant challenges.
- ERD through specific design and implementation practices is an absolute must.
Horizontal Gravel Packs
Outline

- Introduction
- Circulating path in a standard gravel pack
- Some history
- Project planning and execution
- Limitations of horizontal gravel packs in ERD wells
- Future challenges
Introduction

- Gravel packing is a commonly applied technique to control formation sand production from open-hole oil and gas wells.
- In a gravel pack completion, a screen is placed in the well across the productive interval and specially sized, high permeability gravel pack sand is mixed in a carrier fluid and circulated into the well to fill the annular space between the screen and formation.
A basic gravel pack circulating path
Openhole horizontal gravel packing

- OHHGP has gained acceptance as a mainstay completion technique.
- Projected reliability and the potential to achieve significantly higher sustainable production rates have been the major drivers for pursuing this type of completion.
- Interval lengths in excess of 2500 feet are now fairly common, with the current record being 6,938 feet in a well completed in the North Sea by the Texaco North Sea UK Company.
Some history

- First Horizontal, Offshore California (1988)
- 1st Horizontal OHGP Congo 1990
- 1st GOM Shelf Horizontal GP (1993)
- 1st DW GOM HOHGP (8/97)
- 1st HOHGP from Floater (10/98) - Brazil
The demand of new technology:

- Deepwater completions of high volume producers (>15,000 BOPD or >70 MMscf/D) in the GOM with a well life up to 15 years became a major challenge for the industry.
- Increased reliability was needed for the openhole screened completions, and OHHGP was the answer to the problems experienced.
- Some of the difficulties that were encountered will be discussed here.
Key issues in project planning and execution openhole horizontal gravel packs:

- Reservoir study
- Shale stability study
- Formation integrity test
- Gravel pack sand sizing
- Gravel pack screen
- Workstring design
- Well displacement
- Fluid loss control
Issues that can jeopardize performance of successful OHHGP

- Excessive fluid loss
- Varying hole geometry that could lead to premature pack termination
- Hole stability issues leading to hole collapse
- A narrow pressure spread between bottomhole pressure and fracture gradient
Limitations of Extended-Reach Horizontal Gravel Packs

- The Beta-wave (return gravel wave) placement pressure is the main factor in determining the maximum length of a horizontal gravel pack.
- This pressure is limited by the requirement to install the gravel pack without exceeding formation fraction pressure.
Beta-wave Pressure Control

Alpha wave complete. Beta wave begins. No pressure differential across Valve.


With sufficient differential pressure, valve opens to re-establish return circulation path.

Beta wave resumes. Pump pressure reduced due to shorter circulating path.

Beta wave covers upper screen section. Final screenout occurs.
High Rate Well displacement to remove fluff

- Circulating brine at high velocity provides optimum hole cleaning.
- Ensures that drill solids and dynamic filter cake material (fluff) is circulated out.
- The remaining filter cake should be thin and extremely durable.
Future challenges

- New invert gravel pack fluid that has the potential to save rig time by reducing costly OB to WB fluid swaps, and also eliminates the need for acid treatment after pack placement.
- Advancement in tool technology that reduce bottomhole circulating pressure during placement of the sand pack using the Alpha/Beta placement method.
Cont’d

- Advancements in tool technology that allow multiple functions during a single trip of the workstring.
- Advances in screen systems that provide the capability to isolate and pack around shale sections as well as the capability to place the gravel pack while encountering fluid loss.
Final comments

- In the future, the newly developed expandable screen systems may also provide an alternative to horizontal openhole gravel packing.
- In a demanding environment such as deepwater, technology must continue to evolve to meet the need for long term reliability and high productivity.
- It is difficult to say whether one of these technologies will emerge as the dominant technology.
LOC Control Techniques

- Techniques to Control Lost Circulation in Drilling Through Under-Saturated, High-Permeability Formations

Steve Walls
What’s the Problem?

- Producing formations depleted from virgin pressures
- Wellbore stability, casing string designs may cause problem
- Trapped pressures in source rock require high MWs; lead to very high overbalances & Delta P
- Weakened rock matrices
- Synthetic Oil Based Muds
Problem Magnitude

- Losses may be almost inevitable
- Once begun, LOC very difficult to cure when drilling with SBM
- Typically, losses > 25 bbl/hr require a response from rig team
- @ $300/bbl, this could lead to a $180,000 mud loss in 24 hours
- Sen. Dirksen from Illinois
Response Strategies

- Systematic, Rigorous, Progressive
- Ramping-Up Approach
- Avoid the Problem
- Watch Indicators, React to Seepage Losses
- Manage ECD, Hydraulics, ROP
  - Hole Cleaning Cycles
- Kick Tolerance Consideration?
Progressive Response

- Sweeps: $\text{CaCO}_3$, G-Seal, Master-seal, 50-70 bbl’s @ 50-80 #/bbl (Lower end to maintain drilling)
- High Fluid Loss Squeezes: Frac Attack, Gunk Squeezes can be placed through drill string usually
- Dia-SealM & Cement Squeeze: POOH required, TIH OH
- Contingency string or live with the losses if you’re at a casing point
Working the Problem

- Early on, the loss zone(s) must be identified. Area knowledge?
- Resistivity Info (Invasion)
- Sand/Shale Interfaces
- At the Bit
- Casing Shoe or 1st Sand
- Rubble Zones (Sub-salt wells)
- Primary Cementing Considerations
Moving On

- After spotting pills, pull up, circ to ensure drill string is unplugged and free and monitor losses for 3-4 hours while well heals (and LCM migrates into position)
- If squeezing, use a 5-minute hesitation squeeze technique with no more than 50 psi increase per squeeze increment. Max 250-300
Continue to Monitor

- When LOC is healed, it’s usually a temporary fix, except in the case of Dia-SealM & cement squeezes.
- Monitor returns at all times and be aware of positions of drill string tools such as stabilizers and bit.
- If LOC occurs again, determine immediately if it’s a new zone or the problem you just fixed.
Important Considerations

- Care and feeding of the reservoir
- Rock matrix is under-strength, in the case of prior depletion
- Use Risk Management matrix to systematically determine the proper response level
- **DO NOT PRE-TREAT!**
  - Causes the problem you’re trying to avoid
Summary Points

- Lost Circulation, particularly in SBM, can quickly add up to the loss of hundreds of thousands of dollars + severe reservoir damage
- Anticipate the problem (logistics)
- Systematic Response
- Intelligent Drilling with all the relevant data points, ECDs, a patient approach to solutions
LOC Control Techniques

- Techniques to Control Lost Circulation in Drilling Through Under-Saturated, High-Permeability Formations

Steve Walls
What’s the Problem?

- Producing formations depleted from virgin pressures
- Wellbore stability, casing string designs may cause problem
- Trapped pressures in source rock require high MWs; lead to very high overbalances & Delta P
- Weakened rock matrices
- Synthetic Oil Based Muds
Problem Magnitude

- Losses may be almost inevitable
- Once begun, LOC very difficult to cure when drilling with SBM
- Typically, losses > 25 bbl/hr require a response from rig team
- @ $300/bbl, this could lead to a $180,000 mud loss in 24 hours
- Sen. Dirksen from Illinois
Response Strategies

- Systematic, Rigorous, Progressive
- Ramping-Up Approach
- Avoid the Problem
- Watch Indicators, React to Seepage Losses
- Manage ECD, Hydraulics, ROP
  - Hole Cleaning Cycles
- Kick Tolerance Consideration?
Progressive Response

- Sweeps: CaCO$_3$, G-Seal, Master-seal, 50-70 bbl’s @ 50-80 #/bbl (Lower end to maintain drilling)
- High Fluid Loss Squeezes: Frac Attack, Gunk Squeezes can be placed through drill string usually
- Dia-SealM & Cement Squeeze: POOH required, TIH OH
- Contingency string or live with the losses if you’re at a casing point
Working the Problem

- Early on, the loss zone(s) must be identified. Area knowledge?
- Resistivity Info (Invasion)
- Sand/Shale Interfaces
- At the Bit
- Casing Shoe or 1st Sand
- Rubble Zones (Sub-salt wells)
- Primary Cementing Considerations
Moving On

- After spotting pills, pull up, circ to ensure drill string is unplugged and free and monitor losses for 3-4 hours while well heals (and LCM migrates into position)
- If squeezing, use a 5-minute hesitation squeeze technique with no more than 50 psi increase per squeeze increment. Max 250-300
Continue to Monitor

- When LOC is healed, it’s usually a temporary fix, except in the case of Dia-SealM & cement squeezes.
- Monitor returns at all times and be aware of positions of drill string tools such as stabilizers and bit.
- If LOC occurs again, determine immediately if it’s a new zone or the problem you just fixed.
Important Considerations

- Care and feeding of the reservoir
- Rock matrix is under-strength, in the case of prior depletion
- Use Risk Management matrix to systematically determine the proper response level
- DO NOT PRE-TREAT!
  - Causes the problem you’re trying to avoid
Summary Points

- Lost Circulation, particularly in SBM, can quickly add up to the loss of hundreds of thousands of dollars + severe reservoir damage
- Anticipate the problem (logistics)
- Systematic Response
- Intelligent Drilling with all the relevant data points, ECDs, a patient approach to solutions
Towards Better Hole Cleaning

- High lubricity mud and the Use of Sweeps for Hole Cleaning; Understanding the Hole Cleaning Mechanisms

Steve Walls
Many Types of Systems

- But Still 3 Foundations
  - Water-Based (WBM)
  - Oil-Based (Diesel) (OBM)
  - Synthetic-Based (SBM)

  - Progressively higher costs and applicability as drilling severity increases, whether it’s HP, HT, ERD, Hole Stability or, as is most common, a combination of these.
Water-Based Systems

- Benefit the most from lubricants
- Combinations of surfactants, mineral oil, snake oil
- Most successfully used in fit-for-purpose approaches, MLD
  - Milne Point cocktail, ANS
- Highest Friction Factors of any system with the lowest $/bbl cost
- Drill-In Systems (Flo-Pro)
Diesel Oil Muds (OBM)

- Expensive, but very tolerant of contaminants and high temps
- Very stable, minor barite swap tendencies, Compressive
- Very good lubricity
- Serious Issues
  - Exposures
  - Discharges
  - Disposal, Housekeeping
Synthetic Based (SBM)

- Most predominant usage in ERD, Deepwater & areas with hole stability problems
- Very expensive, high lubricity
- Two main types, esther & I-o
- EPA discharges & LC50 issues
- Require the use of a BMP & compliance engineer
- Problems with LOC
SBM Characteristics

- Compressible like OBM
- Lose density as temp rises
- Very subject to barite swap
- Need to be very careful to stabilize density in well before drilling after a trip
- Cuttings dryers, oil retention and monitoring with compliance engineer
Hole Cleaning

- Hole Sweeps
- Hole Angles <30°
  - Improve as well goes vertical
- Very low benefit >30°
- Mainly contaminate mud system and drive up rheologies, causing other wellbore problems
- Satisfy the Office (or Field)
Hole Cleaning Model

- Lore is full of references to chip velocity, annular velocity, hole cleaning profiles (plug to laminar to turbulent)
- All explained in vertical wellbores with concentric annuli
- Seen any of those around lately?
Real Wellbores Today

- Directional Wells, Eccentric Annuli
- Varying hole angles and turns
- ECD problems lead to controlled ROPs, minimum rheologies
- Cuttings fall to bottom of wellbore around drill string, particularly in angle building sections when there’s a high proportion of sliding vs. rotary drilling
Some Snapshots

- 0° – 30°
  - More traditional hole cleaning
- 30° – 50°
  - Cuttings dune, Avalanching
- 50° – 90° (and beyond)
  - Cuttings dunes slowly working up the wellbore
- Picture a sweep in each annulus
How Does Hole get Cleaned?

- The real answer is that many times it doesn’t, resulting in stuck pipe, wasted time on trips, lost wells
- Drillers are Optimists
  - ERD: Exactly Reverse Direction
- Assume hole is NOT clean until it proves otherwise
- Torque, Drag, Circ Press, Cuttings
String Rotation

- This is the real key to hole cleaning
- Not just any rotation: low rpm is insufficient
- ERD Specialists have noted step changes at 120 rpm and again and 150-180 rpm, depending on drill string size
- Not a panacea if ECD is a problem
Patience

- Holes with extended 70° and above tangent sections rarely even begin to clean up until 2 bottoms up are observed.
- Dunes are moving up the well and the hole will unload suddenly.
- 4 bottoms up is typical, it can be more.
- Torque/Drag analysis: condition
Drilling while Cleaning

- It’s not impossible, but the mechanisms need to be understood as they apply to a given wellbore geometry.
- Great advantage of rotary drilling vs. motor drilling is hole cleaning (plus the lower tortuosity and micro-doglegs from tool sets).
- Weighing cuttings.
Summary Points

- Mud systems fit for purpose
- Understand Hole Cleaning mechanism through a given well
- Dubious value (& wasted money and time) of sweep combinations
- Designing the well to be cleaned
  - Drilling Clean (Motor Housings)
  - Tripping Clean (Hole Cleaning)
  - Casing Clean (Back Reaming)
Workshop on Multilateral and Extended Reach Wells

Jerome J. Schubert, TAMU
Bjorn Gjorv, TAMU
Steve Walls, Cherokee Offshore Engineering
Workshop on Multilateral and Extended Reach Wells

- Sponsored by:
  - Minerals Management Service
  - Offshore Technology Research Center
- December 5, 2002
- New Orleans, Louisiana
Introductions

- Bjorn Gjorv, TAMU GAR
- Steve Walls, Cherokee Offshore Engineering
- Jerome Schubert, TAMU, PI
Outline

- Introduction to Extended Reach and Multilateral Wells
  - Describe ERD and ML levels
  - Application

- Economic benefits
  - examples
Outline, con’t.

- New drilling technologies that can enhance ML/ERD
  - Dual Gradient Drilling
  - Expandable tubulars
  - High lubricity muds
  - Hole cleaning
  - State of the art in ERD
  - State of the art in MLD
Outline, con’t.

- Completion, workover, and fishing concepts
  - Horizontal gravel-packed sand control completions
  - Downhole completion tools for ER and ML wells
Outline, con’t.

- Technical difficulties
  - Lost circulation and other well control problems
  - Torque, drag, and buckling
  - Casing wear
  - Cementing

- Questions and discussion

- Adjourn
Introduction to Extended Reach and Multilateral Wells

- Describe ERD and ML wells
Wytch Farm

- SPE 28293 (1994)
BP Exploration Operating Co. Ltd. completed a well in U.K. Wytch Farm oil field with a horizontal reach of 10.1 km, setting a world record.

The M-11 well was drilled from an onshore drill site into a reservoir that extends offshore and was brought into production on Jan. 12 at a rate of 20,000 b/d of oil.
Deutag Drilling is the drilling contractor for extended-reach wells in BP's Wytch Farm oil field. The Deutag rig on drill site M, used to drill the record-breaking M-11 well, is the largest in Europe, with a 3,000 hp draw works, three 1,600 hp mud pumps, and a 45,000 ft-lb top drive. Photo courtesy of BP.
**Wytech Farm Extended-Reach Well Design**

*Generic design.*

Source: BP Exploration Operating Co. Ltd.
Wytch Farm M11 Well

- Stepout (Horiz. Depart.) = 33,181 ft
- Exceeded previous record by 6,729 ft
- Measured Depth = 34,967 ft
- True Vertical Depth (at TD) = 5,266 ft
- Time to drill and case = 173 days
- M11 is the 14th ERD well at Wytch Farm

*REF: Anadrill Press Release 1-23-98*
One third of reserves are offshore under Poole Bay

ERD project began in place of an artificial island in 1991

Saved 150 million in development costs

Development time saved - 3 years

Scheduled with reach of 6.2 km

Prod. before ERD project = 68,000 BOPD

Prod. with 3 ERD wells = 90,000 BOPD
Outline

- Figs. 3-6 Advertisements, PE Int.
- Figs. 7-9, OGJ, Dec. 11, 1995 p.44
- Figs. 10, 11, OGJ, March 16, 1998 p.76
- Figs. 12-17, OGJ, Dec. 1997 p.73
- Figs. 18-24, OGJ, March 23, 1998 p.70
- Oil & Gas Journal, Feb. 28, 2000, p.44
START DRILLING HERE

TOP-DOWN, BOTTOM-UP, OR FROM THE MIDDLE. IT'S UP TO YOU.

Sperry-Sun Drilling Services offers the only multi-lateral drilling systems that allow you to selectively drill laterals in any sequence, at any time, without losing the full bore of the main casing string. This flexibility allows you to set drilling and completion objectives without compromising your plans to accommodate the limitations of other multi-lateral drilling systems.

Sperry-Sun's unique multi-lateral systems, including the LTBS™ (Lateral Tie-Back System) and RMLS™ (Retractable Multi-Lateral System), also provide the greatest versatility in completion design with easy re-entry into any lateral. The technology represented by these systems is the result of Sperry-Sun's unmatched experience in the drilling of multi-laterals.

We're continuing to set industry milestones for multi-laterals with over 60 installations. When you've installed more multi-lateral systems than any other service company, every one is a milestone. Call your Sperry-Sun representative and get more information about how you can start here, or there, or here. But always start with Sperry-Sun for your multi-lateral drilling program.

Sperry-Sun
Drilling Services
P.O. Box 60076, Houston, TX 77265
Phone: (713) 987-4300
Fax: (713) 987-5129
http://www.sperry-sun.com

© Copyright 1990, Sperry-Sun Drilling Services, Inc.
All Trademarks of Sperry-Sun Drilling Services, Inc.
Fig. 1. The Multi-String Completion System provides segregated production and allows lateral re-entry using a dual bore deflector.
Stacked laterals

Dual zone lateral

Austin chalk
Opposing laterals

Austin chalk
Retrievable whipstock

Austin chalk
### Multilateral Completions

**Levels 1 & 2**

<table>
<thead>
<tr>
<th>Description</th>
<th>Illustration</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Open unsupported junction:</strong> Barefoot mother-bore and lateral or slotted liner hung-off in either of the well bores</td>
<td>![Illustration]</td>
</tr>
</tbody>
</table>
| **Mother-bore cased and cemented**  
Lateral open: Lateral either barefoot or with slotted liner hung-off in open hole | ![Illustration] |
Multilateral Completions
Levels 3 & 4

Mother-bore cased and cemented*
Lateral cased but not cemented*:
Lateral liner anchored to mother-bore. It includes a liner hanger but is not cemented*

Mother-bore cased and cemented*
Lateral open:
Both bores cemented at the junction
Multilateral Completions
Levels 5, 6 & 6B

Pressure integrity at the junction:
Achieved with the completion†

Pressure integrity at the junction:
Achieved with the casing†

Downhole splitter:
Large main well bore with two smaller lateral bores of equal size
**Window Milling**

**Step 1**
Run multilateral packer on starter mill assembly

**Step 2**
- Set packer
- Shear starter mill
- Commence milling window

**Step 3**
Complete milling of window
**Drill Lateral and Set Whipstock**

**Step 4**
Drill $8\frac{1}{2}$-in. lateral

**Step 5**
Run hook retrieval tool to pull solid whipstock

**Step 6**
Run and set Hollow whipstock
**Run Liner and Cement**

**Step 7**
Run 7-in., 29 lb/ft 13% chrome lateral liner

**Step 8**
Pump first stage cement

**Step 9**
Pump second stage cement (M-seal E)
MILLING OPERATIONS

Step 10
• Drill out cement
• Drill 6-in. open hole
• Set and cement 41/2-in. liner

Step 11
• Set milling anchor
• Shear out skirted mill assembly
• Commence drill-through of 7-in. line

Step 12
Mill 45/8-in. pilot hole through liner and hollow whipstock
**Step 13**
Run tripsaver mill assembly to open pilot hole from 4 5/8 in. out to 6 1/16 in.

**Step 14**
Mill packer plug and re-establish parent well bore.
**Step 15**
- Run window bushing
- Complete upper well bore

**Step 16**
Run through-tubing diverter to access lateral
Final well status after mill-through

» 6.07 in. ID through packer

» 6.184 in. ID through lateral liner
WindowMaster™

1. R.I.H. WindowMaster™ w/"HydraMaster™" packer
2. Measure orientation w/"MWD" pressure up annulus and set packer
3. Shear bolt & start window cutting
4. Increase W.O.M. & mill/ream window

- "Window Master™" BHA
- Flex pipe
- Watermelon mill
- Shear bolt
- Metal muncher mill
- Whipstock
- "HydraMaster™" packer
- "MWD" packer
- "MWD/DP"
- Watermelon mill w/flex area
- String mill w/flex area
- Metal muncher mill
- Flex pipe
ERD/ML Applications

Attempt to reduce the cost per barrel of oil produced.
Same or increased reservoir exposure with fewer wellbores
Substantial increase in drainage area.
Increased production per platform slot
ERD/ML Applications

- More reserves
- Production from natural fracture systems
- Efficient Reservoir drainage
- Exploiting reservoirs with vertical permeability barriers
ERD/ML Applications

- Improving thin oil zone reservoirs production performance
- Increase ROI
- Reduce well cost
- Reduce time
- Reduce capital cost
ERD/ML Limitations

- Modeling of multilaterals
- Problems during production phase
- Increased cost compared to one conventional well
- Higher risk
- Technology still in development stage
Economic benefits
Wytch Farm

WYTCH FARM EXTENDED-REACH DRILLING RADIUS

Source: BP Exploration Operating Co. Ltd.

Sherwood sandstone reservoir
1,585 m TVD subsea
Drill site
Sherwood existing TD location
Sherwood planned TD location
Radius of development of offshore reserves by extended reach drilling
Complex well geometries boost Orinoco heavy oil producing rates

Oil & Gas Journal, Feb. 28, 2000

- Single horizontal lateral
- Gull-wing well
- Stacked multilateral
- Fishbone well
- Gull-wing, fishbone well
- Stacked fishbone well

~9° API oil. \(~1.2 \times 10^{12}\) bbls in place. \(~250 \times 10^9\) recoverable
Single horizontal lateral

13⅜-in. casing in 500-600 ft
16-in. holes, 500-600 ft

Completion string
ESP or PCP pump

95⅛-in. casing in 12¼-in. hole, 2,000-2,500 ft
8⅝-in. hole 6,000-9,000 ft TD

7-in. slotted liner in 8½-in. hole, 6,000-9,000 ft TD
Stacked multilateral

Hole and casing sizes are the same as single lateral
Gull-wing well

9\(\frac{5}{8}\)-in. casing in 12\(\frac{1}{4}\)-in. hole, 3,000-9,000 ft

Slotted liners
Fishbone well

13,000-20,000 ft total footage in horizontal section

9 5/8-in. casing in 12 1/4-in. hole, 2,000-2,500 ft
Gull-wing, fishbone well

20,000-35,000 ft total footage in horizontal section

9 5/8-in. casing in 12 1/4-in. hole, 3,000-4,000 ft

Sloated liners in 8 1/2-in. hole 6,000-9,000 ft TD
Stacked fishbone well

20,000-35,000 ft total footage in horizontal section
LEVEL 3 JUNCTION

- 9 5/8-in. 40 lb/ft casing
- Electric submersible pump
- Level 3 junction
Unocal

- Dos Cuadras field – California
- Cost of a trilateral well - $2 million
- Cost of 3 conventional horizontals - $3 million
Texaco

- Brookeland field – Austin chalk
- Estimated savings of $500,000 - $700,000 per well as compared to two conventional horizontal wells of equivalent length
UPRC

- Austin Chalk – quadrilateral
- Total cost for re-entry was $605,000 which is 20% less than the cost of two new dual lateral horizontals
Austin Chalk

- Changes from vertical to horizontal to ML led to reductions in development costs from $12/BOE to $5.75/BOE to $4.65/BOE
North Sea

- Reduced development costs by 23% and 44% respectively when horizontal and ML approaches are compared to vertical well development
Saih Rawl Shuaiba reservoir

- Dual lateral wells were drilled for water injection. Five wells completed successfully at 30% cost savings per dual well relative to two single laterals.
Venezuela

- Level 3 Hook Hanger systems have yielded up to 900 bopd increase in production per well.
- Cost 1.58 times that of a single well
- But, Per-day increase in revenue, based on $20/bbl oil, is as much as $18,000/well
Deepwater Brazil

- ML costs an average of 1.43 times that of a single well
- While increased production, revenues and savings have amounted to as much as $10 million over conventional technology applied in the region
TFE - Argentina

Table 1 – Comparison between platform, subsea and ERD (Hidra – Argentina)

<table>
<thead>
<tr>
<th></th>
<th>Capex</th>
<th>NPV</th>
<th>PayOT</th>
</tr>
</thead>
<tbody>
<tr>
<td>Platform</td>
<td>2.3</td>
<td>1.9</td>
<td>5.8</td>
</tr>
<tr>
<td>Subsea</td>
<td>2</td>
<td>5.7</td>
<td>2.4</td>
</tr>
<tr>
<td>ERD</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
</tbody>
</table>

Fig. 1 Location of the Hidra field (Tierra del Fuego – Argentina)

Fig. 2 ERD profile and casing strategy (Hidra field – Argentina – World record)
TFE – U.K.
New drilling technologies that can enhance ML/ERD

Dual Gradient Drilling
Expandable Liners
High Lubricity Muds
Hole Cleaning
SOA in ERD and MLD
Dual Gradient Drilling
Solution: Static Wellbore Pressures

8.6 lb/gal
SEA WATER
HYDROSTATIC
PRESSURE

15.1 lb/gal
SMD

13.9 lb/gal
Conventional

DEPTH

4,472 psi

21,000 psi
Wellbore Pressures

- **Seafloor**
- **Depth**
- **Pressure**

- **Sea Water Hydrostatic Pressure**
- **Mud Hydrostatic Pressure**
- **Fracture Pressure**
- **Pore Pressure**

- Conventional
Wellbore Pressures

- **SEAFLOOR**
- **DEPTH**
- **PRESSURE**

- **MUD HYDROSTATIC PRESSURE**
- **SMD**
- **MUD HYDROSTATIC PRESSURE**
- **Conventional**
- **FRACTURE PRESSURE**
- **SEA WATER HYDROSTATIC PRESSURE**
- **PORE PRESSURE**
Casing Requirements - Conventional

- Seafloor
- Depth
- Pressure

- MUD Hydrostatic Pressure
- Conventional

- Fracture Pressure
- Pore Pressure

- Sea Water Hydrostatic Pressure
Expandable Tubulars

Fig. 1—Cross-section of partially expanded pipe with mandrel.
Expandable Tubulars

Fig. 2—Expandable Tubular are cold worked into the tubular's plastic region.
Expandable Tubulars

Well designs with the same production capacity using unexpanded- and expanded tubulars

Fig. 7—Comparison of a conventional well diagram versus well diagrams that Use expandable tubulars
High lubricity muds
Hole cleaning
State of the art in ERD
State of the art in MLD
Completion, workover, and fishing concepts
Horizontal gravel-packed sand control completions
Downhole completion tools for ER and ML wells
Technical difficulties

Lost Circulation
Well Control Problems
Torque, Drag, and Buckling
Casing Wear
Cementing
Lost circulation and other well control problems

Steve Walls
Torque and Drag
Sliding Motion

- Drag (friction)

\[ F = \mu N = \mu W \sin I \]
Torque

\[ T = \mu W \sin I \frac{d}{24} \]

Force to move pipe, \[ F = \mu W \sin I \]

An approximate equation, with \( W \) in lbf and \( d \) in inches.
Effect of Doglegs

(1) Dropoff Wellbore

\[ \delta = \text{dogleg angle} \]
A. Neglecting Axial Friction (pipe rotating)

\[ N \approx W \sin I + 2T \sin \frac{\delta}{2} \]  

(10)
Effect of Doglegs

Torque = \mu N \left( \frac{d}{2} \right) \approx \mu \left( \frac{d}{2} \right) \left( W \sin I + 2T \sin \frac{\delta}{2} \right)
Buckling
Figure 7 Schematic view of the small scale test loop

- Transparent tube (ID = 11 mm)
- Curvature radius 0.6 m
- Spiral string (OD = 3.4 mm)
- Length 0.65 m
Fig. 2 A schematic for coiled tubing buckling in a vertical wellbore.
Fig. 1—Postbuckled configuration of pipe in a horizontal hole.
Fig. 1—Postbuckled configuration of pipe in a horizontal hole.
When the axial compressive load along the coiled tubing reaches the following sinusoidal buckling load \( F_{cr} \), the initial (sinusoidal or critical) buckling of the coiled tube will occur in the horizontal wellbore.

\[
F_{cr} = 2 \left( \frac{EIW_e}{r} \right)^{0.5}
\]
A more general Sinusoidal Buckling Load equation for highly inclined wellbores (including the horizontal wellbore) is:

\[ F_{cr} = 2 \sqrt{\frac{EI W_e \sin \theta}{r}} \]
<table>
<thead>
<tr>
<th>Deg</th>
<th>Fcr</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>5.00</td>
<td>979</td>
</tr>
<tr>
<td>10.00</td>
<td>1,382</td>
</tr>
<tr>
<td>15.00</td>
<td>1,688</td>
</tr>
<tr>
<td>20.00</td>
<td>1,940</td>
</tr>
<tr>
<td>25.00</td>
<td>2,157</td>
</tr>
<tr>
<td>30.00</td>
<td>2,346</td>
</tr>
<tr>
<td>35.00</td>
<td>2,512</td>
</tr>
<tr>
<td>40.00</td>
<td>2,660</td>
</tr>
<tr>
<td>45.00</td>
<td>2,789</td>
</tr>
<tr>
<td>50.00</td>
<td>2,903</td>
</tr>
<tr>
<td>55.00</td>
<td>3,002</td>
</tr>
<tr>
<td>60.00</td>
<td>3,087</td>
</tr>
<tr>
<td>65.00</td>
<td>3,158</td>
</tr>
<tr>
<td>70.00</td>
<td>3,216</td>
</tr>
<tr>
<td>75.00</td>
<td>3,260</td>
</tr>
<tr>
<td>80.00</td>
<td>3,292</td>
</tr>
<tr>
<td>85.00</td>
<td>3,311</td>
</tr>
<tr>
<td>90.00</td>
<td>3,317</td>
</tr>
</tbody>
</table>

CRITICAL BUCKLING LOAD, lbf

INCLINATION ANGLE, degrees
Helical Buckling in a Horizontal Wellbore

When the axial compressive load reaches the following helical buckling load $F_{\text{hel}}$ in the horizontal wellbore, the helical buckling of coiled tubing then occurs:

$$F_{\text{hel}} = 2 \left(2\sqrt{2} - 1\right) \sqrt{\frac{EIW_e}{r}}$$
A more general helical buckling load equation for highly inclined wellbores (including the horizontal wellbore) is:

\[ F_{\text{hel}} = 2 \left( 2\sqrt{2} - 1 \right) \sqrt{\frac{E I W_e \sin \theta}{r}} \]
Buckling in Vertical Wellbores:

In a vertical wellbore, the buckling will occur if the tubulars becomes axially compressed and the axial compressive load exceeds the buckling load in the vertical section.

This could happen when we “slack-off” weight at the surface to apply bit weight for drilling and **pushing** the coiled tubing through the build section and into the horizontal section.
A helical buckling load for weighty tubulars in vertical wellbores was also derived recently through an energy analysis to predict the occurrence of the helical buckling:

\[ F_{\text{hel,b}} = 5.55 \left( \frac{E I W_e}{\rho} \right)^{2/3} \]
Helical Buckling in Vertical Wellbores:

This helical buckling load predicts the first occurrence of helical buckling of the weighty tubulars in the vertical wellbore.

The first occurrence of helical buckling in the vertical wellbore will be a one-pitch helical buckle at the bottom portion of the tubular, immediately above the KOP.
Helical Buckling in Vertical Wellbores:

The upper portion of the tubular in the vertical wellbore will be in tension and remain straight. When more tubular weight is slacked-off at the surface, and the helical buckling becomes more than one helical pitch, the above helical buckling load equation may be used for the top helical pitch of the helically buckled tubular.
Helical Buckling in Vertical Wellbores:

The top helical buckling load $F_{hel,t}$ is calculated by simply subtracting the tubular weight of the initial one-pitch of helically buckled pipe from the helical buckling load $F_{hel,b}$, which is defined at the bottom of the one-pitch helically buckled tubular:

$$F_{hel,t} = 5.55(EIW_e^2)^{1/3} - W_e L_{hel}$$

$$= 0.14(EIW_e^2)^{1/3}$$
From Table 1, it is also amazing to find out that the top helical buckling load, $F_{hel,t}$, is very close to zero. This indicates that the “neutral point”, which is defined as the place of zero axial load (effective axial load exclusive from the hydrostatic pressure force), could be approximately used to define the top of the helical buckling for these coiled tubings.
Conclusions

1. When conducting drilling, well completion and wireline logging in horizontal wells using CT, helical buckling of the tubing in the vertical section of the horizontal wells will usually happen. How to reduce this buckling will be a significant challenge in developing and extending CT technology for horizontal wells.
2. The CT may buckle helically in the horizontal section when conducting the above operations, but it is seldom for the CT to buckle in the build section of a horizontal well.
3. The axial load distribution of helically buckled CT will be largely affected by the frictional drag generated by the helical buckling. The CT may be "locked-up" in a horizontal well when a large portion of CT is helically buckled, to the point where you can hardly increase the bottom load, such as the bit weight, by "slacking-off" weight at the surface, nor push the CT further into the wellbore.
4. The equations on tubular buckling and axial load distributions presented here make it possible to predict the actual bit weight/packer load, and the maximum horizontal section length, for drilling, well completion, CT wire logging, CT stimulation, and other CT operations in horizontal wells. Generally, larger size of CT will reduce the risk of helical buckling and the amount of resulting frictional drag.
Casing wear
Excess torque and drag

- Threaten the success of completion if it exceeds the capacity of the Drive system or drillstring.
- Can result in casing wear
Excess torque and drag

- Can be prevented or reduced.
  - Wellbore profile.
    - Low doglegs
    - Catenary profile
  - High lubricity muds
  - Non-rotating drillpipe protectors
  - Rotary steerable systems
Catenary wellbore
Non-rotating drillpipe protectors

Figure 1: 3-1/2” Low-Drag NRDPP Inside 7” Casing
Non-rotating drillpipe protectors

Table 1: Average Rotational and Sliding COF’s.

<table>
<thead>
<tr>
<th>RESULTS</th>
<th>Low Drag NRDPP</th>
<th>Bare Drill Pipe</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average Sliding COF</td>
<td>0.11</td>
<td>0.21</td>
</tr>
<tr>
<td>Average Rotational COF</td>
<td>0.03</td>
<td>0.20</td>
</tr>
</tbody>
</table>

Figure 10: Slack-Off Weight. Actual measured drill string weight, with and without Low-Drag NRDPPs.
Rotary Steerable Systems

Drilling directional wells with a rotary steerable system results in a smoother wellbore. This results from constant rotation and deflecting the drillstring through adjustments downhole. Halliburton’s Geo-Pilot system is depicted above.
Remediation for Casing Wear

- Retrieve and replace
- Scab liners (tie back)
- Plastic liners
- Expandable cased-hole liners
Plastic Liners

Fig. 1. Roller reduction application places a tight-fit liner into the well. Reel capacity varies with liner diameter, and can be 5,000 to 12,000 ft of coiled plastic liner.
Plastic Liners

Fig. 2. Following downsizing, plastic liner is pulled into the well with simple weights that are retrieved through the liner bore after target depth is reached. After weights are removed, liner “memory” takes over and the plastic grows out against the steel pipe.
Fig. 3. As this sample pipe cross-section shows, a properly selected plastic, accurately downsized and successfully fitted, provides a tight-fitting liner that pushes out against the steel with a force that requires about 100 lb/in. to move; i.e., the liner is self-hanging.
Solid Expandable Tubulars

Fig. 1. Early expansion cone used to expand solid expandable tubulars.
Cementing

Variables that affect liner cementing performance in deviated wellbores
Cementing

- Displacement flow rate
- Cement slurry rheology
- Turbulators placement
- Centralization
Displacement flow rate

- Prodhoe Bay wells
  - 8-1/2” x 7” liner
    - Circulate at a velocity of 420-540 ft/min
  - 6-6/4” x 5-1/2” liner
    - Circulate at 600 ft/min
  - Cement slurry was displaced at 12 BPM
Cement slurry rheology

- Field results show more success with thinner cement slurries.
- This allows turbulent flow
- PV of 30-40
- YP of 3-5
- Results in a maximum swirl and turbulence
Turbulators placement

- Short 5 inch cylinders with spiral rigid vanes welded and positioned at approximately 30-45 deg.
- Forces the fluid to flow in a spiral pattern around the casing and wellbore.
- Two per joint is usually good
- Point in same direction
Centralization

- Must have enough centralizers to support the casing to centralize properly
Critical ERD Technologies
Critical Technologies for Success in Extended Reach Drilling (ERD) by Payne, M.L., Cocking, D.A., and Hatch, A.J.

Presented at the SPE ATCE, 1994, NO
This paper discusses critical technologies for ERD.

- Torque/drag
- Drillstring design
- Wellbore stability
- Hole cleaning . . .
Outline - cont’d

- Casing considerations
- Directional drilling optimization
- Drilling dynamics
- Rig sizing

This paper is based on knowledge and experience gained from Wytch ERD project
Torque/Drag

- Optimization of directional profile
- Mud lubricity
- Torque reduction tools
- Modeling considerations
Optimization of directional profile

- Simple build and hold profile is not successful
  - High torque and drag
  - BUR = 4 deg./30 m from near surface
Directional profile - cont’d

- Pseudo-catenary profile is used
  - Initial BUR = 1.0 - 1.5 deg./30 m
  - Maximum BUR = 2.5 deg./30 m
  - BUR increase = 0.5 deg./400 m
  - Target angle = 80 - 82 deg.
  - Torque reduction
  - Easy to run or slide drilling assemblies
Mud lubricity

- It is important but complex.
- It affects torque and drag.
- WBM is used in the beginning.
- OBM is used after setting 13-3/8 in. casing.
- Oil-water ratio has a significant impact on lubricity — more oil => less friction.
Torque reduction tools

- Non-rotating DP protectors
  - Typically one on every other joint
  - Reduced torque ~ 25%

- Lubricating beads
  - Expensive for OBM
  - Reduced torque ~ 15%
Modeling considerations

- No torque/drag model is adequate for dynamic drilling conditions
- Use MWD sub to measure downhole torque on bit and WOB
- Using MWD data, estimate friction coefficients to monitor and to predict downhole conditions such as torque/drag, wellbore stability, and hole cleaning
Drillstring design

- Top-drive rotary system capacity
  = 45 - 60 kips-ft
- Useful only if the drillstring provides matching strength
Drillstring design for high torsional capacity

- Grade S-135 is conventional
- Grades up to 165 ksi are considered non-conventional and “high strength”
- High torque thread compounds
- High torque connections
  - Double-shoulder tool-joints
  - Wedge thread tool-joints
Hole stability for high hole inclination

- Use correct mud weight
- Stress data from:
  - Leak-off test
  - Extensometer
  - 4-arm calipers
- Chemical interactions between mud and formation also affect stability
Hole cleaning

- Flowrate is the primary hole cleaning tool - up to 1,100 gpm in the 12 1/4” hole
- Rheology
- Pipe Rotation
- Circulate cuttings out - prior to trip
- Monitoring of hole cleaning
Solids control

- Solids control in mud is essential for long MD holes where hole cleaning efficiency may tend to be low
- May need extra processes or equipments
Casing consideration

- Casing wear avoidance
  - Tungsten carbide protects the drillpipe well, but is hard in casing
  - Use of new generation of hard-metal, e.g. chromium-based metals
  - Use of alternative hard-facing materials
- Several casing running options
Casing running options

Three primary considerations
- Maximum available running weight
- Frictional losses of running weight
- Mechanical losses of running weight
Directional well planning

- Anti-collision considerations
  - It is necessary when well separation is small.
- Target sizing (ex. 200 m by 350 m)
- Profile planning (ex. pseudo-catenary profile)
Hydraulic consideration

- Proper selection of PDM rotor nozzles
- Bit nozzle selection
  - Maximum bit pressure drop of 500 psi
BHA philosophy

- Change of one “primary” BHA component at a time.
- Use of steerable PDMs.
- Development of solid relationships with bit manufacturers and advancement of bit designs with those of the BHA.
Tortuousity considerations (dog-leg severity)

- Need to minimize slide interval and frequency
  - Slide on 5-7 m increments to maintain low angular change
Emerging technologies

- Rotary-steerable system
- Azimuth control tool
Surveying

- MWD
- Gyro surveys for specific objectives:
  - Anti-collision requirements
  - To reduce lateral errors at target entry
  - Definitive survey at target entry
Drilling dynamics

- Torsional stick/slip vibrations cause chaotic bit and drillstring motion and adversely affect bit life, ROP, and rotary drilling capacity
- Rotary feedback system to reduce torsional vibrations
- Bit/BHA induced lateral vibrations
- Hole Spiral
Rig sizing

- Requirements depend on ERD project size.
- Proper rig and drilling equipment is critical.
- It is necessary to determine maximum anticipated drilling torques and margins.
- Rig power efficiency must be analyzed.
Conclusions

- Special rig configurations and drilling equipments are necessary to successfully pursue extreme ERD objectives.
ERD operations require intense engineering focus on monitoring and analysis of field data and forecasting on future wells. High levels of team-based performance can be critical to ERD success.
Questions and discussion
The End
Thank you