

WellCAP®
IADC WELL CONTROL ACCREDITATION PROGRAM

DRILLING OPERATIONS
CORE CURRICULUM AND RELATED JOB SKILLS
FORM WCT-2DS

SUPERVISORY LEVEL

The purpose of the core curriculum is to identify a body of knowledge and a set of job skills that 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 	<ul style="list-style-type: none"> ■ <i>Define two types of kick: unintentional and intentional.</i> ■ <i>Identify causes of unintentional kicks.</i> ■ <i>Describe the piston effect (suction and how increased drag may be associated with swab).</i> ■ <i>Describe the effect of the items at left 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>
<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>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 following page.

Kick Detection continued.

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. Other pore pressure indicators 6. 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 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 following page.

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. "Trapped" pressure 10. Casing shoe pressure 11. Surge and swab pressures 12. Hydrostatic pressure change due to loss of fluid level and fluids with different mud densities 13. Static and dynamic calculation of bottomhole pressure 14. Fracture pressure (leak-off pressure) as defined by API RP 59 	<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> ■ <i>Estimate system pressure losses due to pump speed and/or fluid density changes.</i> ■ <i>Explain causes and effects of surge pressures on wellbore.</i> ■ <i>Calculate hydrostatic pressure changes due to loss of fluid levels and/or density (e.g., pills, slugs, washes, spacers, etc.).</i>

Pressure Concepts and Calculations continued on next page.

TRAINING TOPICS	JOB SKILLS
<p>B. Calculations</p> <ol style="list-style-type: none">1. Volume of tanks and pits2. Volume of a cylinder as related to pump output3. Displacement of open and closed pipe4. Annular capacity per unit length5. Annular volume6. Hydrostatic pressure7. Fracture pressure (as defined by API RP 59)8. Formation pressure9. Conversion from pressure to equivalent fluid density10. Kill mud weight11. Circulation time12. Bottoms up time for normal drilling13. Total circulating time, including surface equipment14. Surface-to-bit time15. Bit-to-shoe time16. Bottoms up strokes17. Surface-to-bit strokes18. Bit-to-shoe strokes19. Total circulating strokes, including surface equipment20. Pump output (look up from chart values only)21. Equivalent circulating density based on annular pressure drop data	<p>■ Be able to perform the calculations listed at left.</p>

CORE CURRICULUM & JOB SKIL -- PRESSURE CONCEPTS AND CALCULATIONS

Pressure Concepts and Calculations continued on next page.

Pressure Concepts and Calculations continued

TRAINING TOPICS	JOB SKILLS
22. Relationship between pump pressure and pump speed	
23. Relationship between pump pressure and mud density	
24. Maximum allowable annulus surface pressure	
25. Effect of water depth on formation strength calculation	
26. Gas laws $PV=K$	
27. Weighting material required to increase density per volume	
28. Volume increase due to increase in density	
29. Volume to be bled off, corresponding to pressure increase (volumetric method)	
30. Initial circulating pressure	
31. Final circulating pressure	
32. Riser volume and fluid required to displace	
33. Choke and kill line volumes	
34. Choke and kill line strokes	
35. Choke and kill line circulation time	
36. Pressure drop per step	

Pressure Concepts and Calculations continued on next page.

TRAINING TOPICS	JOB SKILLS
<p>C. Conversion of pressure to an equivalent mud weight</p> <ol style="list-style-type: none"> 1. Required mud weight <ol style="list-style-type: none"> a. Fluid density increase required to balance formation pressure 2. Equivalent circulating density (ECD) <ol style="list-style-type: none"> a. ECD loss during flow check while drilling b. No ECD loss during tripping flow check 	<ul style="list-style-type: none"> ■ Calculate fluid density increase required to balance formation pressure. ■ Calculate the effect of circulating friction pressure losses on surface and downhole pressures.
<p>D. Volume/Height relationship and effect on pressure</p>	<ul style="list-style-type: none"> ■ Calculate height of a given volume of fluid.
<p>E. Drop in pump pressure as fluid density increases during well control operations</p>	<ul style="list-style-type: none"> ■ Describe why pump pressure drops as fluid density increases during a constant bottomhole pressure method.
<p>F. Maximum wellbore pressure limitations</p> <ol style="list-style-type: none"> 1. Surface (e.g., wellhead, BOP, casing) 2. Subsurface (e.g., perforations, casing shoe, open hole formation) 	<ul style="list-style-type: none"> ■ Describe the consequences of exceeding maximum wellbore pressure limitations.

IV. PROCEDURES

TRAINING TOPICS	JOB SKILLS
<p>A. Alarm limits</p> <ol style="list-style-type: none"> 1. High and low pit level 2. Return flow sensor 3. Trip tank level 4. Others (i.e., H₂S and flammable/explosive gas sensors) 	<ul style="list-style-type: none"> ■ <i>Demonstrate the procedures for setting well control monitoring indicators, including, where applicable, the items at left.</i>
<p>B. Pre-recorded well control information</p> <ol style="list-style-type: none"> 1. Standpipe pressure at slow pump rates 2. Well configuration 3. Fracture gradient 4. Maximum safe casing pressures <ol style="list-style-type: none"> a. Wellhead rating b. Casing burst rating c. Pipe/Tubing collapse d. Subsurface weak zone (optional) 	<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>

Procedures continued on next page.

TRAINING TOPICS	JOB SKILLS
<p>C. Flow checks</p> <ol style="list-style-type: none">1. While drilling – normal flow back2. While tripping – well is hydrostatically balanced (no ECD loss considerations)3. While drilling – normal flow back4. While drilling – abnormal flow back5. Loss of equivalent circulating density (ECD) – pumps off6. While tripping – well is hydrostatically balanced (no ECD loss considerations)7. Use and purpose of trip sheet	<ul style="list-style-type: none">■ Describe the procedure to perform a flow check in the situations listed at left.■ Recognize and measure normal flow back.■ Recognize a flow that differs from normal flow back..■ Take action based on recognition of flow.■ Explain how to establish that a well is static before starting trip.■ Explain why an absence of flow (during flow check) is not an absolute indicator that there is no influx.■ Demonstrate understanding that the primary indicator of influx is the trip sheet (hole fill-up) rather than flow check.

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>D. 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 tubular used 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 f. Notify supervisor 	<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>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>For any shut-in, verify well closure by demonstrating that the flow paths listed at left are closed.</i>

Procedures continued on next page

Procedures continued

TRAINING TOPICS	JOB SKILLS
<ul style="list-style-type: none"> 5. During wireline operations <ul style="list-style-type: none"> a. Individual responsibilities b. Close BOP with consideration for cutting/closure around wire 6. During other rig activities <ul style="list-style-type: none"> a. Individual responsibilities b. Use of surface equipment to shut-in well c. Close choke d. Notify supervisor 7. Verification of shut-in <ul style="list-style-type: none"> a. Annulus <ul style="list-style-type: none"> 1) Through BOP 2) At the flow line b. Drillstring <ul style="list-style-type: none"> 1) Pump pressure relief valves 2) Standpipe manifold c. Wellhead/BOP <ul style="list-style-type: none"> 1) Casing valve (not applicable to subsea stack) 2) Broaching to surface (outside of wellbore) d. Choke manifold <ul style="list-style-type: none"> 1) Choke 2) Overboard lines 	

Procedures continued on next page.

Procedures continued.

TRAINING TOPICS	JOB SKILLS
<p>E. 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 4. Effects of density differences from gas, oil, or salt water kick on surface pressures 5. Situations in which shut-in drillpipe pressure exceeds shut-in casing pressures <ol style="list-style-type: none"> a. Cuttings loading b. Inaccurate gauge readings c. Density of influx fluid greater than drilling fluid d. Flow through drill string e. Blockage downhole 6. Maximum safe annulus pressure 7. Pressure between casing strings 	<ul style="list-style-type: none"> ■ <i>Explain or demonstrate recommended procedures to use for well monitoring during shut-in.</i> ■ <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>List two consequences on surface pressure resulting from shutting-in on a gas vs a liquid kick of equivalent volume.</i> ■ <i>Perform choke manipulation to achieve specific pressure or volume objectives..</i> ■ <i>Demonstrate procedure for relieving trapped pressure without creating underbalance.</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> ■ <i>List two situations in which shut-in drillpipe pressures would exceed shut-in casing pressures.</i> ■ <i>List hazards if closed-in annulus pressure exceeds maximum safe pressure.</i> ■ <i>Describe at least one method for controlling bottomhole pressure (BHP) while gas is migrating.</i> ■ <i>Identify two causes of pressure between casing strings..</i> ■ <i>Describe potential hazard(s) of pressure trapped between casing strings and actions required.</i>

Procedures continued on next page.

TRAINING TOPICS	JOB SKILLS
<p>F. Response to massive or total loss of circulation</p> <ol style="list-style-type: none"> 1. During drilling, fill annulus with fluid in use 2. Notify supervisor immediately 3. Use of bridging materials (e.g., cement, gunk plugs, lost circulation materials, etc.) 4. Elimination of overbalance 	<ul style="list-style-type: none"> ■ <i>Identify at least two methods of responding to massive or total loss of circulation during a well kill operation.</i> ■ <i>Upon observing loss of circulation, perform the actions listed at left.</i>
<p>G. Tripping</p> <ol style="list-style-type: none"> 1. Procedures used for keeping hole filled <ol style="list-style-type: none"> a. Using rig pump b. Using trip tank c. Using recirculating trip tank (continuous fill) 2. Methods of measuring and recording hole fill volumes 3. Procedure and line up to keep hole filled 4. Wet trip calculations <ol style="list-style-type: none"> a. Return to mud system b. No return to mud system 5. Dry trip calculations 6. Slugs 7. Trip margin <ol style="list-style-type: none"> a. Measure hole fill-up b. Recognize discrepancy from calculated fill-up c. Take appropriate action <ol style="list-style-type: none"> 1) At flow, go to shut-in 2) At no flow and short fill-up, go back to bottom 8. Procedure and line up to keep hole filled 	<ul style="list-style-type: none"> ■ <i>Perform the items listed at left with regard to hole fill up on trips.</i> ■ <i>Demonstrate, explain, or perform the actions listed at left with regard to tripping.</i>

CORE CURRICULUM & JOB SKIL – GAS CHARACTERISTICS AND BEHAVIOR

*Procedures continued on next page
Procedures continued*

TRAINING TOPICS	JOB SKILLS
9. Calculate correct fill volumes <ul style="list-style-type: none"> a. Wet trip b. Dry trip 10. Explain trip margin 11. Explain the effect of slugs on hole fill up 12. Measuring displacement volumes while tripping into hole <ul style="list-style-type: none"> a. With check valve in drillstring b. Without check valve in drillstring 	
H. Well control drills (types and frequency) <ul style="list-style-type: none"> 1. Pit drills 2. Trip drills 3. Personnel evacuation 4. Diverter drills as they relate to shallow gas hazards 	<ul style="list-style-type: none"> ■ <i>Describe the steps involved in conducting the types of drills listed at left.</i>
I. 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) 3. Interpret data from formation tests 4. Effect of fluid density change as applicable <ul style="list-style-type: none"> a. Leak-off test (at least one method) <ul style="list-style-type: none"> 1) Calculate equivalent mud weight for leak-off test pressure b. Formation pressure integrity test <ul style="list-style-type: none"> 1) With check valve in drillstring 5. 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 the leak-off test and formation pressure integrity test.</i> ■ <i>Describe how formation competency test results may be affected by fluid density change.</i>

Procedures continued on next page.

TRAINING TOPICS	JOB SKILLS
<p>J. Stripping operations</p> <ol 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 4. Calculations relating to volumes and pressures to be bled for a given number of drillstring stands run in the hole 5. Stripping with/without volumetric control. 	<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>
<p>K. Shallow gas hazards</p> <ol style="list-style-type: none"> 1. Mechanisms and timing of events 2. Kill procedures <ol style="list-style-type: none"> a. Shut-in b. Use of diverters <ol style="list-style-type: none"> 1) With drillpipe 2) Running casing c. Riserless drilling 3. Pilot holes 4. During and after cementing conductor and surface casing 5. Setting barite or cement plugs 	<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> ■ <i>Explain the use of pilot holes.</i> ■ <i>Describe the technique or procedure for preparing and setting barite or cement plugs.</i> ■ <i>Describe the difference between diverting and conventional well kills.</i> ■ <i>Describe the difference between diverting and conventional well kills.</i> ■ <i>List at least two conditions under which the use of a diverter may be applicable.</i> ■ <i>List at least two potential hazards when using a diverter.</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 3. H₂S 4. CO₂ 	
<p>B. Density</p> <ol style="list-style-type: none"> 1. Gas 2. Gas and mud mixtures 	<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> ■ <i>Explain the effect of gas cutting on bottomhole pressure and the use of pit level monitoring to recognize hydrostatic loss.</i> ■ <i>Describe the conditions where gas cutting may have little effect on hydrostatic head and bottomhole pressure.</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>

Gas Characteristics and Behavior continued on next page.

CORE CURRICULUM & JOB SKIL – GAS CHARACTERISTICS AND BEHAVIOR

Gas Characteristics and Behavior continued.

TRAINING TOPICS	JOB SKILLS
<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>
<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 2. CO₂ and OBM 3. 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> ■ <i>Describe how dissolved gas affects wellbore pressures when it comes out of solution.</i> ■ <i>Describe the sequential consequences of gas evolving from the mud system.</i>

VI. FLUIDS

TRAINING TOPICS	JOB SKILLS
<p>A. Types of drilling fluids</p> <ol style="list-style-type: none"> 1. Water based mud 2. Oil based mud (OBM), synthetic oil based mud (SOBM) 3. Cement 4. Completion fluids 	<p>■ <i>Identify types of drilling fluids.</i></p>
<p>B. Fluid property effects on pressure losses</p> <ol style="list-style-type: none"> 1. Density 2. Viscosity 3. Changes in mud properties due to contamination by formation fluids 	<p>■ <i>Explain how fluid properties affect pressure losses.</i></p>
<p>C. Fluid density measuring techniques</p> <ol style="list-style-type: none"> 1. Mud balance 2. Pressurized mud balance 	<p>■ <i>Measure fluid density.</i></p>
<p>D. Mud properties following weight-up and dilution</p> <ol style="list-style-type: none"> 1. Gel strengths 2. Plastic viscosity and yield point (PV and YP) 	<p>■ <i>Explain the effects of weighting-up and diluting fluid on gel strength, PV and YP.</i></p>

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 (BHP) equals formation pressure <ol style="list-style-type: none"> a. Close choke and observe pressure gauges (SIDPP + SICP = 0 psi) b. If hydrostatic balance is restored, open BOPs and check for flow c. Resume operations 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> ■ <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>

Constant Bottomhole Pressure Well Control continued on next page.

TRAINING TOPICS	JOB SKILLS
<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. Well control and kill – calculations and procedures <ol style="list-style-type: none"> a. Proficiency in both constant bottomhole pressure well control methods – Driller's and/or Wait & Weight Method <ol style="list-style-type: none"> 1) Bring pump up to slow kill rate while opening choke 2) Maintain surface pressure while circulating according to method 3) Increase mud weight in pits to kill weight 4) Line up pump to kill mud 5) Line up choke manifold and auxiliary well control equipment 6) Pump kill weight mud until kill mud completely fills the wellbore 7) Circulate until all kicks are removed from well 8) Shut off pumps 9) Close choke and observe pressure gauges (SIDPP + SICP = 0 psi) 10) If hydrostatic balance is restored, open BOPs and check for flow 11) Resume operations b. Preparing the killsheet 2. Organize the specific responsibilities of the rig crew during a well control/kill operation 	<ul style="list-style-type: none"> ■ <i>Demonstrate proficiency in implementing both the Wait & Weight and Driller's Methods.</i> ■ <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 these steps 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> ■ <i>Demonstrate or describe the process of organizing the specific responsibilities of the rig crew during the execution of a well kill operation.</i>

Constant Bottomhole Pressure Well Control continued on next page.

Constant Bottomhole Pressure Well Control continued.

TRAINING TOPICS	JOB SKILLS
<p>D. Well control kill sheets</p> <ol style="list-style-type: none"> 1. Well control calculations <ol style="list-style-type: none"> 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 <ol style="list-style-type: none"> a. Surface b. Subsurface 3. Selection of a kill rate for pump <ol style="list-style-type: none"> a. Allowing for friction losses b. Barite delivery rate c. Choke operator reaction time d. Pump limitations e. Surface fluid handling capacity 	<ul style="list-style-type: none"> ■ <i>Correctly fill out a kill sheet for one well control method.</i> ■ <i>Determine weight up material required and corresponding volume increase.</i> ■ <i>Describe the consequences of exceeding maximum wellbore pressure at surface and subsurface.</i> ■ <i>Identify factors affecting selection of kill rate for pump.</i>

Constant Bottomhole Pressure Well Control continued on next page.

TRAINING TOPICS	JOB SKILLS
<p>E. Well control procedures</p> <ol style="list-style-type: none"> 1. Procedure to bring pump on and off line and change pump speed while holding bottomhole pressure constant using choke <ol style="list-style-type: none"> a. Use of casing pressure gauge b. Lag time response on drillpipe pressure gauge 2. Initial circulation pressure <ol style="list-style-type: none"> a. Using recorded shut-in drillpipe pressure and reduced circulating pressure b. Without a pre-recorded value for reduced circulating pressure c. Adjustment for difference in observed vs. calculated circulating pressure 3. Choke adjustment during well kill procedure <ol style="list-style-type: none"> a. Changes in surface pressure as a result of changes in hydrostatic head or circulating rates <ol style="list-style-type: none"> 1) Drop in pump pressure as fluid density increases in drillstring during well control operations 2) Increase in pump pressure with increased pump rate and vice versa b. Pressure response time <ol style="list-style-type: none"> 1) Casing pressure gauge (immediate) 2) Drillpipe pressure gauge (lag time) 4. Handling of problems during well control operations <ol style="list-style-type: none"> a. Pump failure b. Changing pumps c. Plugged or washed out nozzles d. Washout or parting of drillstring e. BOP failure <ol style="list-style-type: none"> 1) Flange failure 	<ul style="list-style-type: none"> ■ <i>Demonstrate bringing pump on and off line and changing pump speed while holding bottomhole pressure constant using choke.</i> ■ <i>Determine correct initial circulating pressures.</i> ■ <i>Operate choke to achieve specific pressure objectives relative to selected constant bottomhole pressure methods.</i> ■ <i>Describe why pump pressure drops as fluid density increases during a constant bottomhole pressure method.</i> ■ <i>Given a scenario detailing a well control problem, identify the problem and demonstrate or describe an appropriate response.</i> <p style="text-align: right;"><i>Constant Bottomhole Pressure Well Control continued on next page.</i></p>

CORE CURRICULUM & JOB SKILLS – CONSTANT BOTTOMHOLE PRESSURE WELL CONTROL METHODS

Constant Bottomhole Pressure Well Control continued

TRAINING TOPICS	JOB SKILLS
<ul style="list-style-type: none"> 1) Weephole leakage 2) Failure to close 3) Failure to seal f. Plugged or washed out choke g. Fluid losses h. Flow problems downstream of choke i. Hydrates j. Malfunction of remote choke system k. Mud/Gas separator l. Problems with surface pressure gauges m. Annulus pack-off 5. Considerations if using a diverter 	
<p>F. Other well control methods</p> <ul style="list-style-type: none"> 1. Volumetric, including lubrication/bleed <ul style="list-style-type: none"> a. During drilling b. During well testing/completion 2. Bullheading <ul style="list-style-type: none"> a. During drilling b. During well testing/completion 3. Reverse circulation during well testing/completion 4. Reasons for selecting the specific well control methods 5. Assumptions and limitations of methods 	<ul style="list-style-type: none"> ■ <i>Demonstrate proficiency in control/kill methods including volumetric with lubrication and bleeding, bullheading, etc.</i>

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 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"> ■ Describe the relationship between mud pit and flow sensors, and drill floor kick indications. ■ List at least two reasons for possible gauge inaccuracies. ■ Describe the purpose and use of the mud pump/stroke counter (e.g., stroke rate, flow rate, and displaced volume). ■ Measure current drilling parameters.

Equipment continued on next page.

Equipment continued.

TRAINING TOPICS	JOB SKILLS
<p>B. BOP configuration</p> <ol style="list-style-type: none"> 1. Components (See API RP 53, most recent version) <ol style="list-style-type: none"> a. Annular preventer b. Ram preventers/elements <ol style="list-style-type: none"> 1) Blind 2) Blind/Shear 3) Pipe 4) Variable bore pipe 5) Ram elements c. Drilling spool or integral body d. Valves 2. Functions 	<ul style="list-style-type: none"> ■ <i>Demonstrate basic understanding of the use of ram and annular preventers.</i> ■ <i>Identify flow path for normal drilling operations.</i> ■ <i>Identify flow path for well control operations.</i> ■ <i>Identify areas exposed to high and low pressure during shut-in and pumping operations.</i> ■ <i>Identify and confirm line-up for equipment pressure testing, shut-in, and pumping operations.</i> ■ <i>Demonstrate ability to shut-in the well in the event of primary equipment failure.</i> ■ <i>Given a BOP stack configuration, identify potential flow paths for kill operations.</i> ■ <i>Given a BOP stack configuration, identify shut-in, monitoring, and circulation operations which are possible and those which are not.</i> ■ <i>Given a BOP stack configuration, select an appropriate BOP to effect closure on a given tubular.</i>
<p>C. Manifolds and piping</p> <ol style="list-style-type: none"> 1. Standpipe 2. Choke 	

Equipment continued on next page.

TRAINING TOPICS	JOB SKILLS
<p>D. Valving</p> <ol style="list-style-type: none"> 1. BOP stack 2. Drillstring <ol style="list-style-type: none"> a. Full opening valves (DPSV, kelly cock, kelly valve) b. Check valves c. Float valves – advantages and disadvantages 3. Choke manifold <ol style="list-style-type: none"> a. Adjustable choke <ol style="list-style-type: none"> 1) Hydraulic (remote operated) 2) Manual b. Fixed choke c. Valves to direct flow 4. Mud pressure relief 	<ul style="list-style-type: none"> ■ 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.

Equipment continued.

TRAINING TOPICS	JOB SKILLS
<p>E. Auxiliary well control equipment</p> <ol style="list-style-type: none"> 1. Mud/Gas separator <ol style="list-style-type: none"> a. Gas blow-through b. Vessel rupture 2. Mud pits <ol style="list-style-type: none"> a. Suction pit b. Return pit c. Mixing equipment 3. Degasser 4. Trip tank <ol style="list-style-type: none"> a. Gravity feed b. Recirculating type 5. Top drive systems <ol style="list-style-type: none"> a. Kelly valves, lower b. Spacing out c. Shutting-in d. Stripping 	<ul style="list-style-type: none"> ■ <i>Define function, operating principles, flowpaths, and components of mud-gas separators.</i> ■ <i>List two possible consequences of overloading the mud-gas separator and explain the appropriate corrective actions .</i> ■ <i>Describe pit alignment during well control operations (e.g., vacuum degasser, flaring).</i> ■ <i>Describe the procedures for handling of gas in return fluids (e.g., vacuum degasser, flaring).</i> ■ <i>Describe the characteristics of a trip tank (e.g., small cross-section, accurate fluid volume measurements).</i> ■ <i>Describe considerations when using top drive systems.</i>

Equipment continued on next page.

TRAINING TOPICS	JOB SKILLS
<p>F. BOP closing unit – function and performance</p> <ol style="list-style-type: none"> 1. Usable fluid volume test <ol style="list-style-type: none"> a. Gas blow-through b. Vessel rupture 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 pre-charge pressure, minimum system pressure, normal regulated operating pressure, maximum system pressure.</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 	<ul style="list-style-type: none"> ■ <i>Explain use of testing and completion well control equipment.</i>

Equipment continued on next page.

Equipment continued.

TRAINING TOPICS	JOB SKILLS
<p>H. Pressure and function tests</p> <ol style="list-style-type: none"> 1. Maximum safe working pressure <ol style="list-style-type: none"> 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 <ol style="list-style-type: none"> 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 <ol style="list-style-type: none"> a. Function and testing of high pressure well control equipment <ol style="list-style-type: none"> 1) BOP stack 2) Manifolds 3) Auxiliary well control equipment b. Function and testing of low pressure well control equipment <ol style="list-style-type: none"> 1) Mud-gas separator 2) Fluid/Gas pathways 5. Pressure or function testing of diverter systems 	<ul style="list-style-type: none"> ■ <i>Identify the maximum safe working pressure for a given set of well control equipment upstream and downstream of the choke.</i> ■ <i>List at least two reasons for possible de-rating of the working pressure of the well control equipment.</i> ■ <i>Describe correct installation, maintenance, wear, and replacement requirements, and describe rings, flanges, and connectors.</i> ■ <i>Perform, explain, or demonstrate function and testing of high pressure well control equipment, low pressure well control equipment, and diverter systems.</i>

Equipment continued on next page.

TRAINING TOPICS	JOB SKILLS
<p>I. Well control equipment arrangements</p> <p>1. General arrangements for BOP, valving, manifolds, and auxiliary equipment (applicable to both written and practical testing)</p> <p>a. BOP, manifold plug, and valve line-up</p> <ol style="list-style-type: none"> 1) For drilling operations 2) For shut-in 3) For well control operations 4) For testing 	<ul style="list-style-type: none"> ■ <i>Identify the flow path for well control operations.</i> ■ <i>Identify areas exposed to high and low pressure during shut-in and pumping operations.</i> ■ <i>Identify and confirm line-up for equipment pressure testing, shut-in, and pumping operations.</i> ■ <i>Demonstrate ability to shut-in the well in the event of primary equipment failure.</i> ■ <i>Demonstrate the correct alignment of standpipe and choke manifold valves, including downstream valves for the the following conditions:</i> <ol style="list-style-type: none"> a. <i>Drilling operations</i> b. <i>Shut-in</i> c. <i>Well control operations</i> d. <i>Testing.</i>

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

TRAINING TOPICS	JOB SKILLS
<p>A. Incorporate by reference</p> <ol style="list-style-type: none"> 1. API and ISO Recommended Practices, Standards, and Bulletins pertaining to well control 2. Regional and/or local regulations where required 	
<p>B. Bridging Documents</p>	<ul style="list-style-type: none"> ■ <i>Describe how bridging documents can resolve differences between operator and contractor well control policies (e.g., shallow gas and diverter operations).</i>

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 described 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.

TRAINING TOPICS	JOB SKILLS
<p>C. Kick detection issues</p> <ol style="list-style-type: none"> 1. Vessel motion 2. With and without riser 3. Riser collapse 4. Water depth (BOP placement) 	<ul style="list-style-type: none"> ■ <i>Describe how the items listed at left affect kick detection.</i>
<p>D. Procedures</p> <ol style="list-style-type: none"> 1. Choke and/or kill line friction <ol style="list-style-type: none"> a. Measurement of choke and/or kill line friction b. Compensating for choke and/or kill line friction <ol style="list-style-type: none"> 1) Static kill line 2) Casing pressure adjustment 2. Removing trapped gas from BOPs <ol style="list-style-type: none"> a. Use of bleed lines b. U-tubing of trapped gas 3. Clearing riser <ol style="list-style-type: none"> a. Gas in riser b. Displacing riser with kill weight mud 4. Hydrostatic effect of riser disconnects and re-connects 5. Spacing and hang-off 6. Effect of depth on formation competency 	<ul style="list-style-type: none"> ■ <i>Define or describe the effect of fluids of different densities in the choke and kill lines for both levels.</i> ■ <i>Explain consequences of trapped gas in subsea BOP system.</i> ■ <i>Describe specific procedure for removing trapped gas from the BOP stack following a kill operation.</i> ■ <i>Describe killing a subsea riser with kill mud and the consequences of failure to fill riser with kill mud after circulating out a kick.</i> ■ <i>Describe possible consequences of trapped gas removal in terms of well behavior or riser without riser margin.</i> ■ <i>Describe steps necessary to space out drillpipe and hang-off using motion compensator, ram locks, etc.</i>
<p>E. Compensating for hydrostatic head changes in choke lines</p>	<ul style="list-style-type: none"> ■ <i>Demonstrate ability to adjust circulating pressures to compensate for choke line friction.</i> ■ <i>Demonstrate ability to adjust choke appropriately to compensate for rapid change in hydrostatic pressure due to gas in long choke lines.</i>
<p>F. Hydrates</p>	<ul style="list-style-type: none"> ■ <i>Identify possible complications caused by hydrates.</i>

XI. SHUT-IN FOR SUBSEA AND DEEPWATER WELLS

TRAINING TOPICS	JOB SKILLS
<p>A. Shut-in for subsea wells</p> <ol style="list-style-type: none"> 1. Pre-kick preparation 2. Hard shut-in vs. soft shut-in 3. Annular shut-in vs. ram shut-in 4. Shut-in while drilling 5. Shut-in while tripping 6. Shut-in while making a connection 7. Shut-in with bit above BOPs 8. Shut-in while running casing/liner 9. Masking of choke pressure by high gel strength in C&K lines 10. Reading shut-in drill pipe pressure 	<ul style="list-style-type: none"> ■ <i>Demonstrate the ability to shut in the well in a timely manner to minimize influx after observing positive flow indicators.</i> ■ <i>For any shut-in, verify well closure by demonstrating the flow paths are closed.</i> ■ <i>Describe how choke pressure readings are affected in deepwater by the high gels of the mud in the choke and kill lines.</i>

XII. SUBSEA AND DEEPWATER WELL KILL CONSIDERATIONS

TRAINING TOPICS	JOB SKILLS
<p>A. Constant bottom hole pressure methods</p> <ol style="list-style-type: none"> 1. Driller's method 2. Wait and weight method 	<ul style="list-style-type: none"> ■ <i>Demonstrate proficiency in implementing both the Wait & Weight and the Drillers Method.</i> ■ <i>Identify differences in using either of these methods in subsea environment.</i>
<p>B. Bullheading</p>	<ul style="list-style-type: none"> ■ <i>Identify when bullheading should be used in lieu of constant bottom hole pressure methods.</i> ■ <i>Demonstrate proficiency in implementing a bullheading procedure.</i>
<p>C. Number of choke and kill lines</p>	<ul style="list-style-type: none"> ■ <i>Explain how the number of choke and kill lines can affect circulating well kill methods.</i>
<p>D. Volumetric method</p>	<ul style="list-style-type: none"> ■ <i>Explain differences in volumetric methods for subsea.</i>
<p>E. Dynamic lubrication methods</p>	<ul style="list-style-type: none"> ■ <i>Explain dynamic lubrication of gas below subsea BOP stack.</i>

XIII. SUBSEA AND DEEPWATER WELL CONTROL – SHALLOW FLOW(S)

TRAINING TOPICS	JOB SKILLS
<p>A. Shallow flow(s) prior to BOP installation</p> <ol style="list-style-type: none"> 1. Shallow water flow 2. Shallow gas 	<ul style="list-style-type: none"> ■ Describe the mechanisms that can result in shallow flow. ■ Discuss difficulty in controlling flows, emphasis must be placed on detection, prediction and prevention.
<p>B. Shallow flow detection</p> <ol style="list-style-type: none"> 1. Shallow flow indicators 2. Shallow flow detection methods and equipment 	<ul style="list-style-type: none"> ■ Explain how shallow flows can be detected, e.g.: <ul style="list-style-type: none"> • during drilling, • while running casing, • during/after cementing.
<p>C. Shallow flow prevention technique, procedures and practices</p>	<ul style="list-style-type: none"> ■ Describe ways to prevent shallow water and shallow gas flows.
<p>D. Shallow flow well control methods</p> <ol style="list-style-type: none"> 1. Shallow water flow 2. Shallow gas 3. Lost circulation and formation breakdown 	<ul style="list-style-type: none"> ■ Explain how to implement shallow water kill procedures. ■ Explain how to implement shallow gas kill procedures. ■ Explain how to implement lost circulation and/or formation breakdown procedures.

XIV. SUBSEA AND DEEPWATER WELL CONTROL – KICK PREVENTION AND DETECTION

TRAINING TOPICS	JOB SKILLS
<p>A. Kick Prevention & Detection</p> <ol style="list-style-type: none"> 1. Early kick detection <ol style="list-style-type: none"> a. Drilling data analysis b. Pressure detection services c. Pressure transition management d. General practices to managing pressure e. Drilling fluid analysis f. Simulated connections g. Mud gas levels 2. Tripping practices <ol style="list-style-type: none"> a. Circulating trip gas 3. Subsea Circulating Practices 4. Connection and rotating practices 5. Ballooning 	<ul style="list-style-type: none"> ■ <i>Explain why subsea kick detection is more difficult.</i> ■ <i>Describe how a leak-off test should be conducted in subsea operating environments.</i> ■ <i>Explain why early kick detection is necessary in deepwater operating environments.</i> ■ <i>Explain reasons for pressure transition problems in deepwater.</i> ■ <i>Describe how pressure detection services can detect kicks or lost circulation.</i> ■ <i>Describe “best practices” to managing pore and fracture pressures in deepwater drilling environments.</i> ■ <i>Describe practices used to identify ballooning vs. well kicks.</i>
<p>B. Riser gas considerations</p> <ol style="list-style-type: none"> 1. Danger of free gas in riser 2. When to apply gas in riser procedures 3. Considerations for handling gas in riser <ol style="list-style-type: none"> a. Alternatives for handling riser gas b. Riser circulation timing (1/4, 1/2, 3/4, etc.) 	<ul style="list-style-type: none"> ■ <i>Explains the risks and hazards of free gas in the riser. Demonstrate proficiency in implementing procedures for handling riser gas.</i> ■ <i>Explain the usage of the diverter system in handling riser gas.</i> ■ <i>Explain the benefits of having: 1) a riser mud gas separator, and 2) riser boost lines.</i>

XV. SUBSEA AND DEEPWATER WELL CONTROL – BOP ARRANGEMENTS

TRAINING TOPICS	JOB SKILLS
<p>A. Subsea BOP Stack</p> <ol style="list-style-type: none"> 1. BOP Arrangements 2. Placement of rams/outlets 3. Moored and dynamic positioned rig 4. Hang-off 5. BOP instrumentation arrangements 6. External loading of BOP equipment 7. Hot stab requirements 	<ul style="list-style-type: none"> ■ Describe the purpose/function of rams in a subsea stack. ■ Describe placement of rams/outlets in a subsea stack. ■ Describe the differences between BOP stacks on moored and dynamic positioning rigs BOP. ■ Describe essential hang-off requirements for BOP rams. ■ Describe BOP instrumentation preferred for deepwater.
<p>B. Choke manifold system</p> <ol style="list-style-type: none"> 1. Overboard / mud gas separator bypass 2. Strip tank tie-in 3. Low pressure gauges 4. Hydrate inhibition 	<ul style="list-style-type: none"> ■ Explain the diverter and surface gas handling facilities to meet deepwater riser gas requirements. ■ Explain the alignment of choke/kill manifold in preparation of well control procedures. ■ Explain the importance of displacement fluids required to be displaced into choke/kill lines in deepwater.
<p>C. Subsea control systems</p> <ol style="list-style-type: none"> 1. Direct hydraulics 2. Multiplex 3. Acoustics 	<ul style="list-style-type: none"> ■ Explain block position. ■ Explain pilot system. ■ Explain subsea accumulator bottles. ■ Explain BOP response time. ■ Explain BOP / wellhead connectors / disconnect. ■ Explain dedicated hydraulic line. ■ Explain subsea control pods. ■ Explain “usable” fluid.

DeepwaterBOPArrangement continued on next page.

D. Diverter System – Floating Unit

1. Configuration and components
2. Diverter line size and location
3. Line-up for diversion
 - a. Valve arrangement and function
 - b. Valve operational sequence
 - c. Limitations of the diverter system

- *Describe principle of operation of the diverter system on a floating unit.*

XVI. SUBSEA AND DEEPWATER WELL CONTROL – RISER SYSTEM

TRAINING TOPICS	JOB SKILLS
<p>A. Riser considerations</p> <ol style="list-style-type: none"> 1. Design 2. Operating characteristics 	<ul style="list-style-type: none"> ■ <i>Describe and identify key components required for a riser management system.</i> ■ <i>Describe and identify riser design and operating characteristics.</i> <ul style="list-style-type: none"> • <i>Collapse</i> • <i>Buoyancy</i> • <i>Tension Loading</i>
<p>B. Boost lines</p>	<ul style="list-style-type: none"> ■ <i>Explain how the use of boost lines affects the kick detection process.</i>
<p>C. Fill-up valves (dump valve)</p>	<ul style="list-style-type: none"> ■ <i>Describe the purpose of a fill-up valve.</i> ■ <i>List two situations where the use of a fill-up valve is required.</i>

XVII. SUBSEA AND DEEPWATER WELL CONTROL – ROV INTERVENTIONS

TRAINING TOPICS	JOB SKILLS
A. Minimum subsea BOP/ROV intervention functions 1. Hot stab plug considerations 2. ROV capabilities	■ <i>Explain how an ROV can be used in well control intervention.</i>
B. Common BOP override functions	■ <i>Identify common override functions and how they can be used to effect efficient well control.</i>

XVIII. SUBSEA AND DEEPWATER WELL CONTROL – DRILLING FLUIDS

TRAINING TOPICS	JOB SKILLS
<p>A. Subsea drilling fluid considerations</p> <ol style="list-style-type: none"> 1. Temperature effects 2. Hydrates 	<ul style="list-style-type: none"> ■ <i>Identify how the drilling fluid properties affect:</i> <ul style="list-style-type: none"> • <i>Losses and fracture propagation</i> • <i>Ballooning</i> • <i>Equivalent circulating densities</i> • <i>Temperature stability</i> • <i>Gas solubility (OBM, SBM)</i> • <i>Leak-off tests (OBM, SBM)</i> • <i>Fluid compressibility (OBM, SBM)</i> • <i>Riser margin</i> • <i>Hydrate formation, prevention and removal, e.g., glycol addition</i> ■ <i>Explain the effect of the low temperature on the pressure losses in the choke and kill lines.</i>
<p>B. Fluid storage</p> <ol style="list-style-type: none"> 1. Weighted systems for shallow water flow kill 2. Barite storage/mixing capacities and rates 3. Kill weight mud 	<ul style="list-style-type: none"> ■ <i>Describe how barite storage, kill weight mud storage, and the rig's mud mixing system can be used to control shallow water flows.</i>

XIX. SUBSEA AND DEEPWATER WELL EMERGENCY DISCONNECT

TRAINING TOPICS	JOB SKILLS
<p>A. DP emergency disconnect considerations</p> <ol style="list-style-type: none"> 1. Yellow/Red alert considerations 2. Emergency disconnect sequence functions 3. Autoshear and deadman systems 4. Acoustic back-up systems 	<ul style="list-style-type: none"> ■ <i>List two situations that would call for an emergency disconnect on a dynamically positioned rig.</i> ■ <i>List the consequences of a Failure to Disconnect.</i>

XX. 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 options</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>3. Special kill sheet</p>	<ul style="list-style-type: none"> ■ <i>Explain the following considerations related to horizontal well control:</i> <ul style="list-style-type: none"> a. <i>Any kill sheet modifications</i> b. <i>Influx detection</i> c. <i>Procedure for off bottom kill</i> d. <i>Gas behavior in horizontal section</i> e. <i>Pressurized drilling equipment</i>
<p>C. Off bottom kills</p>	<ul style="list-style-type: none"> ■ <i>Explain off bottom kills.</i>
<p>D. 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>

Special Situations continued on next page.

Special Situations continued.

TRAINING TOPICS	JOB SKILLS
E. Combination thief and kick zones 1. Thief zone on top, kick zone on bottom 2. Kick zone on top, thief zone on bottom	■ <i>Explain problems and procedural responses for combination thief and kick zone.</i>
F. False kick indicators 1. Kelly cut 2. Background gas 3. Bottoms up with OBM 4. Fluid transfer	■ <i>Describe false kick indicators.</i>
G. Pipe reciprocation during well kill (biaxial loading)	■ <i>Explain procedure for pipe movement during well kill.</i>
H. Underbalanced drilling 1. Producing while drilling 2. Pressurized drilling equipment <ul style="list-style-type: none"> a. Rotating annular b. Rotating head 	■ <i>Explain well control procedures for underbalanced drilling.</i>
I. Slim-hole well control considerations	■ <i>Explain well control concerns during slim-hole drilling.</i>
J. Coiled tubing	■ <i>Explain well control during coiled tubing operations.</i>
K. Snubbing	■ <i>Explain well control during snubbing operations.</i>

Special Situations continued on next page.

CORE CURRICULUM & JOB SKILLS – RULES, ORDERS & POLICIES

Special Situations continued.

TRAINING TOPICS	JOB SKILLS
L. New well control technology and equipment	
M. High pressure/high temperature considerations	
N. Tapered string/tapered hole	
O. Wellhead component failure points 1. Casing hangers 2. Casing isolation seals 3. Connections and fittings	
P. Shut-in and circulating kick tolerance	