WellCAP®
IADC WELL CONTROL ACCREDITATION PROGRAM

COILED TUBING WELL CONTROL OPERATIONS
CORE CURRICULUM AND RELATED JOB SKILLS

FORM WCT-2CTS

SUPERVISORY LEVEL

The Supervisory "stand-alone" course focuses exclusively on well control practices for coiled tubing well servicing operations performed through the christmas tree. The course is structured to provide job skills for coiled tubing operations performed in both onshore and offshore environments.

The "Supervisory" level certification requires a minimum of 36 hours of instruction. The well control training focuses on use of the tested mechanical well control barriers in the coiled tubing well control stack, CT bottomhole assembly and related surface equipment as referenced in **API RP 16ST**, *Recommended Practice for Coiled Tubing Well Control Equipment Systems and Operations*. In the Supervisory Coiled Tubing Well Control Operations training curriculum, conventional pumped-fluid hydrostatic pressure control methods applicable in coiled tubing operations are offered, in addition to the use of tested mechanical well control barriers. The equipment-based well control practices are reinforced with the "CT Operational Contingencies" personnel drills.

The target audience for the Supervisory Coiled Tubing Well Control Operations course includes coiled tubing unit supervisors and asset company representatives.

IADC WellCAP recommends that <u>at least</u> one person holding a current Supervisory level well control certification be on location at all times during coiled tubing operations. The individual may be either a CT service representative or an asset representative.

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

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I. REASONS FOR PERFORMING COILED TUBING OPERATIONS

TRAINING TOPICS	JOB SKILLS
A. Definition of Coiled Tubing Operations	• *Describe coiled tubing operations.*
B. Reasons for Performing Coiled Tubing Operations: a. Completing for production from a new reservoir. b. Completing a well in more than one reservoir. c. Stimulating reservoir. d. Reworking a producing reservoir to control water, gas production and/or water coning. e. Repair or fish mechanical failure. f. Cement repair. g. Remove sand, scale or other solids impeding production h. Perform logging or perforating operations. i. Cleanout drillstrings that have become blocked due to lost circulation. j. Perform well kill operations.	• *Identify reasons for performing coiled tubing activities or working over a well.*

II. DEFINITIONS AND CALCULATIONS

TRAINING TOPICS	JOB SKILLS
A. Pressure Fundamentals 1. Definition of pressure a. Force b. Area 2. Types of pressure a. Pressure gradient 1) Liquid 2) Gas b. Hydrostatic pressure 1) General 2) Effect of fluid level change c. Total downhole pressure 1) Multiple fluid columns with varying densities 2) Considering shut-in surface pressures d. Bottomhole pressure e. Formation pressure 1) Balanced 2) Underbalanced 3) Overbalanced f. Differential pressure g. Trapped pressure h. Swab pressure i. Surge pressure j. Fracture pressure 3. Circulating frictional pressure losses a. Pressure losses in straight tubing and bent tubing. 4. Equivalent static fluid density a. Definition b. Pressures expressed as an equivalent fluid weight 5. Equivalent circulating density a. Definition b. Frictional pressure loss effects on downhole pressure c. Surface pressure effects d. U-tube principles	• *Define the following items:* o *Force* o *Pressure gradient* o *Hydrostatic pressure* o *Bottomhole pressure* o *Differential pressure* o *Total downhole pressure* o *Formation pressure* • *Calculate pressure gradient, hydrostatic pressure, bottomhole pressure, differential pressure and total downhole pressure.* • *Calculate effect of surface pressure on downhole pressures.* • *Demonstrate understanding of U-tube concept.* • *Calculate hydrostatic changes due to fluid level changes.* • *Calculate fluid column height to generate a specific hydrostatic pressure.* • *Explain causes and effects of swab and surge pressures in the wellbore.* • *Explain circulating frictional pressure losses and effects on pressure and equivalent circulating density for forward and reverse circulation (spooled and straight tubing).* • *Define and calculate equivalent fluid density.* • *Calculate overbalance or underbalance conditions.* • *Define the difference between a mechanical and fluid barrier.* • *Calculate potential pressure below plug or bridge.*

TRAINING TOPICS	JOB SKILLS
B. Static Wells and Live Wells 1. Defination of static well condition 2. Defination of live well condition 3. Differences between static and live wells	• *Define* o *Live wells - both flowing (dynamic) and shut-in* o *Static wells* • *Describe the differences between a static well (BHP is hydrostatically balanced with wellbore fluids) and a live well (BHP is hydrostatically underbalanced with wellbore fluids).*
C. Volumes, Capacities and Displacements 1. Definition of displacement a. Open-ended tubulars b. Close-ended tubulars 2. Definition of capacity a. Coiled tubing string b. Host tubing string c. Annulus (CT & host and host & casing) d. Open hole e. Tanks	• *Define* o *Displacement* o *Capacity* o *Volume* • *Calculate* o *Capacity of tubulars, annulus, etc.* o *Displacement of tubulars, etc.* o *String volume, annulus volume, string displacement, etc.*
D. Force 1. Definition of force 2. Pipe-light operations – snubbing 3. Pipe-heavy operations - stripping 4. Buckling of CT at surface 5. Buckling of CT within the wellbore 6. Buoyancy 7. Differential pressure	• *Define force and buoyancy.* • *Calculate net force effects due to pressure against a surface and due to differential pressure.* • *Calculate buoyancy effects and stripping force.* • *Define snub force and describe forces that must be overcome to push/pull pipe into/out of a pressured well.* • *Recognize situations that may lead to buckling.* • *Demonstrate ability to determine estimated force needed to buckle the coiled tubing between the stripper and lowest fully-supported gripper block.* • *Demonstrate ability to determine estimated force needed to buckle coiled tubing below the stripper assembly (within the wellbore).*

III. INFLUX FUNDAMENTALS

TRAINING TOPICS	JOB SKILLS
A. Definition of a Fluid Influx	• *Define a fluid influx.*
B. Causes of a Fluid Influx 1. Insufficient fluid density 2. Reduction in hydrostatic pressures 3. Swabbing the well 4. Loss of circulation 5. Intentional Influx (well production & Underbalanced Operations)	• *Identify causes of a fluid influx.* • *Explain how the following can result in a fluid influx:* o *Insufficient fluid density* o *Failure to keep hole full* o *Swabbing the well* o *Lost circulation* o *Gas lifting*
C. Fluid Influx Detection 1. Influx indicators and warning signs including, but not limited to: a. Increase in return fluid flow rate b. Gain in tank volume c. Well flowing with pump shut down d. Decrease in pump pressure/increase in pump rate e. Volume displacement change during pipe movement f. Change in surface pressures g. Change in coiled tubing weight h. Oil or gas shows during circulation i. Changes in fluid density	• *Identify indicators and warning signs of a fluid influx.* • *List the indicators and reliability of each (situational dependent).*
D. Importance of Influx Management 1. Manage influx volume 2. Consequences of not managing influx volumes a. Extreme changes in operating pressures b. Possible release of poisonous gases c. Pollution d. Potential for fire e. Loss of life, equipment resources	• *Reinforce need for CT operations to be prepared for influx containment.* • *Identify the benefit of timely response to influx indicators.* • *Identify or describe potential consequences of improper or untimely response to influx indicators.*

IV. GAS CHARACTERISTICS AND BEHAVIOR

TRAINING TOPICS	JOB SKILLS
A. Pressure and Volume Relationship (Boyles Law)	• *Describe pressure and volume relationships for gas.* • *Calculate simple pressure-volume gas relationships.*
B. Gas Expansion and Migration Relationships 1. In the wellbore a. Gas density based on pressure b. Effect on bottomhole pressure c. Effect on surface pressure d. Control of gas expansion	• *Describe the effects of gas migration (controlled expansion, uncontrolled expansion and unexpanded) on surface equipment and downhole pressures.*
C. Solubility of Gases 1. Water based fluid 2. Oil based fluid 3. Effect on influx detection 4. Gas migration	• *Describe the effects of gas solubility on the following:* o *Influx detection* o *Gas migration* o *Gas flashing as flow exits choke line (rapid depressurization)*

V. DRILLING, COMPLETION AND WORKOVER FLUIDS

TRAINING TOPICS	JOB SKILLS
A. Use of Fluids 1. Convey materials into or out of the well 2. Deliver hydraulic energy 3. Stimulation 4. Control pressure 5. Environmental concerns 6. Control fluid loss 7. Minimize formation damage 8. Minimize corrosion	• *Identify the typical uses for fluids pumped during coiled tubing operations.*
B. Liquids 1. Water based fluids a. Water b. Muds c. Brines (selection based on density requirements) d. Gels e. Stimulation fluids – Acids f. CO_2 2. Oil and synthetic based fluids 3. Emulsions and suspensions	• *Describe hazards of working with high-pressure liquids.* • *Describe or demonstrate an understanding of the suction and discharge sections of the liquid pump.* • *Identify various liquid types and their relative densities.* • *Describe why various liquid types would be used.*
C. Nitrogen Gas 1. Safety issues and pumping equipment 2. Single-phase gas 3. Multi-phase a. Nitrofied fluids b. Foamed fluids c. Atomized fluids	• *Describe hazards of working with an energized fluid.* • *Describe or demonstrate an understanding of the cryogenic section, supply loop and pumps on a nitrogen unit.* • *List and describe three activities using nitrogen.* • *Describe the transportation, care and handling of liquid nitrogen.* • *Describe hazards associated with liquid nitrogen.*

TRAINING TOPICS	JOB SKILLS
D. Fluid Properties and Characteristics 1. Density 2. Viscosity 3. pH	• *Describe fluid properties:* o *Density* o *Viscosity*
E. Fluid Flow Behavior 1. Flow rates 2. Frictional pressure losses 3. Fluid flowpath geometry (wellbore/coiled tubing) 4. Flowpath restrictions (wellbore, downhole tools)	• *Describe frictional pressure loss changes due to the following:* o *Density* o *Viscosity* o *Flow rate* o *Well geometry* o *Downhole restrictions* • *Demonstrate capability to recognize frictional pressure loss changes for fluid flow within:* o *Coiled tubing (coiled on the service reel)* o *Coiled tubing (straightened within the wellbore)* o *Coiled tubing X wellbore annuli*
F. Fluid Measuring Techniques and Concerns 1. Techniques a. Conventional and pressurized mud balance b. Rheometers c. Marsh funnel 2. Rheological Concerns a. Effect of temperature b. Settling of solids c. Crystallization d. Hydrates	• *Describe desirable properties of drilling, workover and completion fluids.* • *Describe undesirable properties and how it may effect running/pulling activities* • *Using a mud balance, demonstrate or explain the procedure to measure the density of a fluid.* • *Using a Marsh funnel, demonstrate or explain how to take a funnel viscosity measurement.* • *Describe other techniques for measuring fluid density and viscosity.* • *Describe fluid density changes due to temperature effects.* • *Describe conditions that would lead to settling of solids in the fluid.* • *Define hydrates and describe conditions that would lead to formation of hydrates.*

VI. GENERAL OVERVIEW OF SURFACE AND SUBSURFACE WELLBORE EQUIPMENT

TRAINING TOPICS	JOB SKILLS
A. Production (Christmas) Tree 1. Equipment a. Pressure gauges b. Gauge flange or cap c. Swab valve d. Flow cross or flow tee e. Wing valves f. Master valves g. Surface safety valves 2. Configuration	• *Identify and describe function and configuration of the key christmas tree components.* o *Master, swab and flow line valves* o *Hanger nipple sealing mechanisms* o *Surface safety valve (SSV)* o *SCSSV control line pressure as a function of tubing pressure*
B. Completion Tubulars 1. Ratings a. Burst b. Collapse	• *Identify tubing ratings (burst and collapse).*
C. Completion Equipment 1. Tubing hanger 2. Surface controlled subsurface safety valves (SCSSV) 3. Gas lift mandrels and valves 4. Packers and bridge plugs 5. Landing nipples and tubing plugs 6. Sliding sleeve 7. Multiple completion zones 8. Isolation valves 9. Multi-laterals 10. Multi-string completions 11. Gravel-pack screens, slotted liners, etc. 12. Electric submersible pumps (ESP)	• *Describe the primary function of the sliding sleeves and ported nipples as communication devices.* • *Describe the primary function of side pocket mandrels, either with a working valve (gas lift, circulation, and chemical injection) or with a dummy valve installed.* • *Describe the primary function, restrictions, applications and positioning of surface and sub-surface controlled safety valves:* o *Sub-surface controlled sub-surface safety valves (differential pressure design or ambient pressure design).* o *SCSSV's (wireline retrievable and tubing retrievable)* • *Demonstrate understanding of relationship of intervention tool size versus installed tubing ID restrictions.*
D. Safety Systems and Emergency Shutdown Devices (ESDs)	• *Identify areas on rig or platform where ESDs may be found.* • *Describe the sequence of events once an ESD is activated.* • *Describe the potential consequences to a coiled tubing intervention operation if the ESD is inadvertently activated.*

VII. OVERVIEW OF COILED TUBING EQUIPMENT

TRAINING TOPICS	JOB SKILLS
A. Coiled Tubing Equipment 1. Coiled tubing string 2. Service reel 3. Injector 4. Control console 5. Power units 6. Pumping units (liquid and nitrogen) 7. Stable support structures (stands, masts, cranes, etc.) 8. Compensated support structures (lift frames, motion compensated stands, etc.) – Offshore deepwater training only.	• *Identify and describe general coiled tubing unit components.* o *Tubing* o *Service reel* o *Injector* o *Control cabin (console)* o *Power unit* o *Pumps and circulating system* • *Describe general sizes and types of tubing utilized by coiled tubing units.* • *Describe and identify equipment factors contributing to fatigue and failure of coiled tubing.* • *Describe and identify mechanical causes of damage to coiled tubing.* • *Describe general equipment layout.* • *Describe limitations of equipment.* • *Describe general rig-up of CT and well control equipment on stable support structure.* • *Describe general rig-up of CT and well control equipment on compensated support structure (offshore deepwater training only).*
B. Stripper (Pack-Off) Assemblies 1. Top entry 2. Side door entry 3. Ram type 4. Elastomer types and properties 5. Retainers and inserts 6. Annular equipment	• *Identify the main components and sealing elements. Sealing elements to include function of external seals.* • *Describe or demonstrate how to install sealing elements.* • *Identify and describe the components subject to wear or failure and describe or demonstrate how these may be repaired at the jobsite.* • *Describe the operating principles and limitations of a stripper assembly.* • *Describe effects of well pressure on obtaining pressure seal.*

TRAINING TOPICS	JOB SKILLS
C. Well Control Stack Rams 1. Ram functions (sealing and mechanical): a. Blind b. Shear c. Slip d. Pipe 2. Ram Types a. Single b. Combination (shear-blind or pipe-slip) c. Variable bore d. Shear-seal safety head 3. Ram body types (singles, duals, triples, quads, quints) 4. Fluid inlet/outlet: a. Flow cross or flow tee (and isolation valves) b. Choke line c. Kill line (with isolation and check valves) 5. Equalizer valves	• *Identify and describe function, uses and configuration of key well control stack components.* • *Given well information, identify pressure rating of equipment for specific operations.* • *Describe operating principles and limitations of well control stack.* • *Describe components that may be well-pressure assisted to affect a seal on closure.* • *Describe major components and operating principles of well control stack closing and locking mechanisms.* • *Identify and describe the components subject to wear or failure and describe or demonstrate how these may be repaired at the jobsite.* • *Describe or demonstrate proper installation procedures of sealing elements.* • *Describe and identify the different types of sealing elements from a schematic drawing.* • *Given a well control stack arrangement, be able to state what operations can be performed.* • *Describe or demonstrate the benefits of a shear-blind combination rams versus a blind ram and separate shear ram.* • *Given a scenario, describe what equipment is necessary, and select a suitable well control stack arrangement (e.g., use and placement of shear or shear-blind rams).* • *Describe or demonstrate the correct sequence to shear pipe.*
D. Additional Well Control Equipment 1. Flow Check Devices 2. Bottom Hole Assembly and Connectors 3. Spacer spools and lubricators 4. Pump lines and bleed lines 5. Tanks	• *Define flow check devices.* • *Identify bottomhole assembly components and describe uses and installation.* • *Describe general functions of lubricators and spacer spools and their use.* • *Identify potential risks when using lubricators or spacer spools.* • *Identify net forces acting on lubricators and spacer spools.* • *Identify flow path(s) used in well control operations.* • *Identify locations for choke and kill line valves.*

TRAINING TOPICS	JOB SKILLS
E. Chokes and Choke Manifolds 1. Fixed chokes 2. Manual adjustable chokes 3. Remote adjustable chokes and back-up systems 4. Choke manifolds	• *Describe function and components of a typical choke system.* • *Explain how back-up system(s) to remotely-operated chokes work.*
F. Accumulators 1. Usable fluid volume test 2. Closing time test 3. Accumulator pressure a. Pre-charge pressure b. Minimum system pressure c. Operating pressure d. Maximum system pressure 4. Optional remote or back-up well control stack control panel 5. Calculations for sizing accumulator and usable volume.	• *Demonstrate understanding of the accumulator system functions, calculate the usable liquid volume in the accumulator system and explain the consequences of losing nitrogen pre-charge pressure.* • *Describe the reasons for and procedure used to perform a usable fluid volume test.* • *Assuming a 3,000 psig accumulator system operating pressure, state the following:* o *Typical pre-charge pressure* o *Minimum system pressure* o *Normal stabilized operating pressure* o *Maximum system pressure* • *Demonstrate the ability to operate the well control stack rams from the unit control panel.*
G. Coiled Tubing Limitations 1. Coiled tubing material strengths 2. Ratings a. Burst b. Collapse 3. Coiled tubing bend-cycle fatigue a. Pressure b. Surface damage c. Corrosion d. Mechanical defects/slip marks e. Welds f. Erosion 4. Tensile and compressive load limitations a. Surface buckling b. Plastic collapse	• *Demonstrate understanding that coiled tubing is available in different strength grades.* • *Identify tubing ratings (burst and collapse), including effects of ovality, tensile load or compressive load.* • *Demonstrate understanding of tubing behavior in sour and/or corrosive environments.* • *Describe and identify physical factors leading to fatigue and failure of coiled tubing.* • *Describe and identify mechanical causes of damage to CT.* • *Demonstrate understanding that coiled tubing has a finite operating life (tube body, skelp-end welds and tube-to-tube welds).* • *Demonstrate understanding that excessive tension or compression loads can break the tubing.* • *Demonstrate understanding about effects of ovality on collapse pressure derating of pipe.* • *Demonstrate ability to read a "generic" tubing force analysis graph.*

TRAINING TOPICS	JOB SKILLS
H. Fluid Measuring Devices 1. Volume pumped a. Pump stroke counter b. Rate vs. time 2. Fluid flow indicators (flowmeters) 3. Tank volume totalizer 4. Tank level indicator	• *Describe various fluid measuring devices and their uses:* o *Stroke counter* o *Fluid flow meter* o *Volume totalizer* o *Tank level indicator* o *Coriolis flow meter* o *Vane-type flow meter*
I. Gas Detection and Handling Systems 1. Gas detectors 2. Fluid-Gas separators 3. Degasser	• *Describe functions of fluid-gas separators.* • *Describe function of degasser.* • *Describe function of gas detectors.*

VIII. RIG BLOWOUT PREVENTER EQUIPMENT

TRAINING TOPICS	JOB SKILLS
A. Rig Blowout Preventer Equipment 1. Blowout preventer 2. Annular preventers and strippers 3. Rams a. Blind b. Pipe-multiple string c. Shear d. Shear-blind e. Variable bore pipe and slip f. Sealing elements 4. Valves 5. Configuration	• *Given a rig BOP configuration and coiled tubing well control stack configuration, be able to identify the proper crossovers/adapters that must be utilized.* • *Describe the complications and consequences of coiled tubing operations when rigged up on a rig BOP stack.* • *Given a rig BOP configuration, describe or demonstrate procedures to rig up the coiled tubing well control stack.*

IX. PROCEDURES

TRAINING TOPICS	JOB SKILLS
A. Pre-Recorded Well Information 1. Well configuration a. Top and bottom of completion interval(s) b. Packer/tool locations c. Tubular dimensions, lengths and properties d. Deviation survey (MD, TVD) e. Casing and liner dimensions, lengths and properties 2. Maximum allowable surface pressures a. Wellhead rating b. Casing burst and collapse ratings c. Tubing burst and collapse ratings d. Production zone/perforations e. Other (pump lines and returns lines) 3. Fluid densities in well 4. Reservoir data a. Pore pressure b. Fracture pressure c. Temperature d. Sour/corrosive service	• *Demonstrate ability to document pre-recorded data significant to well control situations (perforation interval, packer locations, tubing strengths, safe working pressures, etc.).* • *Demonstrate ability to document coiled tubing string lengths, strengths, capacities, safe working pressures and fatigue status.*
B. Securing the Well 1. Procedure (steps not necessarily in order) a. Individual responsibilities b. Regain pressure containment c. Secure well d. Notify supervisor	• *List the precautions to be taken when opening a valve under pressure.* • *Understand the necessary procedures when shutting in the well at the christmas tree (e.g., number of turns to close, which master valve to use, ensuring running equipment will not be across the valves etc.).*
C. Well Control Drills 1. Emergency operating contingencies for CT well control equipment failure.	• *Describe the purpose for CT well control drills and proper response.* • *Describe or demonstrate techniques (and sequence of execution) to secure the well for the given operation.* • *Describe or demonstrate the necessary procedures when securing the well with coiled tubing in the hole.* • *Review the CT Well Control Drill Emergency Contingencies (see "CT Operation Contingencies" package).*

TRAINING TOPICS	JOB SKILLS
D. Verification of Secured Well Conditions 1. Annulus/production tubing a. Through well control stack b. At the flowline outlet (on christmas tree) 2. Coiled tubing a. Pump b. Service reel manifold c. Flow check device (if applicable) 3. Wellhead/well control stack/christmas tree a. Casing valve b. Crown/swab, wing, master valves, etc. 4. Manifold a. Manifold valves b. Choke(s) (manual and remote)	• *Identify appropriate valves/well control stack equipment that will be closed to properly secure the well.*
E. Well Monitoring During Operations 1. Record keeping a. Tubing and casing pressures i. At initiation of operations ii. At regular intervals 2. Pressure increase at surface and downhole due to: a. Gas migration b. Gas expansion c. Pressure between casing strings d. Increases in temperature within the wellbore	• *Explain or demonstrate recommended procedures to use for well monitoring during well intervention operations.* • *Demonstrate ability to read, record and report well record keeping parameters.* • *Describe the effects of trapped pressure (below mechanical devices) on operating pressure.* • *Demonstrate procedure for relieving trapped pressure without creating underbalanced conditions.* • *Identify at least two causes for change in pressure between casing strings.*

X. WELL CONTROL TECHNIQUES

TRAINING TOPICS	JOB SKILLS
A. Objectives of Well Control Techniques 1. Well intervention (without killing the well): a. Relies on pressure containment through surface well control equipment. 2. Well intervention (killing the well): a. Circulate formation fluid out of wellbore or bullhead fluid back into formation. b. Establish hydrostatic well control. c. Avoid additional influxes. d. Avoid excessive surface and downhole pressures so as not to induce an underground blowout or lose kill fluids to formation.	• *Explain and list objectives of well intervention well control techniques without killing the well:* o *For operations where well is allowed to flow.* o *For operations where well is not allowed to flow.* • *Explain and list objectives of well intervention well control technique to kill the well:* o *Circulate formation fluid out of well* o *Displace formation fluid back into formation* o *Reestablish hydrostatic control* o *Avoid excessive surface and downhole pressures* o *Avoid additional influxes*
B. Well Intervention Operations (without killing the well): **1.** Use of well control equipment components: a. Stripper assemblies. b. Ram assemblies. c. Choke lines (flow-tee or cross, tree, valves, chokes, etc.) d. Kill lines (through well control stack or tree). e. Downhole flow-check devices in BHA. f. Coiled tubing string.	• *Explain use of well control equipment components commonly used to maintain pressure isolation:* o *Coiled tubing string* o *Stripper assembly* o *Pipe ram* o *Blind ram* o *Pipe-slip ram* o *Shear-blind ram* o *Flow control valves* o *Downhole check-valve(s)* • *Describe or demonstrate proper function of well control equipment components for maintaining pressure isolation within well.*

TRAINING TOPICS	JOB SKILLS
C. Techniques for Killing a Well 1. Well types 2. Bullheading 3. Constant bottomhole pressure (BHP) techniques a. Driller's method (typically preferred method) b. Wait and weight	• *Given a set of wellbore conditions, select the most appropriate control/kill technique(s) for the well type.* o *Gas wells* o *Oil wells* o *Gas/oil wells (with or without shut-in gas cap)* o *Liquid filled wells with and without influx (e.g., completion or workover fluids, muds, etc.).* • *Describe and demonstrate on simulator or through a detailed example, at least two techniques for killing a well.* • *Describe the effects of different kill pump rates on wellbore pressures and on wellbore conditions, consistent with the formation strength, coiled tubing frictional pressure loss, annulus frictional pressure loss, wellbore conditions and fluid-handling capacity of the surface disposal system.*
D. No Returns Pumping Technique (Bullheading) 1. Determine status of shut-in coiled tubing pressure (SICTP), shut-in annular pressure (SIAP). 2. Pump rates and pressure limitations a. Maximum pump pressure b. Frictional pressure loss of pumped fluids vs. rate c. Gain in hydrostatic pressure vs. volume pumped d. Burst pressure of tubulars e. Collapse pressure of tubulars f. Formation injectivity index and fracture pressure 3. Determine volume to be pumped a. Theoretical volume to formation b. Overdisplacement (if any) c. Volume needed to fill surface lines (including CT) 4. Pump rate vs. volume pumped 5. Gas migration vs. pumped fluid velocity 6. Gas migration vs. pumped fluid viscosity 7. Determine if well has been successfully killed	• *Describe and/or demonstrate knowledge and proficiency in the bullhead method:* • *Given shut-in well conditions (accumulated wellbore debris, including sand and wax) together with well and equipment data, explain if the bullheading method should be applied or not.* • *Prepare a pumping schedule for bullheading a given well scenario.* • *Explain need to fill CT with kill fluid prior to conducting simultaneous bullhead pumping operations (through CT and annular space).* • *Calculate the necessary pumping rate for bullheading a gas well for a given well configuration with respect to formation injectivity.* • *Calculate the maximum allowable surface pressure with given well data.* • *Describe gas migration affects in fluids pumped while bullheading.* • *Explain how to minimize gas migration while bullheading using:* o *Pump rates* o *Viscous pills* o *Pumpdown device(s)* • *Describe advantages and disadvantages of overdisplacement.* • *Given a scenario, or simulation/test well exercise, determine if well has been successfully killed.*

TRAINING TOPICS	JOB SKILLS
E. Lubricate and Bleed Method 1. Fluid pressure/volume relationship 2. Pressure management vs. volumetric fluid lost or added 3. Safety margin, working margin and minimum pressures 4. Snubbing considerations	• *Describe and demonstrate on a simulator or through a detailed example, the "lubricate and bleed" well control technique.* • *Calculate the pressure/volume relationship.* • *Describe the difference between safety and working margins.* • *Demonstrate ability to accurately measure volumes bled or added and ability to maintain correct surface pressure(s).* • *Define and determine if pipe light or pipe heavy conditions are present based on a given well scenario.* • *Describe differences in running pipe in/out and choke and/or pump manipulation procedures given well type (i.e., gas, oil, gas/oil, liquid filled with influx, liquid filled without influx, etc.).* • *Describe choke manipulations to achieve pressure / rate objectives.*
F. Constant Bottomhole Pressure (BHP) Methods 1. Well shut-in will stop influx when BHP equals formation pressure 2. Circulating out an influx with choke back pressure to maintain desired BHP 3. Bottom of the workstring must be at the influx formation (or bottom of the well) to effectively circulate the control or kill fluid to displace produced fluids from the well.	• *Describe and demonstrate on a simulator or through a detailed example, a constant bottomhole pressure (BHP) technique.* • *From a schematic, identify proper pump and manifold alignment.* • *Explain how pump/choke manipulation relates to maintaining BHP.*
G. Preparation of Well Control Kill Worksheet 1. Well control calculations a. Tubing and annular volumes, volume per stroke and pumping time. b. Fluid density increase required to balance formation pressure. c. ICP and FCP as appropriate for methods taught. 2. Maximum wellbore pressure limitations a. Surface b. Subsurface 3. Selection of pump rate a. Allowing for frictional pressure losses b. Choke operator reaction time 4. Pump limitations	• *Prepare a well control worksheet for killing a well:* • *Calculate tubing and annulus volumes* • *Determine fluid density increase (if required)* • *Calculate total volume/pump strokes to displace fluid in well.* • *Calculate total volume/pump strokes to circulate the well and time required (as appropriate)* • *Identify wellbore pressure limitations and list consequences of exceeding pressure limitations identified.* • *Select pump rate, considering frictional pressure losses, choke operator reaction time, pump limitations, etc.* • *Review and discuss circulation kill worksheets prepared for a "gas well" and a "horizontal well" (where applicable, the aforementioned worksheets must be represent offshore/deepwater operations).*

TRAINING TOPICS	JOB SKILLS
H. Well Control Procedures 1. Procedure to bring pump on line and change pump speed while holding BHP constant using the choke. a. Use of annulus pressure gauge. b. Lag time response on circulating pressure gauge. 2. Procedure for determining pre-kill circulating pressure (PKCP) and initial circulating pressure (ICP) a. Using recorded shut-in tubing pressure and reduced circulating pressure. b. Without a pre-recorded value for reduced circulating pressure. c. Adjustment for difference in observed vs. calculated circulating pressures. 3. Choke adjustment during well kill operations a. Changes in circulating pressure as a result of changes in hydrostatic head or circulating rates b. Drop in pump pressure as fluid density increases in tubing during well control operations. c. Increase in pump pressure with increased pump rate. 4. Changes in annulus pressure during well control operations a. Adjustments due to fluid velocity changes across the choke b. Adjustments due to changes in fluid type across the choke c. Adjustments due to fluid density change in the annulus 5. Pressure response time a. Annulus pressure gauge (immediate) b. CT pressure gauge (lag time) 6. Procedure for shutting down, shutting in and determining if kill attempt was successful. 7. Shutting down pump while maintaining correct pressure on choke. 8. Observing pressures. 9. Determining change in pressures versus time. 10. Bleeding/venting trapped pressure. 11. Checking for flow.	• *Describe and demonstrate on simulator or through a detailed example, procedures for “Drillers” method or “Wait and Weight” method:* o *The ability to bring pump on and off line using the annulus gauge.* o *The ability to define pre-kill circulating pressure (PKCP), initial circulating pressure (ICP) and final circulating pressure (FCP) and describe where they are used in a well control circulation kill program.* o *The ability to establish correct pre-kill circulating pressure and initial circulating pressure.* o *Obtaining an initial circulating pressure without a pre-recorded reduced circulating pressure.* o *The ability to relate changes in choke position to changes seen on the circulating pump pressure (CT pressure) gauge.* o *The ability to control pressures using a choke while maintaining a constant pump speed given gas expansion and changes in fluid velocity, type and density.* o *The ability to follow the constant bottomhole pressure well control plan using the pump and choke.* o *Describe and/or demonstrate procedures to shut well back in after kill attempt and determine if successful.* o *Describe or demonstrate a procedure to ensure pressures are not trapped after well has been circulated.*

XI. COMPLETION WELLBORE COMPLICATIONS AND SOLUTIONS

TRAINING TOPICS	JOB SKILLS
A. Blockages & Trapped Pressure in Tubing/Wellbore 1. Wireline plugs 2. Subsurface safety valves (storm chokes) 3. Surface controlled subsurface safety valve 4. Bridge plugs 5. Sand bridges 6. Paraffin 7. Hydrates	• *Given specific well data, identify a possible blockage in the well and determine most appropriate well control response.* • *Identify sources of potential trapped pressure.* • *Determine potential pressures beneath various downhole plugs, valves, etc.* • *Describe procedure for resolving sources of trapped pressure identified at left.*
B. Pressure on Casing 1. Hole in tubing 2. Hole in casing 3. Seal or packer leak. 4. Failed squeeze job or patch	• *Identify sources of pressure on casing and explain the well control implications (pressure or temperature change responsible for pulling seals out of sealbore, etc.).*
C. Underground Flow	• *Describe conditions that may lead to flow from one zone into another.* • *Based on wellbore parameters, identify possible solutions to remediate underground flow.*
D. Paraffin	• *Describe the possible effects of paraffin accumulation on well control.* • *Describe how paraffin formation occurs and may be prevented.* • *Include suggestions regarding how to remediate a paraffin plug using coiled tubing solutions.*
E. Hydrates	• *Describe the possible effects of hydrates on well control.* • *Describe how hydrate formation occurs and may be prevented.* • *Include suggestions regarding how to remediate a hydrate plug using coiled tubing solutions.*
F. Lost Circulation	• *Identify signs of lost circulation.* • *List at least two possible remedies to lost circulation.*

XII. COILED TUBING SERVICE COMPLICATIONS AND SOLUTIONS

TRAINING TOPICS	JOB SKILLS
A. Collapsed Coiled Tubing	• *Identify indications of collapsed coiled tubing* • *Describe potential complications and required actions to be taken.*
B. Pneumatically-Controlled Valves	• *Describe how SCSSV's, Surface Master Valves, etc. are controlled by pneumatically-controlled systems. Describe how a pneumatically-controlled system should be operated during coiled tubing operations to avoid inadvertent closure.*
C. Off-Bottom Well Control Operations 1. Junk in Hole 2. Stuck Tool String 3. Hole Angle	• *Identify causes and alternatives available for performing well control operations off bottom due to junk, stuck tools, collapsed tubing, etc.* • *Identify indications of CT becoming stuck in the wellbore.* • *Describe how hole angle and drag affects ability to run to target depth and come out of the hole with CT string.* • *Identify factors that may be used to reduce drag and/or assist in transporting the CT string to target depth.* • *Describe potential complications and required actions to be taken.*
D. Long BHA Deployment Issues 1. Fishing assemblies 2. Perforating assemblies 3. Gravel pack assemblies 4. Isolation assemblies 5. Other long-length BHA's	• *Describe tools, equipment and precautions that must be used while deploying long length BHA's under pressure (lubricator related issues for fishing, perforating guns).* • *Identify potential complications and list possible solutions.* • *Describe well control considerations when performing coiled tubing conveyed wireline and logging operations.*
E. H_2S Considerations	• *Describe additional procedures, precautions training, and supplemental safety equipment necessary while operating in an H_2S environment.* • *Describe limitations, modifications or replacement equipment necessary to work in an H2S environment.*
F. Operations with Specific Well Control Concerns 1. Perforating 2. Acidizing 3. Stimulation (fracturing, energized fluids, etc.)	• *List and describe well control hazards and extra safety precautions for:* o *Unexpected pressures or loss of pressure containing capabilities* o *Tubular failures due to acid attack* o *Mechanical failures due to to N_2 use and the compressive and expansive problems associated with N_2 services.* • *Deployment issues with long BHA assemblies*

XIII. ORGANIZING A WELL CONTROL OPERATION

TRAINING TOPICS	JOB SKILLS
A. Personnel Assignments	• *Identify personnel assignments and those who are required to participate in well control operations.* • *Establish job responsibilities for well control operatons.*
B. Pre-Recorded Information	• *List required information that is available prior to well intervention activities.* • *Describe locations of pre-recorded information, collection process, and where supervisor will keep well documentation.*
C. Plan Responses to Anticipated Well Control Scenarios	• *Describe procedures for implementing responses to well control scenarios.* • *Given certain well information, define most likely well control scenarios.*
D. Communications Responsibilities 1. Planning and outlining routine well control communications 2. Organizing non-routine operation communications	• *Describe the lines of communication and the roles of personnel, including the importance of pre-job on site planning meetings and tourly safety meetings.* • *Analyze and describe the communication modifications that may be necessary because of a non-routine well control operation.*

XIV. TESTING

TRAINING TOPICS	JOB SKILLS
A. Installation of Rings, Flanges and Connections	• *Describe or demonstrate proper installation of rings, flanges and connections.* • *Given a scenario, be able to describe or demonstrate which adapters and connectors are necessary to complete a hook-up using proper pressure ratings, dimensions, ring types, etc.*
B. MAWP and Equipment Function Tests 1. Maximum safe working pressures of well control equipment 2. Areas exposed to both high and low pressures during shut-in and pumping operations	• *Identify the maximum safe working pressure for the well control equipment components.* • *Describe the intended function test to be performed for each well control equipment component.*
C. Well Control Equipment Component Testing 1. Requirements for pressure testing 2. Performing pressure tests	• *Describe pressure-testing procedures for well control equipment components.* • *Identify pressure test frequency as required by local regulatory authority.* • *Describe/identify proper pressure test recorders and piping and demonstrate correct procedures used to pressure test a given well control component.*

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

TRAINING TOPICS	JOB SKILLS
A. Incorporate by Reference 1. API and ISO recommended practices, standards and bulletins pertaining to well control 2. Regional and/or local regulations where required	• *Describe or identify appropriate regional government regulations pertaining to job being completed.*