Part 1

Production Logging Fundamentals

Production Logging Interpretation

Learning Objectives

By the end of this lesson, you will be able to:

- Present the calibration principles of flowmeter tools
- Present the principles involved in interpreting production logging tool data
- Illustrate the performance of cased hole logs in multi-phase flow
- Review the application of cased hole logs in deviated wells
• Spinner-type velocimeter which records a continuous flow profile versus depth.
• Sensitive to the velocity differential between the tool and the surrounding fluid.
• Most effective for single phase flow conditions in wells with high production rates and/or small inner casing diameter.

**Flowmeter Calibration – Spinner Reversal**

**Spinner Reversal Phenomenon**

- A change of direction in spinner rotation under downhole external flow conditions.

**Continuous Flowmeter**

- Spinner-type velocimeter which records a continuous flow profile versus depth.
- Sensitive to the velocity differential between the tool and the surrounding fluid.
- Most effective for single phase flow conditions in wells with high production rates and/or small inner casing diameter.

---

**Flowmeter Calibration – Spinner Reversal**

**Increasing Velocity**

- Fluid entries

**No Flow**

- Below the fluid entry level, the spinner rotates clockwise due to tool movement in static fluid.
The spinner stalls when tool velocity is close to fluid velocity.

The spinner starts rotating again, in the opposite direction, as fluid velocity exceeds tool velocity.
Flowmeter Response and Calibration

- There is no practical higher limit to spinner velocity measurement
- There is a minimal flow rate below which the tool will not operate
  - The spinner will not rotate, due to internal friction and fluid viscosity
- Fluid viscosity has an effect on spinner speed
  - Low viscosity increases spinner speed
  - The downhole response curve of spinner speed versus fluid velocity must be established

©PetroSkills, LLC. All Rights Reserved.
Flowmeter Calibration – Sign Conventions

\[ V_c = \text{Cable Speed (Tool Velocity)} \]

<table>
<thead>
<tr>
<th>( V_c &gt; 0 ) Tool Running Down (Depth Increasing)</th>
<th>( V_c &lt; 0 ) Tool Running Up (Depth Decreasing)</th>
</tr>
</thead>
<tbody>
<tr>
<td>( V_f &gt; 0 ) Fluid Moving Up</td>
<td>( V_f &lt; 0 ) Fluid Moving Down</td>
</tr>
<tr>
<td>( V_c &gt; 0 ) Tool Running Down</td>
<td>( V_c &lt; 0 ) Tool Running Up</td>
</tr>
<tr>
<td>(</td>
<td>V_c</td>
</tr>
<tr>
<td>(</td>
<td>V_c</td>
</tr>
<tr>
<td>(</td>
<td>V_c</td>
</tr>
<tr>
<td>(</td>
<td>V_c</td>
</tr>
</tbody>
</table>

Flowmeter Logging (Log Up and Log Down)

Flowmeter Logging (Log Up and Log Down)
Flowmeter Multipass Calibration Technique

![Graph showing Flowmeter Multipass Calibration Technique]

- **Slope** depends only on tool geometry.
- **Zero Flow Line**
- **Fluid Velocity**
- **Tool Velocity (ft/min)**
- **Spinner Response (rps)**

### Multiple Data Points

- This plot is essential to identify possible issues at stations:
  - Readings do not align, or
  - Slopes differ too much
- Anomalies should be investigated while the tool is still downhole
- Company representatives should be present and interpreting recordings in real time
Turbulent Versus Laminar Flow

Dye injection

Laminar

Higher Flow Rates

Turbulent

Low Flow Rates

Spinner Response under various flow regimes

APPARENT VELOCITY

CORRECTION FACTOR

AVERAGE VELOCITY

Laminar

Turbulent
Laminar Flow

- Flowmeter centered in tubing and measuring maximum rate
- To derive the actual flowrate, we need the fluid $V_{average}$
- The speed vector has parabolic pattern
- Use approximation to get $V_a$
  \[ V_{average} = 0.50 \times V_{max} \]
- For actual flowrate, use caliper reading

Turbulent Flow

- Turbulence is related to the Reynolds number, $N_{Re}$ of the fluid flow
  - If $N_{Re} < 2000$, flow is laminar
  - If $N_{Re} > 2000$, flow is turbulent
- Matching the Reynolds number is not, on its own, sufficient to guarantee flow similitude
- Fluid flow is generally chaotic, and small changes to shape and surface roughness can result in very different flows
- The prominent reference is *Technology of Artificial Lift Methods, Volume 1* (Brown & Beggs)
In turbulent flow, the relation between $V_{\text{max}}$ and $V_{\text{average}}$ is more complex. 

$$V_{\text{average}} = 0.83 \times V_{\text{max}}$$

**Turbulence is related to the Reynolds number, $N_{Re}$ of the fluid flow**

If $N_{Re} < 2000$, flow is laminar
If $N_{Re} > 2000$, flow is turbulent

A multiphase flow is ALWAYS TURBULENT

In turbulent flow, the relation between $V_{\text{max}}$ and $V_{\text{average}}$ is more complex.

---

**Two-Phase Production Fluid Flow Regimes**

- **Deviated hole**: dispersed oil on higher side and single-phase water on lower side
- **Sub-horizontal well**: single-phase oil flows on higher side while single-phase water flows on lower side with thin mixing zone
- **Sub-vertical well**: oil and water (mixed) across the wellbore

* Two-Phase means “non-miscible”
Two-Phase* Production: Fluid Flow Regimes

- Multiphase flow regimes vary along the well with:
  - Phase densities
  - Well deviation
  - Average velocity
  - Holdup
  - Interfacial tension
  - Phase viscosity

* Two-Phase means "non-miscible"
Remarks:
If Area A = Area B \(\Rightarrow\) no water production is observed at surface. In extreme cases, the bottom hole water content may be close to 1 (100%), without water production reaching surface, except traces, sometimes.

Two-Phase Production: Logging in Deviated Hole

- Effect of the logging tool running direction (UP vs DOWN)

**Tool Positioning in Well According to Logging Direction**

**Apparent Velocity Profiles in Well**

Top casing **→** Apparent up flow

Bottom casing **→** Apparent down flow

**Remarks:**
If Area A = Area B \(\Rightarrow\) no water production is observed at surface. In extreme cases, the bottom hole water content may be close to 1 (100%), without water production reaching surface, except traces, sometimes.

Two-Phase Production: Logging in Deviated Hole

**Velocity Profile in Well with Water Cycling at Bottom Hole**
Modelling of Two-Phase Flow (Water & Oil)

Flowmeter and Gradiomanometer Analysis

“Holdup” Assumptions

- **A** = Pipe free cross section
- **Q_t** = Total Flowrate
- **V_s** = Slippage Velocity
- **V_o** = Oil Velocity
- **V_w** = Water Velocity
- **Y_w** = Water Holdup

**Y_w + Y_o = 1**

and

**Y_w = (p_t - p_o) / (p_w - p_o)**

where \( p_t \) is the Gradiomanometer reading at depth

\[
Q_o = (1 - Y_w) \times (Q_t + V_s \times A \times Y_w)
\]

\[
Q_w = Y_w \times [Q_t - A \times V_s \times (1 - Y_w)]
\]

where **A** = Flow Area = \( (\text{Area}_{oil} - \text{Area}_{oil}) \times 1.78 \)

In the expression above:

“**A**” cross section bears a factor 1.78 which is a units conversion factor (see next)
Section A = \( \frac{\pi}{4} \) ID\(^2\) (in\(^2\))  
Slippage \( V_s \) = ft/min

Thus, when multiplying, the units for \( A \times V_s \) are: in\(^2\) x ft/min

To convert the mathematical \( A \times V_s \) expression to bbl/day

\[ \text{in}^2 \times \text{ft/min} \times 12 \] (convert ft to inches)

\[ \text{in}^2 \times \text{ft/min} \times 12 \times 1.03 \times 10^{-4} \] (convert cu. in to bbl)

\[ \text{in}^2 \times \text{ft/min} \times 12 \times 1.03 \times 10^{-4} \times (24 \times 60) \] (convert min to day)

Solving the above results in the value of: 1.78 bbl/day

This chart shows the correlation predicting slippage velocity as a function of fluid parameters in vertical wells.

Slippage Velocity. Courtesy of Schlumberger.
In deviated wells, the slippage velocity $V_s$ curve takes the shape below.

- Note that $V_s$ is maximal when the heavy phase fraction is low, and that $V_s$ increases with deviation.

**Slippage Velocity (Deviated Wells)**

- Oil – water
- Gas – liquid

**Asymmetrical Threshold Velocity**

- Asymmetrical threshold?
  - Asymmetry of tool hardware between lower and upper surface of propeller
  - Possible high level of friction at lower speeds
  - Tool surface at times seen differently by fluids, depending on the direction of tool displacement

2 x $V_t = 2$ times threshold velocity
Two-Phase Flow Segregation

- Why negative thresholds?
  - In deviated holes, fluids segregation is observed: oil flow is faster on the upper side of pipe, so water will flow on the lower side.
  - Flowmeter "sees" oil while logging down and water while logging up, so the apparent value of threshold looks negative.

Manual Diphasic Interpretation Procedure

1. Critical analysis of logs and recorded data
   - Logs: GR, flow, pressure, density, temperature...
   - Detailed recap and status of operations
   - Fluids PVT data
   - Well geometrical data

2. Logs depth correlations (mandatory)

3. Selection of zones and stations for analysis

4. Determination of average velocity per zone
   - Read spinner response (up and down at different cable speed + stations)
   - Plot diagram for in-situ calibration
   - Calculate slope for each response line
   - Determine threshold velocity for each stations where reversal occurs
   - Determination of apparent fluid velocity $V_{\text{average}}$
**Manual Diphasic Interpretation Procedure**

5. **Calculation of fluid PVT characteristics**
   - Bubble point pressure, $R_s$, $R_{sb}$ (when oil)
   - In-situ properties
   - Volumetric factors (oil, gas, water)

6. **Determination of average flow for each zone**
   - Evaluation of correction factor, according to Re, Reynolds number

---

**Minimum data needed:**

5. **Calculation of fluid PVT characteristics**
   - Density of stock tank oil
   - Gas density
   - Water salinity
   - Oil GOR

6. **Determination of average flow for each zone**
   - Specific gravity and viscosity of mixture
   - Casing ID
   - Spinner OD
   - Oil GOR
### Manual Diphasic Interpretation Procedure

**7 Correction of pressure gradient measurements (high flowrates, if necessary)**
- Friction
- Inclination

**8 Selection of diphasic interpretation model per zone**
- Oil-water or liquid-gas

**9 Calculation of volume fractions ("Holdup of heavy phase")**

---

**Minimum data needed:**

#### 7 Correction of pressure gradient measurements, if necessary
- Wellbore ID
- OD of Gradiomanometer tool
- Density and viscosity of mixture
- Average corrected mixture flowrate

#### 8 Selection of diphasic interpretation model per zone
- Bubble point pressure, when oil present
- Bottom hole flowing pressure
- Corrected pressure gradient
- Water cut

#### 9 Calculation of volume fractions ("Holdup of heavy phase")
- Corrected pressure gradient
- In-situ phase densities
Manual Diphasic Interpretation Procedure

10 Evaluation of slippage velocities between phases

11 Calculation of flow rates at bottom hole conditions

12 Calculation of flow rates at surface conditions

Minimum data needed:

10 Evaluation of slippage velocities between phases
- Holdup
- In-situ phase densities

11 Calculation of flow rates at bottom hole conditions
- Average corrected mixture flow rate
- Holdup
- Slippage velocity

12 Calculation of flow rates at surface conditions
- Volumetric factors (B_o, B_g, B_w)
- R_s (GOR)
Approximation for Three-Phase Flow

- The procedure applied to diphasic flow can be used to get an approximate solution when three phases are present in the well, especially if the third phase contribution is low compared to others.

- For oil and gas with low water cut (saturated reservoir), water will flow at same velocity as oil.
- For oil and gas with low amount of free gas (reservoir close to bubble point conditions), gas will flow at same velocity as oil.
- For gas and water with low amount of oil (condensate reservoirs), oil will flow at same velocity as water.
Part 1

Production Logging Fundamentals

Production Logging in Three-Phase Flow

Learning Objectives

By the end of this lesson, you will be able to:

- Review the application of recent advances in cased hole logs in deviated and horizontal wells
- Present actual field applications of production logs in three-phase flow
- Illustrate how production logs can assist water shut-off decisions
In sub-horizontal wells flowing in multiphase mode, small changes in well inclination and flow regime influence the flow profile.

Multiphase fluid flow in deviated and horizontal wells can be very complex, primarily due to phase segregation with gravity.

Most highly deviated and horizontal wells will not have sufficient velocities to keep the fluid phases in the mixture and thus phase separation will occur.
Gas-liquid flow regimes vary with:

- Relative differences in phase densities
- Deviation
- Average velocity
- Proportion of each phase, holdup
- Interfacial tension
- Viscosity of each phase

Logging vendors research the development of tools that can quantify the flow characteristics of fluids in these new well standards.

- Schlumberger has identified that the traditional production profile logging is valid in wells with less than 20 degree deviation.
- In deviations between 20-85°, the cross-sectional flow patterns are much more complex due to phase separation which causes varying flow velocities and volumes occupied by each phase.

- Heavier fluid phase moves along the bottom of the flow area, and flows slower than a lighter fluid phase.
- The volume occupied by the cross section is not necessarily equivalent to the relative flow distribution measured at the surface.
  - This is called Stratified Flow.
When well deviations are in the range of 85-95°, the flow becomes very stratified.
It is important to identify the individual phase volumes across the tubular as well as their respective flow velocities.
Diphasic flow of either oil/water or gas/water can be easily identified with the new generation of logging sensors and tools.
The presence of free gas in an oil/water system can result in as many as six different major flow regimes.
For any given flow rate, the hold-up and velocity profile of each phase will vary with the well deviation.

Flow patterns transitions need continuity of correlations when calculating pressure losses.
Three-Phase Flow

- The mathematical modelling of three-phase flow is not well mastered and little research has been achieved on such conditions, and on slippage velocities.
- In theory, values of flow rates and fluid velocities should be measured in each cross section of the pipe.
- Then, all those data should be integrated to derive flow rates of each individual phase.
- This is hardly possible because most measurements are not valid, or not even possible to realize at the same time.
- The only way out is to try and solve flow equations globally in-situ.

- Slippage velocity oil-water:  \( V_{sow} = V_o - V_w \)
- Slippage velocity gas-water:  \( V_{sgw} = V_g - V_w \)

Three-Phase Flow

- In three-phase flow, there are no correlations for relative fluid velocities and slippage velocity.
- With conventional tools, it is usually impossible to directly obtain phase velocity measurements.
- Slippage velocities might need to be derived from correlations in two-phase mode.
  - Slippage velocity oil-water:  \( V_{sow} = V_o - V_w \)
  - Slippage velocity gas-water:  \( V_{sgw} = V_g - V_w \)
- This approach is sometimes incomplete.
Three-Phase Flow Investigation Methods

- New logging devices enable identification of various fluids flowing, and allow the computation of the fraction of total flow that each fluid represents.

- With the constituent fluids thus identified, downhole flow rate measurements are much more meaningful.

- Both the fluid mixture and velocity must be considered in selecting appropriate logging devices.
  - Measurement of parameters that vary sufficiently for reasonable resolution between the constituent fluids of a multi-phase flow.

- The highest benefits of a device that measures fluid densities are obtained when defining gas entry into liquids.

- For oil-water mixtures, the specific gravities are closer to each other and resolution is difficult.

Three-Phase Flow Investigation Methods

- Volume fractions are determined by using a set of appropriate tools.

- If the velocity of one phase can be measured directly, then the flow rate of that phase can be calculated from: \( Q_i = V_i Y_i A \)

- If at least 2 phases velocities are directly measured, the third one can be calculated by difference from total flow.
Three-Phase Flow Equations

- Expanding to three-phase flow can be attempted with the same logic as for two-phase flow by deriving the following equations.
  - \( A \) is the tubular cross section open to flow
  - \( S_{o/w} \) is the slippage rate oil-water: \( S_{o/w} = Y_o Y_w V_{sow} A \)
  - \( S_{o/g} \) is the slippage rate gas-oil: \( S_{o/g} = Y_o Y_g (V_{sgw} - V_{sow}) A \)
  - \( S_{g/w} \) is the slippage rate gas-water: \( S_{g/w} = Y_g Y_w V_{sgw} A \)

- The flow rate of each phase may be written as:
  - Oil Rate: \( Q_o = Y_o Q_t + S_{o/w} - S_{o/g} \)
  - Water Rate: \( Q_w = Y_w Q_t - S_{o/w} - S_{g/w} \)
  - Gas Rate: \( Q_g = Y_g Q_t + S_{o/g} + S_{g/w} \)

Thus, 5 independent measurements are needed to solve the system. For instance:
- Gradiomanometer
- Capacitance
- Nuclear Densimeter
- Pulsed Neutron
- Carbon Oxygen Tools

This is a system of 5 equations with 10 unknowns.
GHOST Tool Arrangement Overview

GHOST: Gas Holdup Optical Sensor Tool

Gas holdup = \frac{\text{Time above threshold}}{\text{Total time}}

Main Applications
- Run in combination with spinner to help quantify multiphase flow.
- More realistic determination of gas hold-up at all well angles.
- Locate fluid entries by hold-up and gas bubble count.
- Possibly quantify gas flow from the hydrocarbon bubble count.
- Locate gas-liquid interface in stratified multiphase horizontal flow.
- Can be run in memory mode on slick line as well as with a tractor and/or coiled tubing.

Limitations
- CANNOT discriminate between oil and water phases.
- Will not work in emulsions, when gas bubbles are larger than 3mm.
- If bubble velocity is higher than 6 ft/sec (2 m/sec), the tool is not effective and classical density tools can be used.
GHOST Tool Arrangement Overview

Operating Technique

• The best results will occur when the flow is towards the tips of the probes.
• These probes can be placed at 3 different distances from the wellbore wall with low rates being closer to the outside and turbulent, or poor hole conditions being closer to the inside.
• When this tool is run with the normal PSP (Production Services Platform) logging string, the four probes are mounted on the centralizer arms of the Full Bore Spinner.

Three-Phase Flow Logging Methods

• Direct measurement of water flow velocity has been done since the 1990’s with the WFL (Water Flow Log).

• WFL gives the possibility to treat water independently from other fluids by measuring \( V_w \) and, in favorable cases, \( Q_w \) (from TDT log) or \( Y_w \) (using RST log).
**Water Flow Log Principle**

- The water velocity is computed from the time of travel of neutron-activated oxygen of water between the neutron generator and the near and far detectors.
- The tool "vertical" (i.e., well depth) resolution is the distance between generator and detectors.

**Three-Phase Flow Investigation Methods**

- **PVL (Phase Velocity Log)** measures directly $V_o$ and $V_w$, when chemicals solved in water, or oil, are used.
  - This is particularly important in highly deviated and horizontal wells with multi-phase flow, where the flow pattern is complicated.
  - Phase velocity measurements are made with either the cross-correlation flowmeter, the Water Flow Log, or with chemical markers designed to mix specifically with one particular phase.
  - Velocity-shot measurements, using radioactive tracers, have also been used.
    - In a typical chemical marker technique, a gadolinium-rich marker is injected into the flow stream, dissolving in either oil or water.
    - Gadolinium has a high capture cross section, or sigma, so that a slug of fluid with high sigma moves with the appropriate phase up the borehole.
    - This slug can be detected by a standard pulsed-neutron capture tool, and the velocity of the phase is computed from the time of travel between ejector and detector.
**Phase Velocity Log Principle**

- The water velocity is computed from the time of travel of an oil-miscible marker between the ejection nozzle and the Reservoir Saturation Tool (RST).
- The tool "vertical" (i.e., well depth) resolution is the distance between ejector and detector, i.e., 25 ft (7.3 m).

\[ \text{Phase velocity} = \frac{L}{T} \]

**Water Holdup Measurement: FloView Probe**

- Holdup is a calculation of the volume ratio that the water occupies in the wellbore.
- The Water Hold-Up Tool (Capacitance Tool) is sensitive to the dielectric constant of the flowing stream.
  - Wellbore fluids flow through a tool chamber that acts as a capacitor in an oscillator circuit.
  - The capacitance varies with changes in the dielectric constants of the fluids flowing through the chamber.
  - The Capacitance Tool is used to identify the oil, gas, and water phases in highly deviated and horizontal wells.
    - The tool carries several individual sensors around the circumference of the wellbore which provides the fluid phase distribution over the cross-section of the hole.
Water Holdup Measurement: FloView Probe

- The FloView holdup probe (no spinner) measures the bubble count (light phase) in dispersed phase by taking 4 independent measurements in 4 pipe quadrants.
- Measurement of the bubble count of the light phase of the stream is converted to velocity at the station of measurement.
- FloView can provide the velocity of the dispersed phase, derived from the displacement speed of bubbles.

\[
\text{Water holdup} = \frac{\text{Time in short circuit}}{\text{Total time}}
\]

Water Holdup Measurement: FloView Probe

- Low frequencies correspond to high-dielectric-constant fluids (water), and high frequencies correspond to low-dielectric constant fluids (hydrocarbons).
- The tool can differentiate between water and hydrocarbons, but it can give erroneous results in stratified flow applications.
- It is necessary to calibrate the tool so that water hold-up can be calculated from the oscillator frequency.
Water Holdup Measurement: FloView Probe

Main Applications

- Run in combination with spinner to help quantify multiphase flow.
- Reasonable determination of gas/water hold-up at well angles.
- Can also be run in memory mode on slick line as well as with a tractor and/or coiled tubing.

Limitations

- Frequency differences between the two hydrocarbon phases (oil and gas) are small and may be non-distinguishable.
- Erroneous results can be obtained in stratified flow applications where the detected fluid is predominantly only one of the fluid phases. This tends to occur in well deviations exceeding 45° but can also occur at lower deviations if the flow velocities are too low.
- Tool must be centralized.
- Location of spinners may not identify the individual (different) velocities of each phase, hence the necessity to carry several spinners.

FloScan Imager (FSI)

- New tools have further developed the understanding and interpretation of high angle flow patterns, thus significantly extending some of the more traditional production logging technology and interpretation techniques.
- Sensing probes are now on the arm of the centralizer.

Mini spinner cartridge with integrated one-wire detector
Optical GHOST probe
Electrical FloView probe
**FloScan Imager (FSI)**

- Measures local fluid velocity
- Measures water holdup
- Measures gas holdup

The sensors are positioned to allow their measurements to yield a map of fluid velocities and holdups along a vertical diameter of the wellbore at every survey depth.

**FloScan Real-Time Logging**

Flowrate data and phase distribution can be analyzed and recorded in real-time by the Flow Scanner.
Conventional Spinner vs FloScan Spinners

Computer Processed Interpretation
Conventional PL vs FloScan Imager

The resulting production of 556 BOPD (barrel of oil per day) and 2532 BWPD (barrel of water/day) represented a 9-fold increase in oil production.

• Inclination of well: 37°
• Producing with gas lift from 6 open intervals
• Production: 2058 B/D (barrel liquid per day) (327 m³/d)
• Water cut: 97%

As a result, 90% of the oil production was erroneously attributed to the lower perforations with the conventional tool analysis.
Back to Work Suggestions

- Meet with a production engineer in your group and ask for a production log waiting for interpretation.
- Practice by yourself and compare your views and conclusions with those of specialists.
- Get some additional explanations where grey areas remain.

Back to Work Suggestions

- Meet with your supervisor to be assigned to witness/participate in an actual logging job.
- On the job, run a real-time log interpretation, suggest additional or repeated logging passes, diagnose log data quality and conclude.
<table>
<thead>
<tr>
<th>PetroAcademy™ Production Operations</th>
</tr>
</thead>
<tbody>
<tr>
<td>▪ Production Principles Core</td>
</tr>
<tr>
<td>▪ Well Performance and Nodal Analysis Fundamentals</td>
</tr>
<tr>
<td>▪ Onshore Conventional Well Completion Core</td>
</tr>
<tr>
<td>▪ Onshore Unconventional Well Completion Core</td>
</tr>
<tr>
<td>▪ Primary and Remedial Cementing Core</td>
</tr>
<tr>
<td>▪ Perforating Core</td>
</tr>
<tr>
<td>▪ Rod, PCP, Jet Pump and Plunger Lift Core</td>
</tr>
<tr>
<td>▪ Reciprocating Rod Pump Fundamentals</td>
</tr>
<tr>
<td>▪ Gas Lift and ESP Pump Core</td>
</tr>
<tr>
<td>▪ Gas Lift Fundamentals</td>
</tr>
<tr>
<td>▪ ESP Fundamentals</td>
</tr>
<tr>
<td>▪ Formation Damage and Matrix Stimulation Core</td>
</tr>
<tr>
<td>▪ Formation Damage and Matrix Acidizing Fundamentals</td>
</tr>
<tr>
<td>▪ Flow Assurance and Production Chemistry Core</td>
</tr>
<tr>
<td>▪ Sand Control Core</td>
</tr>
<tr>
<td>▪ Sand Control Fundamentals</td>
</tr>
<tr>
<td>▪ Hydraulic Fracturing Core</td>
</tr>
<tr>
<td>▪ Production Problem Diagnosis Core</td>
</tr>
<tr>
<td>▪ Production Logging Core</td>
</tr>
<tr>
<td>▪ Production Logging Fundamentals</td>
</tr>
</tbody>
</table>