

WellCAP®
IADC WELL CONTROL ACCREDITATION PROGRAM

DRILLING OPERATIONS
CORE CURRICULUM AND RELATED JOB SKILLS

FORM WCT-2DF

FUNDAMENTAL LEVEL

The purpose of the core curriculum is to identify a body of knowledge and a set of job skills which can be used to provide well control skills for drilling operations (including well testing and initial completion). The curriculum is divided into three course levels: Introductory, Fundamental, and Supervisory.

The suggested target students for each core curriculum level are as follows:

INTRODUCTORY: Floorhand, Derrickman
(May also be appropriate for non-technical personnel)

FUNDAMENTAL: Derrickman, Assistant Driller, and Driller

SUPERVISORY: Toolpusher, Superintendent, and Drilling Foreman

Upon completion of a well control training course base on curriculum guidelines, the student should be able to perform the job skills in italics identified by a "■" mark (e.g., ■ *Identify causes of kicks*).

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I. CAUSES OF KICKS

TRAINING TOPICS	JOB SKILLS
<p>A. Unintentional flow or "kick" from a formation</p> <ol style="list-style-type: none"> 1. Failure to keep hole full 2. Swabbing effect of pulling pipe <ol style="list-style-type: none"> a. Hole and pipe geometry b. Well depth c. Mud rheology d. Hole conditions and formation problems e. Pipe pulling and running speed f. BHA configuration 3. Loss of circulation 4. Insufficient density of drilling fluid, brines, cement, etc. 5. Abnormally pressured formation 6. Lowering pipe too rapidly into hole (surge) 7. Annular gas flow after cementing <p>B. Intentional flow or "kick" from a formation</p> <ol style="list-style-type: none"> 1. Drill stem test 2. Completion 	<ul style="list-style-type: none"> ■ <i>Define two types of kick: unintentional and intentional.</i> ■ <i>Identify causes of <u>unintentional</u> kicks.</i> ■ <i>Describe the piston effect (suction and how increased drag may be associated with swab).</i> ■ <i>Describe the effect of the following on surge and swab pressures:</i> ■ <i>Describe how fluid density can be unintentionally reduced, i.e., barite ejected by centrifuge, dilution, cement settling, temperature effects on fluids, settling of mud weighting materials, etc.</i> ■ <i>Identify causes of <u>intentional</u> kicks.</i>

II. KICK DETECTION

TRAINING TOPICS	JOB SKILLS
<p>A. Kick indicators</p> <ol style="list-style-type: none"> 1. Gain in pit volume (rapid increases in fluid volume at the surface) 2. Increase in return fluid-flow rate (with no pump strokes per minute increase) 3. Well flowing with pump shut down 4. Hole not taking proper amount of fluid during trips 5. Well monitoring and alarm devices <ol style="list-style-type: none"> a. Pit volume totalizers (PVT) b. Relative flow increase 	<p>■ <i>Identify kick indicators.</i></p>
<p>B. Warning signals that indicate a kick may be occurring or is about to occur</p> <ol style="list-style-type: none"> 1. Drilling rate change 2. Trip, connection, and background gas change 3. Gas-cut mud 4. Water-cut mud or chloride concentration change 5. Decrease in circulating pressure or increase in pump strokes 	<p>■ <i>Identify kick warning signals.</i></p>

Kick Detection continued on next page.

TRAINING TOPICS	JOB SKILLS
<p>C. Indications of possible increasing formation pressure</p> <ol style="list-style-type: none"> 1. Cuttings size and shape <ol style="list-style-type: none"> a. Torque b. Drag c. Fill d. Volume of cuttings e. Appearance of sloughing shale 2. Temperature changes 3. Gas levels 4. Change in flow rate or mud properties of drilling fluid 5. Rate of penetration increase 	<p>■ <i>Recognize and explain how the conditions listed at left are associated with well control.</i></p>
<p>D. Importance of responding to kick indicators in a timely manner</p> <ol style="list-style-type: none"> 1. Minimize <ol style="list-style-type: none"> a. Kick size b. Surface pressures c. Lost operations time 2. Consequences of not responding <ol style="list-style-type: none"> a. Kick becomes a blowout b. Release of poisonous gases c. Pollution d. Fire 	<p>■ <i>Identify the importance of early detection and the consequences of not responding to a kick in a timely manner.</i></p>

Kick Detection continued on next page.

Kick Detection continued.

TRAINING TOPICS	JOB SKILLS
<p>E. Distinguishing kick indicators and warning signals from other occurrences</p> <ol style="list-style-type: none"> 1. <u>Increases</u> in pit level <ol style="list-style-type: none"> a. Surface additions b. Flow from formation 2. <u>Decreases</u> in pit level <ol style="list-style-type: none"> a. Solids control b. Dumping mud c. Lost circulation 3. Drilling rate changes <ol style="list-style-type: none"> a. Rate of penetration (ROP) as a function of weight on bit, formation type, RPM, and pump rate b. Drilling break (rapid increase in ROP) c. Rapid decrease d. Associate change in ROP with changes in formation 4. Gas cut mud and/or gas in drilled cuttings 	<ul style="list-style-type: none"> ■ <i>Identify the causes of changes in pit level.</i> ■ <i>Identify drilling rate changes.</i>

III. PRESSURE CONCEPTS AND CALCULATIONS

TRAINING TOPICS	JOB SKILLS
<p>A. Types of pressure</p> <ol style="list-style-type: none"> 1. U-tube concept and hydrostatic column 2. Pressure gradient 3. Formation gradient 4. Hydrostatic pressure 5. Bottomhole pressure 6. Differential pressure 7. Surface pressure 8. System pressure losses (circulating friction pressure losses) 9. Hydrostatic pressure change due to loss of fluid level and fluids with different mud densities 	<ul style="list-style-type: none"> ■ <i>Demonstrate understanding of u-tube concept and hydrostatic column.</i> ■ <i>Define pressure gradient.</i> ■ <i>Define formation pressure gradient.</i> ■ <i>Define and calculate hydrostatic pressure.</i> ■ <i>Define and calculate bottomhole pressure.</i> ■ <i>Define surface pressure and describe its effect on downhole pressures.</i> ■ <i>Explain system pressure losses.</i>

Pressure Concepts and Calculations continued on next page.

Pressure Concepts and Calculations continued.

TRAINING TOPICS	JOB SKILLS
<p>B. Calculations</p> <ol style="list-style-type: none"> 1. Volume of tanks and pits 2. Volume of a cylinder as related to pump output 3. Displacement of open and closed pipe 4. Annular capacity per unit length 5. Annular volume 6. Hydrostatic pressure 7. Fracture pressure (as defined by API RP 59) 8. Formation pressure 9. Conversion from pressure to equivalent fluid density 10. Kill mud weight 11. Circulation time 12. Bottoms up time for normal drilling 13. Total circulating time, including surface equipment 14. Surface-to-bit time 15. Bit-to-shoe time 16. Bottoms up strokes 17. Surface-to-bit strokes 18. Bit-to-shoe strokes 19. Total circulating strokes, including surface equipment 20. Pump output (look up from chart values only). 	<p>■ <i>Be able to perform the calculations listed at left and below.</i></p> <p align="right"><i>Pressure Concepts and Calculations continued on next page.</i></p>

21. Relationship between pump pressure and mud density
22. Maximum allowable annulus surface pressure
23. Weighting material required to increase density per volume
24. Volume increase due to increase in density
25. Volume to be bled off, corresponding to pressure increase (volumetric method)
26. Initial circulating pressure
27. Final circulating pressure
28. Riser volume and fluid required to displace
29. Choke and kill line volumes
30. Choke and kill line strokes
31. Choke and kill line circulation time
32. Pressure drop per step

Pressure Concepts and Calculations continued on next page.

CORE CURRICULUM & JOB SKILLS – PRESSURE CONCEPTS AND CALCULATIONS

Pressure Concepts and Calculations continued.

TRAINING TOPICS	JOB SKILLS
<p>C. Conversion of pressure to an equivalent mud weight</p> <p>1. Required mud weight</p> <p> a. Fluid density increase required to balance formation pressure</p>	<ul style="list-style-type: none"> ■ <i>Calculate fluid density increase required to balance formation pressure.</i> ■
<p>D. Volume/Height relationship and effect on pressure</p>	<ul style="list-style-type: none"> ■ <i>Calculate height of a given volume of fluid.</i>
<p>E. Drop in pump pressure as fluid density increases during well control operations</p>	<ul style="list-style-type: none"> ■ <i>Describe why pump pressure drops as fluid density increases during a constant bottomhole pressure method.</i> ■
<p>F. Maximum wellbore pressure limitations</p> <p>1. Surface (e.g., wellhead, BOP, casing)</p> <p>2. Subsurface (e.g., perforations, casing shoe, open hole formation)</p>	<ul style="list-style-type: none"> ■ <i>Describe the consequences of exceeding maximum wellbore pressure limitations.</i>

IV. PROCEDURES

TRAINING TOPICS	JOB SKILLS
<p>A. Pre-recorded well control information</p> <p>1. Standpipe pressure at slow pump rates</p>	<ul style="list-style-type: none"> ■ <i>Identify appropriate pre-recorded information.</i> ■ <i>Record standpipe pressure at slow pump rate.</i> ■ <i>Read at choke console.</i> ■ <i>Recognize an error in gauge readings based on discrepancies between readings.</i>
<p>B. Flow checks</p> <p>1. While drilling – normal flow back</p> <p>2. While drilling – abnormal flow back</p> <p>3. Loss of equivalent circulating density (ECD) with pumps off</p> <p>4. While tripping – well is hydrostatically balanced (no ECD loss considerations)</p> <p>5. Use and purpose of trip sheet</p>	<ul style="list-style-type: none"> ■ <i>Describe the procedure to perform a flow check in the situations at left.</i> ■ <i>Recognize and measure normal flow back.</i> ■ <i>Recognize a flow that differs from normal flow back..</i> ■ <i>Take action based on recognition of flow.</i> ■ <i>Explain how to establish that a well is static before starting trip.</i> ■ <i>Explain why an absence of flow (during flow check) is not an absolute indicator that there is no influx.</i> ■ <i>Demonstrate understanding that the primary indicator of influx is the trip sheet (hole fill-up) rather than flow check.</i>

Procedures continued on next page.

Procedures continued.

TRAINING TOPICS	JOB SKILLS
NOTE: THE FOLLOWING LISTS ARE NOT INTENDED TO PRESCRIBE THE EXACT SEQUENCE OF EVENTS.	
<p>C. Shut-in</p> <ol style="list-style-type: none"> 1. While drilling <ol style="list-style-type: none"> a. Individual responsibilities b. Pick up (with pump on) c. Space-out d. Shut pump off e. Flow check f. Close-in BOP g. Close choke h. Notify supervisor 2. While tripping <ol style="list-style-type: none"> a. Individual responsibilities b. Close off drillstring bore given variety of tubulars c. Close BOP d. Notify supervisor 3. While running casing <ol style="list-style-type: none"> a. Individual responsibilities b. Install device to stop potential flow through casing c. Close appropriate BOP or divert as appropriate d. Close choke as applicable e. Notify supervisor 4. While cementing <ol style="list-style-type: none"> a. Individual responsibilities b. Space out, including consequences of irregular tubular lengths c. Shut pump off d. Close BOP e. Close choke 	<ul style="list-style-type: none"> ■ <i>Upon observing positive flow indicators, shut in the well in a timely and efficient manner to minimize influx. Proceed according to a specific procedure which will address the operations listed at left.</i> ■ <i>Design a shut-in procedure for the operations listed at left.</i> ■ <i>List differences between the Soft vs Hard methods of well control as defined by API RP 59 for both levels (see API RP 59).</i> ■ <i>Upon observing positive flow indicators, shut in the well in a timely and efficient manner to minimize influx. Proceed according to a specific procedure which will address the operations listed at left.</i> ■ <i>Design a shut-in procedure for the operations listed at left.</i> ■ <i>For any shut-in, verify well closure by demonstrating that the flow paths described at left are closed.</i>

Procedures continued on next page.

- f. Notify supervisor
- 5. During other rig activities
 - a. Individual responsibilities
 - b. Use of surface equipment to shut-in well
 - c. Close choke
 - d. Notify supervisor
- 6. Verification of shut-in
 - a. Annulus
 - 1) Through BOP
 - 2) At the flow line
 - b. Drillstring
 - 1) Pump pressure relief valves
 - 2) Standpipe manifold
 - c. Wellhead/BOP
 - 1) Casing valve (not applicable to subsea stack)
 - 2) Broaching to surface (outside of wellbore)
 - d. Choke manifold
 - 1) Choke
 - 2) Overboard lines

Procedures continued on next page.

Procedures continued.

TRAINING TOPICS	JOB SKILLS
<p>D. Well monitoring during shut-in</p> <ol style="list-style-type: none"> 1. Recordkeeping <ol style="list-style-type: none"> a. Time of shut-in b. Drillpipe and casing pressures <ol style="list-style-type: none"> 1) At initial shut-in 2) At regular intervals c. Estimated pit gain 2. Principles of bleeding volume from a shut-in well <ol style="list-style-type: none"> a. Trapped pressure <ol style="list-style-type: none"> 1) Causes 2) Relief of b. Pressure increase at surface and downhole from <ol style="list-style-type: none"> 1) Gas migration 2) Gas expansion 3. Determining shut-in drillpipe pressure when using a drillpipe float 	<ul style="list-style-type: none"> ■ <i>Read, record, and report well shut-in recordkeeping parameters.</i> ■ <i>Identify at least two causes of trapped pressure.</i> ■ <i>Describe the effects of trapped pressure on wellbore pressure.</i> ■ <i>Perform choke manipulation to achieve specific pressure or volume objectives..</i> ■ <i>If a float valve is in use (ported or non-ported), demonstrate the procedure to open the float to obtain shut-in drillpipe pressure.</i>
<p>E. Response to massive of total loss of circulation</p> <ol style="list-style-type: none"> 1. During drilling, fill annulus with fluid in use 2. Notify supervisor immediately 	<ul style="list-style-type: none"> ■ <i>Identify at least one method of responding to massive or total loss of circulation during a well kill operation.</i> ■ <i>Upon observing loss of circulation, perform the actions described at left.</i>

Procedures continued on next page.

Procedures continued.

TRAINING TOPICS	JOB SKILLS
<p>F. Tripping</p> <ol style="list-style-type: none">1. Procedures used for keeping hole filled<ol style="list-style-type: none">a. Using rig pumpb. Using trip tankc. Using recirculating trip tank (continuous fill)2. Methods of measuring and recording hole fill volumes3. Wet trip calculations<ol style="list-style-type: none">a. Return to mud systemb. No return to mud system4. Dry trip calculations5. Slugs	<ul style="list-style-type: none">■ <i>Perform the actions listed at left with regard to hole fill up on trips.</i>

Procedures continued on next page.

CORE CURRICULUM & JOB SKILLS – PROCEDURES

Procedures continued.

TRAINING TOPICS	JOB SKILLS
6. Trip margin <ul style="list-style-type: none"> a. Measure hole fill up b. Recognize discrepancy from calculated fill up c. Take appropriate action 7. At flow, go to shut-in 8. At no flow and short fill up, go back to bottom <ul style="list-style-type: none"> a. Procedure and line up to keep hole filled 	<ul style="list-style-type: none"> ■ <i>Perform the actions listed at left with regard to hole fill up on trips.</i> ■ <i>Demonstrate, explain, or perform procedure and line up to keep hole filled.</i>
G. Formation competency <ul style="list-style-type: none"> 1. Pressure integrity test (testing to a specific limit) 2. Leak-off test (testing to formation injectivity) <ul style="list-style-type: none"> a. Leak-off test (at least one method) b. Formation pressure integrity test 3. Prepare the well for leak-off testing 	<ul style="list-style-type: none"> ■ <i>Describe or perform proper hook-up and procedures for conducting a formation leak-off test or competency test for a given configuration.</i> ■ <i>Identify from a plot the point at which leak-off begins.</i> ■ <i>Describe or perform preparation for leak-off test, leak-off test, and formation pressure integrity test</i>
H. Stripping operations <ul style="list-style-type: none"> 1. Line up for bleeding volume to stripping tank 2. Stripping procedure through BOP 3. Measurement of volume bled from well 	<ul style="list-style-type: none"> ■ <i>Define the following aspects of stripping: purpose, suitability, and method.</i> ■ <i>Demonstrate stripping procedures listed at left.</i>
I. Shallow gas hazards <ul style="list-style-type: none"> 1. Mechanisms and timing of events 2. Kill procedures <ul style="list-style-type: none"> a. Shut-in b. Use of diverters (with drillpipe and while running casing) 3. Riserless drilling 	<ul style="list-style-type: none"> ■ <i>Explain why it is relatively easy to become underbalanced at shallow depths (e.g., hole sweeps, gas cutting, swabbing, lost circulation)</i> ■ <i>Explain the limited reaction time for kick detection.</i> ■ <i>Explain the well control procedural options available (i.e., shut-in vs. divert).</i>

V. GAS CHARACTERISTICS AND BEHAVIOR

TRAINING TOPICS	JOB SKILLS
<p>A. Gas types</p> <ol style="list-style-type: none"> 1. Hydrocarbon 2. Toxic <ol style="list-style-type: none"> a. H₂S b. CO₂ 	<ul style="list-style-type: none"> ■ <i>Recognize the relatively low density of gas and its effect on the hydrostatic column.</i> ■ <i>Describe how the presence of gas affects wellbore pressure.</i>
<p>B. Density</p> <ol style="list-style-type: none"> 1. Gas 2. Gas and mud mixtures 	<ul style="list-style-type: none"> ■ <i>Explain the effect of gas cutting on bottomhole pressure and the use of pit level monitoring to recognize hydrostatic loss.</i>
<p>C. Migration</p> <ol style="list-style-type: none"> 1. If the well is left shut-in while gas is migrating 2. If the well is allowed to remain open with no control 3. If bottomhole pressure is controlled 	<ul style="list-style-type: none"> ■ <i>Explain the consequences of gas migration.</i>
<p>D. Expansion</p> <ol style="list-style-type: none"> 1. While in well 2. Through surface equipment 	<ul style="list-style-type: none"> ■ <i>Explain the relationship between pressure and volume of gas in the wellbore.</i> ■ <i>Explain why a gas kick must expand as it is circulated out in order to keep bottomhole pressure constant.</i> ■ <i>Explain the consequences of gas moving through the choke from a high pressure area to a low pressure area.</i>

Gas Characteristics continued on next page.

Gas Characteristics continued.

TRAINING TOPICS	JOB SKILLS
<p>E. Compressibility and phase behavior</p> <ol style="list-style-type: none"> 1. Hydrocarbon gas can enter the well in either liquid or gaseous form, depending on its pressure and temperature 2. Hydrocarbon gas entering as a liquid may not migrate or expand until it is circulated up the wellbore 3. Liquids can move down the annulus and come up the drillstring 	<ul style="list-style-type: none"> ■ <i>Describe how hydrocarbon gas may not migrate and the consequences for well control.</i>
<p>F. Solubility in mud</p> <ol style="list-style-type: none"> 1. Combinations of gas and liquid in which solubility issues may apply: <ol style="list-style-type: none"> a. H₂S and water b. CO₂ and water c. H₂S and OBM d. Methane and OBM e. CO₂ and OBM 2. Gases dissolved in mud behave like liquids 	<ul style="list-style-type: none"> ■ <i>Identify combinations of gas and liquid which may result in solubility issues (H₂S and water, CO₂ and water, H₂S and OBM, methane and OBM, CO₂ and OBM).</i> ■ <i>Describe the difficulty of detecting kicks with soluble gases while drilling and/or tripping.</i>

VI. FLUIDS

TRAINING TOPICS	JOB SKILLS
<p>A. Types of drilling fluids</p> <ol style="list-style-type: none">1. Water based mud2. Oil based mud (OBM), synthetic oil based mud (SOBM)3. Cement4. Completion fluids <p>B. Fluid density measuring techniques</p> <ol style="list-style-type: none">1. Mud balance2. Pressurized mud balance	<ul style="list-style-type: none">■ <i>Identify types of drilling fluids.</i> ■ <i>Measure fluid density.</i>

VII. CONSTANT BOTTOMHOLE PRESSURE WELL CONTROL METHODS

TRAINING TOPICS	JOB SKILLS
<p>A. Objectives of well control methods</p> <ol style="list-style-type: none"> 1. Circulate kick safely out of the well 2. Re-establish primary well control by restoring hydrostatic balance 3. Avoid additional kicks 4. Avoid excessive surface and downhole pressures so as to prevent inducing an underground blowout 	
<p>B. Principles of constant bottomhole pressure methods</p> <ol style="list-style-type: none"> 1. Shutting-in well will stop influx when bottomhole pressure equals formation pressure 2. Circulating out a kick by maintaining enough choke back pressure to keep bottomhole pressure equal to or slightly greater than formation pressure 3. Bottom of the drillstring must be at the kicking formation (or bottom of the well) to effectively kill the kick and be able to resume normal operations 	<ul style="list-style-type: none"> ■ <i>Explain how pump and choke manipulation relates to maintaining constant bottomhole pressure.</i>
<p>C. Example steps for maintaining constant bottomhole pressure well control: Driller's or Wait & Weight methods</p> <ol style="list-style-type: none"> 1. Close choke and observe pressure gauges (SIDPP + SICP = 0 psi) 2. If hydrostatic balance is restored, open BOPs and check for flow 3. Resume operations 4. Preparing the killsheet 	<ul style="list-style-type: none"> ■ <i>Read, record and report drillpipe and annulus pressures</i> ■ <i>List the phases of at least one constant bottomhole pressure well control method.</i> ■ <i>Explain how the steps at left relate to maintaining bottomhole pressure equal to or greater than formation pressure.</i> ■ <i>Demonstrate proficiency in at least one constant bottomhole pressure well control method (Driller to act under the direction of Supervisor).</i> <p style="text-align: right;"><i>Constant Bottomhole Pressure continued on next page.</i></p>

D. Well control kill sheets

1. Well control calculations
 - a. Drillstring and annular volumes
 - b. Fluid density increase required to balance increased formation pressure
 - c. Initial and final circulating pressure as appropriate for method(s) taught
2. Maximum wellbore pressure limitations
 - a. Surface
 - b. Subsurface
3. Selection of a kill rate for pump
 - a. Barite delivery rate
 - b. Pump limitations
 - c. Surface fluid handling capacity

- *Correctly fill out a kill sheet for one well control method.*
- *Determine weight up material required and corresponding volume increase.*
- *Describe the consequences of exceeding maximum wellbore pressure (surface and subsurface).*

E. Well control procedures

1. Procedure to bring pump on and off line and change pump speed while holding bottomhole pressure constant using the choke
 - a. Use of casing pressure gauge
 - b. Lag time response on drillpipe pressure gauge
2. Handling problems during well control operations
 - a. Pump failure
 - b. Plugged or washed nozzles
 - c. Plugged or washed choke
 - d. Fluid losses
 - e. Annulus pack-off
3. Considerations if using a diverter

- *Demonstrate bringing pump on and off line and changing pump speed while holding bottomhole pressure constant using choke.*
- *Given a scenario detailing a well control problem, identify the problem and demonstrate or describe an appropriate response.*
- *Describe the difference between diverting versus conventional well kills.*

VIII. EQUIPMENT

TRAINING TOPICS	JOB SKILLS
<p>A. Well control related instrumentation</p> <ol style="list-style-type: none"> 1. Fluid pit level indicator 2. Fluid return indicator 3. Pressure measuring equipment and locations <ol style="list-style-type: none"> a. Locations <ol style="list-style-type: none"> 1) Standpipe pressure gauge 2) Drillpipe pressure gauge 3) Pump pressure gauge 4) Casing pressure gauge (also referred to as choke manifold or annular pressure gauge) b. Range and accuracy c. Gauge selection for well control readings and control during well killing operations 4. Mud pump/Stroke counter 5. Mud balance and pressurized mud balance 6. Gas detection equipment <ol style="list-style-type: none"> a. H₂S b. Flammable/Explosive gases 7. Drilling recorder <ol style="list-style-type: none"> a. Pit volume (number of barrels of fluid in the pit) b. Flow rate c. Rate of penetration (ROP) d. Pressure e. Strokes per minute (SPM) f. Mud weight g. Depth recorder 	<ul style="list-style-type: none"> ■ <i>Describe the relationship between mud pit and flow sensors, and drill floor kick indications.</i> ■ <i>Describe the purpose and use of the mud pump/stroke counter (e.g., stroke rate, flow rate, and displaced volume).</i> ■ <i>Measure current drilling parameters.</i> <p align="right"><i>Equipment continued on next page.</i></p>

B. BOP configuration

1. Components (See API RP 53, most recent version)
 - a. Annular preventer
 - b. Ram preventers/elements
 - 1) Blind
 - 2) Blind/Shear
 - 3) Pipe
 - 4) Variable bore pipe
 - 5) Ram elements
 - c. Drilling spool or integral body
 - d. Valves
2. Functions

Equipment continued.

- *Demonstrate basic understanding of the use of ram and annular preventers.*
- *Identify flow path for normal drilling operations.*
- *Identify flow path for well control operations.*
- *Identify areas exposed to high and low pressure during shut-in and pumping operations.*
- *Identify and confirm line-up for equipment pressure testing, shut-in, and pumping operations.*
- *Demonstrate ability to shut-in the well in the event of primary equipment failure.*
- *Given a BOP stack configuration, identify potential flow paths for kill operations.*
- *Given a BOP stack configuration, identify shut-in, monitoring, and circulation operations which are possible and those which are not.*
- *Given a BOP stack configuration, select an appropriate BOP to effect closure on a given tubular.*

Equipment continued on next page.

Equipment continued.

C. Manifolds and piping

1. Standpipe
2. Choke

D. Valving

1. BOP stack
2. Drillstring
 - a. Full opening valves (DPSV, kelly cock, kelly valve)
 - b. Check valves
 - c. Float valves – advantages and disadvantages
3. Choke manifold
 - a. Adjustable choke
 - 1) Hydraulic (remote operated)
 - 2) Manual
 - b. Fixed choke
 - c. Valves to direct flow
4. Mud pressure relief

- *Describe opening and closing a full-opening safety valve.*
- *Describe the difference in use between a full-opening safety valve and a check valve (e.g., inside BOP).*
- *Be able to identify compatibility of thread types.*
- *Distinguish the function of the choke from that of other valve types.*
- *Define the function of a choke.*
- *Describe the function of adjustable chokes, both manual and hydraulic.*
- *Identify changes in valve positions resulting from opening or closing the diverter.*

Equipment continued on next page.

E. Auxiliary well control equipment

1. Mud/Gas separator
 - a. Gas blow-through
 - b. Vessel rupture
2. Mud pits
 - a. Suction pit
 - b. Return pit
 - c. Mixing equipment
 - d. Degasser
3. Trip tank
 - a. Gravity feed
 - e. Recirculating type
6. Top drive systems
 - a. Kelly valves, lower
 - b. Spacing out
 - c. Shutting-in
 - d. Stripping

- *Define function, operating principles, flowpaths, and components of mud-gas separators.*
- *Describe pit alignment during well control operations (e.g., vacuum degasser, flaring).*
- *Describe the procedures for handling of gas in return fluids (e.g., vacuum degasser, flaring).*
- *Describe the characteristics of a trip tank (e.g., small cross-section, accurate fluid volume measurements).*

Equipment continued on next page.

Equipment continued.

<p>F. BOP closing unit – function and performance</p> <ol style="list-style-type: none"> 1. Usable fluid volume test 2. Closing time test 3. Accumulator pressure <ol style="list-style-type: none"> a. Pre-charge pressure b. Minimum system pressure c. Operating pressure d. Maximum system pressure 4. Adjustment of operating pressure <ol style="list-style-type: none"> a. Manifold pressure regulator b. Annular pressure regulator 5. Operating functions <ol style="list-style-type: none"> a. Regulator b. Unit/Remote switch c. By-pass valve d. Accumulator isolator valve 	<ul style="list-style-type: none"> ■ <i>Demonstrate understanding of the function of the accumulator system, including an explanation of the consequences of losing nitrogen pre-charge pressure.</i> ■ <i>Identify major components of a BOP control system.</i> ■ <i>Describe the reasons and procedure for a usable fluid volume test.</i> ■ <i>State, for a 3000 psi system, the pressures listed at left:</i> ■ <i>List two reasons for adjusting regulated annular operating pressure.</i> ■ <i>Demonstrate the ability to operate the BOP from the driller's panel and the remote control panel.</i> ■ <i>Diagnose simple functional problems.</i>
<p>G. Testing/Completion pressure control equipment</p> <ol style="list-style-type: none"> 1. Packers 2. Lubricators 3. Christmas trees 4. Test trees 	

Equipment continued on next page.

H. Pressure and function tests

1. Maximum safe working pressure
 - a. Pressure ratings of all equipment
 - b. Reasons for de-rating
 - c. Areas exposed to both high and low pressures during shut-in and pumping operations
2. General emphasis on quality maintenance practices
 - a. Correct installation
 - b. Maintenance
 - c. Wear and replacement requirements
 - d. Rings, flanges, and connectors
3. Emphasis on quality testing practices
4. Procedures for function and pressure testing all well control equipment
 - a. Function and testing of high pressure well control equipment
 - 1) BOP stack
 - 2) Manifolds
 - 3) Auxiliary well control equipment
 - b. Function and testing of low pressure well control equipment
 - 1) Mud-gas separator
 - 2) Fluid/Gas pathways
 - c. Pressure or function testing of diverter systems

- *Identify the maximum safe working pressure for a give set of well control equipment upstream and downstream of the choke.*
- *Describe correct installation, maintenance, wear, and replacement requirements, and describe rings, flanges, and connectors.*
- *Describe the need for function and pressure testing of BOP equipment.*
- *Perform, explain, or demonstrate the testing operations listed at left.*

Equipment continued on next page.

Equipment continued.

I. Well control equipment arrangements

1. General arrangements for BOP, valving, manifolds, and auxiliary equipment (written and practical testing)
 - a. BOP, manifold plug, and valve line-up
 - 1) For drilling operations
 - 2) For shut-in
 - 3) For well control operations
 - 4) For testing

- *Identify the flow path for well control operations.*
 - *Identify areas exposed to high and low pressure during shut-in and pumping operations.*
 - *Identify and confirm line-up for equipment pressure testing, shut-in, and pumping operations.*
 - *Demonstrate ability to shut-in the well in the event of primary equipment failure.*
 - *Demonstrate the correct alignment of standpipe and choke manifold valves, including downstream valves for the conditions listed at left.*
-

IX. GOVERNMENT, INDUSTRY AND COMPANY RULES, ORDERS AND POLICIES

<i>TRAINING TOPICS</i>	<i>JOB SKILLS</i>
A. Incorporate by reference 1. Regional and/or local regulations where required	

X. SUBSEA WELL CONTROL (REQUIRED FOR SUBSEA ENDORSEMENT)

TRAINING TOPICS	JOB SKILLS
<p>A. Subsea equipment</p> <ol style="list-style-type: none"> 1. Marine riser systems <ol style="list-style-type: none"> a. Drilling with riser b. Drilling without riser 2. BOP control systems <ol style="list-style-type: none"> a. Block position b. Pilot system c. Subsea control pods 3. BOP stack <ol style="list-style-type: none"> a. Lower marine riser package (LMRP) b. Configuration c. Ram locks 4. Ball joint 5. Flex joint 6. Slip joint 7. Riser dump valve 	<ul style="list-style-type: none"> ■ <i>Identify and describe the function of each system listed at left.</i> ■ <i>State how to activate ram locks.</i> ■ <i>Describe reasons for drilling with and without riser.</i> ■ <i>Describe operating principles of subsea BOP stack control system.</i>
<p>B. Diverter system</p> <ol style="list-style-type: none"> 1. Configuration and components 2. Diverter line size and location 3. Line-up for diversion <ol style="list-style-type: none"> a. Valve arrangement and function b. Valve operational sequence c. Limitations of the diverter system 	<ul style="list-style-type: none"> ■ <i>Describe principle of operation of the diverter system on a floating unit.</i>

Subsea Well Control continued on next page.

C. Kick detection issues

1. Vessel motion
2. With and without riser
3. Riser collapse
4. Water depth (BOP placement)

D. Procedures

1. Choke and/or kill line friction
 - a. Measurement of choke and/or kill line friction
 - b. Compensating for choke and/or kill line friction
 - 1) Static kill line
 - 2) Casing pressure adjustment
2. Clearing riser
 - a. Gas in riser
 - b. Displacing riser with kill weight mud
3. Hydrostatic effect of riser disconnects and re-connects
4. Spacing and hang-off

- *Define or describe the effect of fluids of different densities in the choke and kill lines for both levels.*
- *Explain consequences of trapped gas in subsea BOP system.*
- *Describe killing a subsea riser with kill mud and the consequences of failure to fill riser with kill mud after circulating out a kick.*
- *Describe possible consequences of trapped gas removal in terms of well behavior or riser without riser margin.*
- *Describe steps necessary to space out drillpipe and hang-off using motion compensator, ram locks, etc.*

XI. SPECIAL SITUATIONS (OPTIONAL)

NOTE: The following items are not required, but may be added at the school's discretion based on local conditions and needs.

TRAINING TOPICS	JOB SKILLS
<p>A. Hydrogen sulfide (H₂S)</p> <p>1. Risks encountered in well control operations involving H₂S</p> <ul style="list-style-type: none"> a. Toxicity b. Potential for explosion c. Corrosivity d. Solubility <p>2. Well control handling problems</p> <ul style="list-style-type: none"> a. Bullheading b. Circulation with flaring 	<ul style="list-style-type: none"> ■ <i>Identify risks associated with H₂S.</i> ■ <i>Specify crew responsibilities.</i> ■ <i>Identify well control options, including bullheading and circulation with flaring.</i>
<p>B. Horizontal well control considerations</p> <p>1. Influx detection</p> <p>2. Off bottom kill</p>	
<p>C. Underground blowouts</p> <p>1. Indications of underground flow</p> <ul style="list-style-type: none"> a. At shut-in b. During kill 	<ul style="list-style-type: none"> ■ <i>Demonstrate how to recognize loss of formation integrity during shut-in or circulation.</i>