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 80º
- 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

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  - 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’)

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
- 79º Tangent section, drop @ TD
- 3º/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>15º/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)

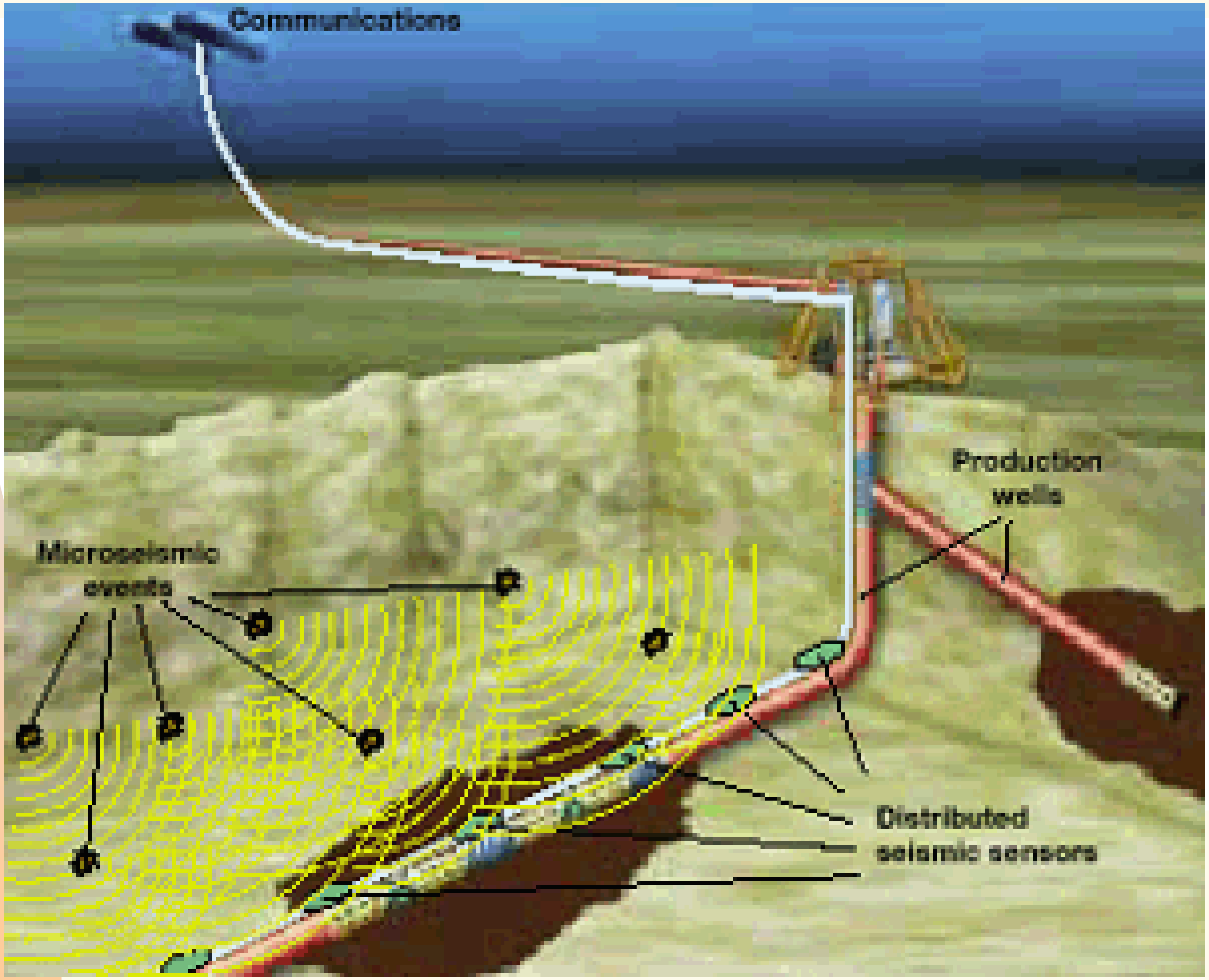
Intelligent Wells

- 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

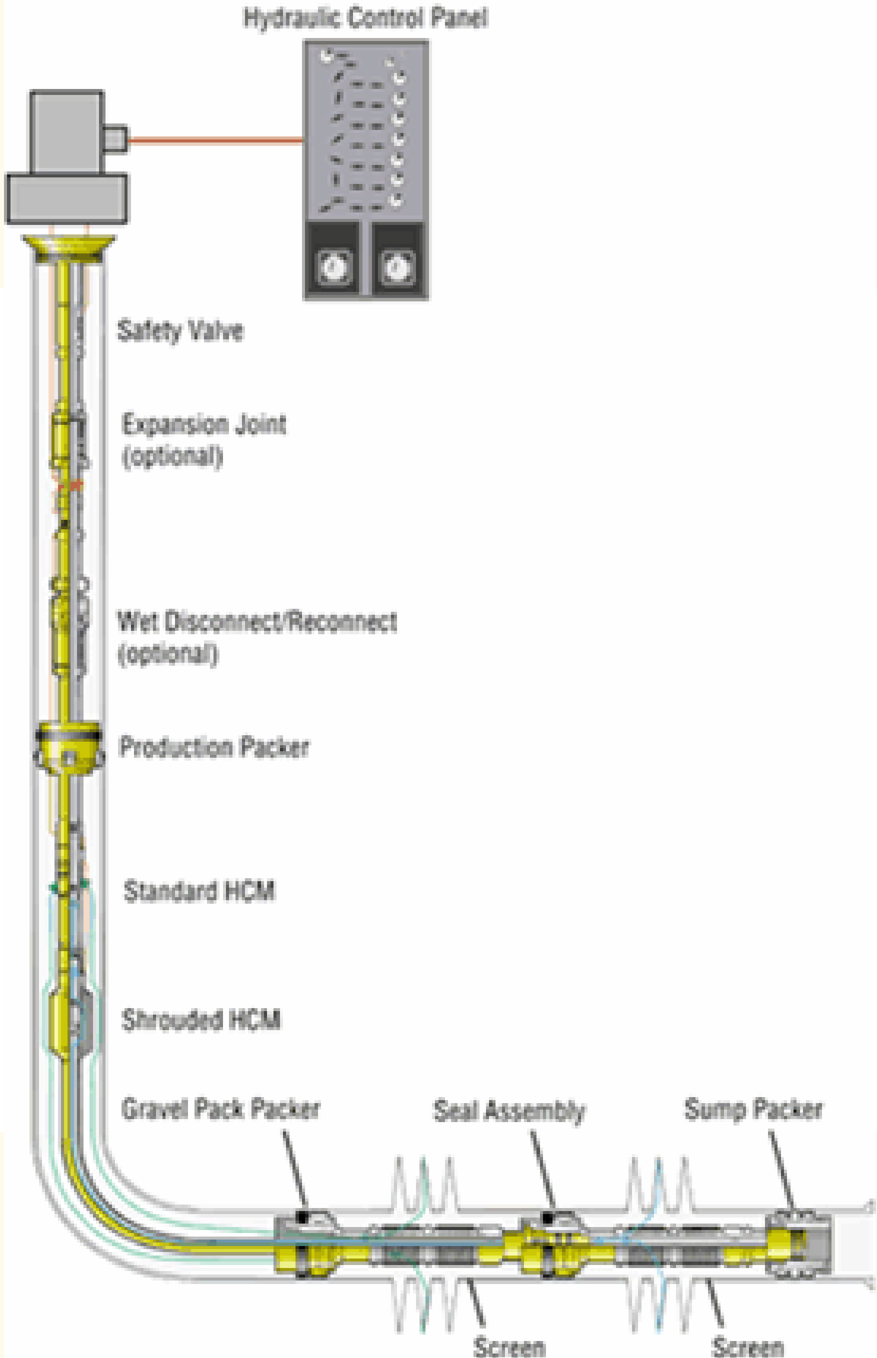
Converging Technology

- 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

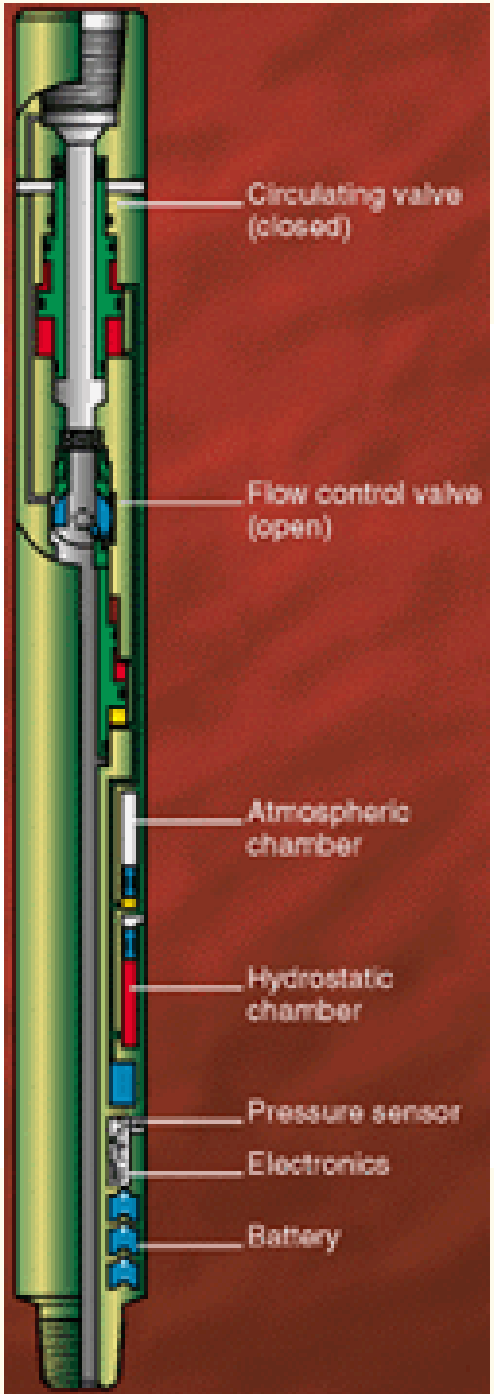
ABB Smart Well Concept

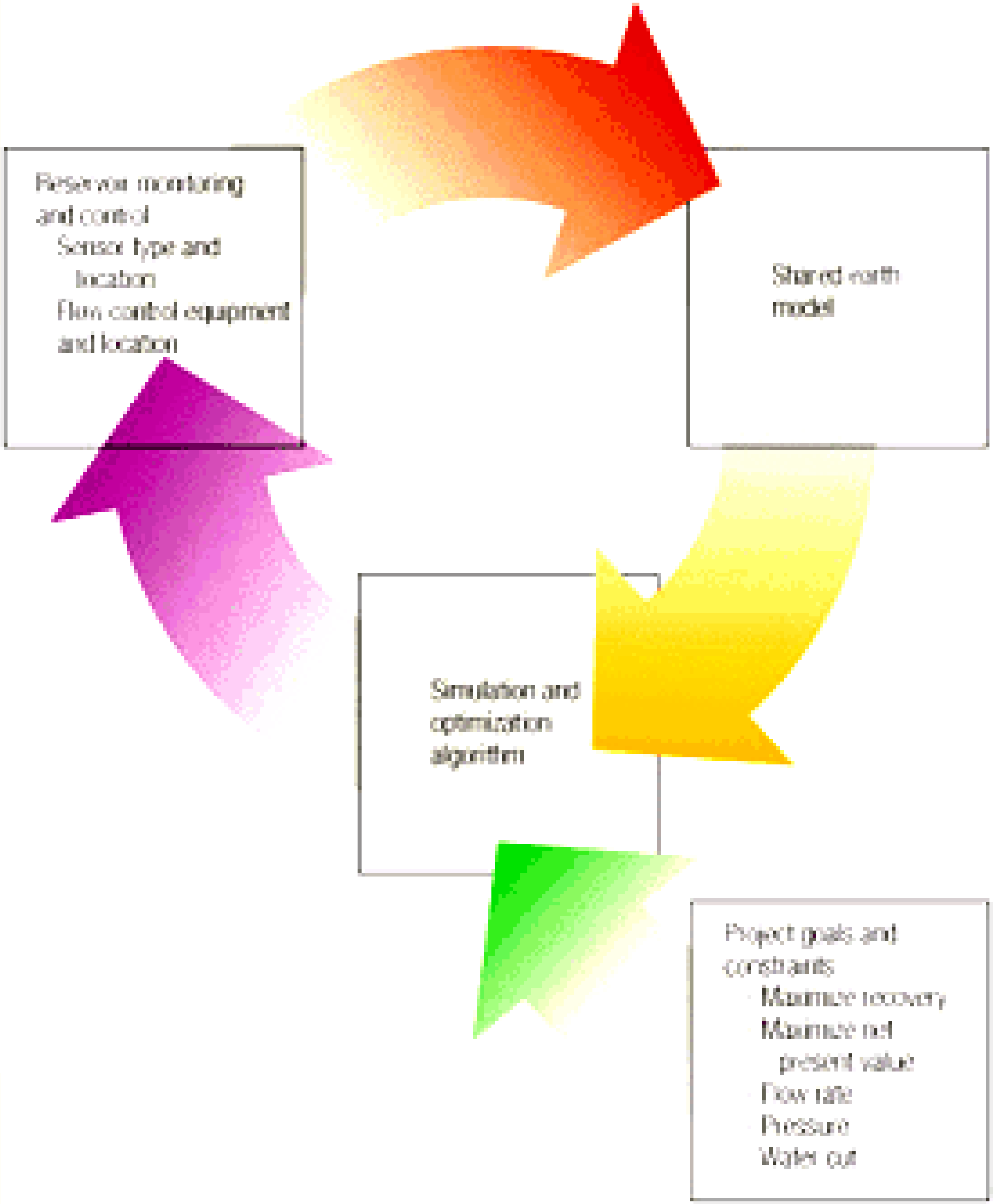


Baker
In-Force
System



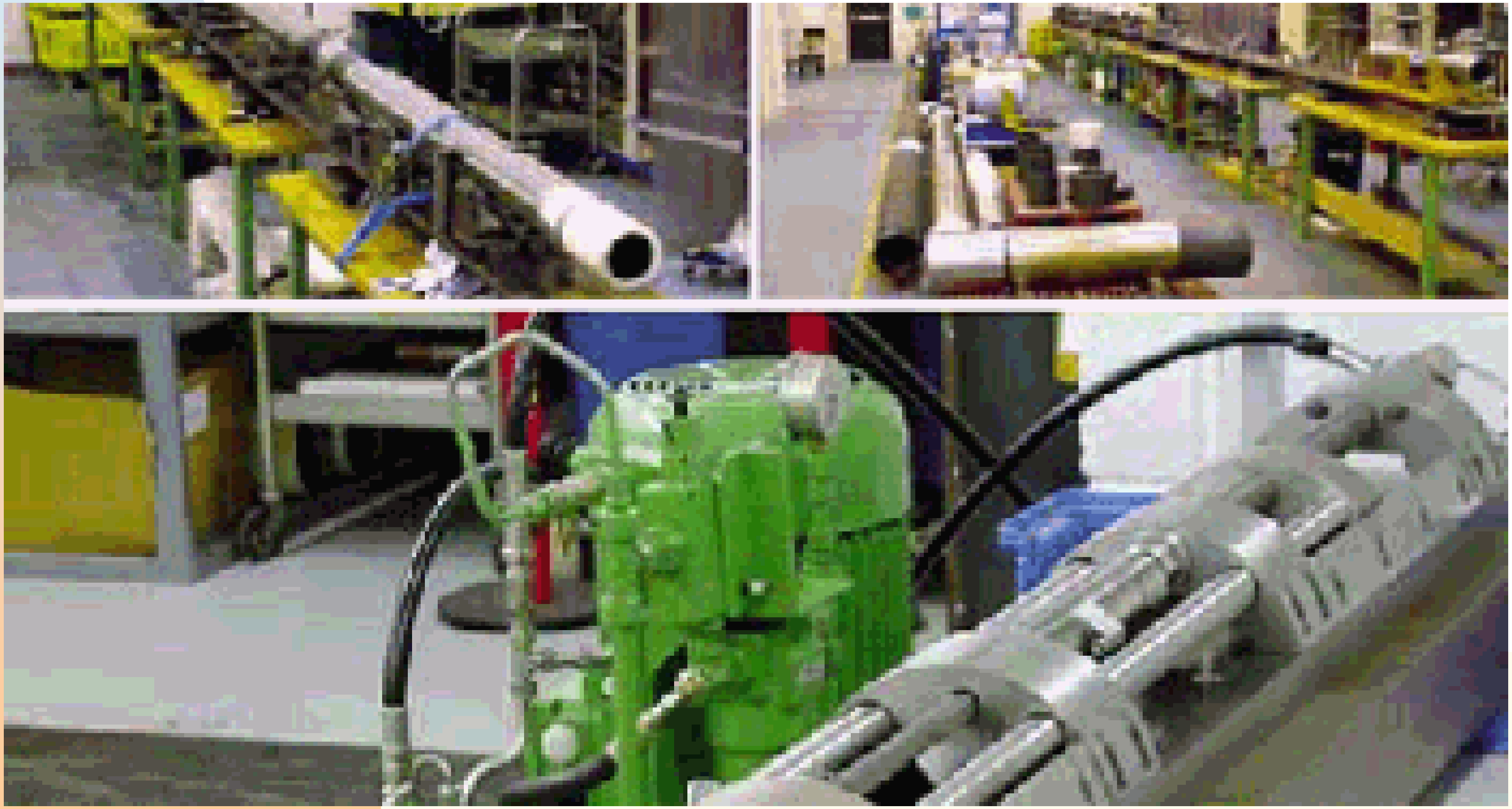
Schlumberger IRIS (Intelligent Remote Implementation System)




Reservoir monitoring and control
Sensor type and location
Flow control equipment and location
Shared earth model
Simulation and optimization algorithm
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

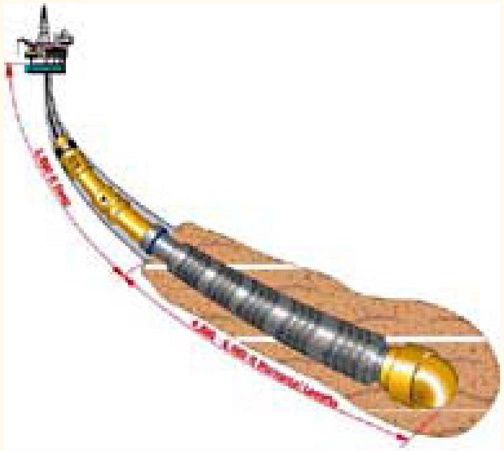
- Viable ERD projects are now being undertaken from small rigs, in deepwater & with very long HDs.
- Current technologies answer most of the limitations of ERD. Those limitations which remain are very significant challenges.
- ERD through specific design and implementation practices is an absolute must.

Horizontal Gravel Packs

20 Years of Service to America
MMS
Minerals Management Service
1982-2002

Outline

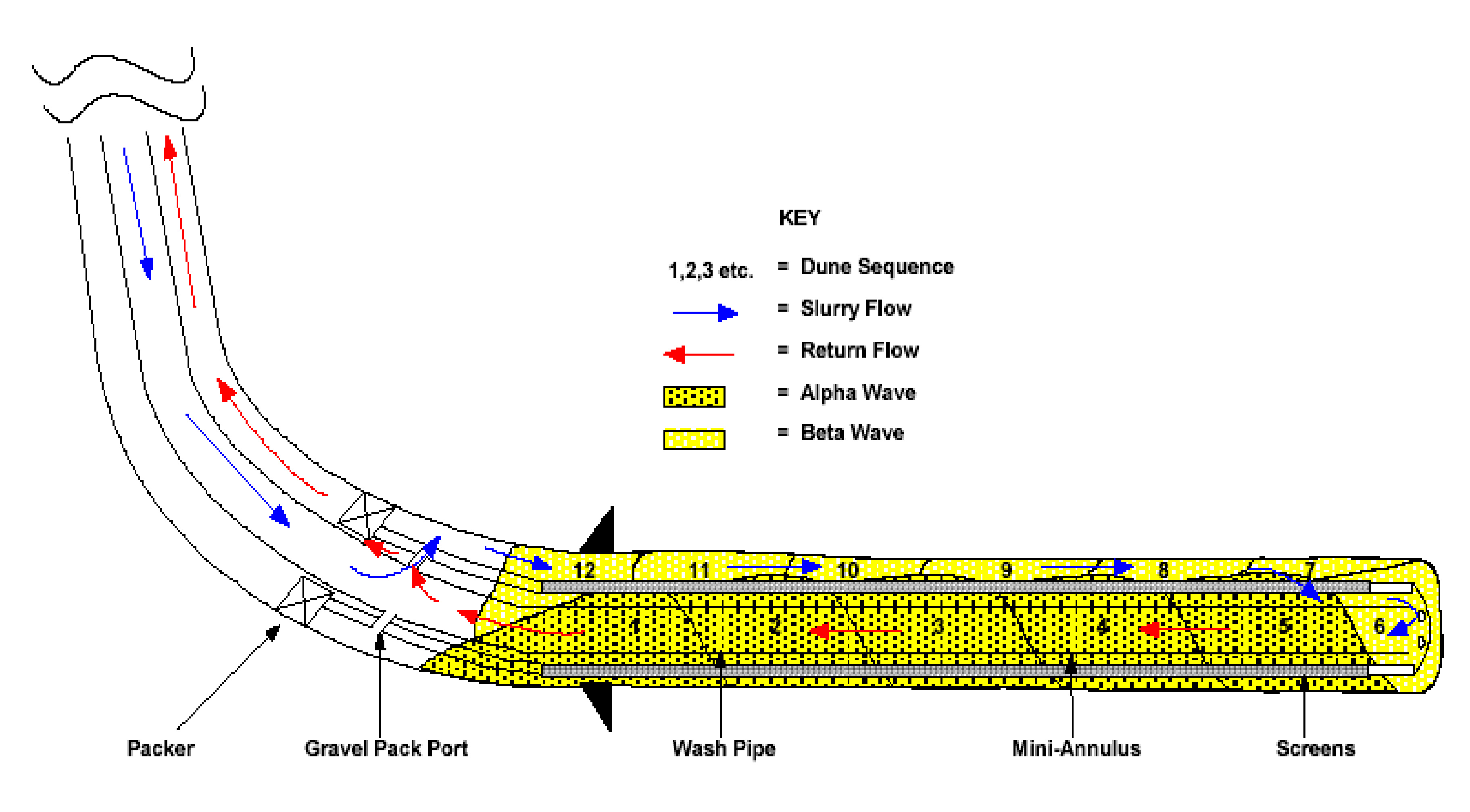
- Introduction
- Circulating path in a standard gravel pack
- Some history
- Project planning and execution
- Limitations of horizontal gravel packs in ERD wells
- Future challenges



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.

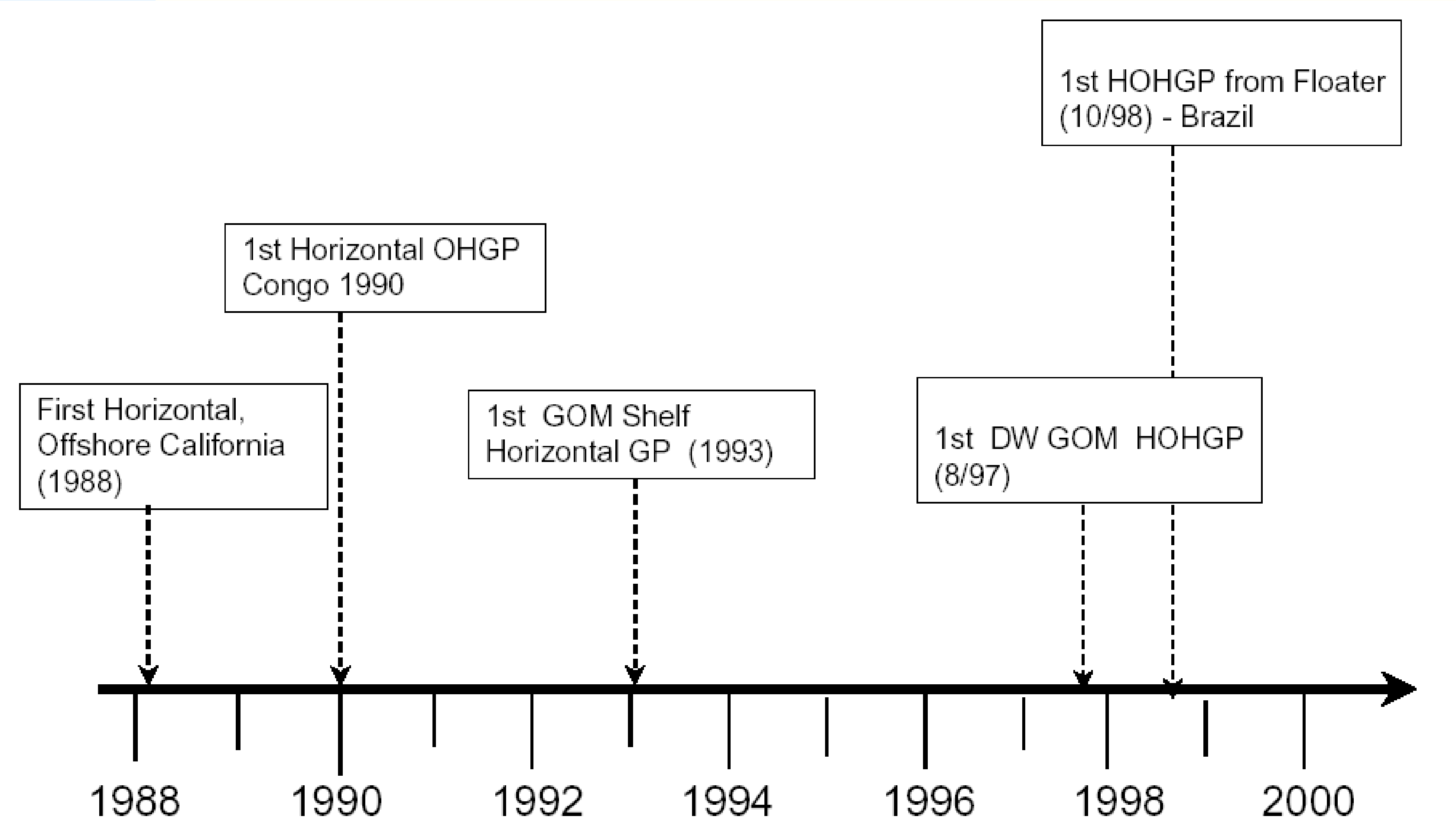
A basic gravel pack circulating path



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



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

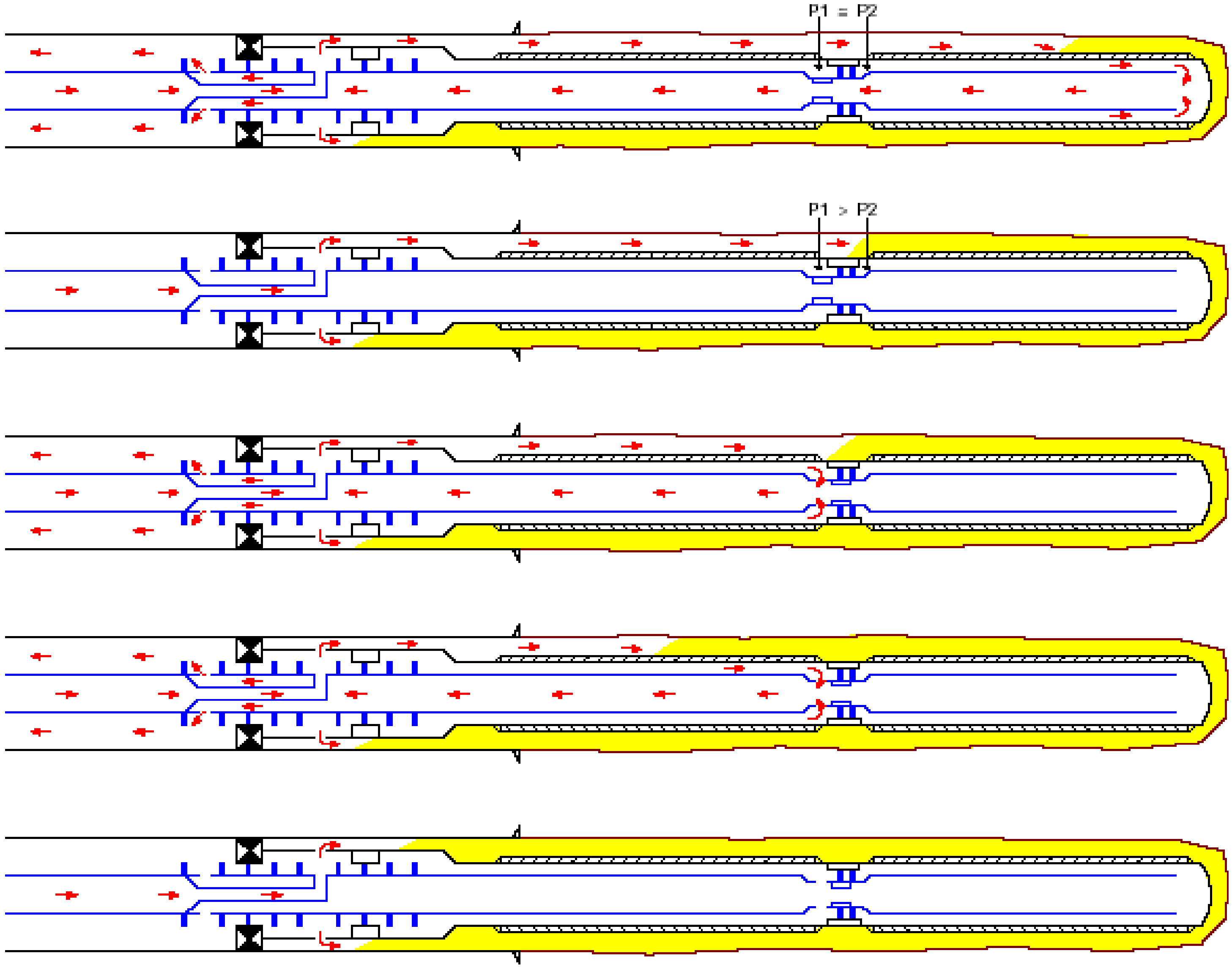
Issues that can jeopardize performance of successful OHHGP

- 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.

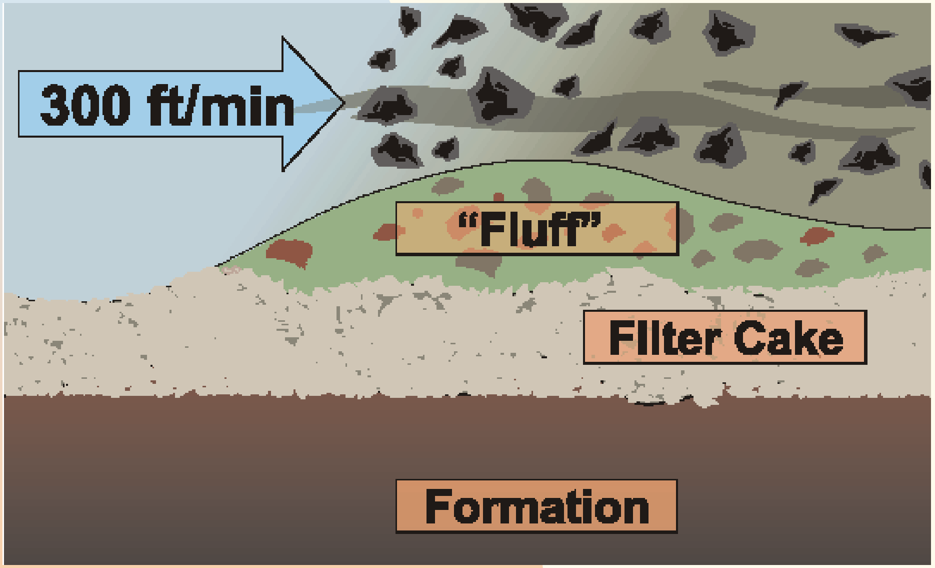
Beta wave covers lower screen section. Valve seals off screen/washpipe annulus causing temporary screenout. Differential across Valve increases.

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 occus.

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: $CaCO_3$, 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

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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 <30º
  - **Improve as well goes vertical**
- Very low benefit >30º
- 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

- 0º – 30º
  - **More traditional hole cleaning**
- 30º – 50º
  - **Cuttings dune, Avalanching**
- 50º – 90º (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 70º 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)**

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MMS
Minerals Management Service
1982-2002

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

- O&GJ, Jan. 19, 1998, p.24
- SPE 28293 (1994)

David Knott
Senior Editor

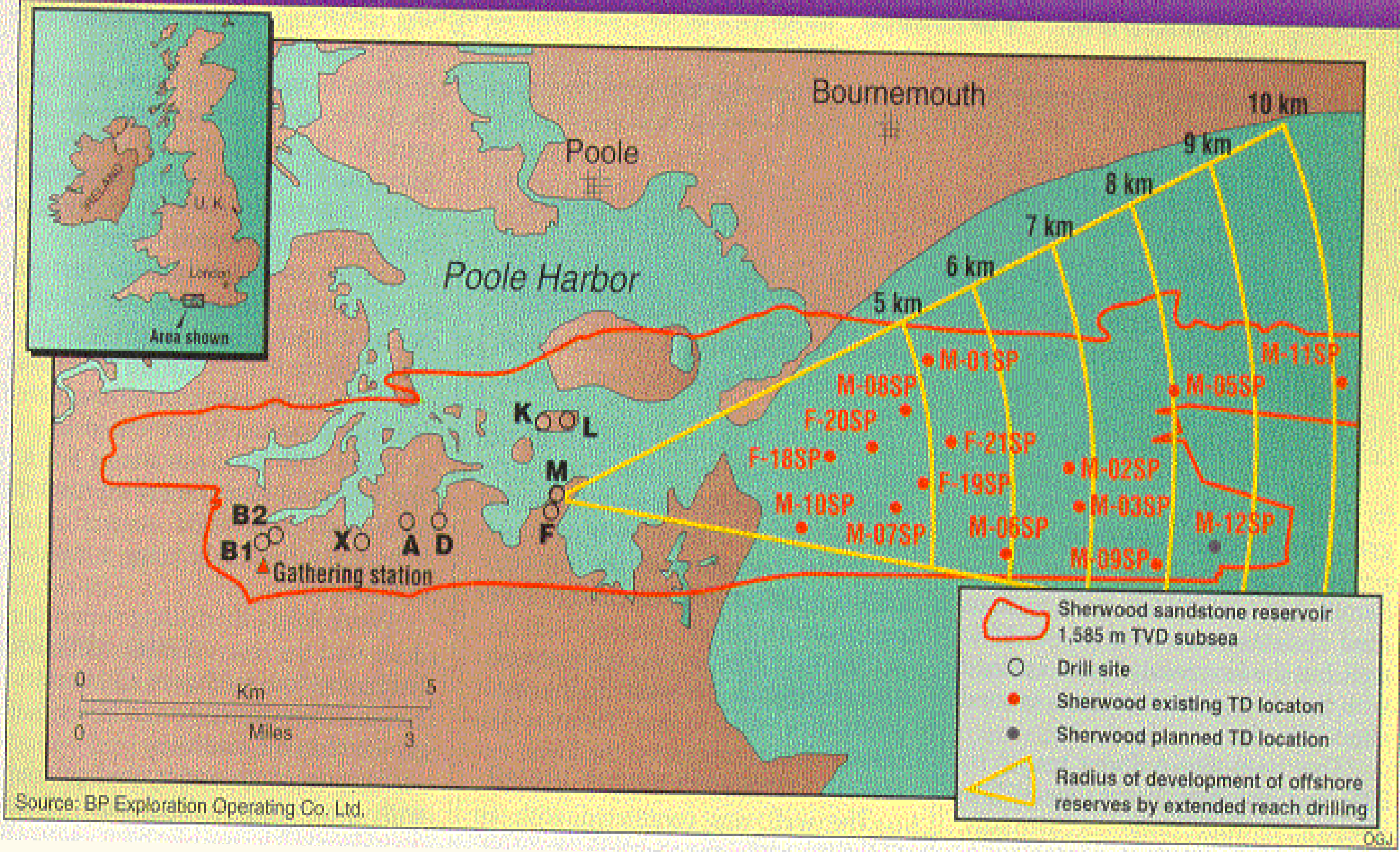
BP Exploration Operating Co. Ltd. completed a well in U.K. Wytch Farm oil field with a horizontal reach of 10.1 km, setting a world record.

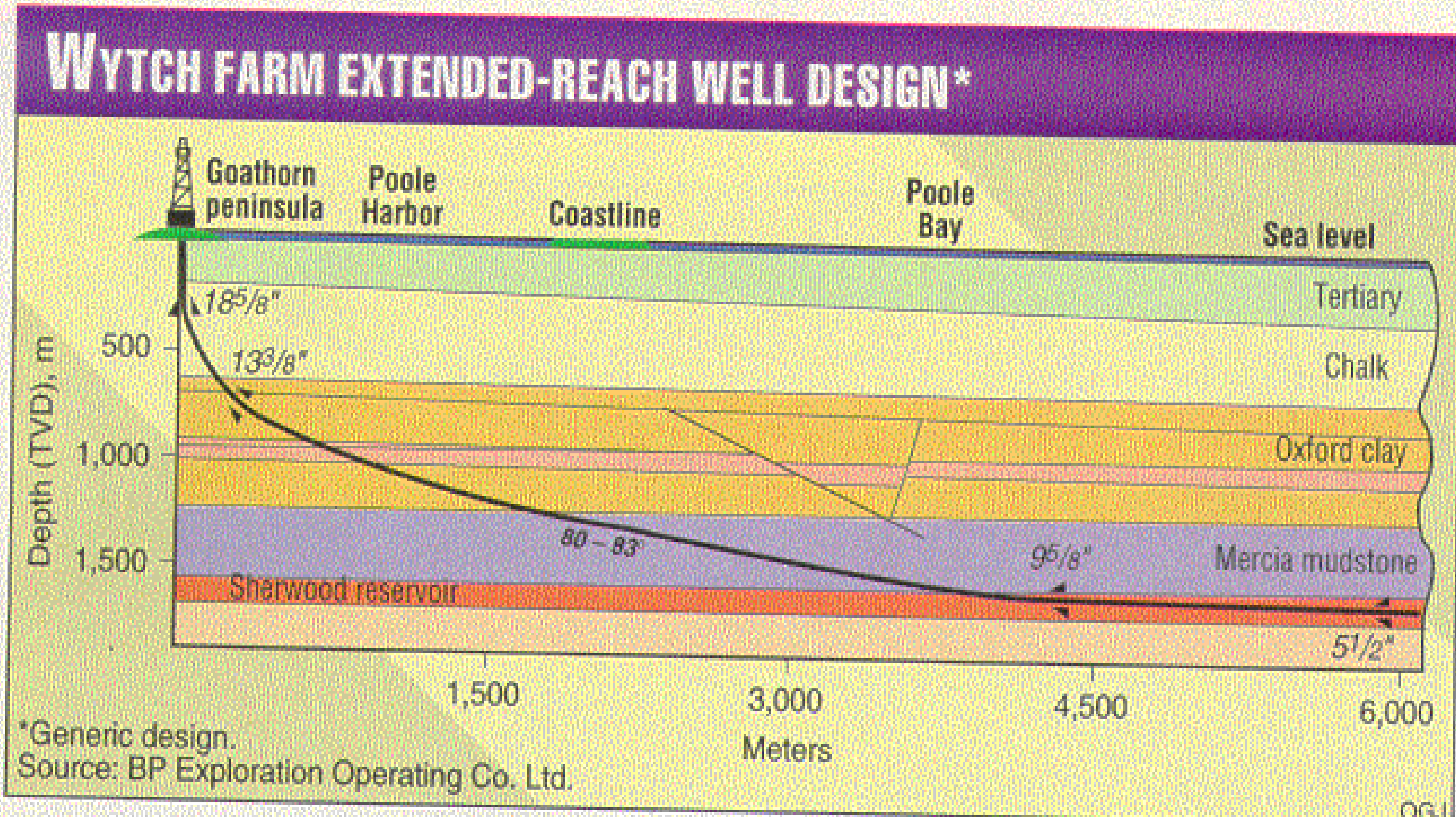
The M-11 well was drilled from an onshore drill site into a reservoir that extends offshore and was brought into production on Jan. 12 at a rate of 20,000 b/d of oil.

REF: O&GJ, Jan. 19, 1998, p.24

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.

Wytch Farm Extended-Reach Drilling Radius





WYTCH FARM EXTENDED-REACH WELL DESIGN*
Goathorn peninsula
Poole Harbor
Coastline
Poole Bay
Sea level
Tertiary
Chalk
Oxford clay
Mercia mudstone
Sherwood reservoir
18⁵/₈"
13³/₈"
80 – 83°
9⁵/₈"
5¹/₂"
Depth (TVD), m
500
1,000
1,500
1,500
3,000
4,500
6,000
Meters
*Generic design.
Source: BP Exploration Operating Co. Ltd.
OGJ

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

Overview cont'd

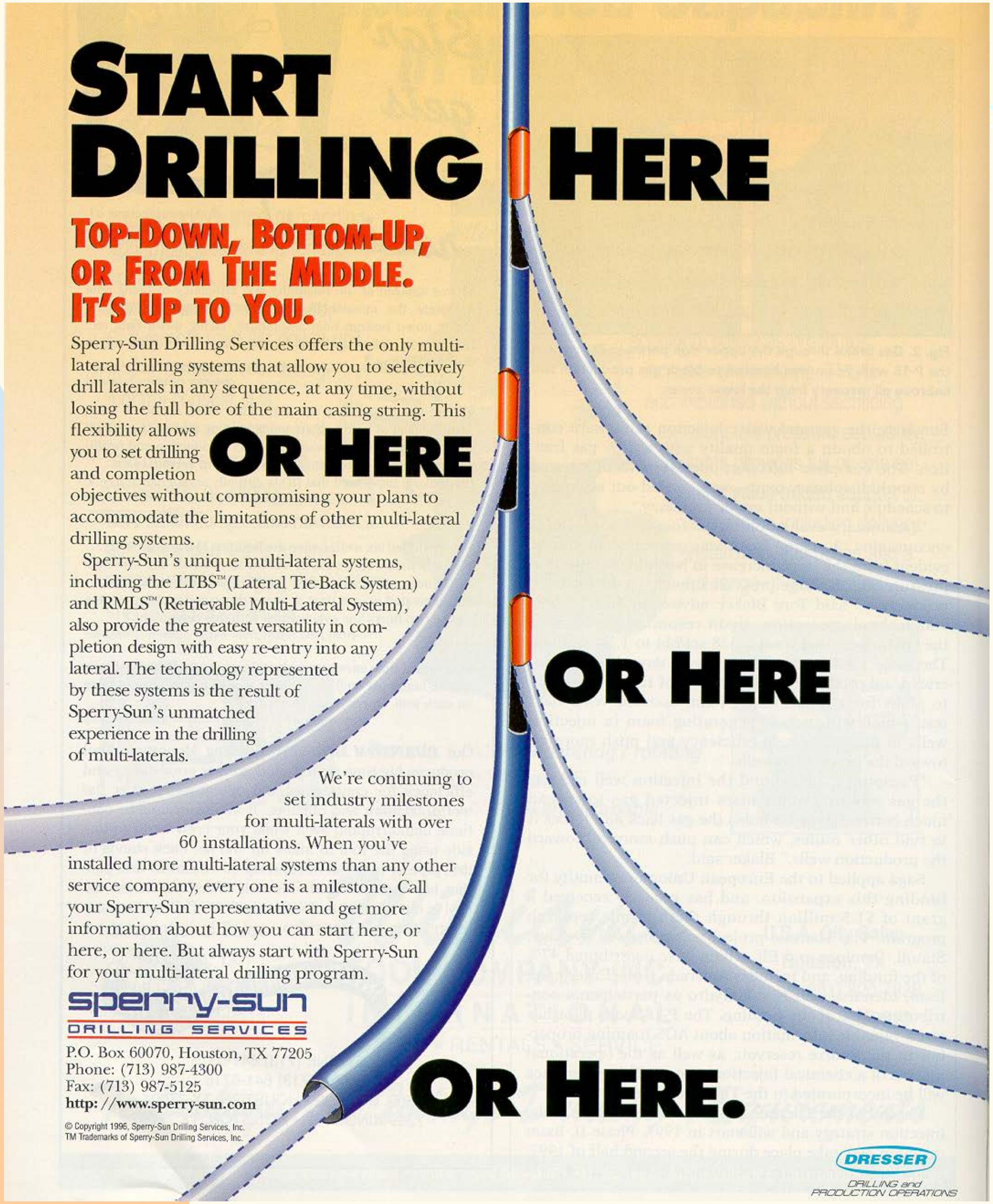
- One third of reserves are offshore under Poole Bay
- ERD project began in place of an artificial island in 1991
- Saved 150 million in development costs
- Development time saved - 3 years
- Scheduled with reach of 6.2 km
- Prod. before ERD project = 68,000 BOPD
- Prod. with 3 ERD wells = 90,000 BOPD

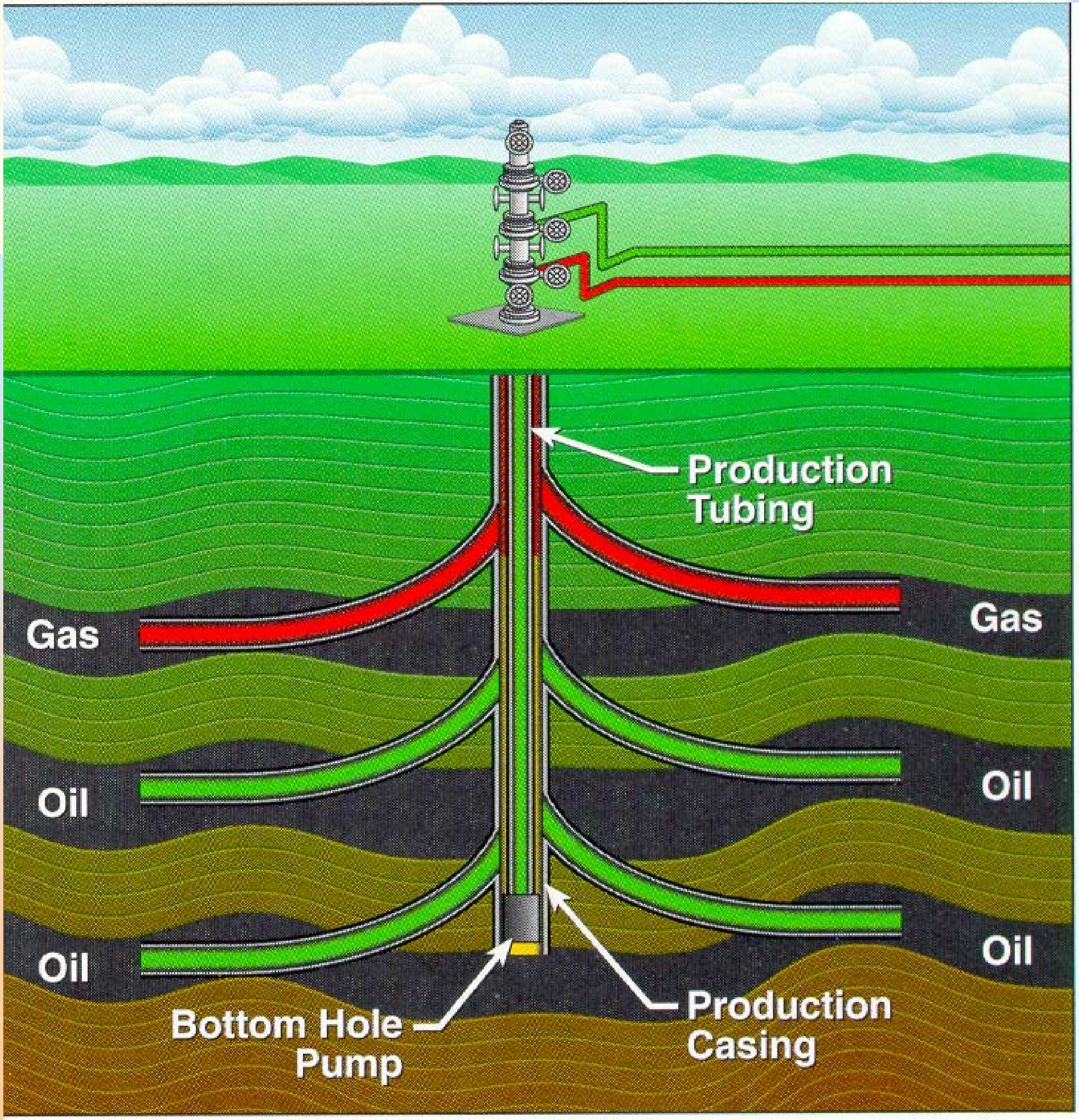
Multilaterals

Outline

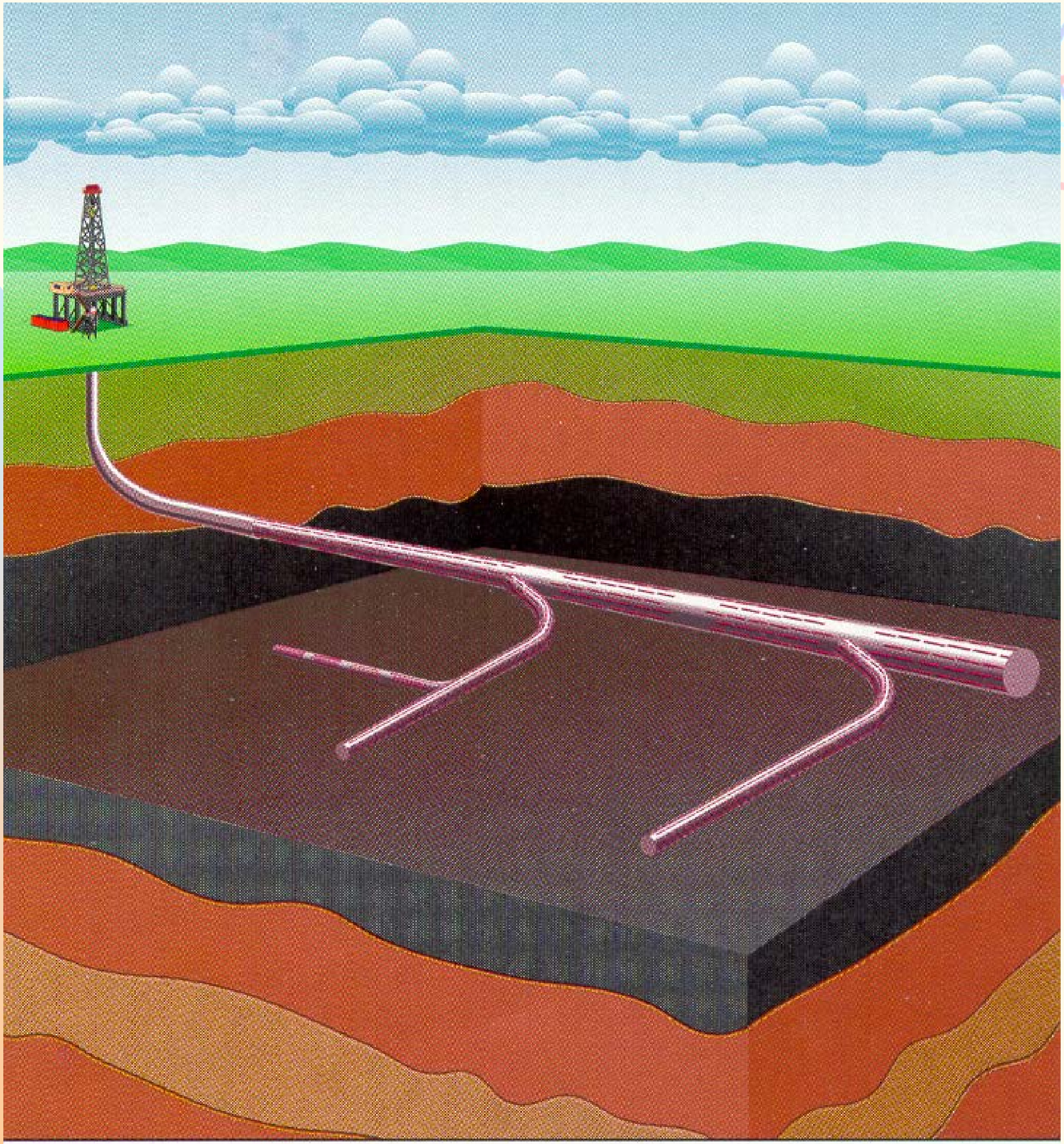
- Figs. 3-6 Advertisements, PE Int.
- Figs. 7-9, OGJ, Dec. 11, 1995 p.44
- Figs. 10, 11, OGJ, March 16, 1998 p.76
- Figs. 12-17, OGJ, Dec. 1997, p.73
- Figs. 18-24, OGJ, March 23, 1998 p.70
- Oil & Gas Journal, Feb. 28, 2000, p.44

20 Years of Service to America
MMS
Minerals Management Service
1982-2002




Production
Tubing
Gas
Gas
Oil
Oil
Oil
Oil
Bottom Hole
Pump
Production
Casing

20 Years of Service to America
MMS
Minerals Management Service
1982-2002



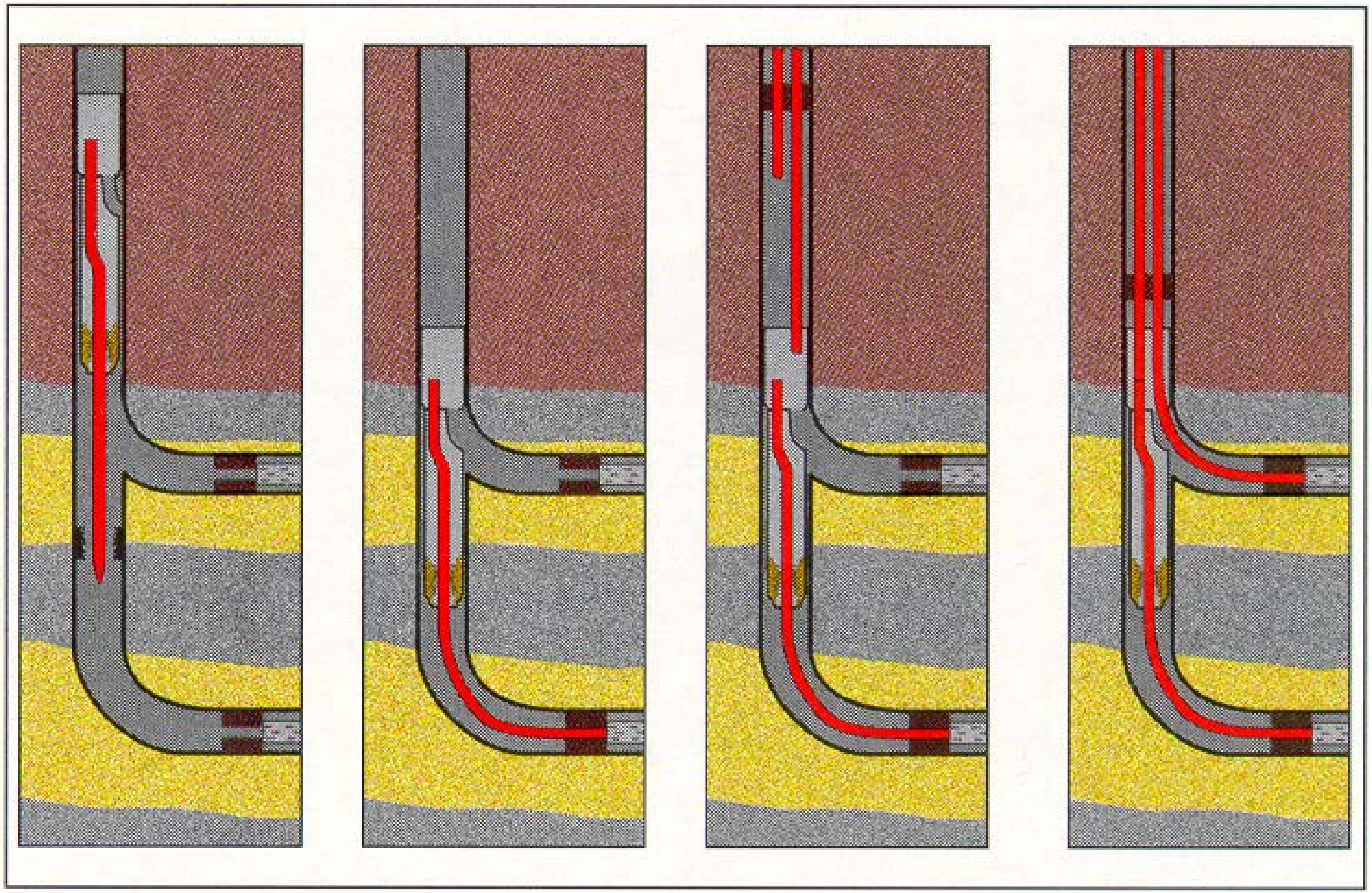
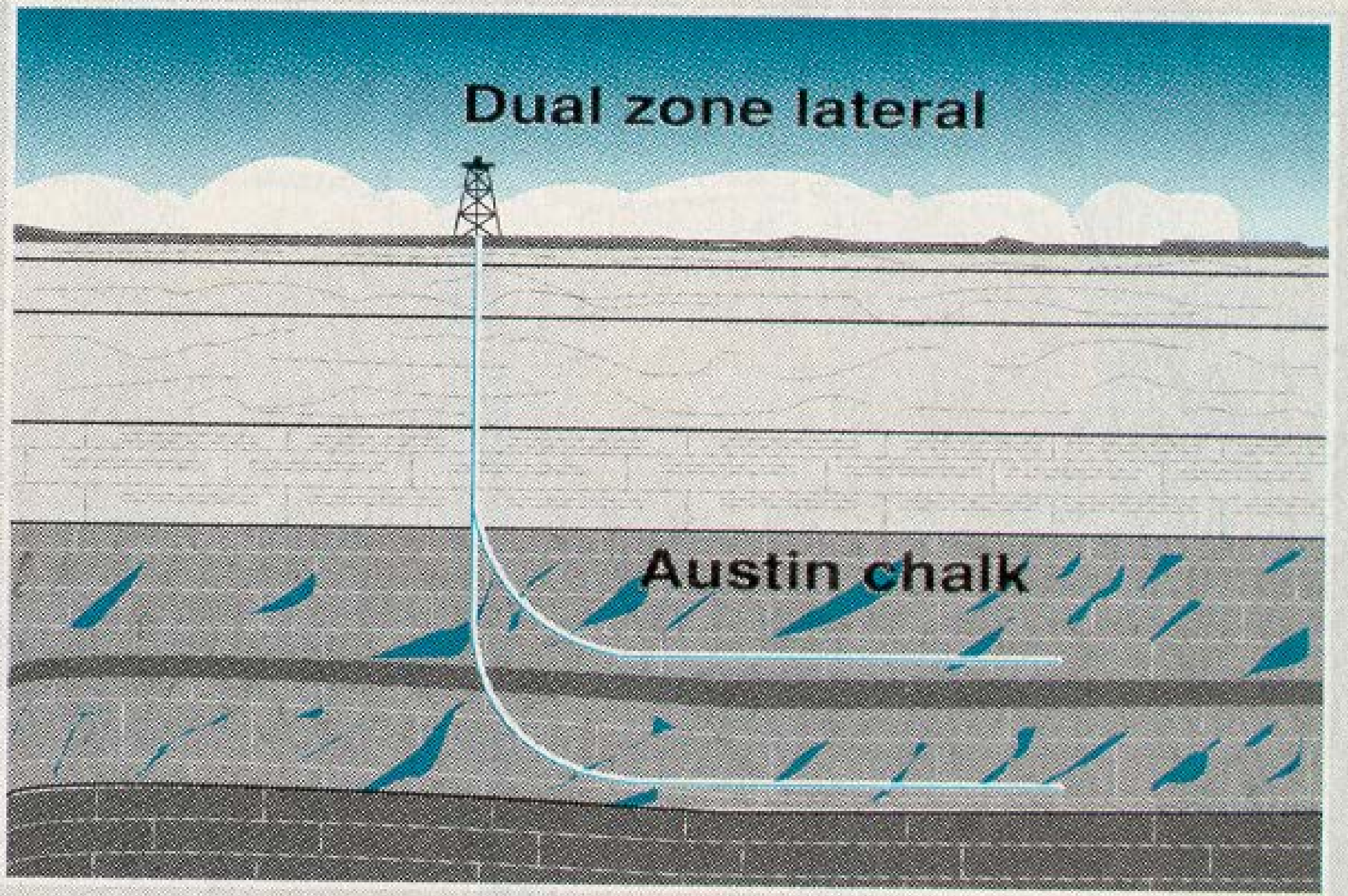


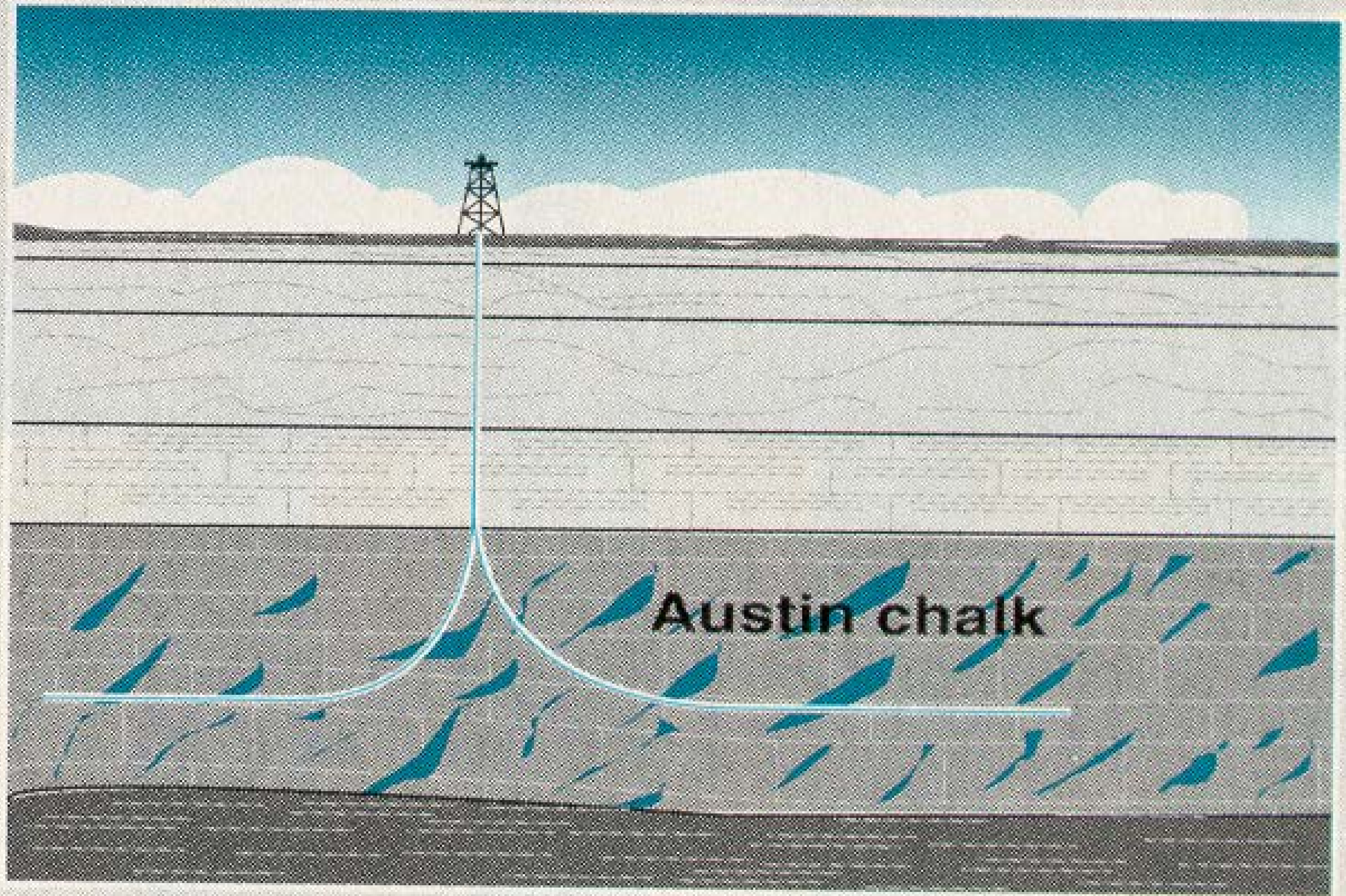
Fig. 1. The Multi-String Completion System provides segregated production and allows lateral re-entry using a dual bore deflector.

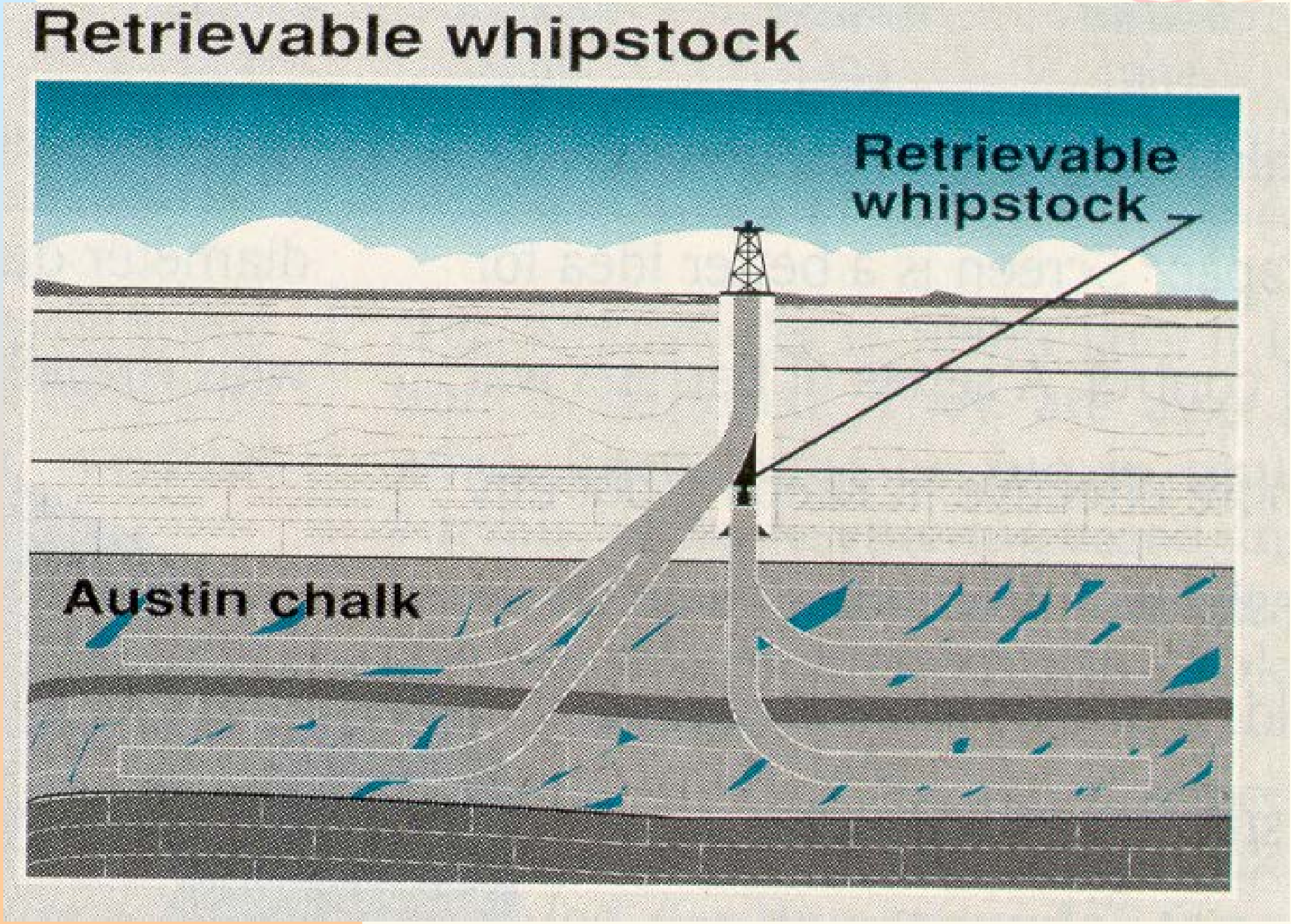
20 Years of Service to America
MMS
Minerals Management Service
1982-2002

Stacked laterals

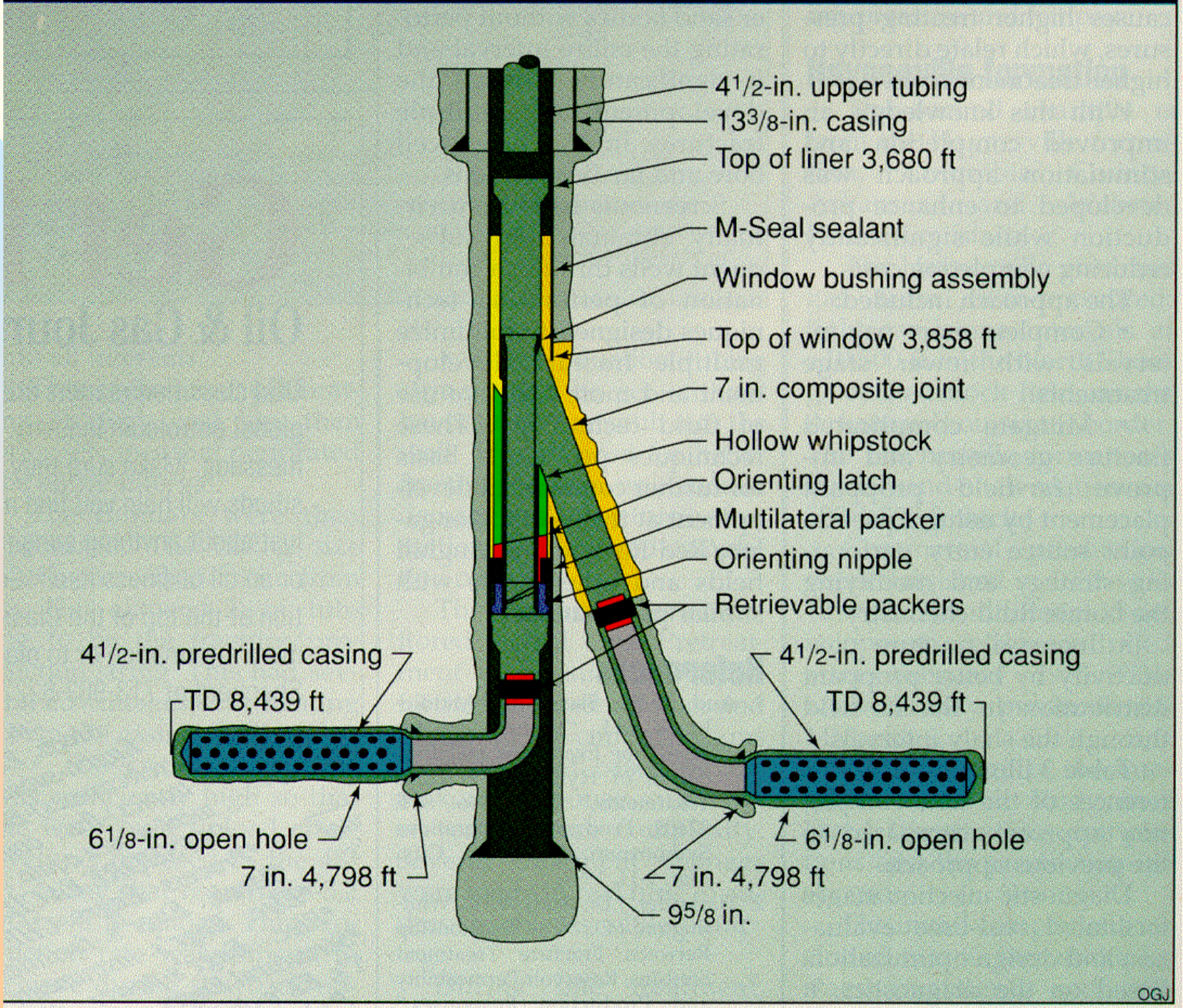


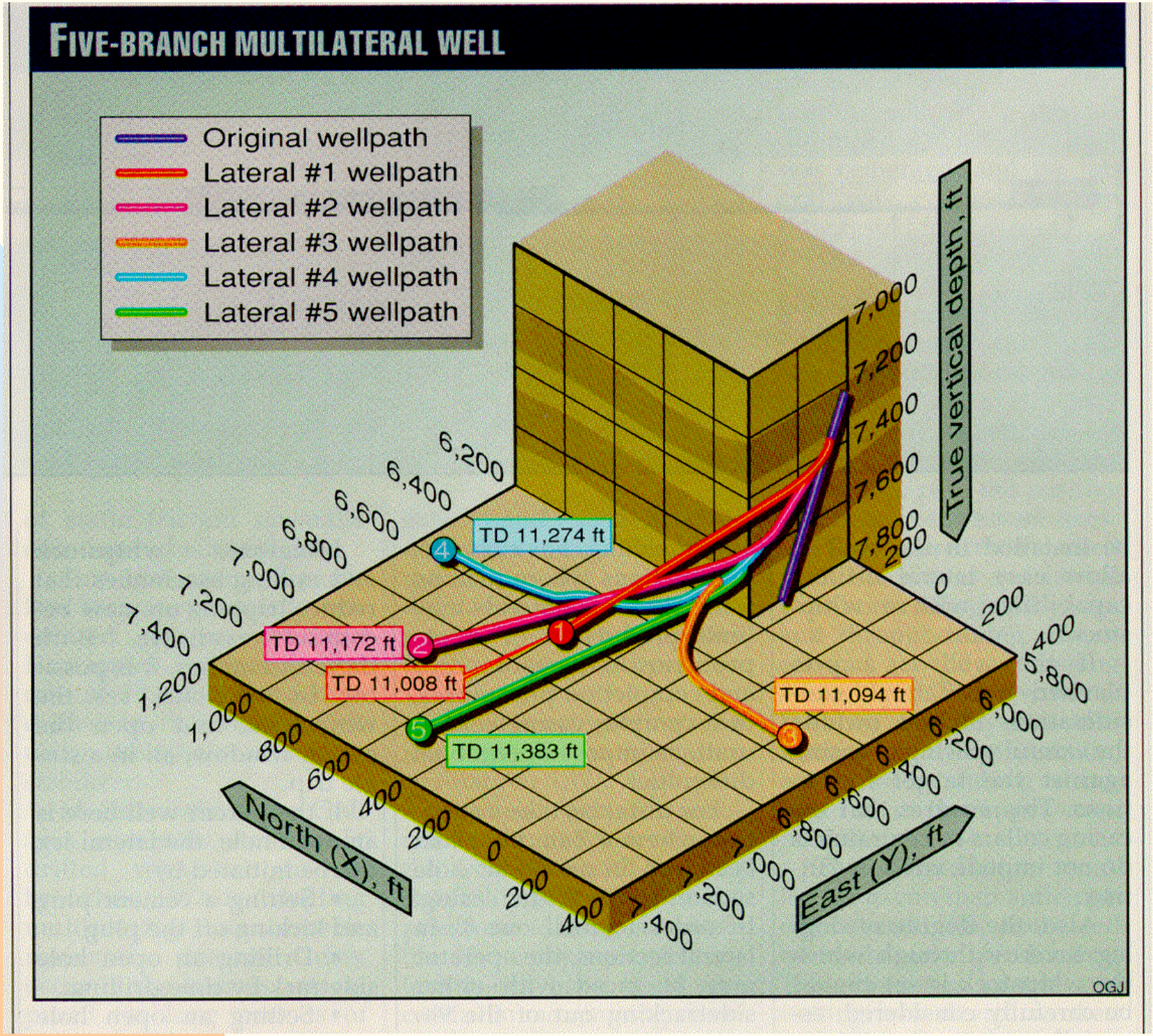
Opposing laterals



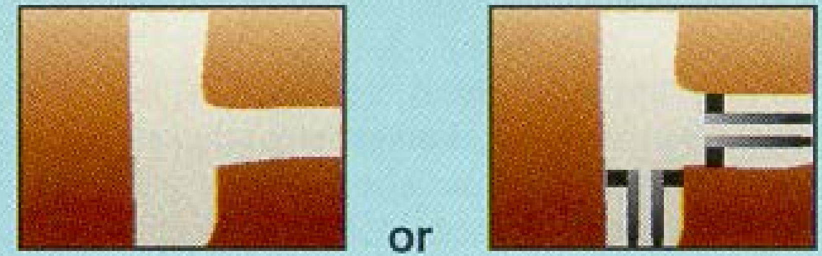
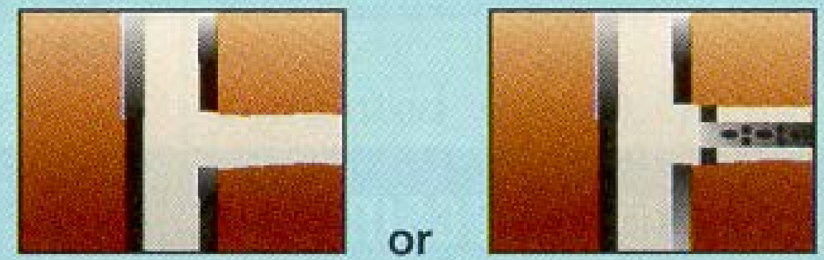

Retrievable whipstock
Retrievable whipstock
Austin chalk

FIRST MULTILATERAL WELL IN MIDDLE EAST




FIVE-BRANCH MULTILATERAL WELL
Original wellpath
Lateral #1 wellpath
Lateral #2 wellpath
Lateral #3 wellpath
Lateral #4 wellpath
Lateral #5 wellpath
TD 11,274 ft
TD 11,172 ft
TD 11,008 ft
TD 11,383 ft
TD 11,094 ft
True vertical depth, ft
7,000
7,200
7,400
7,600
7,800
North (X), ft
East (Y), ft
OGJ

Multilateral Completions Levels 1 & 2

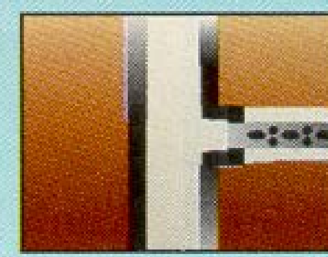
Description	Illustration
Open unsupported junction: Barefoot mother-bore and lateral or slotted liner hung-off in either of the well bores	
Mother-bore cased and cemented* Lateral open: Lateral either barefoot or with slotted liner hung-off in open hole	

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*

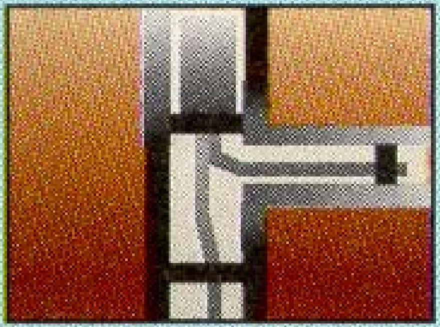
Mother-bore cased and cemented*
Lateral open:
Both bores cemented at the junction

or

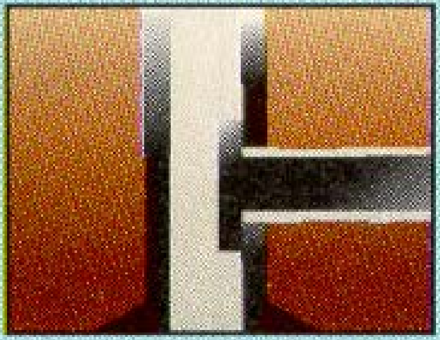


Multilateral Completions Levels 5, 6 & 6B

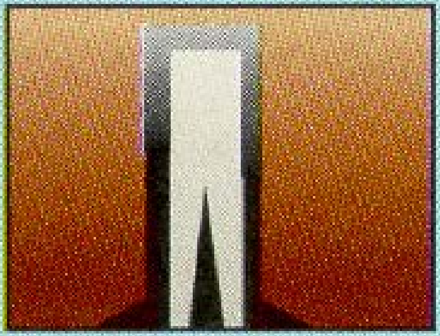
Pressure integrity at the junction:
Achieved with the completion†

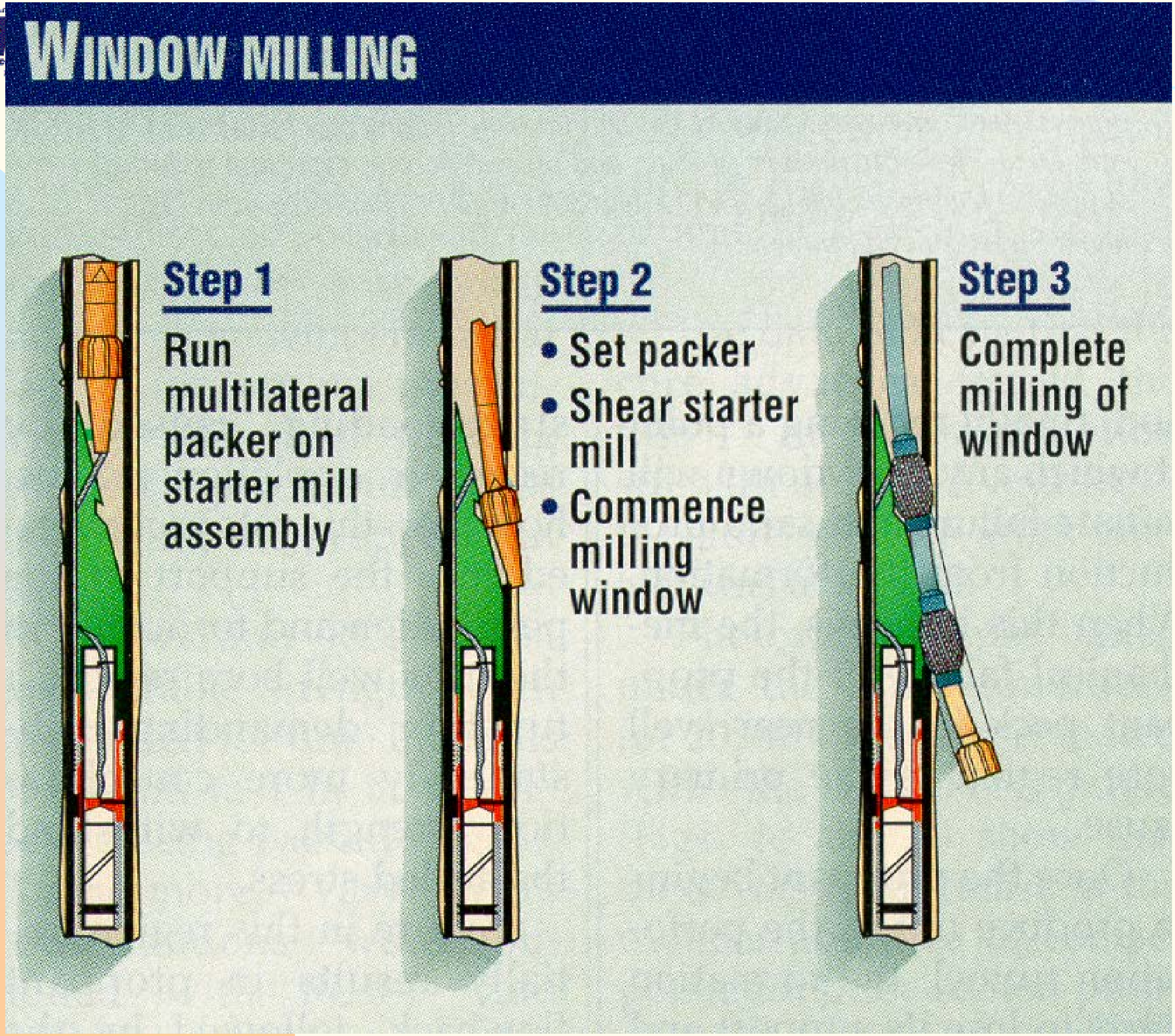


Pressure integrity at the junction:
Achieved with the casing†



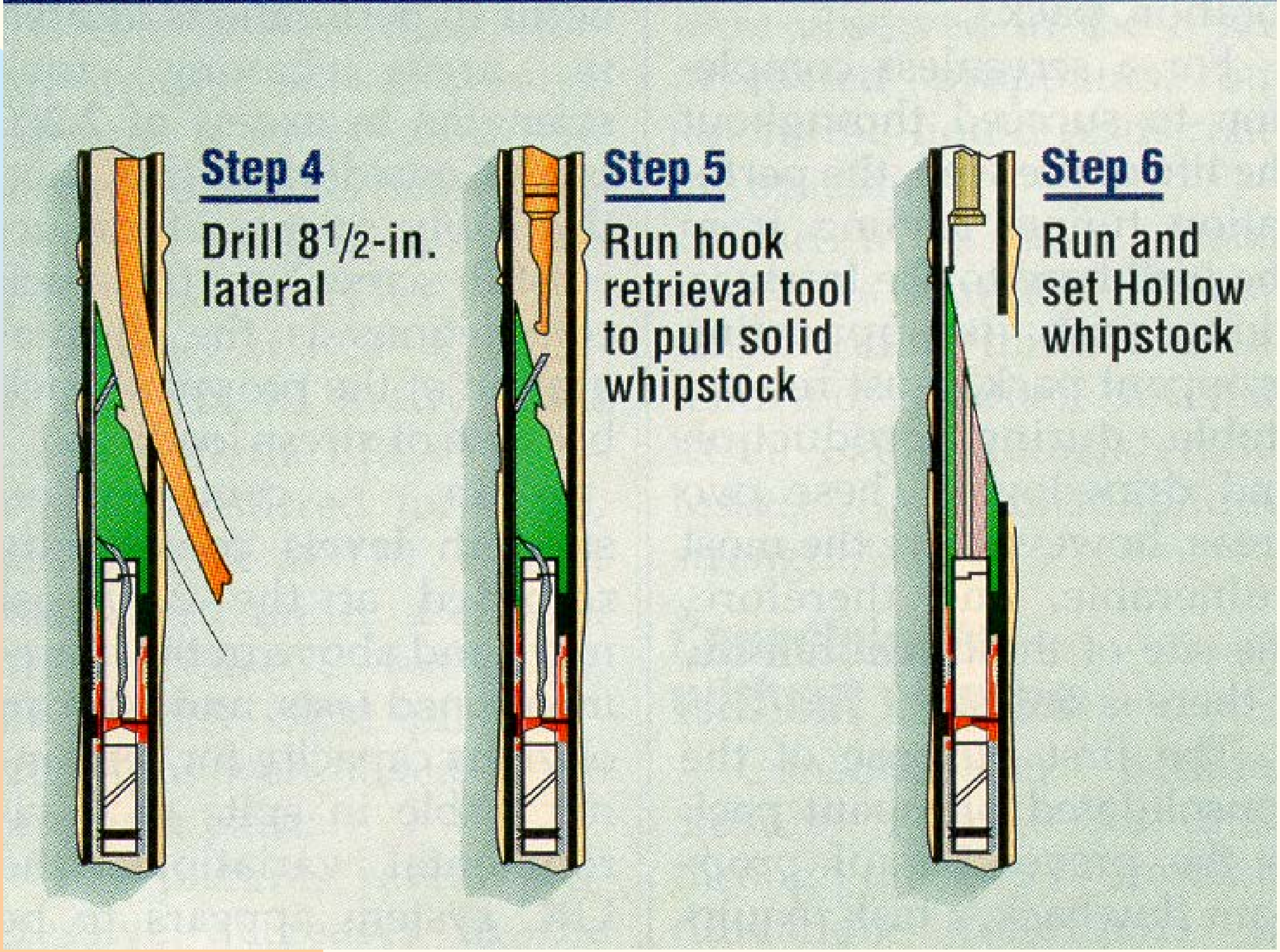
Downhole splitter:
Large main well bore with two smaller lateral bores of equal size



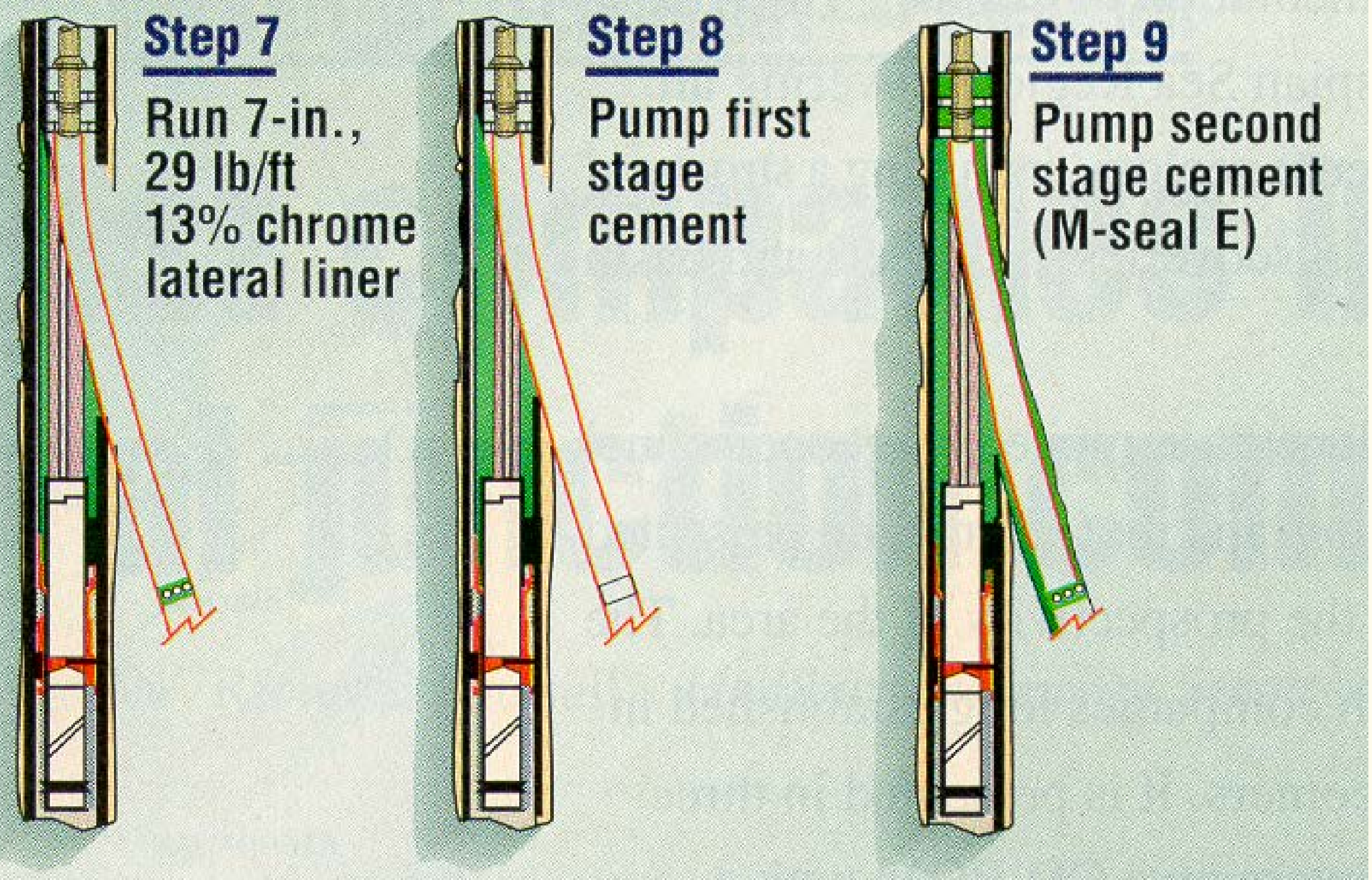


WINDOW MILLING
Step 1
Run multilateral packer on starter mill assembly
Step 2
• Set packer
• Shear starter mill
• Commence milling window
Step 3
Complete milling of window

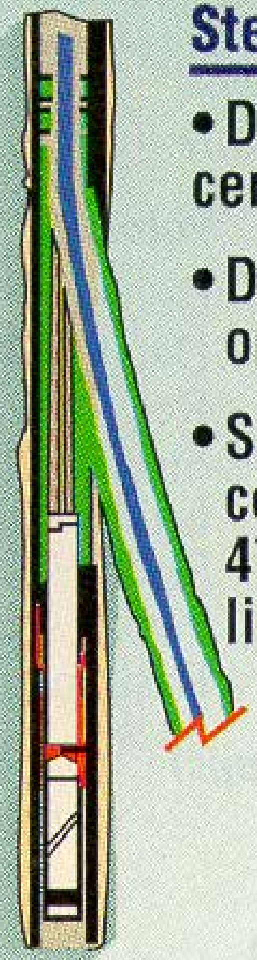
DRILL LATERAL AND SET WHIPSTOCK



RUN LINER AND CEMENT

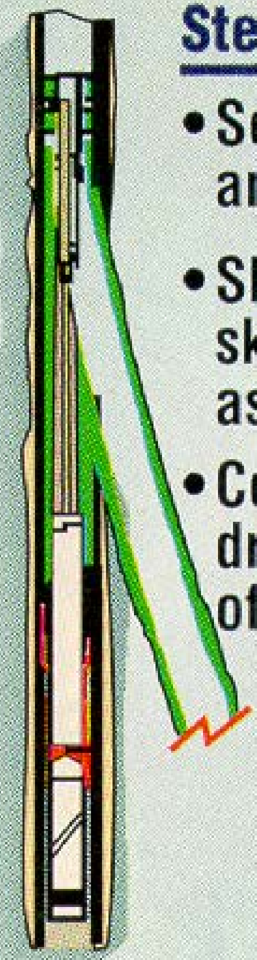


MILLING OPERATIONS



Step 10

- Drill out cement
- Drill 6-in. open hole
- Set and cement $4^1/_2$-in. liner



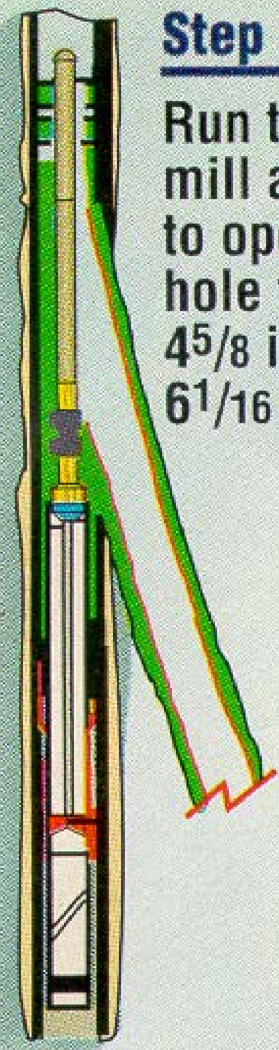
Step 11

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

Step 12

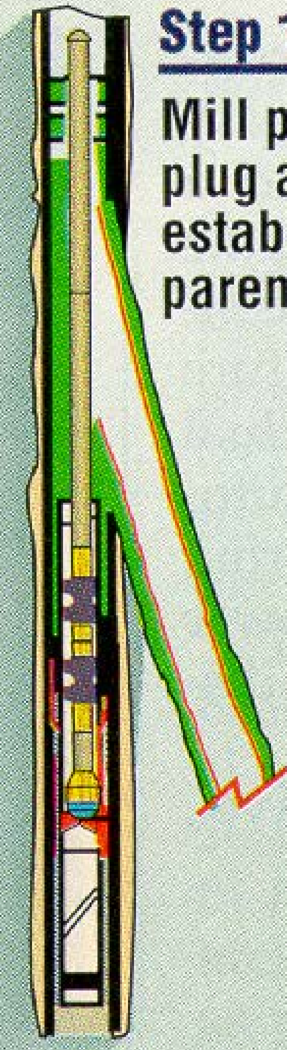
Mill $4^5/_8$-in. pilot hole through liner and hollow whipstock

RE-ESTABLISH PARENT WELL BORE



Step 13

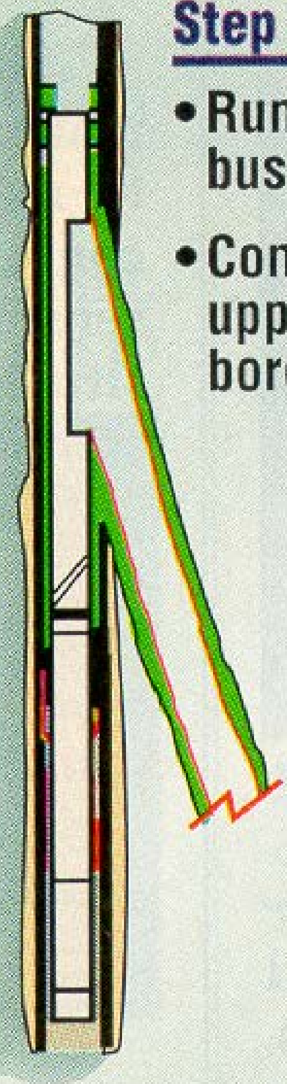
Run tripsaver mill assembly to open pilot hole from $4^{5}/_{8}$ in. out to $6^{1}/_{16}$ in.



Step 14

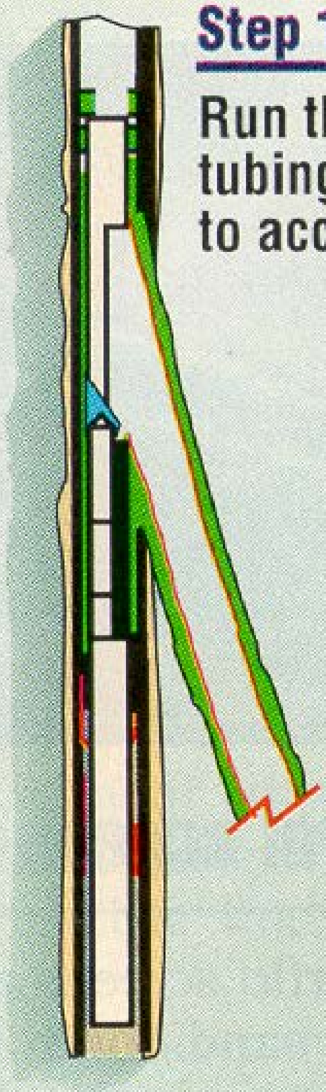
Mill packer plug and re-establish parent well bore

ACCESS LATERAL



Step 15

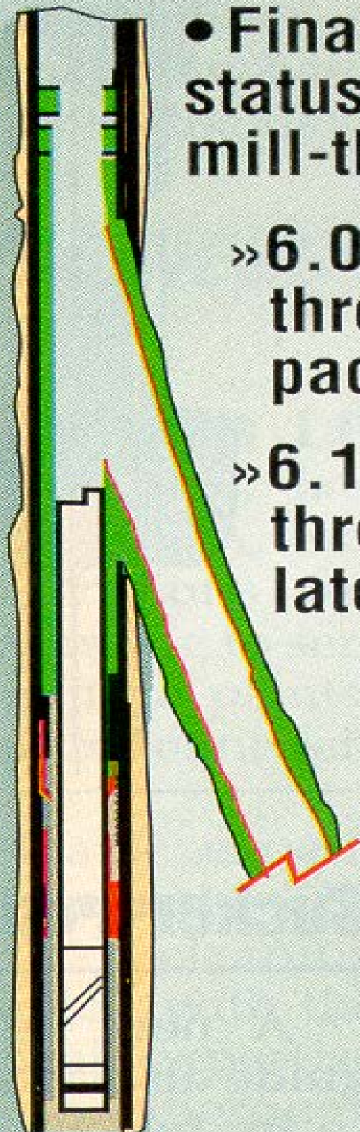
- Run window bushing
- Complete upper well bore



Step 16

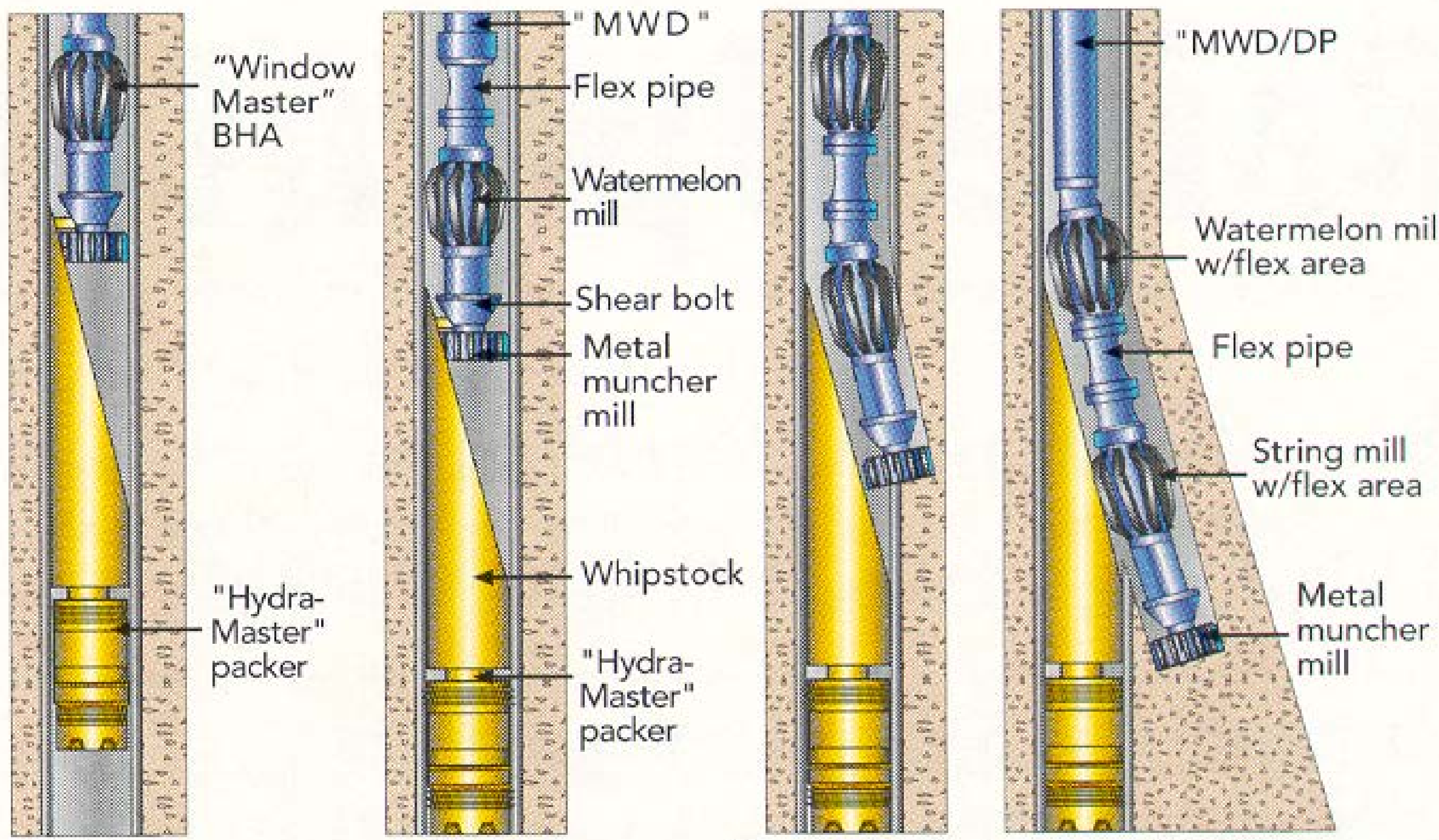
Run through-tubing diverter to access lateral

FINAL WELL CONFIGURATION



- Final well status after mill-through
  - » 6.07 in. ID through packer
  - » 6.184 in. ID through lateral liner

WindowMaster™



R.I.H. WindowMaster w/"HydraMaster" packer

Measure orientation w/"MWD" presure up annulus and set packer

Shear bolt & start window cutting

Increase W.O.M. & mill/ream window

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

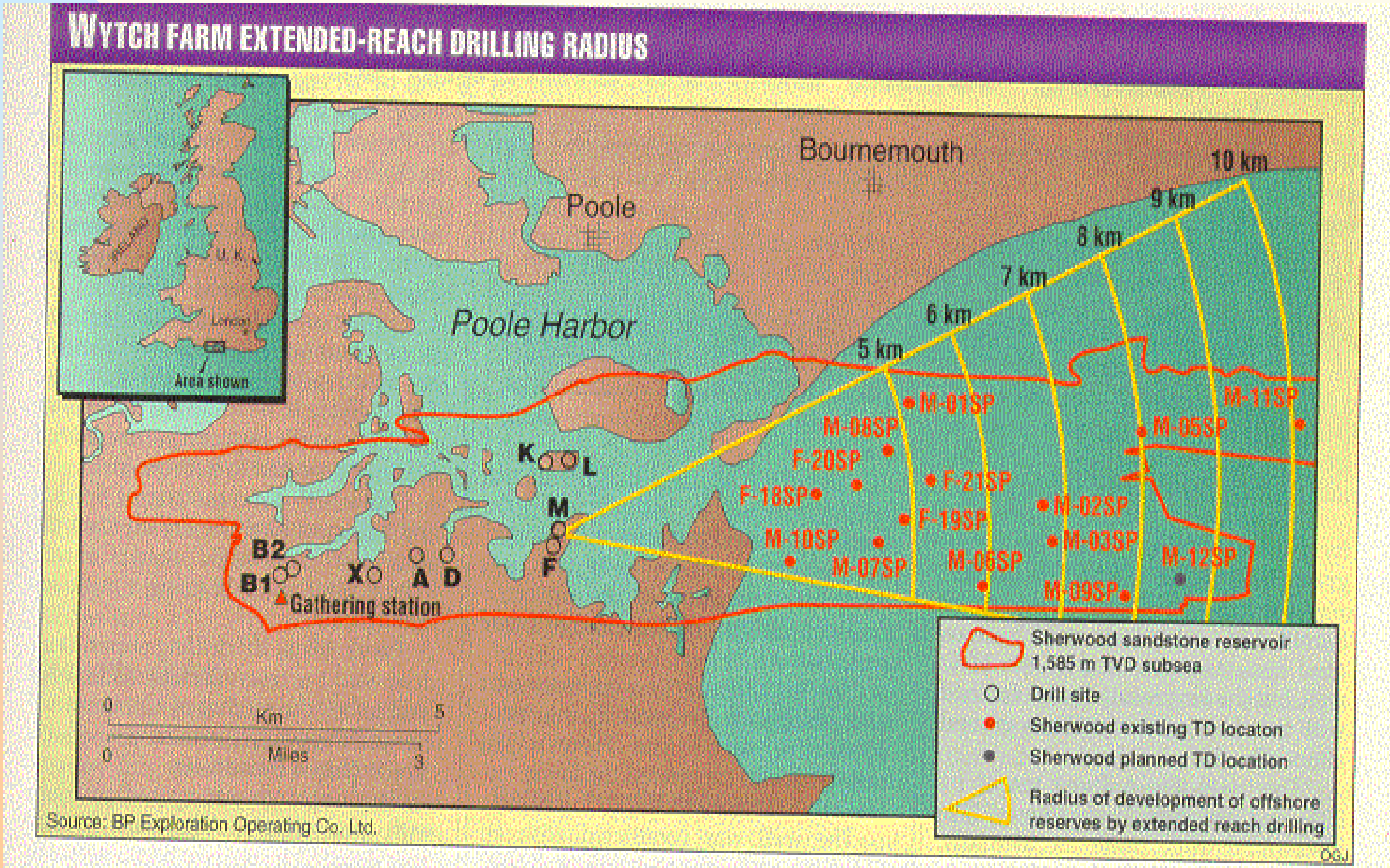
- Improving thin oil zone reservoirs production performance
- Increase ROI
- Reduce well cost
- Reduce time
- Reduce capital cost

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
Bournemouth
Poole
Poole Harbor
10 km
9 km
8 km
7 km
6 km
5 km
M-01SP
M-08SP
F-20SP
F-18SP
F-21SP
F-19SP
M-10SP
M-07SP
M-06SP
M-02SP
M-03SP
M-09SP
M-12SP
M-05SP
M-11SP
K
L
M
F
B2
B1
X
A
D
Gathering station
U.K.
London
Area shown
0
Km
5
0
Miles
3
Sherwood sandstone reservoir 1,585 m TVD subsea
Drill site
Sherwood existing TD locaton
Sherwood planned TD location
Radius of development of offshore reserves by extended reach drilling
Source: BP Exploration Operating Co. Ltd.
OGJ

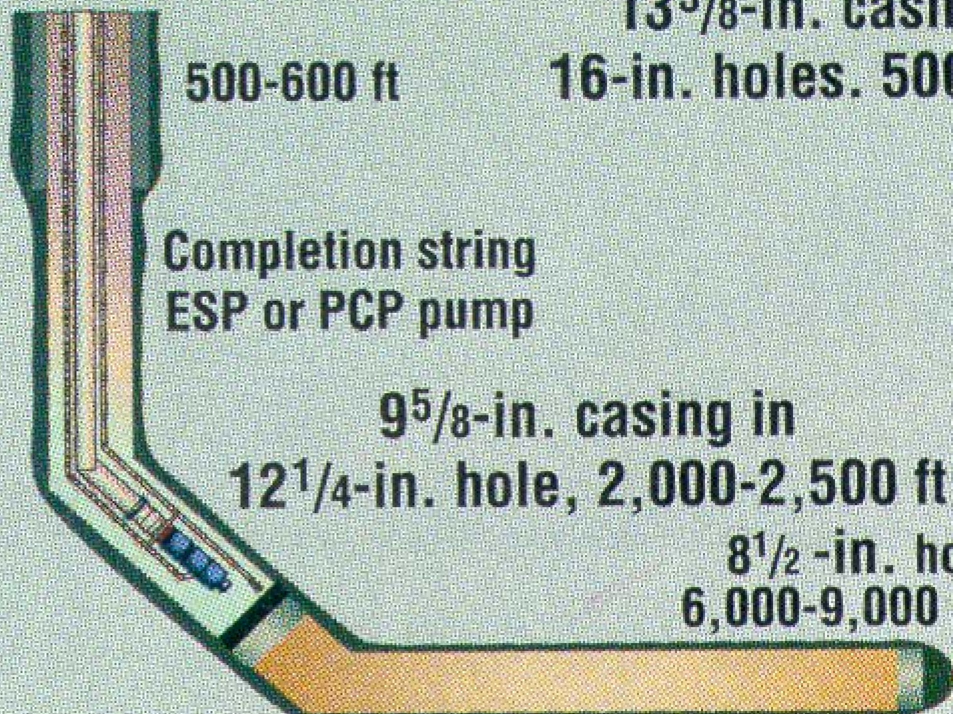
"Complex well geometries boost Orinoco heavy oil producing rates

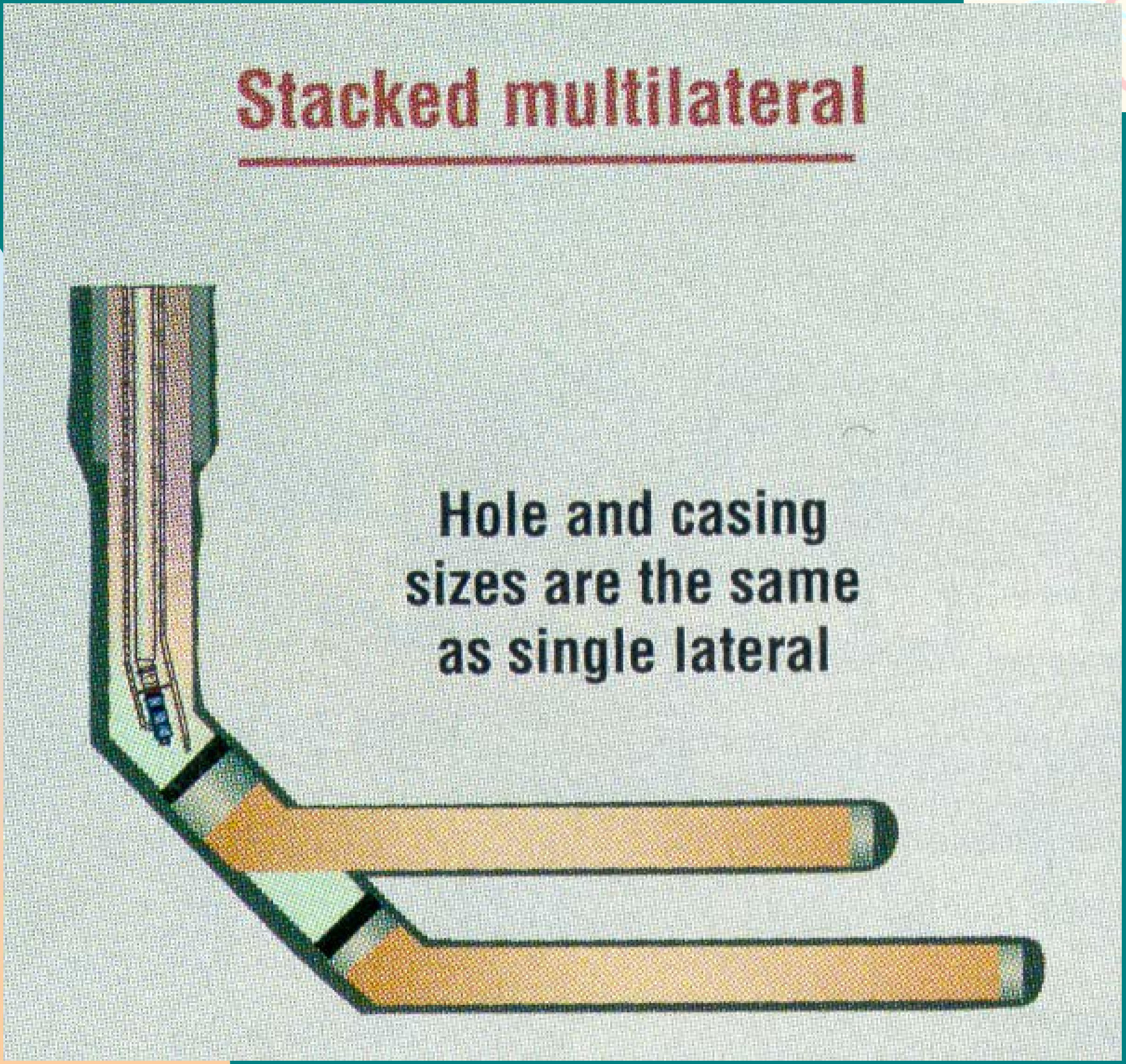
Oil & Gas Journal, Feb. 28, 2000

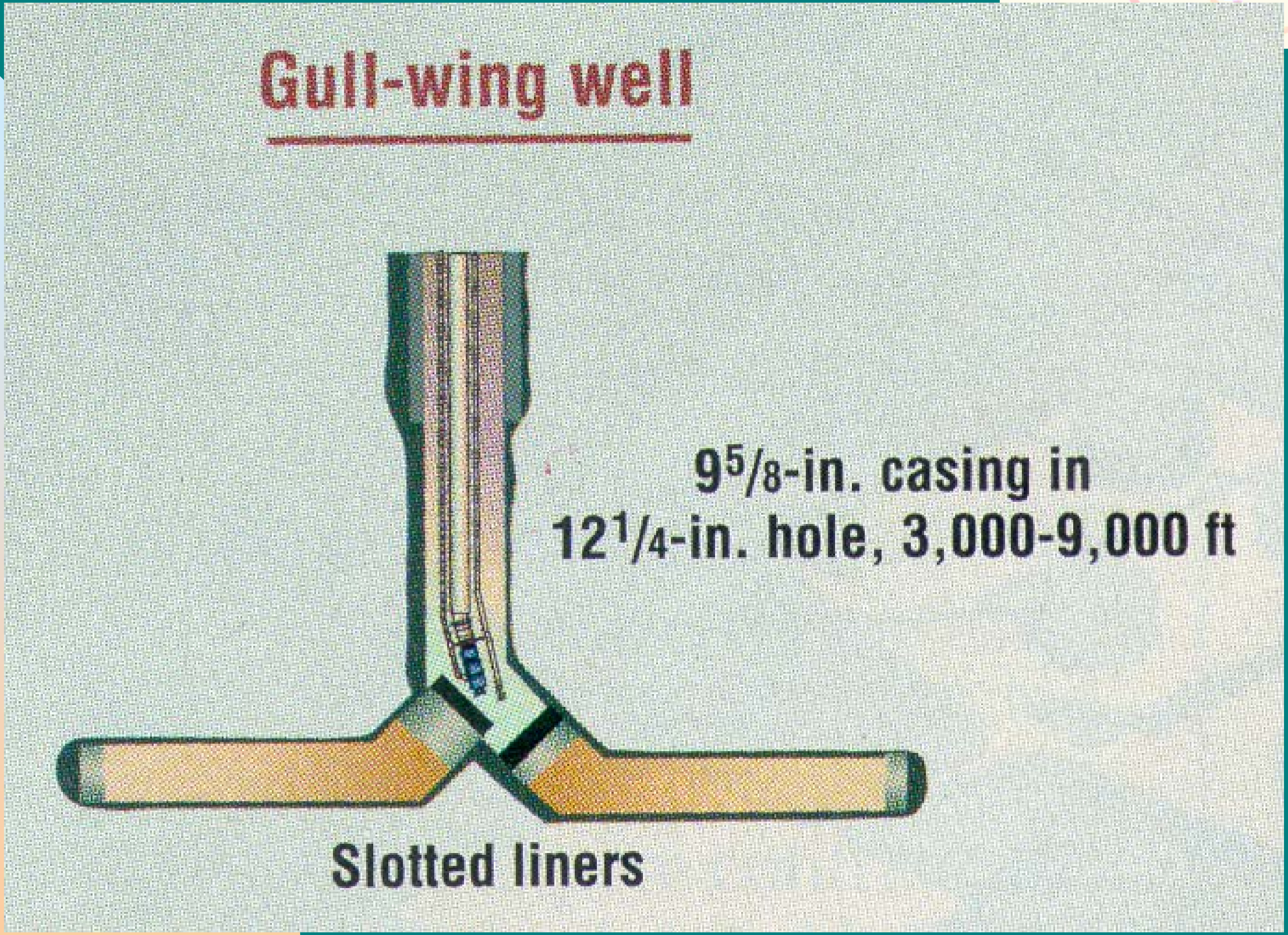
- Single horizontal lateral
- Gull-wing well
- Stacked multilateral
- Fishbone well
- Gull-wing, fishbone well
- Stacked fishbone well

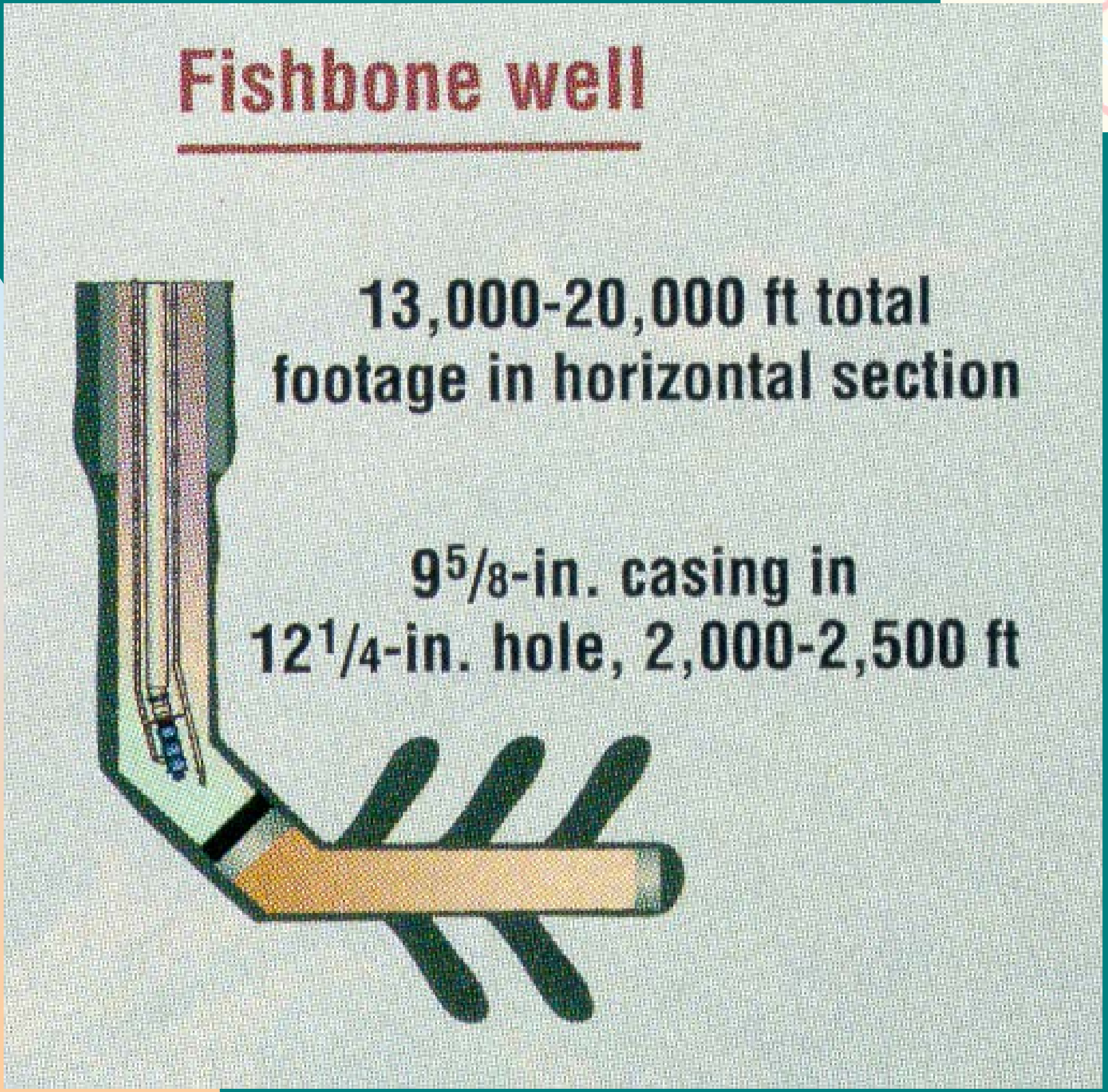
~9^{o}API oil. ~1.2 * 10^{12} bbls in place. ~250 * 10^{9} recoverable

Single horizontal lateral

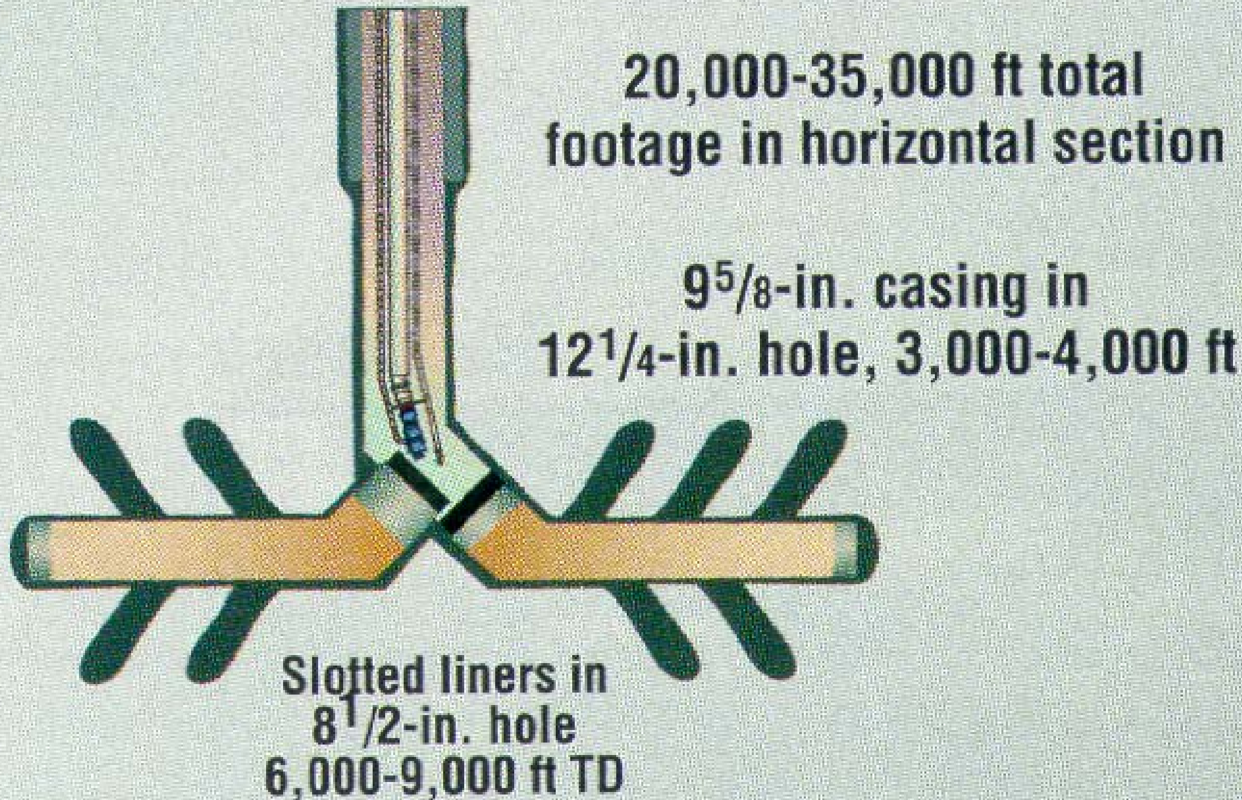


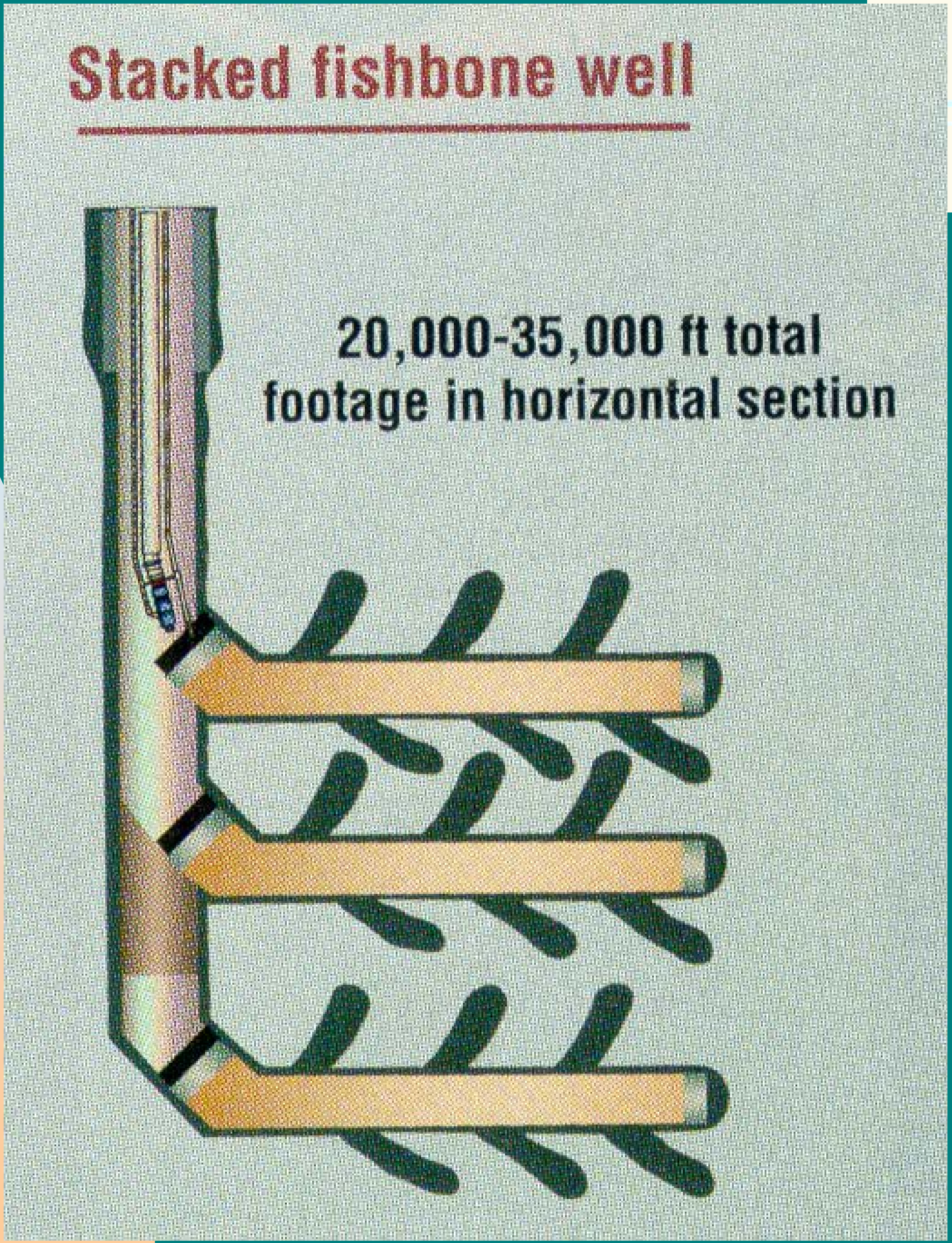

Stacked multilateral
Hole and casing
sizes are the same
as single lateral


Gull-wing well
9 5/8-in. casing in
12 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

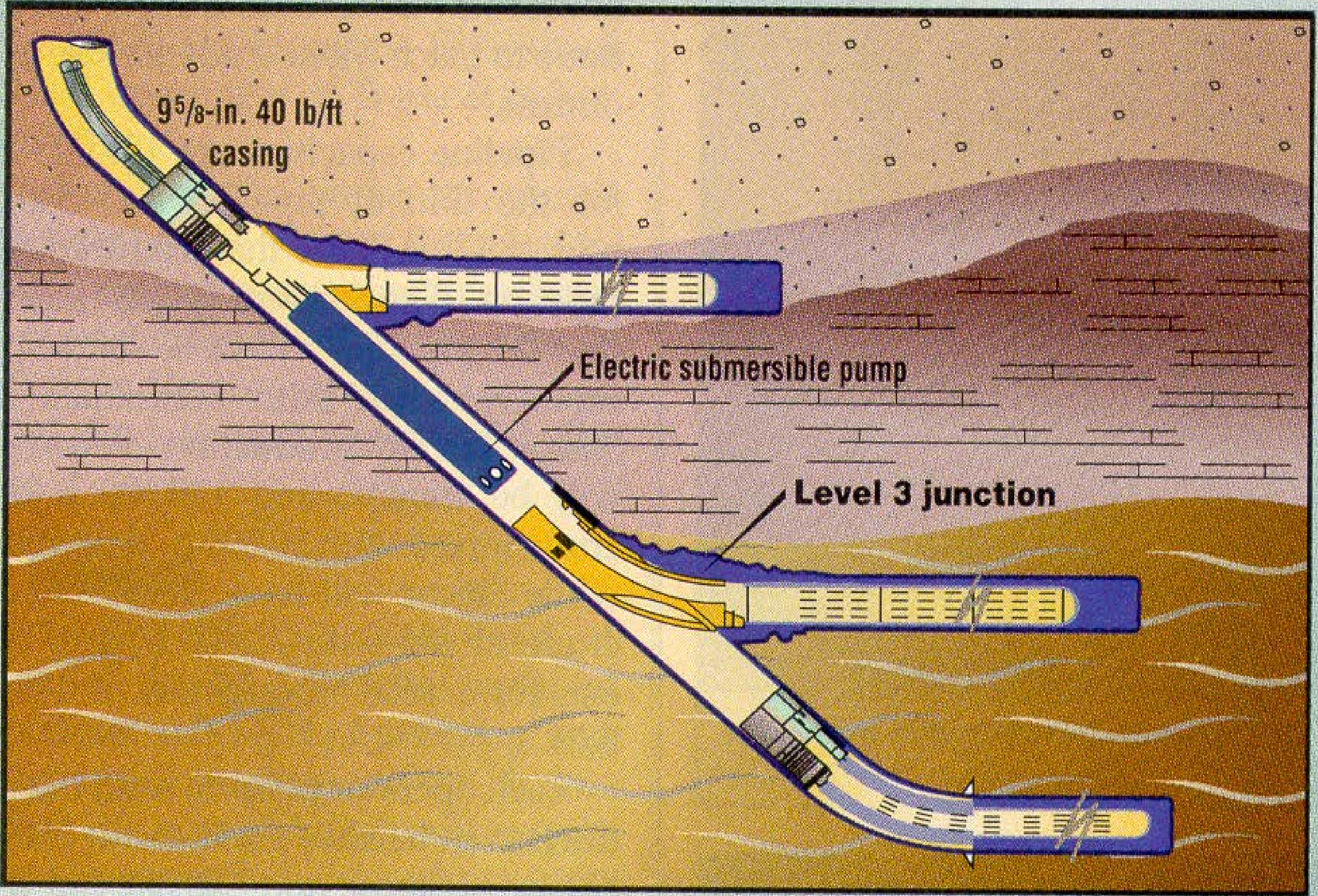
Gull-wing, fishbone well





Stacked fishbone well
20,000-35,000 ft total
footage in horizontal section

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 – quadralateral
- 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

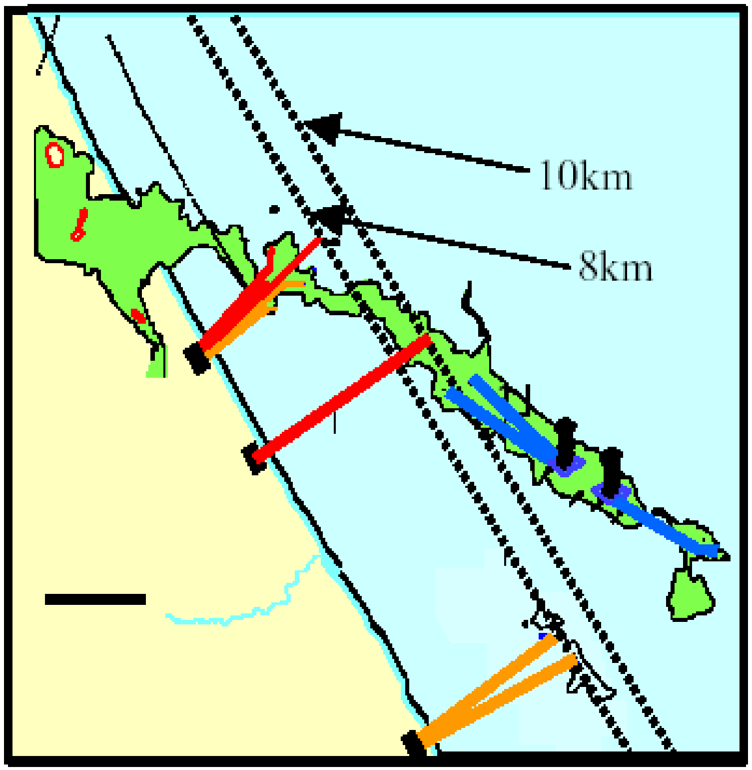


Fig. 1 Location of the Hidra field
(Tierra del Fuego – Argentina)

	Capex	NPV	PayOT
Platform	2.3	1.9	5.8
Subsea	2	5.7	2.4
ERD	1	1	1

Table 1 – Comparaison between platform, subsae and ERD (Hidra – Argentina)

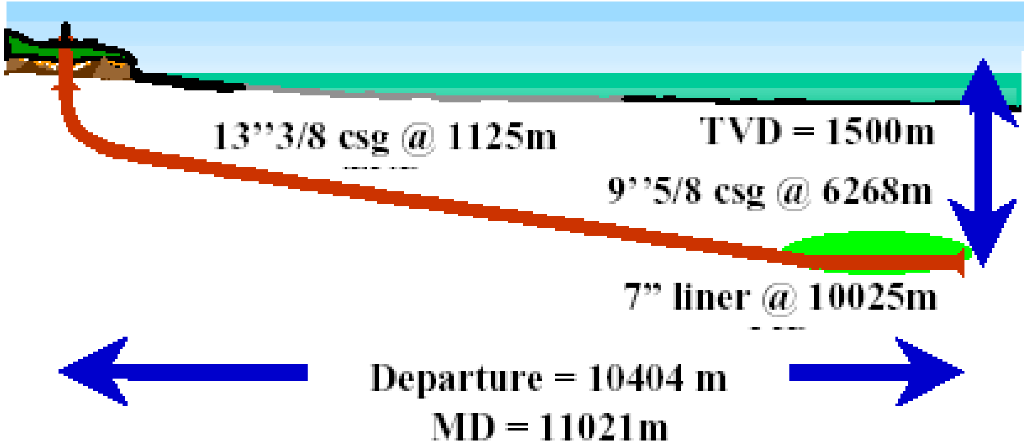
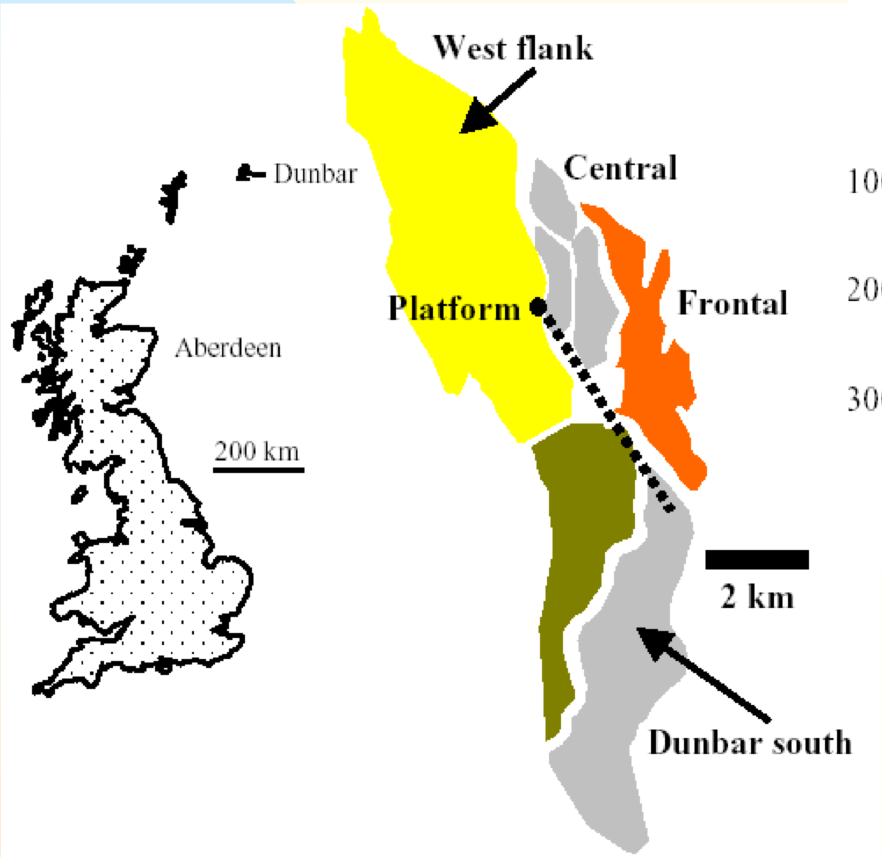
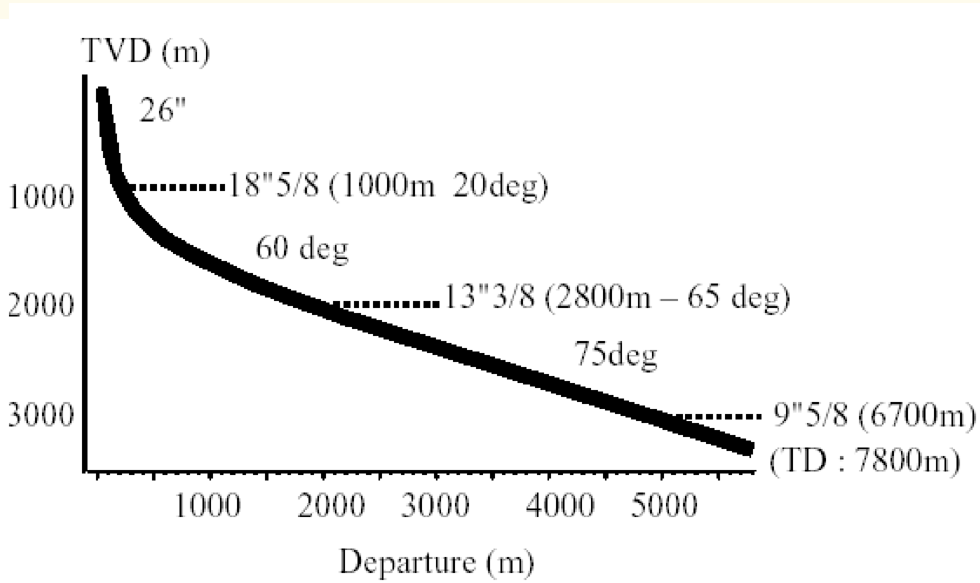


Fig. 2 ERD profile and casing strategy
(Hidra field – Argentina – World record)

TFE – U.K.


West flank
Dunbar
Central
Aberdeen
Platform
Frontal
200 km
2 km
Dunbar south

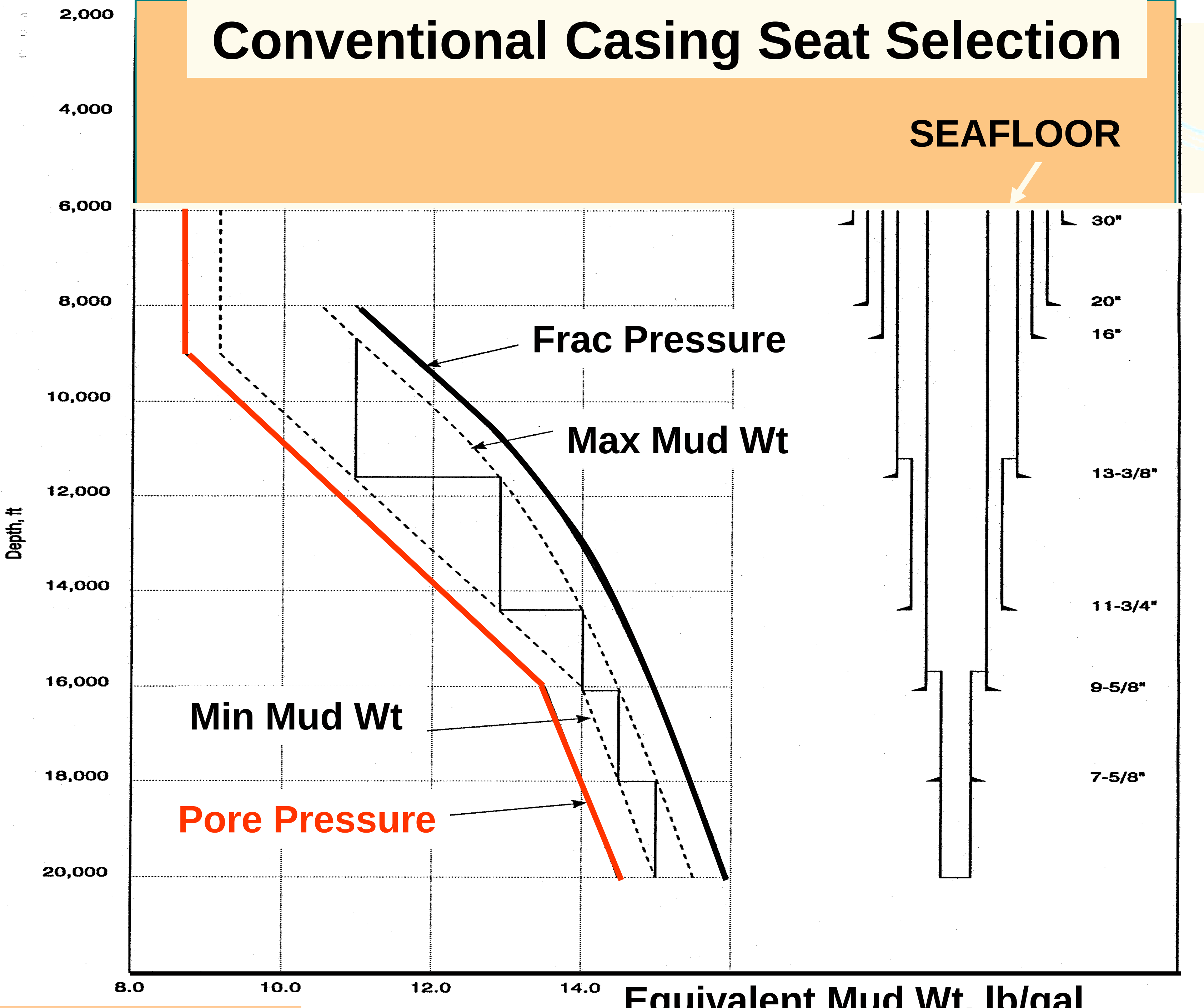

TVD (m)
26"
18"5/8 (1000m 20deg)
60 deg
13"3/8 (2800m – 65 deg)
75deg
9"5/8 (6700m)
(TD : 7800m)
1000
2000
3000
1000
2000
3000
4000
5000
Departure (m)

New drilling technologies that can enhance ML/ERD

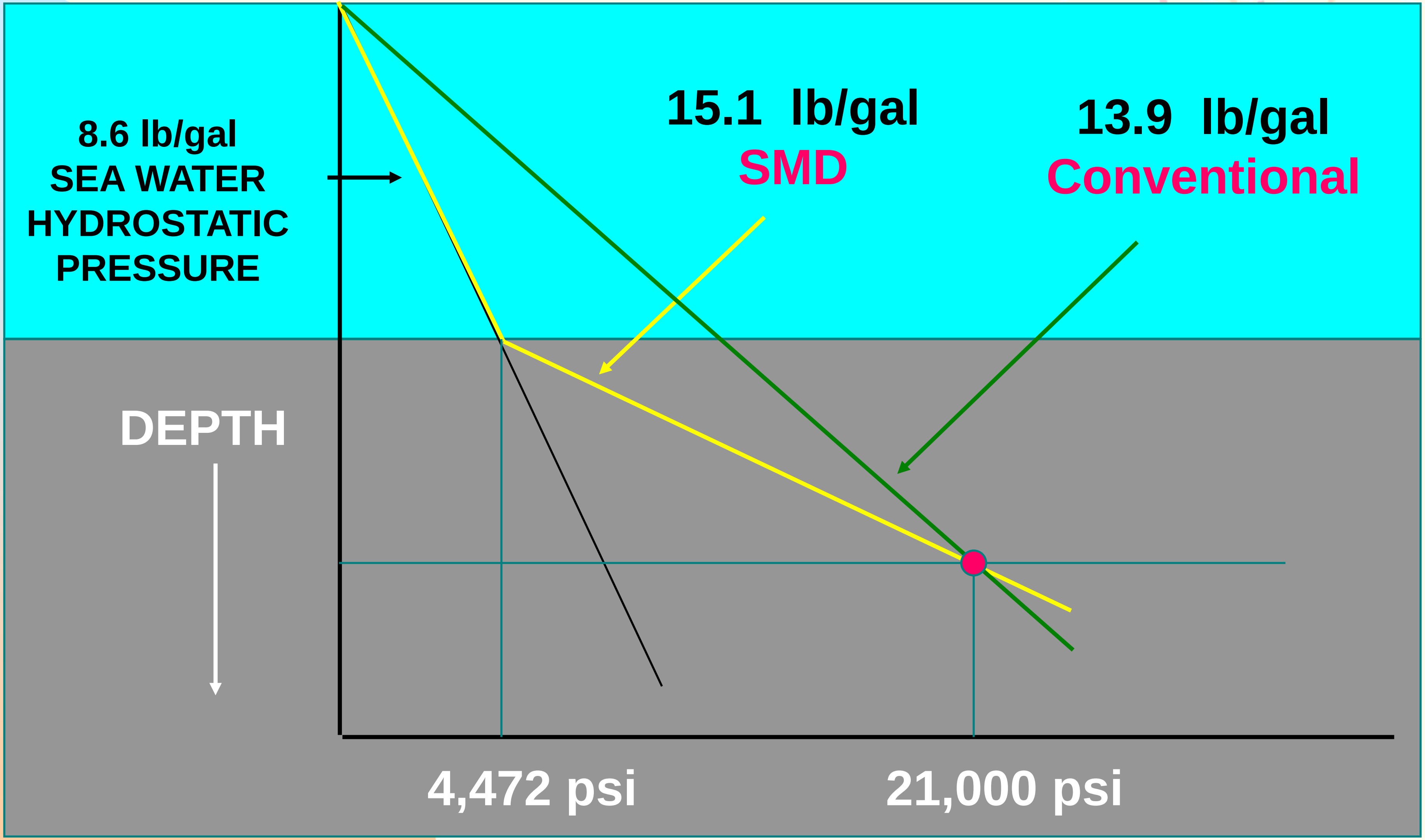
- Dual Gradient Drilling
- Expandable Liners
- High Lubricity Muds
- Hole Cleaning
- SOA in ERD and MLD

Dual Gradient Drilling

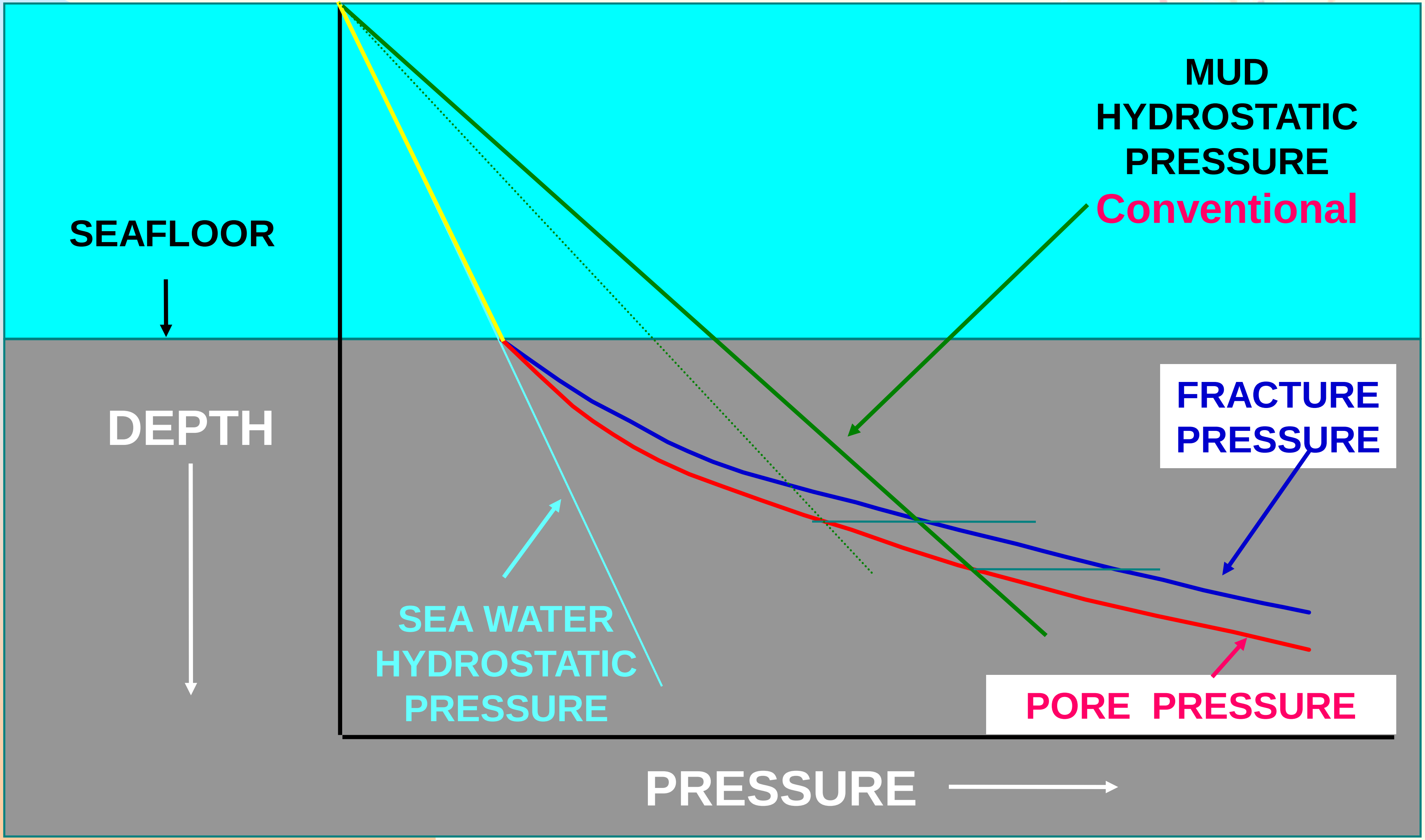
Conventional Casing Seat Selection



Solution: Static Wellbore Pressures

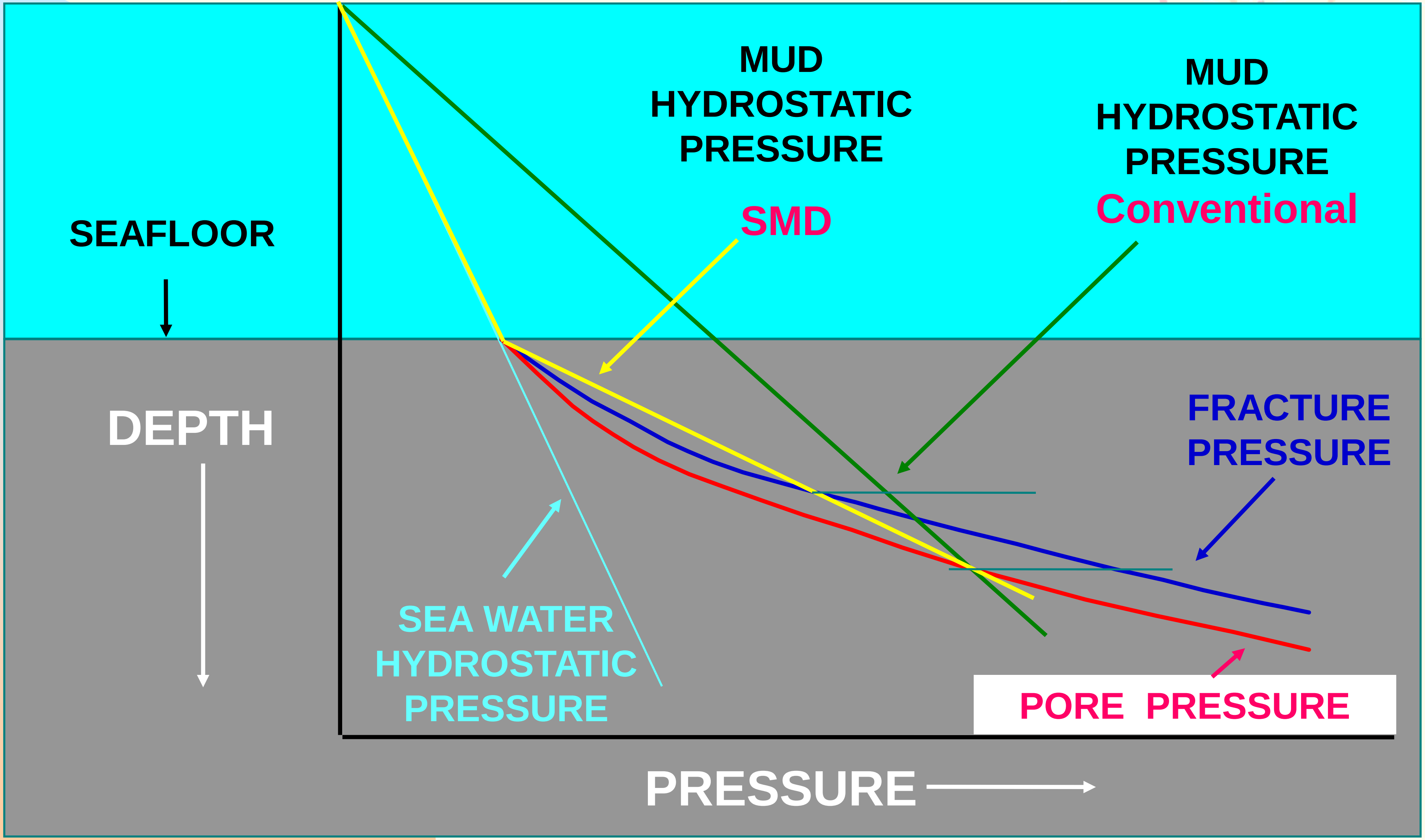


Wellbore Pressures

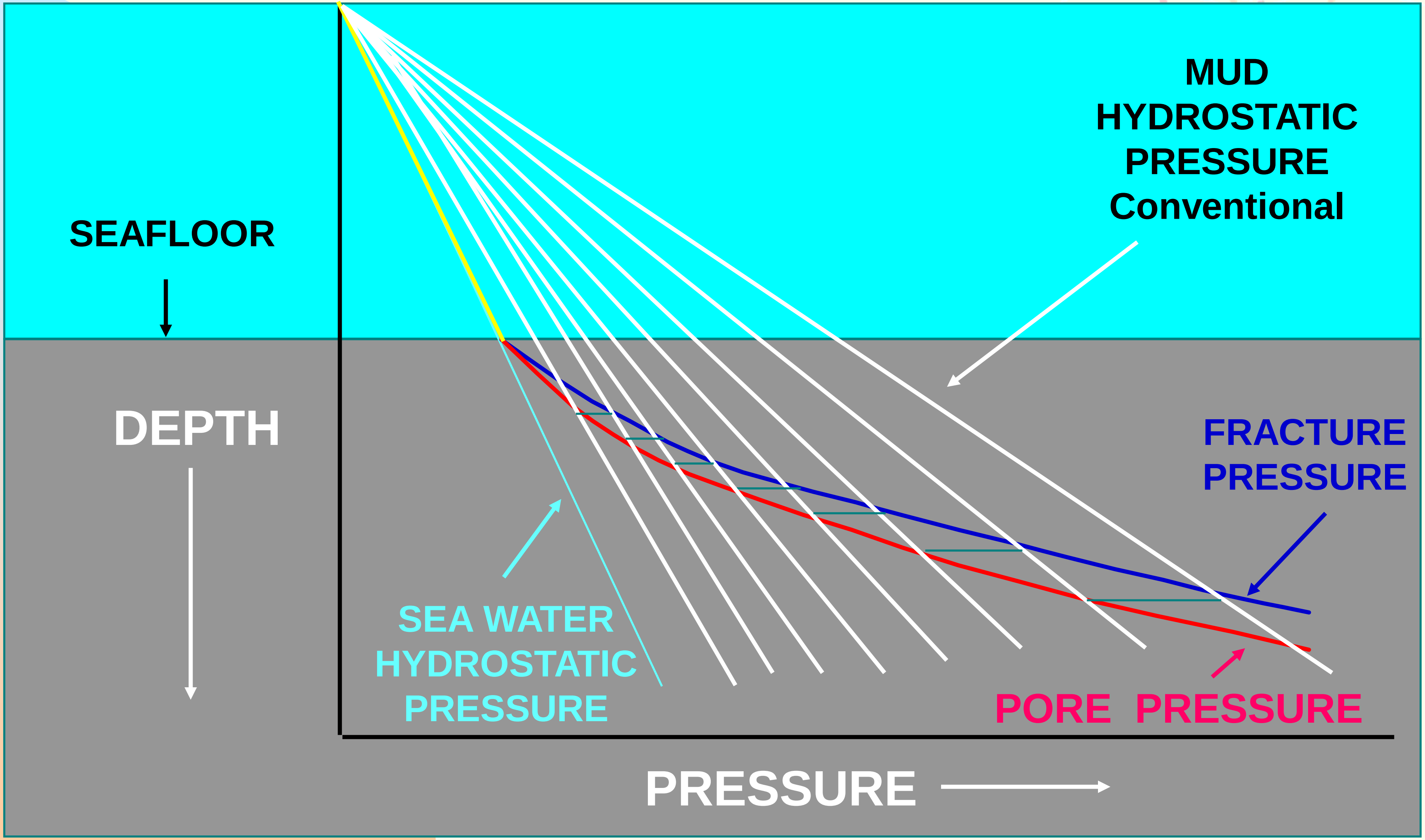


ATM

Wellbore Pressures

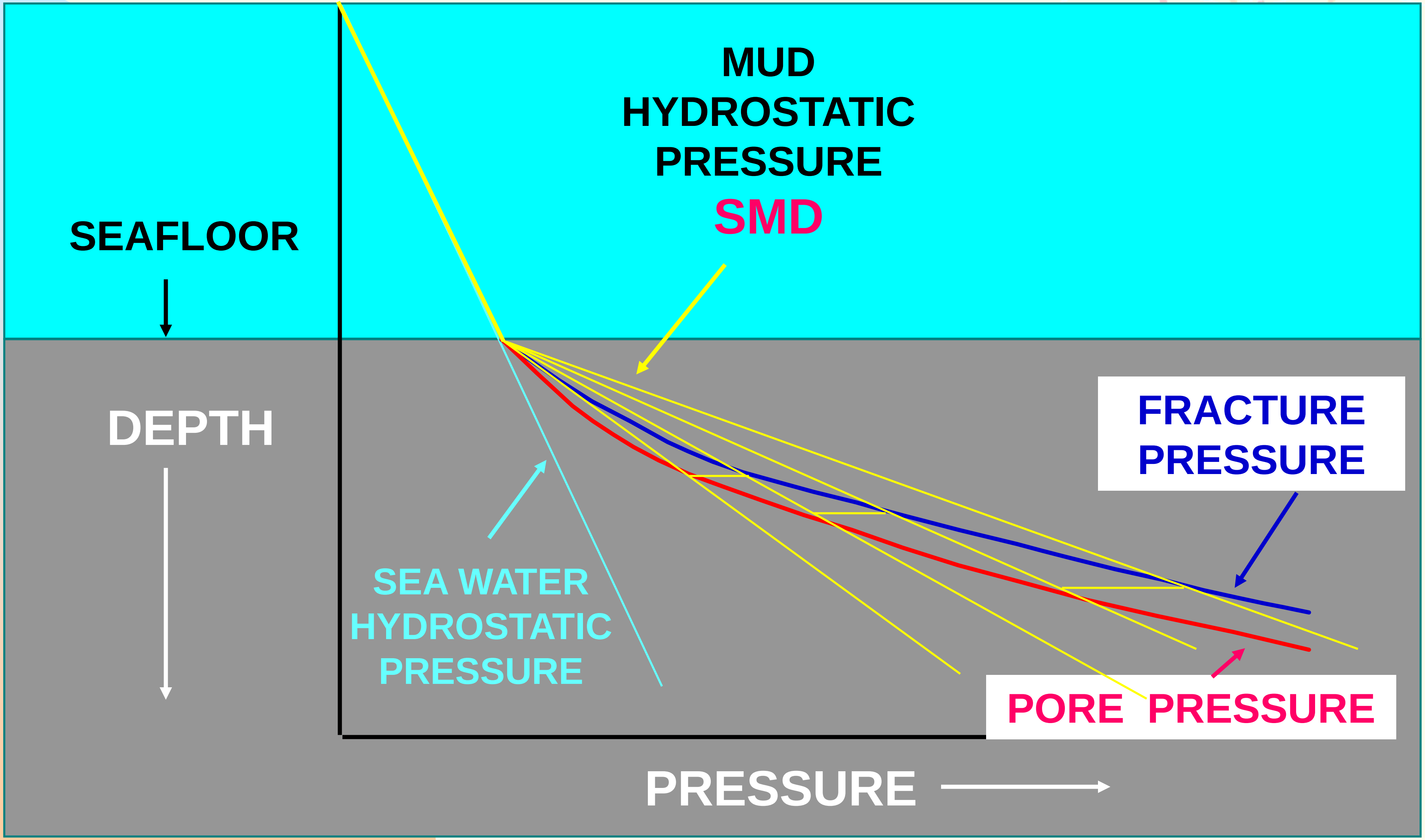


Casing Requirements - Conventional



ATM

Casing Requirements - SMD



Expandable Tubulars

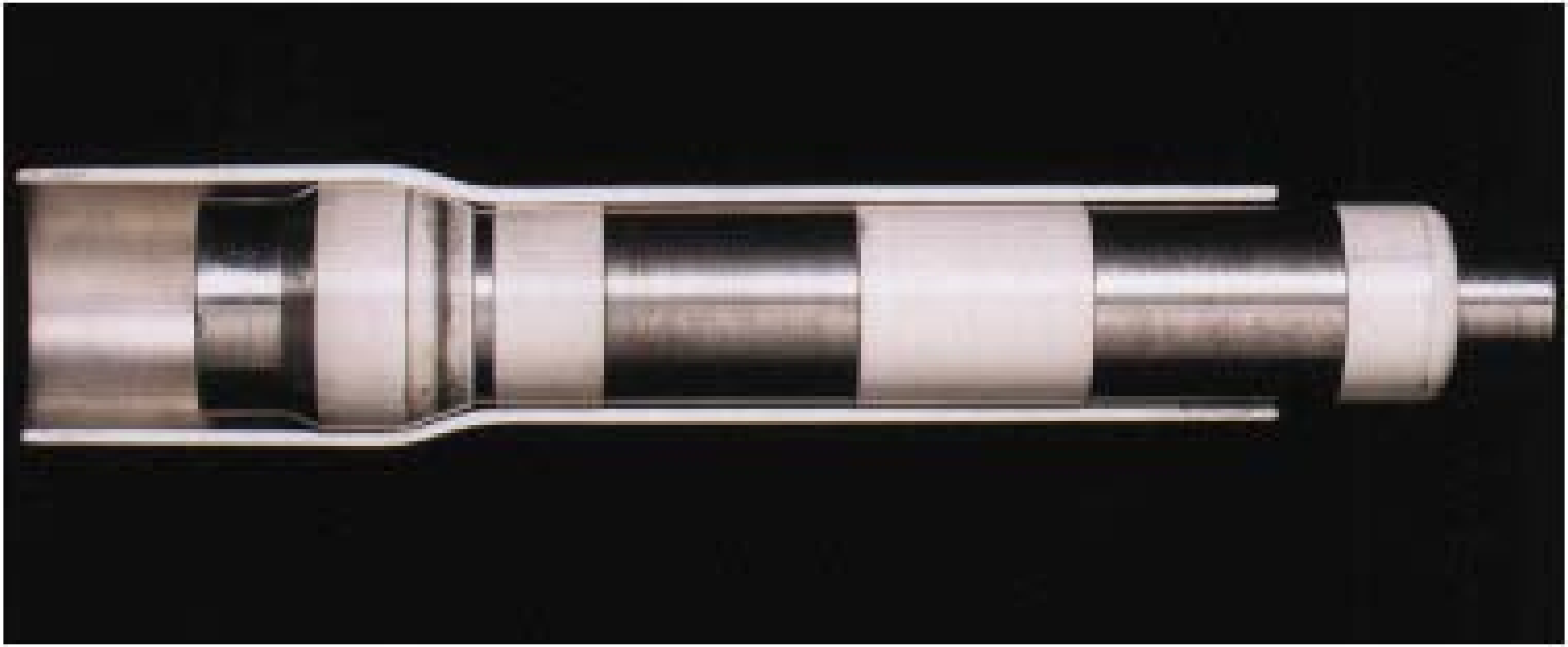


Fig. 1—Cross-section of partially expanded pipe with mandrel.

Expandable Tubulars

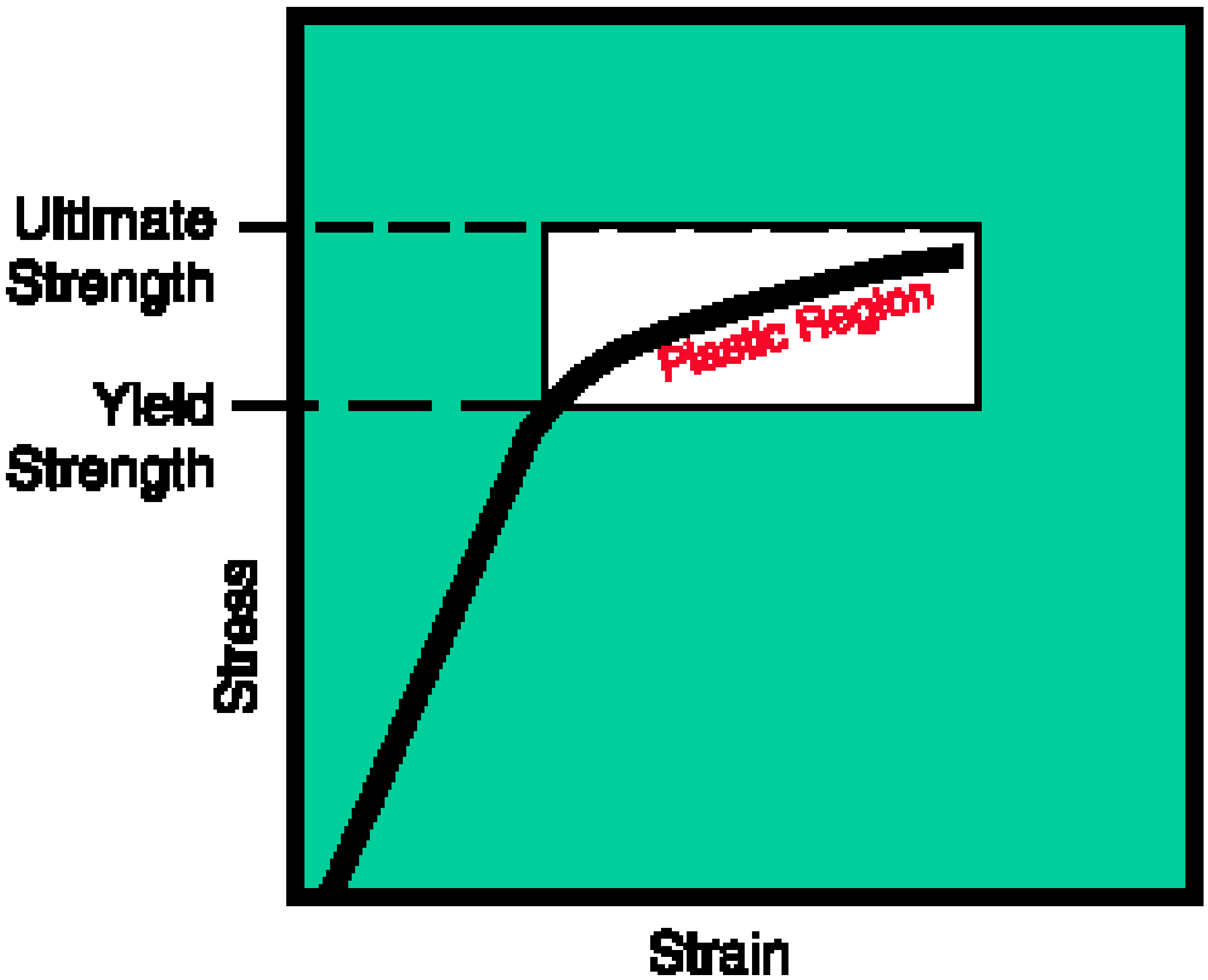


Fig. 2—Expandable Tubular are cold worked into the tubular's plastic region

Expandable Tubulars

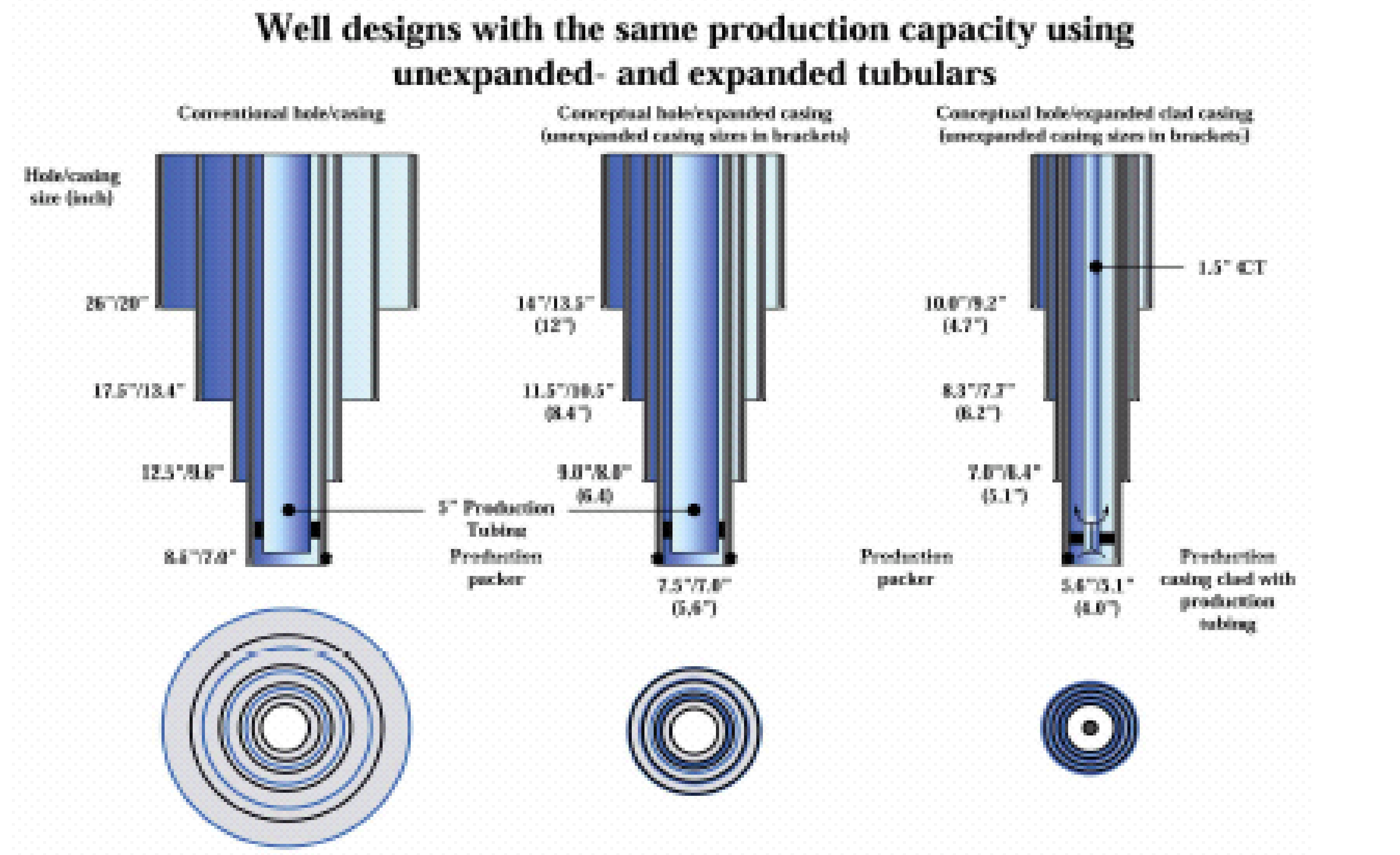


Fig. 7—Comparison of a conventional well diagram versus well diagrams that Use expandable tubulars

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

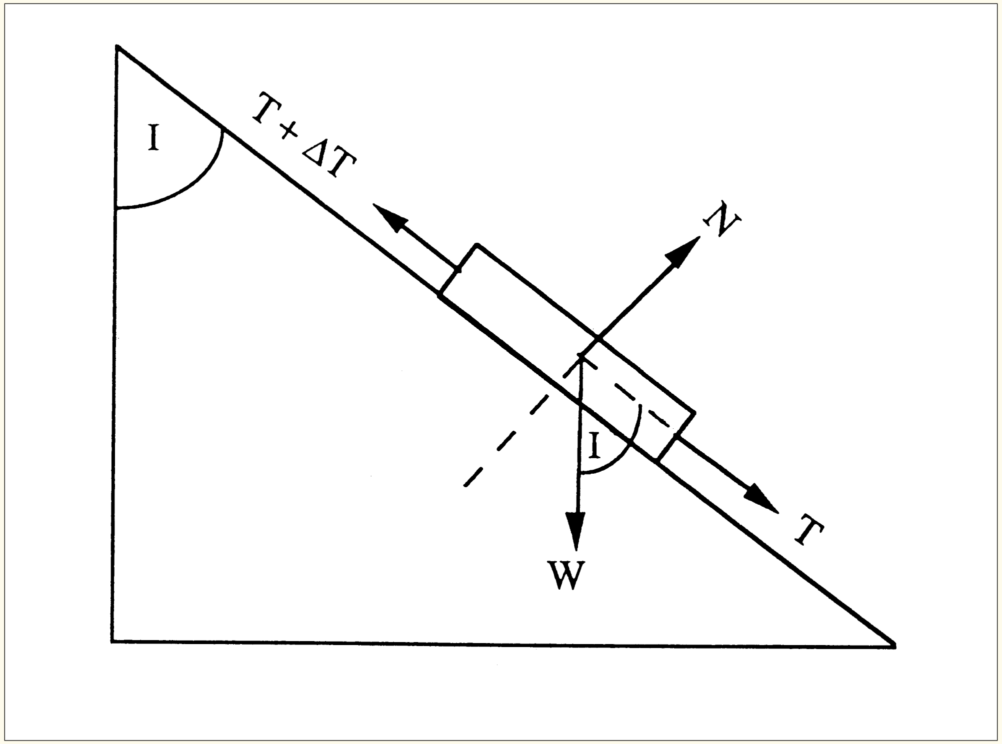
Steve Walls

Torque and Drag

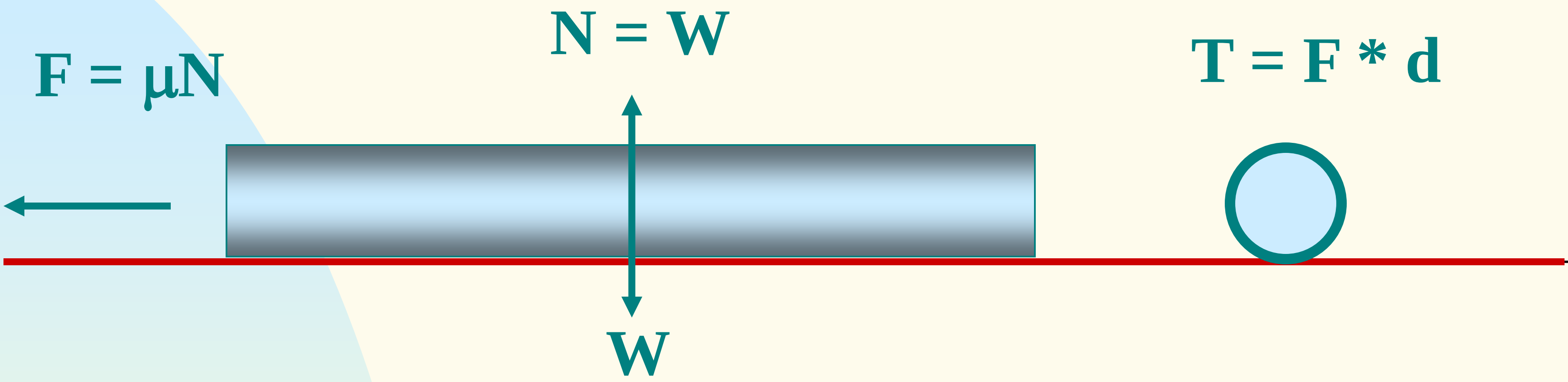
Sliding Motion

- **Drag (friction)**

F = μ N = μ W sin I



Torque



Force to move pipe, $\boxed{F = \mu W \sin I}$

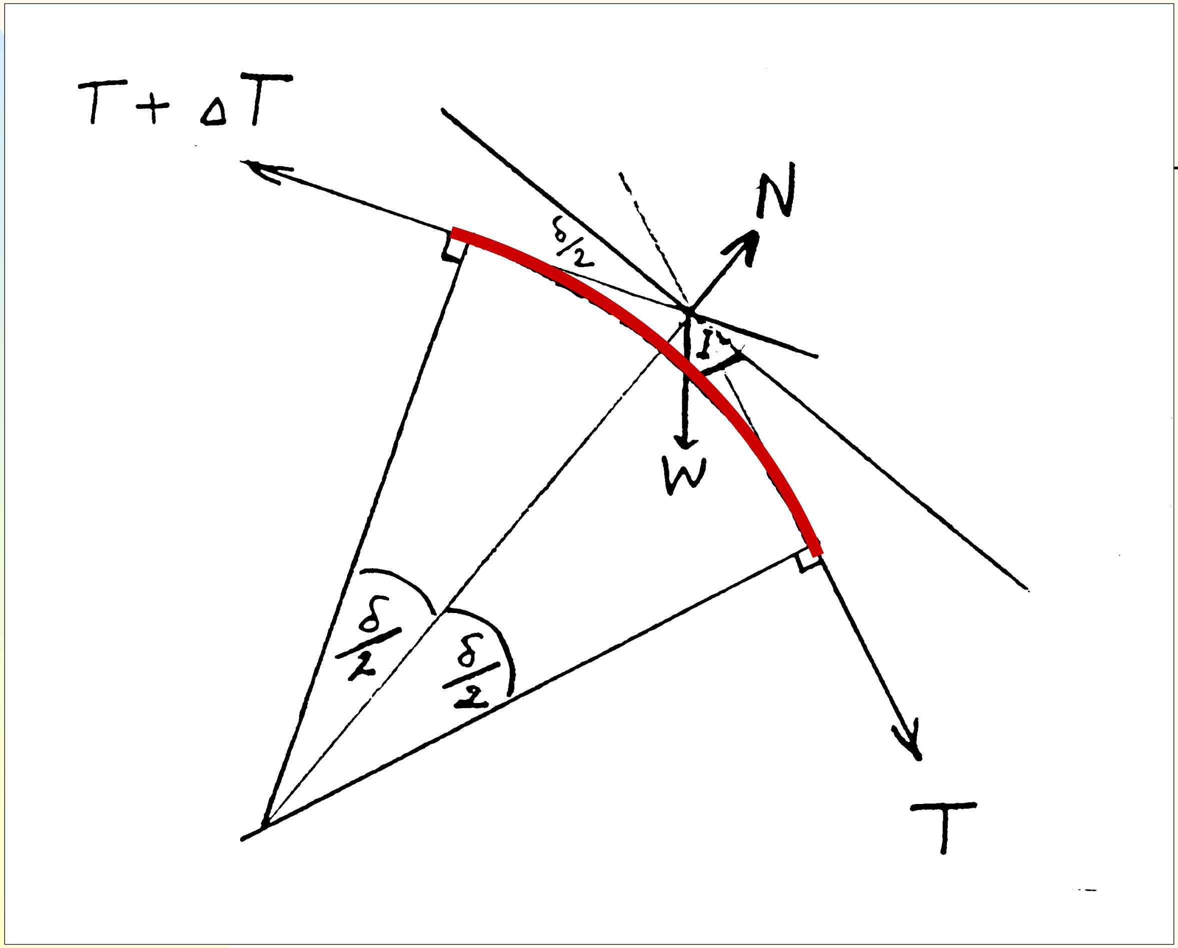
Torque, $\boxed{T = \mu W \sin I \; d/(24\,)}$

An approximate equation, with W in lbf and d in inches

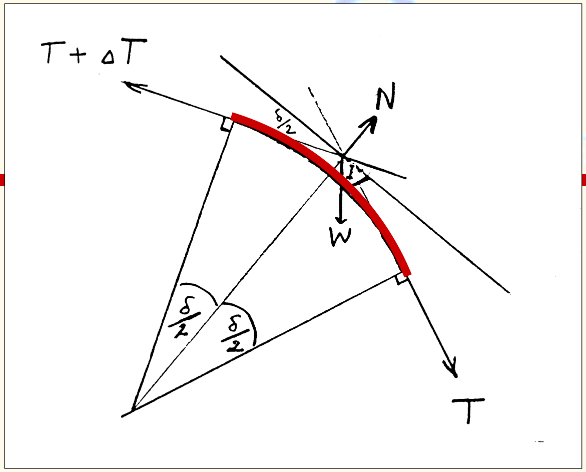
Effect of Doglegs

(1) Dropoff Wellbore

$\delta = \text{dogleg angle}$



Effect of Doglegs



A. Neglecting Axial Friction
pipe rotating)

$$N \cong W \sin I + 2T \sin \frac{\delta}{2} \qquad (10)$$

Effect of Doglegs

$$\text{Torque} = \mu N\left(\frac{d}{2}\right) \cong \mu\left(\frac{d}{2}\right)(W \sin I + 2T \sin\frac{\delta}{2})$$

Buckling

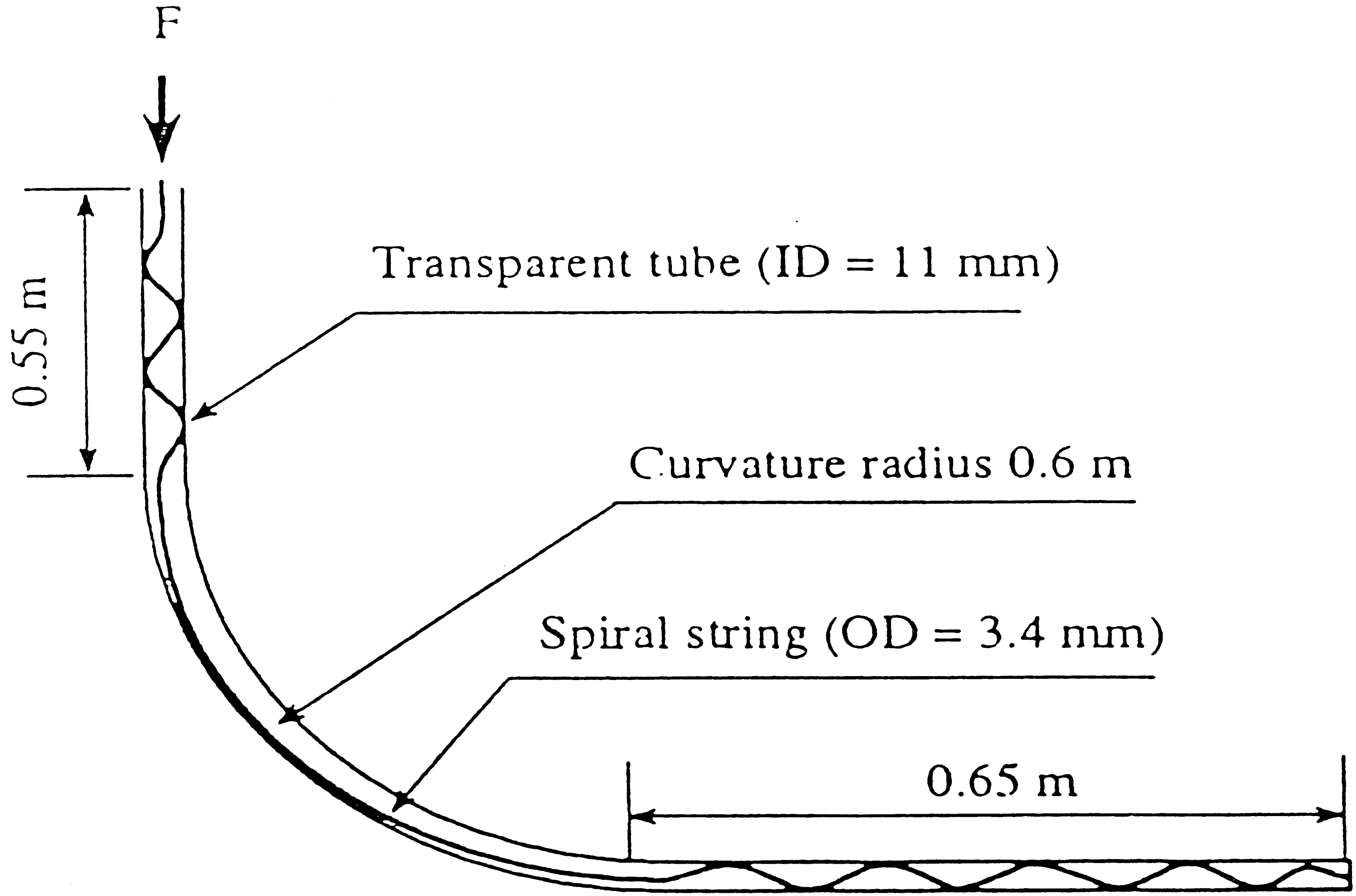


Figure 7 Schematic view of the small scale test loop

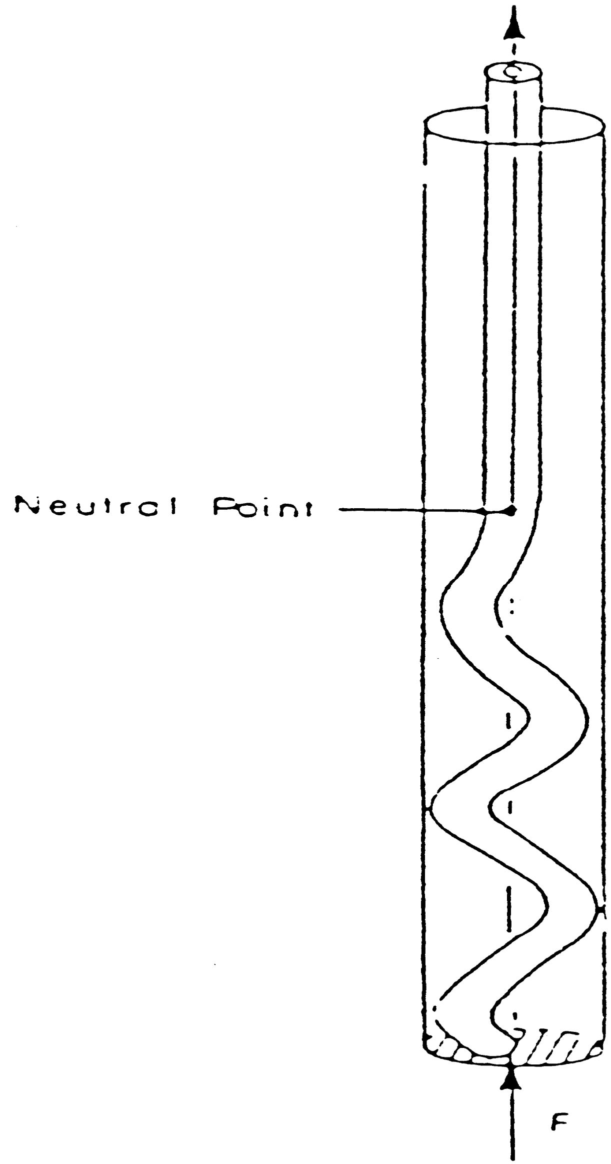


Fig.2 A schematic for coiled tubing buckling in a vertical wellbore.

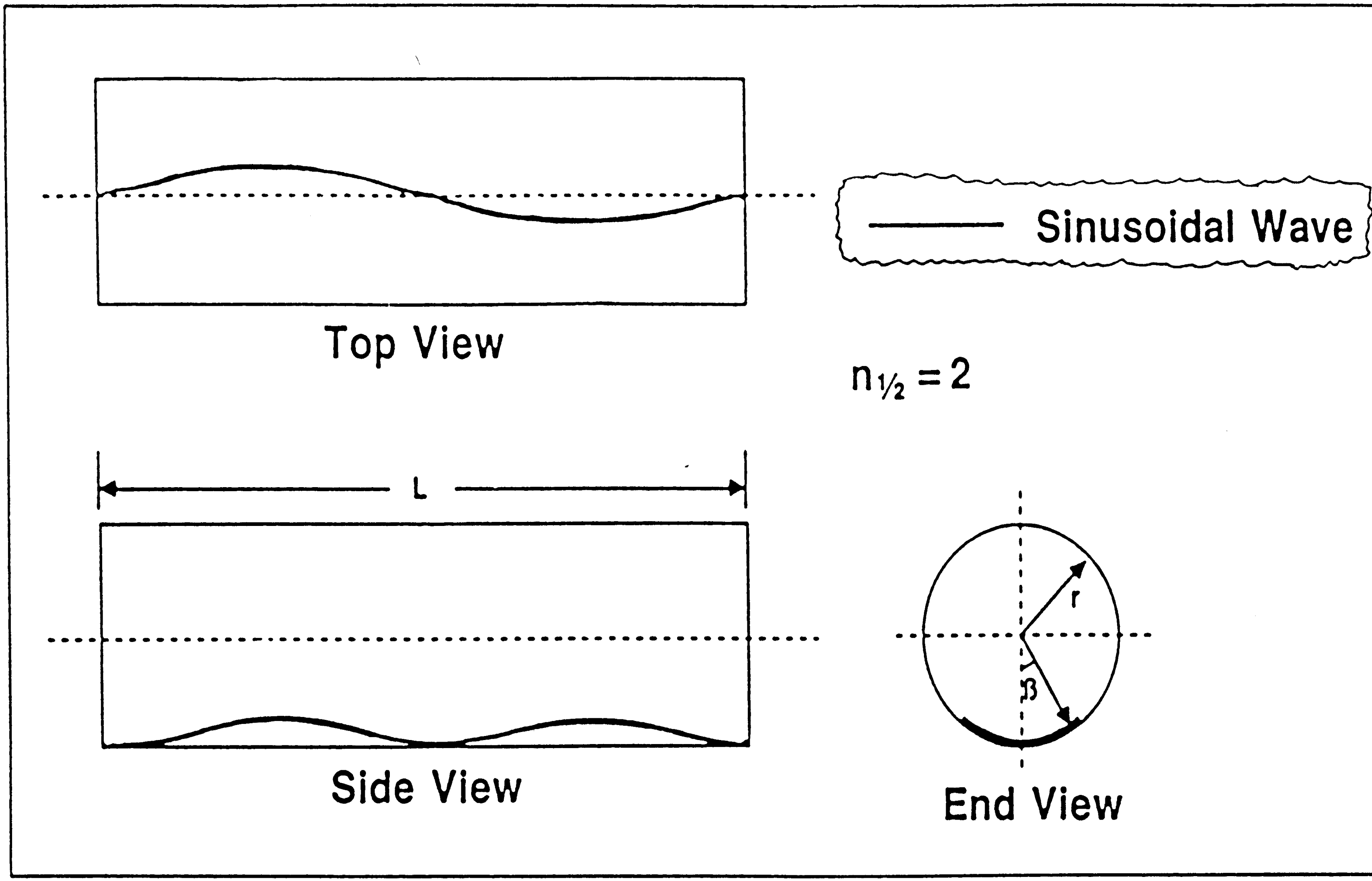


Fig. 1—Postbuckled configuration of pipe in a horizontal hole.

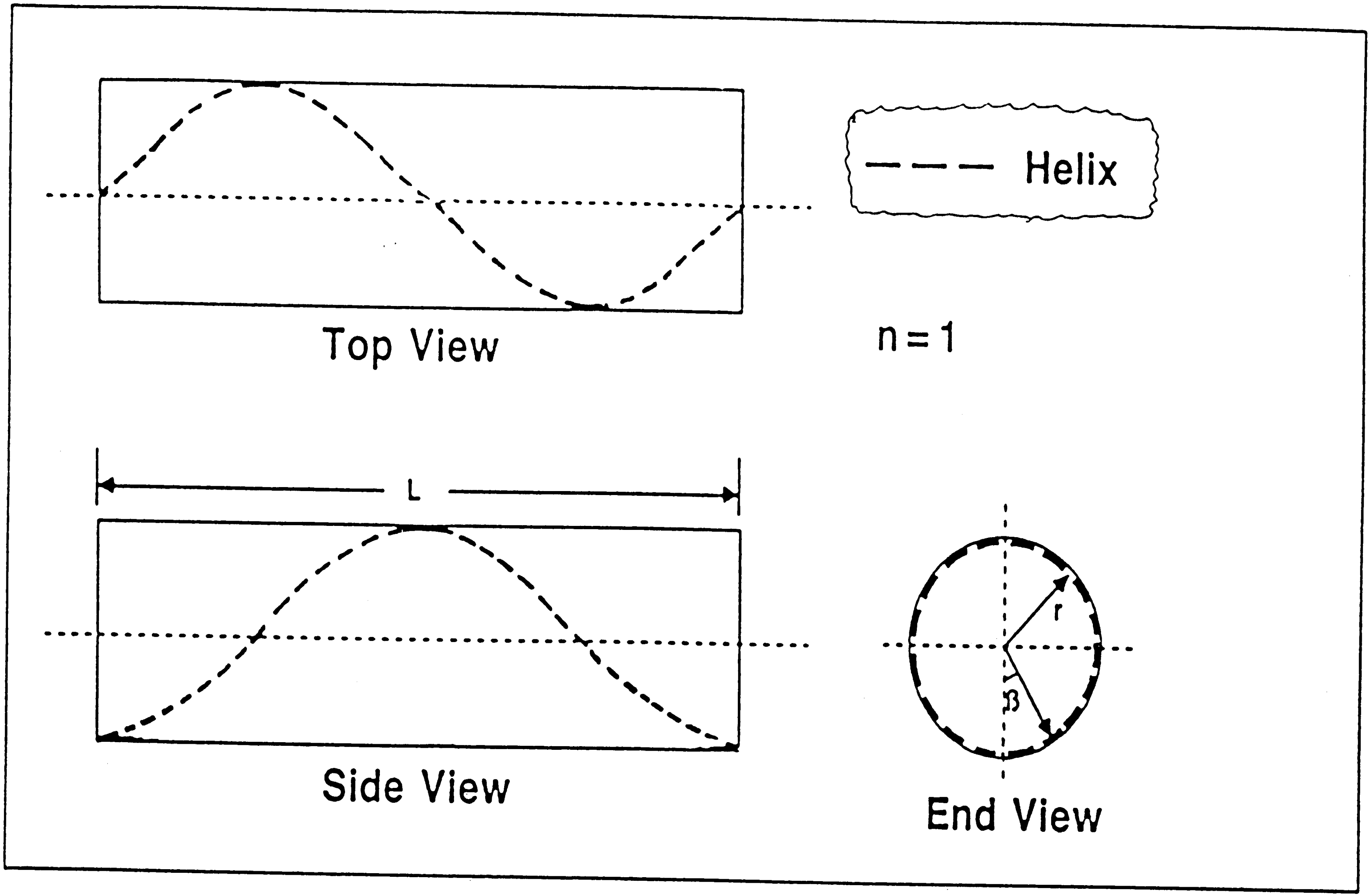
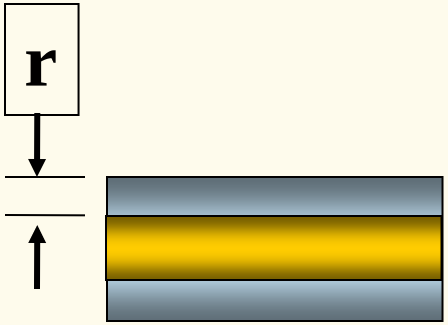


Fig. 1—Postbuckled configuration of pipe in a horizontal hole.

Sinusoidal Buckling in a Horizontal Wellbore

When the axial compressive load along the coiled tubing reaches the following sinusoidal buckling load F_{cr}, the intial (sinusoidal or critical) buckling of the coiled tube will occur in the horizontal wellbore.

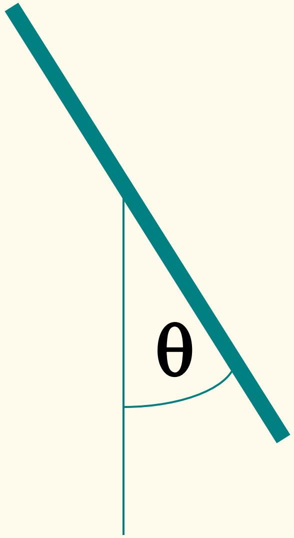
$$F_{cr} = 2\,(EIW_e / r)^{0.5}$$



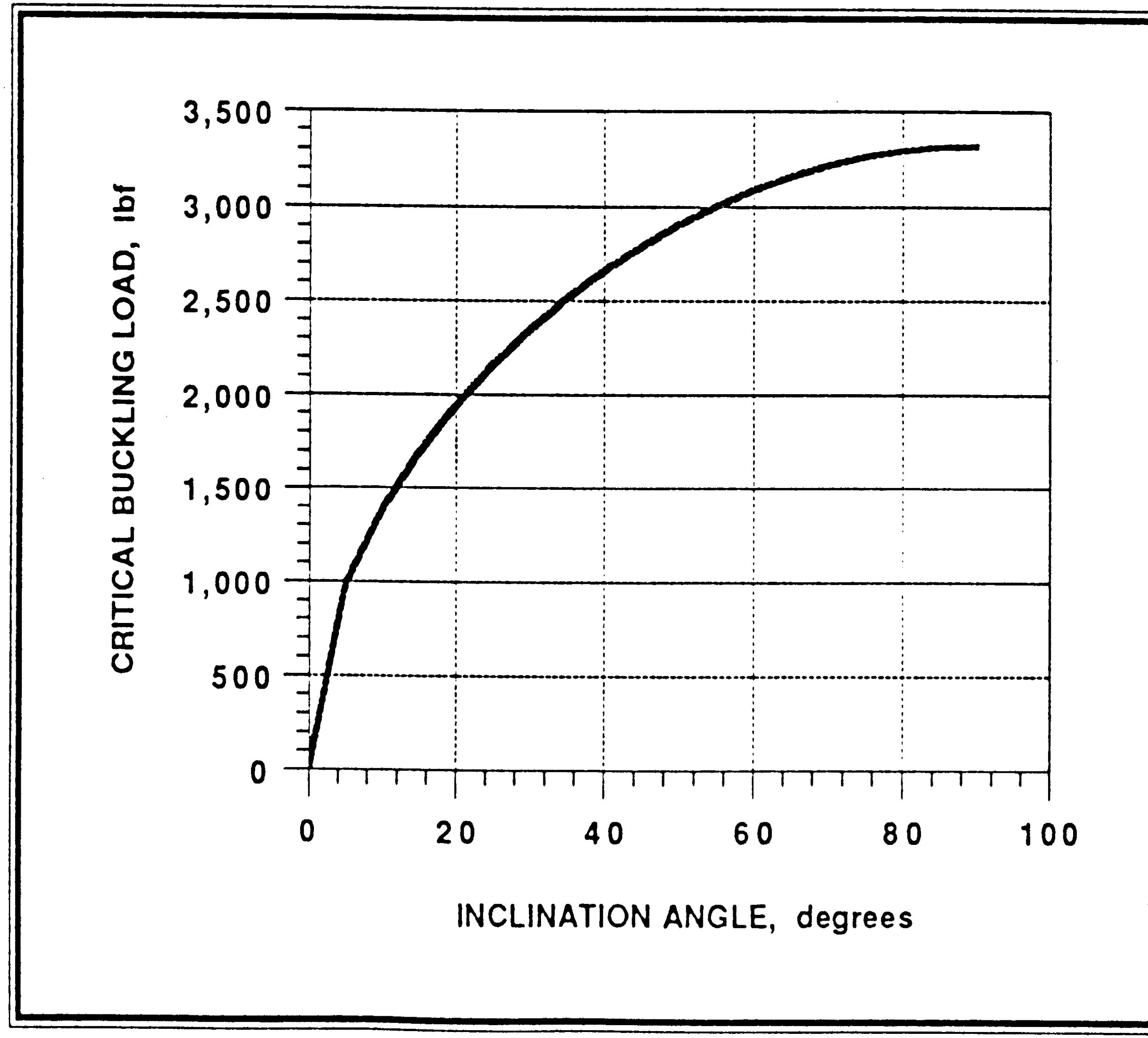
Sinusoidal Buckling Load

A more general Sinusoidal Buckling Load equation for highly inclined wellbores (including the horizontal wellbore) is:

$$F_{cr} = 2\sqrt{\frac{EIW_e \sin\theta}{r}}$$



Deg	Fcr
0	0
5.00	979
10.00	1,382
15.00	1,688
20.00	1,940
25.00	2,157
30.00	2,346
35.00	2,512
40.00	2,660
45.00	2,789
50.00	2,903
55.00	3,002
60.00	3,087
65.00	3,158
70.00	3,216
75.00	3,260
80.00	3,292
85.00	3,311
90.00	3,317



Helical Buckling in a Horizontal Wellbore

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

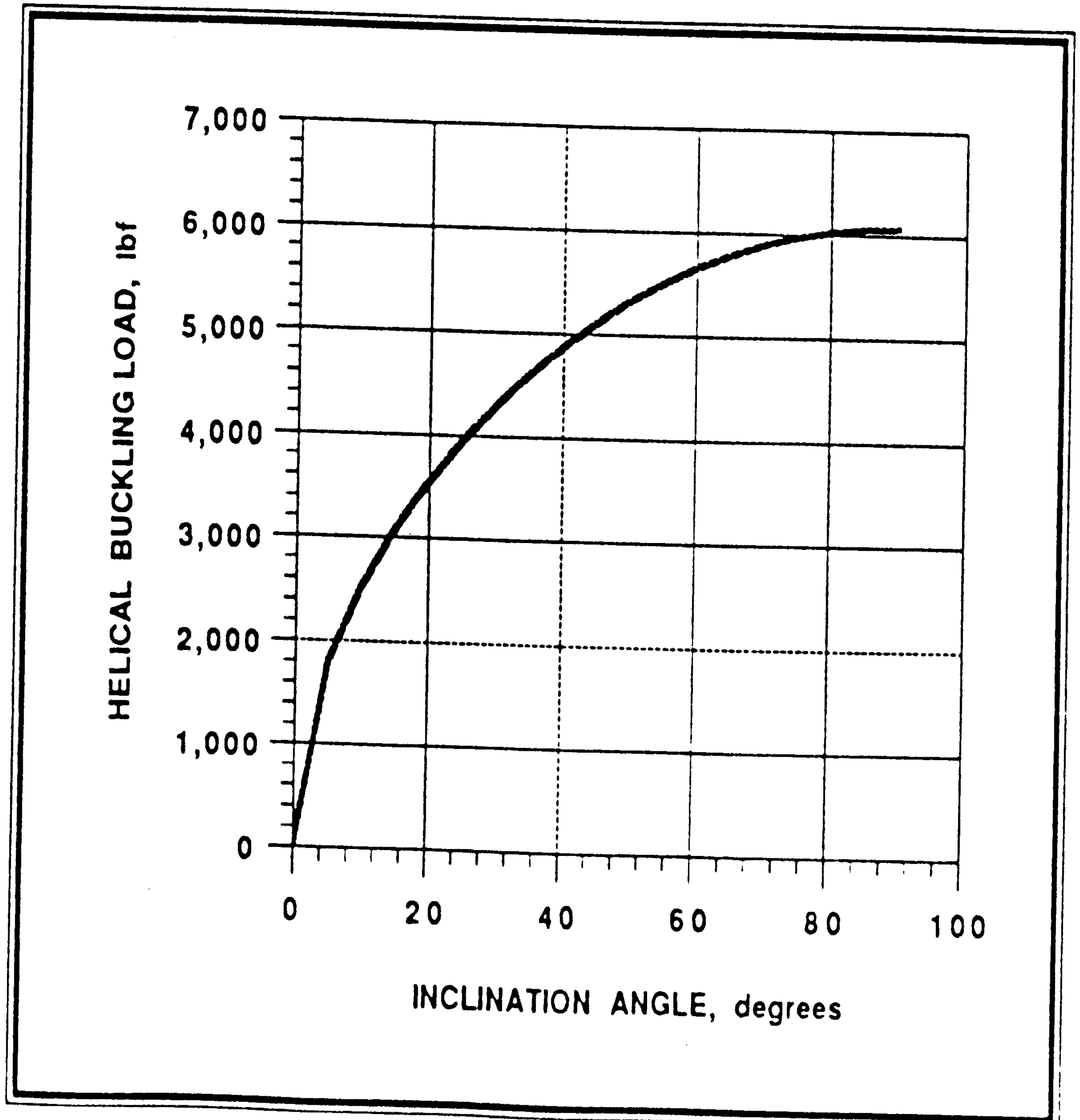
$$F_{hel} = 2\left(2\sqrt{2}-1\right)\sqrt{\frac{E\,I\,W_e}{r}}$$

General Equation

A more general helical buckling load equation for highly inclined wellbores (including the horizontal wellbore) is:

$$F_{hel} = 2\left(2\sqrt{2}-1\right)\sqrt{\frac{EIW_e \sin\theta}{r}}$$

Deg	Fhel
0	0
5.00	1,791
10.00	2,527
15.00	3,086
20.00	3,547
25.00	3,943
30.00	4,289
35.00	4,594
40.00	4,863
45.00	5,100
50.00	5,309
55.00	5,490
60.00	5,644
65.00	5,774
70.00	5,880
75.00	5,961
80.00	6,019
85.00	6,054
90.00	6,065



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.

Helical Buckling in Vertical Wellbores:

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:

$$F_{hel,b} = 5.55(EIW_e^{\,2})^{1/3}$$

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:

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

$$= 0.14(EIW_e^{\,2})^{1/3}$$

Helical Buckling in Vertical Wellbores:

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.

Continue ...

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.

Continue ...

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.

Continue ...

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

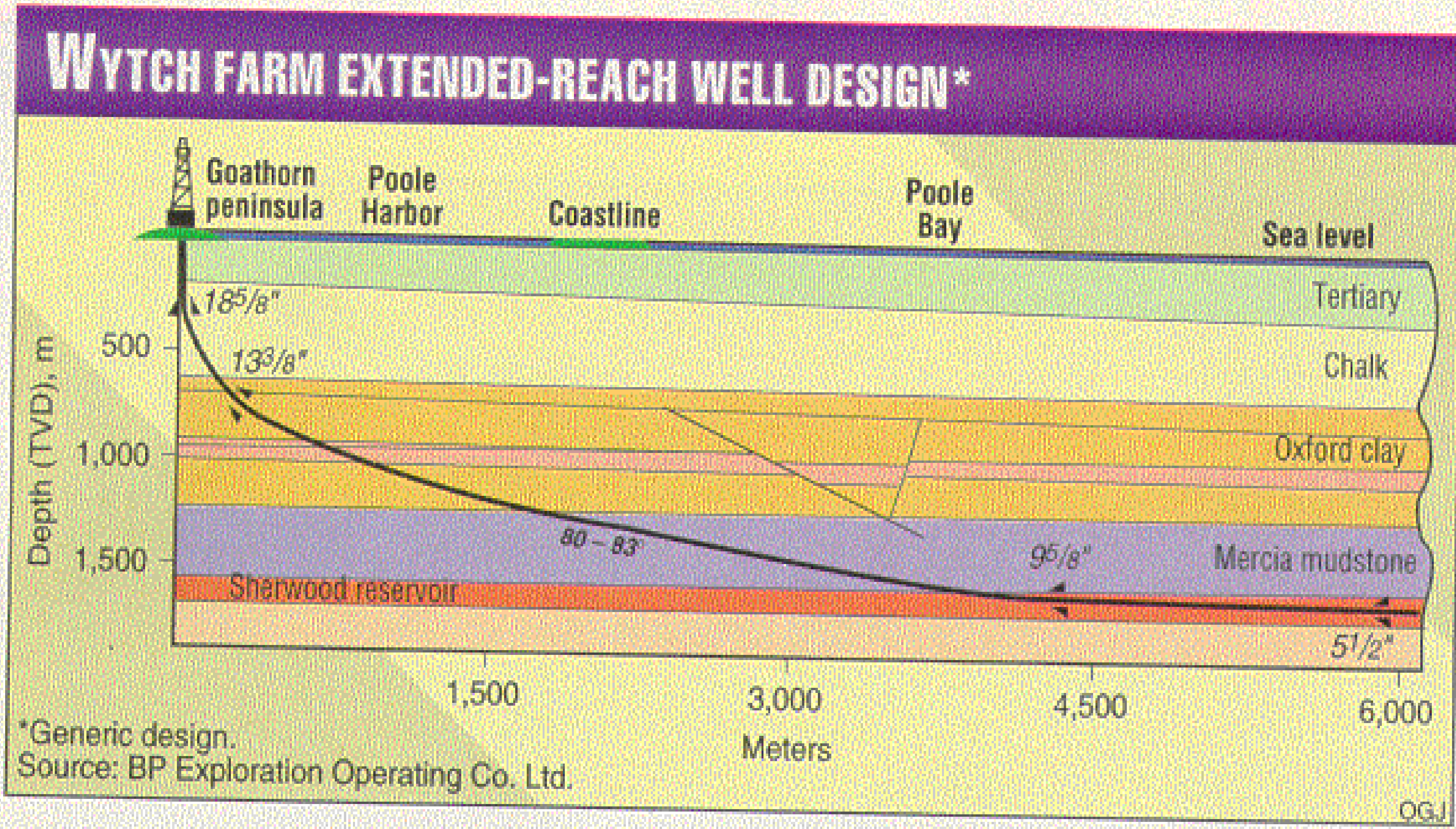
Excess torque and drag

- 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

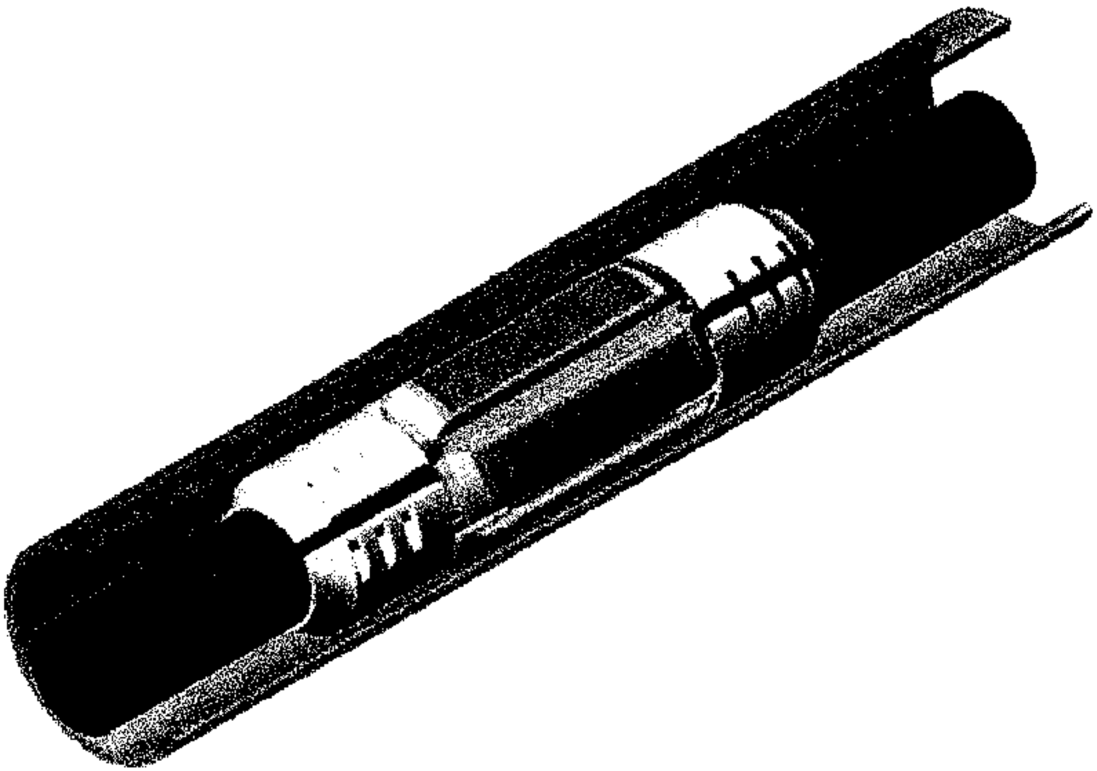
- Can be prevented or reduced.
  - Wellbore profile.
    - Low doglegs
    - Catenary profile
  - High lubricity muds
  - Non-rotating drillpipe protectors
  - Rotary steerable systems

Catenary wellbore



Non-rotating drillpipe protectors

Figure 1: 3-1/2" Low-Drag NRDPP Inside 7" Casing

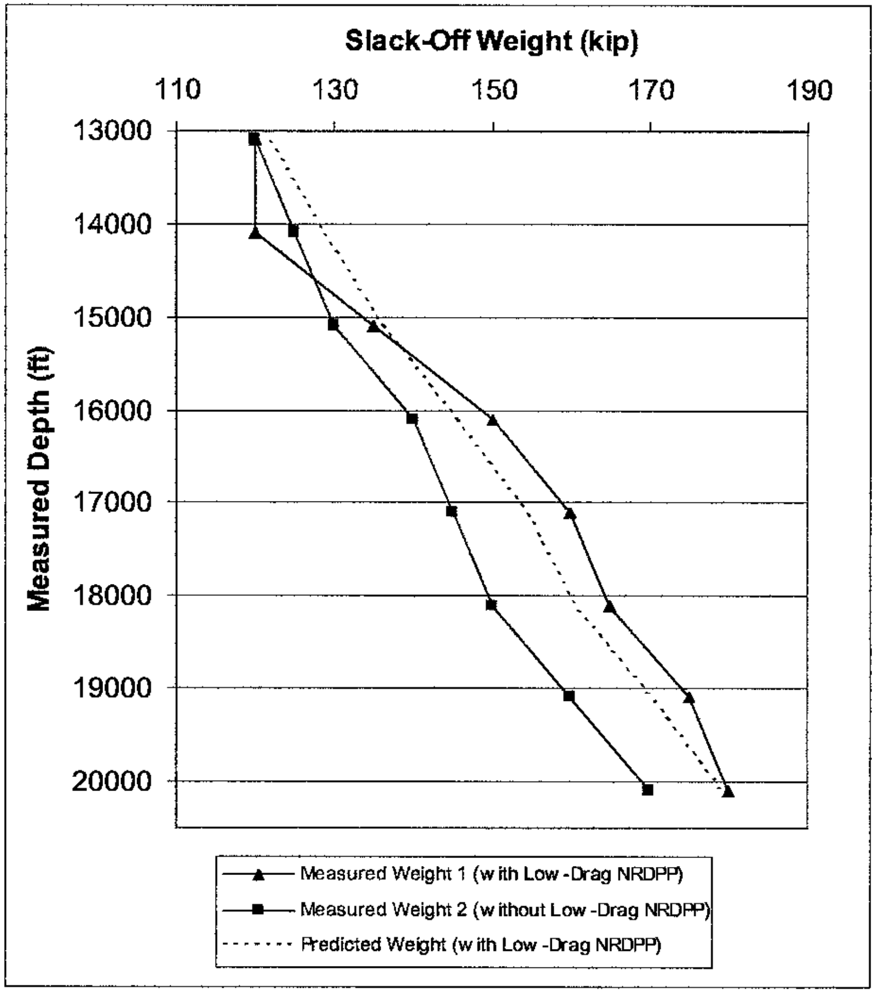


Non-rotating drillpipe protectors

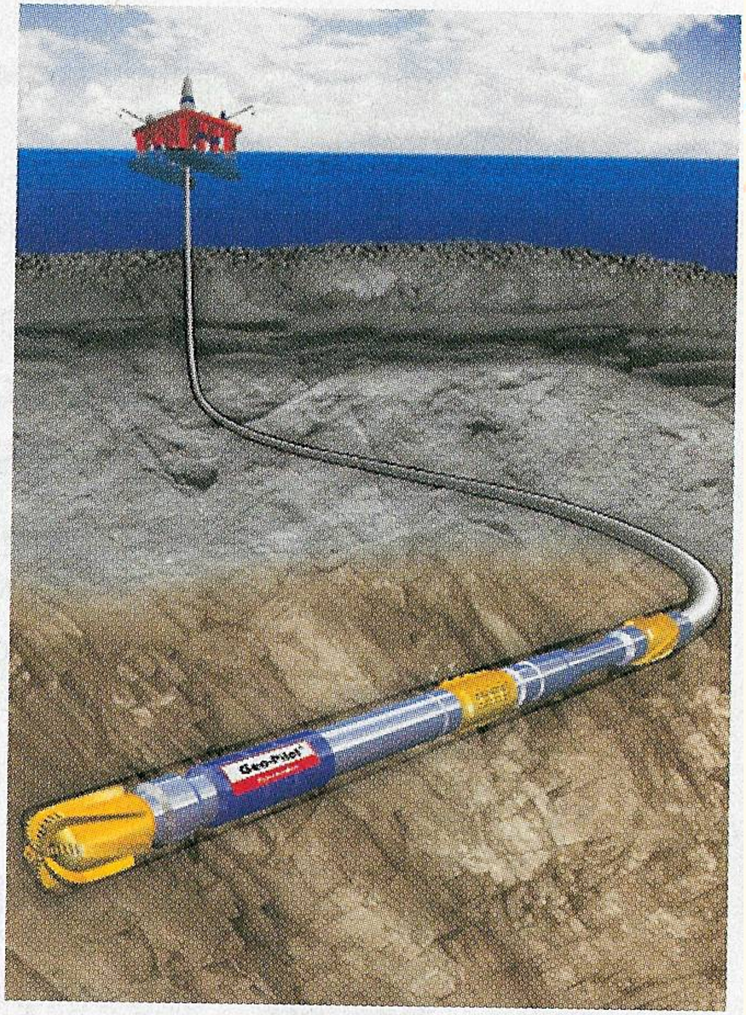
Table 1: Average Rotational and Sliding COF's.

RESULTS	Low Drag NRDPP	Bare Drill Pipe
Average Sliding COF	0.11	0.21
Average Rotational COF	0.03	0.20

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

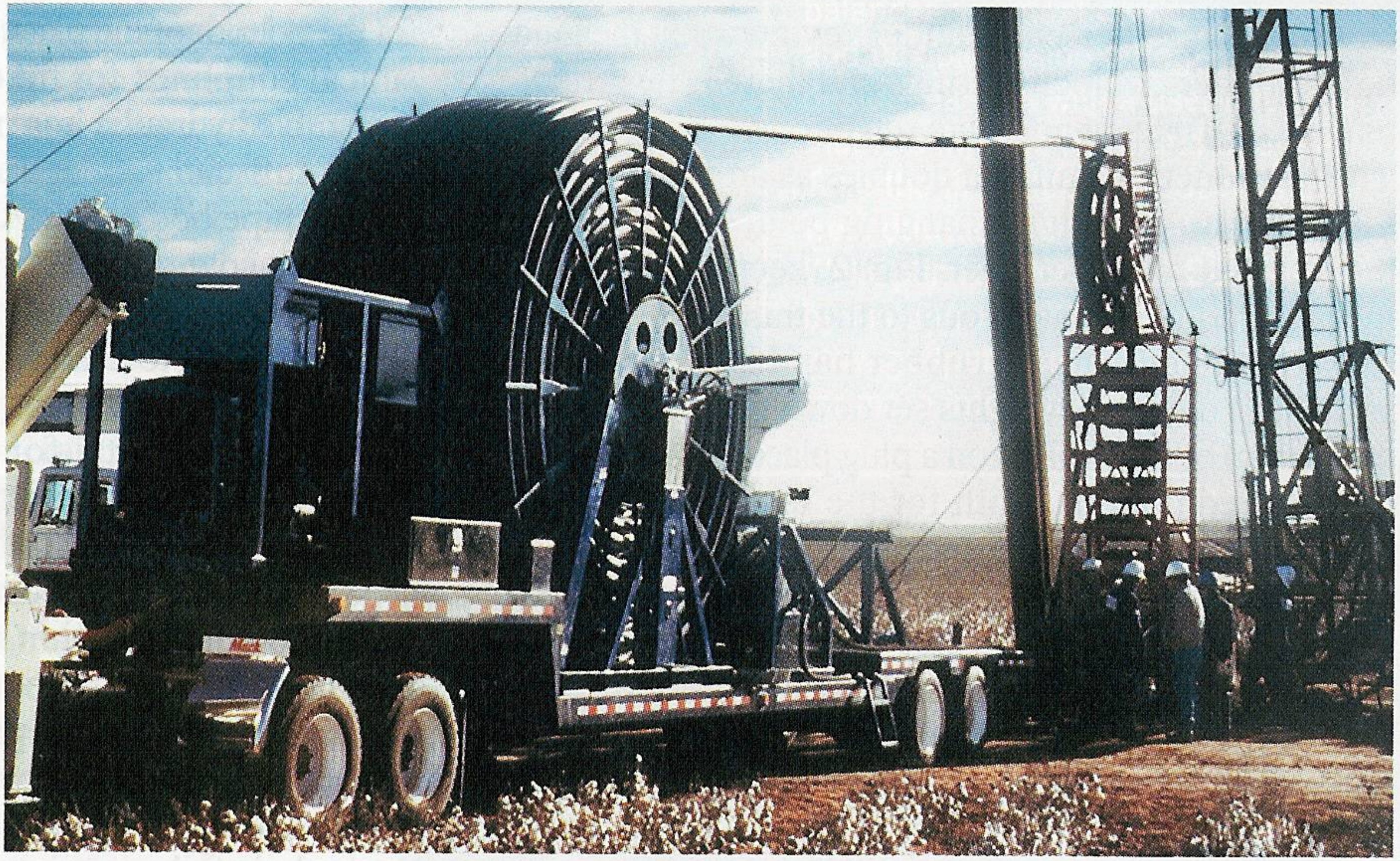


Fig. 1. Roller reduction application places a tight-fit liner into the well. Reel capacity varies with liner diameter, and can be 5,000 to 12,000 ft of coiled plastic liner.

Plastic Liners

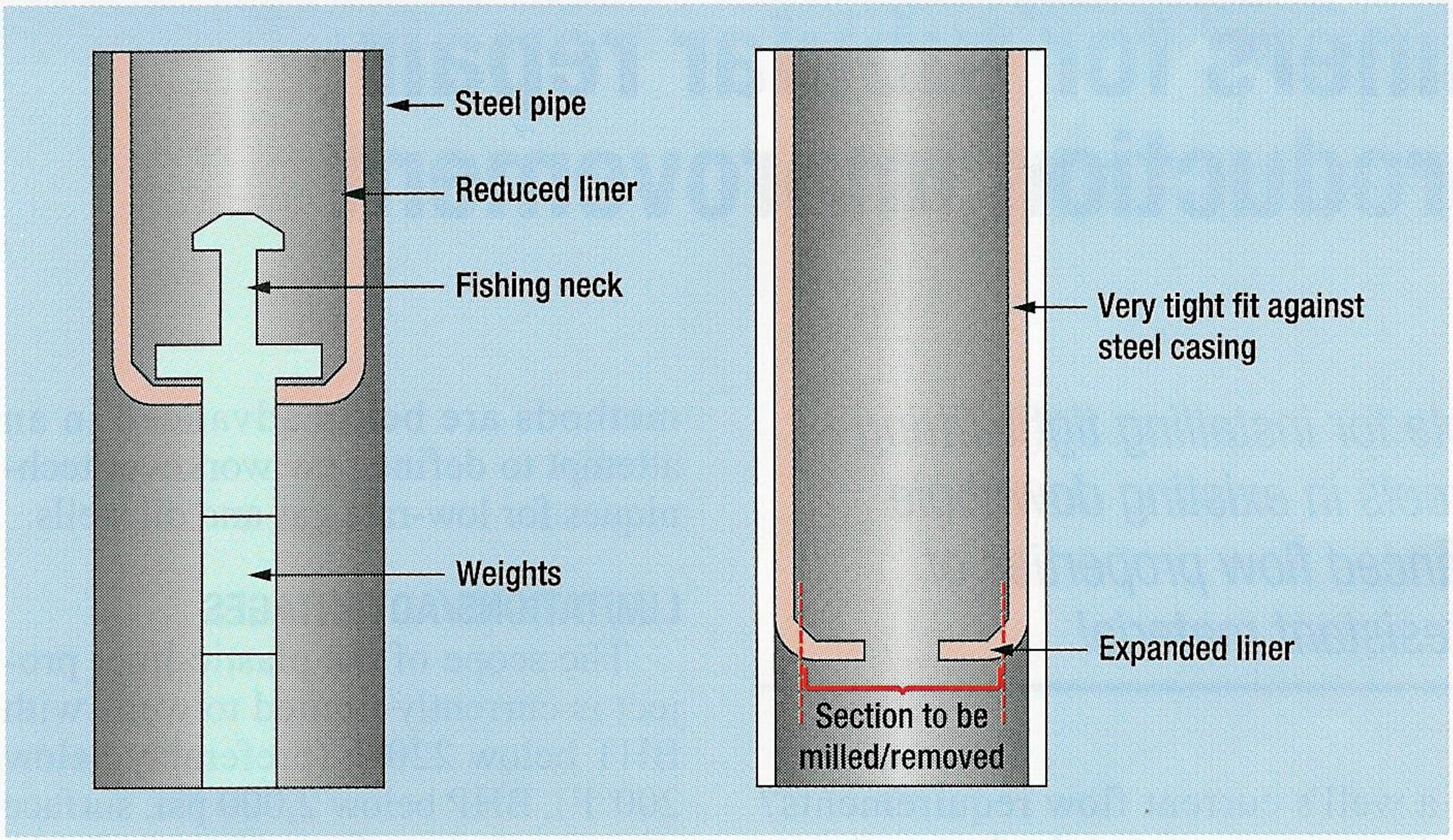


Fig. 2. Following downsizing, plastic liner is pulled into the well with simple weights that are retrieved through the liner bore after target depth is reached. After weights are removed, liner "memory" takes over and the plastic grows out against the steel pipe.

Plastic Liners

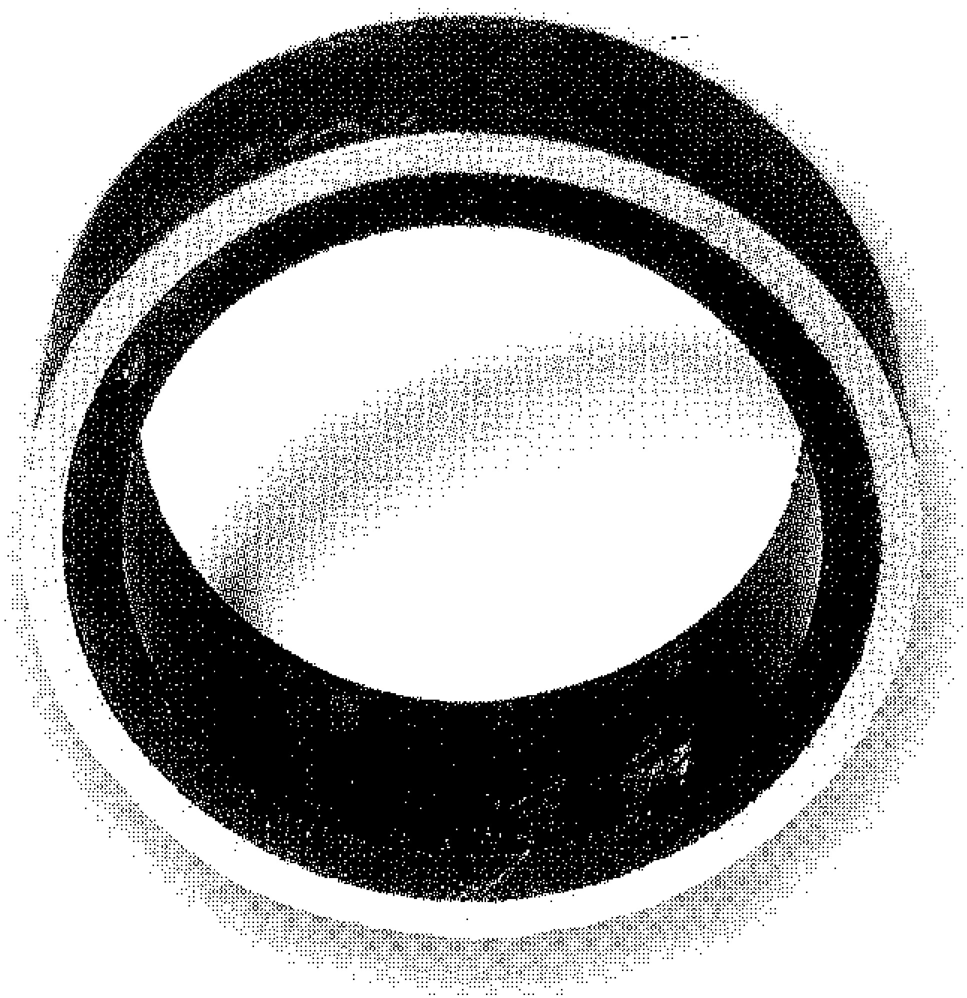


Fig. 3. As this sample pipe cross-section shows, a properly selected plastic, accurately downsized and successfully fitted, provides a tight-fitting liner that pushes out against the steel with a force that requires about 100 lb/in. to move; i.e., the liner is self-hanging.

Solid Expandable Tubulars

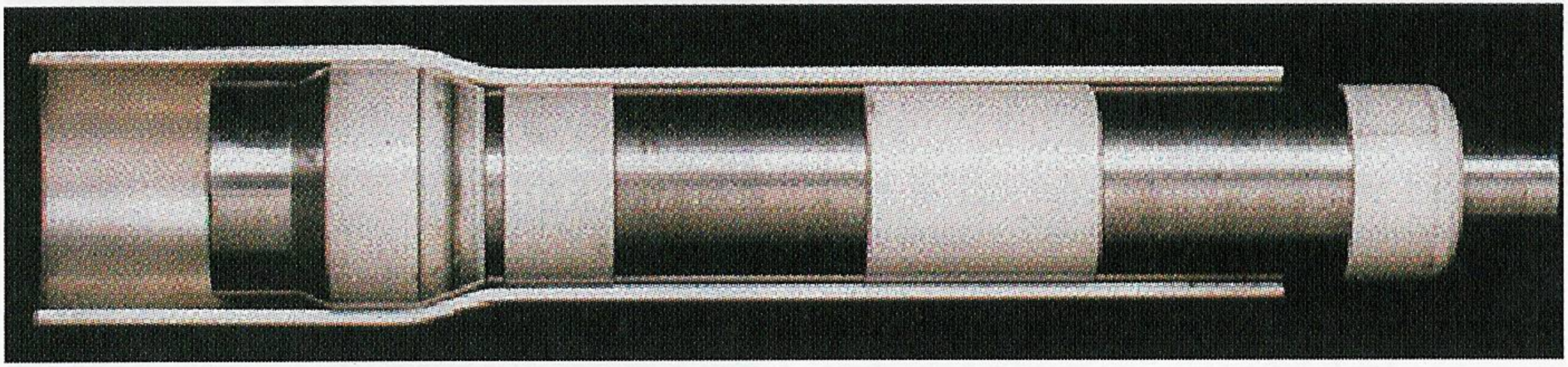


Fig. 1. Early expansion cone used to expand solid expandable tubulars.

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 allow 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

SPE 28293 (1994)

- 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

Outline

- 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 affect 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.

Conclusions cont'd

- 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