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PTTCO Drilling Well Control Training Course

1.1 Course objectives

1. To provide participants with a good understanding of drilling operations and maintenance of wells as they relate to safety, including appreciation of the interrelationship between petroleum operations and industrial activities relating to drilling and maintenance of wells;
2. To provide participants with an advanced knowledge of well control equipment, the safe operation of well control equipment and techniques;
3. To provide participants with a good understanding in preventative well control measures, recognition of well control events, measurement of well control parameters and proper response to observations and measurements;
4. To provide participants with a good understanding of closing in Blowout prevention equipment to stop unwanted formation fluids in the wellbore. In the event of unwanted formations fluids entering the wellbore, then gaining understanding in using the various well control techniques in a controlled manner to regain primary well control and dispose of the unwanted fluids safely;
5. To provide practical hands-on training in proper well control procedures during simulated kick situations using a certified simulator; and
6. To increase risk awareness and to present risk mitigation measures.

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1.2 Course duration

1. Five (5) days.

1.3 Number of trainees in a course

1. Maximum of fifteen (15) persons.

1.4 Prerequisites

1. Basic knowledge of Petroleum Field (Drilling)

1.5 Instructor's specific qualifications

1. All instructors are certified by IWCF/IADC for all levels of well control trainings. Instructors are come from engineering background and they possess practical field experience.
2. The course is under the supervision of more than one Instructor all of them are qualified.

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1.6 Course contents

1. Core curriculum include a body of knowledge and a set of job skills that can be used to provide well control skills for industrial operations related to drilling and maintenance of wells activities including Subsea operations;
2. Practical exercises be provided to give participants hands-on experience in implementing and completing the well control techniques and procedures taught in lecture;
3. The Simulator, well facility, etc. being used provide realistic responses and scenarios that a participant would encounter in the field;
4. A minimum of two simulated well control practice exercises be provided for each participant on a properly certified [IWCF/IADC approved] simulator used for the training and assessment; and
5. Course as a minimum cover the following topics:
    a. Well Control Math and definitions, including:
        i. Basic Math;
        ii. Rounding;
        iii. Pressure fundamentals;
        iv. Volume Calculations (Capacities & Displacements); and
        v. Force.
    b. Government, Industry, and Company Rules, Orders and Policies, including:
        i. IWCF, IADC, API and ISO recommended Practices, Standards and Bulletins pertaining to well control;
        ii. Bridging Documents;
        iii. Federal, Regional and / or local regulations where required;
        iv. Policies & Practices;
        v. As an Supervisor, appreciation of the interrelationship between petroleum operations and industrial operations related to drilling and maintenance of wells;
        vi. Crew's Responsibility During Well Control Operations; and
        vii. Minimum Training Requirements.
    c. Well Planning, including:
        i. Formation Pressure;
        ii. Formation Strength;
        iii. Well Planning;
        iv. Leak Off Test (LOT); and
        v. Formation Integrity Test (FIT).
    d. Pressure Concepts and Calculations, including:
        i. Types of pressure Calculations;
        ii. Pressure versus Force calculations;

iii. Conversion of pressure to an equivalent mud weight;
iv. Volume/Height relationship and effect on pressure;
v. Drop in pump pressure as fluid density increases during well control operations;
vi. Maximum wellbore pressure limitations;
vii. Hydrostatic Pressure;
viii. Formation Pressure;
ix. Height of Influx;
x. Gradient of Influx;
xi. Kill Mud Weight;
xii. ICP;
xiii. FCP;
xiv. Strokes / Time;
xv. Pump Strokes / Pressure Relationship; and
xvi. Mud Weight Change / Pressure Relationship.

e. Gas Characteristics and Behavior, including:
   i. Gas types;
   ii. Density, pressure/volume relationship;
   iii. Boyle's Gas Law and Accumulator Calculations:
   iv. Migration & Gas bubble migration;
   v. Gas Expansion and migration relationships;
   vi. Solubility of gases;
   vii. Pressure/Temperature/Compressibility Effects on Fluids/Gases and phase behavior; and
   viii. Solubility in mud.

f. Well Control Principles, including:
   i. Primary Well Control;
   ii. Kick Fundamentals:
      A. Definition of a kick;
      B. Causes of Kicks:
         - Unintentional flow or "kick" from a formation; and
         - Intentional flow or "kick" from a formation.
      C. Kick Detection:
         - Kick indicators;
         - Warning signals that indicate a kick may be occurring or is about to occur;
         - Indications of possible increasing formation pressure;
         - Importance of responding to kick indicators in a timely manner; and
         - Distinguishing kick indicators and warning signals from other occurrences.

iii. Tripping Practices;
iv. Drilling Fluids:
    A. Types of drilling fluids;
    B. Fluid property effects on pressure losses;
    C. Fluid density measuring techniques; and
    D. Mud properties following weight-up and dilution.
v. Secondary Well Control; and
vi. Tertiary Well Control.

g. Procedures, including:
    i. Set/Check Alarm limits;
    ii. Pre-recorded well control information;
    iii. Flow checks, including checks after cementing;
    iv. Shut-in;
    v. Verification of shut-in;
    vi. Well monitoring during shut-in;
    vii. Response to massive or total loss of circulation;
    viii. Tripping;
    ix. Well control drills (types and frequency);
    x. Formation competency;
    xi. Stripping operations; and
    xii. Shallow gas hazards.

h. Well Control Equipment, including:
    i. Well control related instrumentation;
    ii. BOP configuration;
    iii. Manifolds and piping;
    iv. Valving;
    v. Auxiliary well control equipment;
    vi. BOP closing unit – function and performance;
    vii. Testing/Completion pressure control equipment;
    viii. Pressure and function tests;
    ix. Well control equipment arrangements;
    x. Minimum BOP Requirements;
    xi. Minimum Diverter Requirements;
    xii. Closing Units and Accumulator Requirements;
    xiii. Choke and Kill Manifold Requirements;
    xiv. Other Well Control Equipment;
    xv. Well Control Equipment Testing Requirements;
    xvi. Closing and Opening Ratios; and
    xvii. Government Regulations.

i. Actions Upon Taking A Kick, including:
    i. Detecting a Kick;
    ii. Containment as Early as Possible;
    iii. Shut-in Procedures;
    iv. Hang-off Procedure;
    v. Shut-in Period Prior to Well Kill;
    vi. Gas Migration / Review Gas Law;
    vii. Volume to Bleed to Maintain Constant BHP;
    viii. MASP or MAASP; and
    ix. MGS (Mud Gas Separator).
j. Preparation & Prevention, including:
    i. Preparation of Equipment and Materials;
    ii. Well Control Drills;
    iii. Pre-Recorded Information; and
    iv. Kick Prevention During Operations.
k. Well Control/Kill Methods/Techniques, including:
    i. Objectives of well control techniques;
    ii. Techniques for controlling or killing a producing well;
    iii. Preparing for well entry;
    iv. No returns pumping technique (e.g. Bullheading);
    v. Volumetric method/ technique and lubricate & bleed;
    vi. Constant bottomhole pressure (BHP) methods (forward or reverse circulation);
    vii. Example steps for maintaining constant bottomhole pressure well control;
    viii. Driller's Method;
    ix. Wait and Weight Method;
    x. Stripping;
    xi. Preparation of Well control kill worksheet;
    xii. Well control procedures; and
    xiii. Other well control methods.
l. Well Control Complications and Solutions, including:
    i. Complications:
        A. Trapped pressure;
        B. Pressure on casing;
        C. Underground flow;
        D. Cannot circulate well (i.e. plugged workstring, etc.);
        E. Hydrates; and
        F. Lost circulation

m. Specific Environments, including:
   i. Deviated / Horizontal Well Control.
   ii. Shallow Gas / Diverting Procedures;
   iii. Hydrogen Sulphide;
   iv. HP/HT (High Pressure / High Temperature);
   v. Lost Circulation;
   vi. Underbalanced Drilling;
   vii. Slim Hole; and
   viii. Government Regulations.

n. Subsea Operations, including:
   i. Subsea Well Control, including:
      A. Subsea equipment;
      B. Diverter system;
      C. Kick detection issues;
      D. Procedures;
      E. Compensating for hydrostatic head changes in choke lines;
      F. Choke Line Friction Loss;
      G. Gas in Choke Line / Riser;
      H. Riser Margin;
      I. Hydrates;
      J. Trapped Gas / Removal;
      K. Deepwater Well Control; and
      L. Government Regulations.
   ii. Shut-In for Subsea and Deepwater Wells:
      A. Shut-in for subsea wells.
   iii. Subsea and Deepwater Well Kill Considerations, including:
      A. Constant bottom hole pressure methods;
      B. Bullheading;
      C. Number of choke and kill lines;
      D. Volumetric method; and
      E. Dynamic lubrication methods.
   iv. Subsea and Deepwater Well Control – Shallow Flow(s), including:
      A. Shallow flow(s) prior to BOP installation;
      B. Shallow flow detection;
      C. Shallow flow prevention technique, procedures and practices; and
      D. Shallow flow well control methods.
   v. Subsea and Deepwater Well Control – Kick Prevention and Detection, including:
      A. Kick Prevention & Detection; and
      B. Riser gas considerations.

o. Subsea and Deepwater Well Control – BOP Arrangements, including:
   i. Subsea BOP Stack;
   ii. Choke manifold system;
   iii. Subsea control systems; and
   iv. Diverter System – Floating Unit.

p. Subsea and Deepwater Well Control – Riser System, including:
    i. Riser considerations;
    ii. Boost lines; and
    iii. Fill-up valves (dump valve).
q. Subsea and Deepwater Well Control – ROV Interventions, including:
    i. Minimum subsea BOP/ROV intervention functions; and
    ii. Common BOP override functions.
r. Subsea and Deepwater Well Control – Drilling Fluids, including:
    i. Subsea drilling fluid considerations; and
    ii. Fluid storage.
s. Subsea and Deepwater Well Emergency Disconnect, including:
    i. DP emergency disconnect considerations.

6. Special Situations, including:
    a. Hydrogen sulfide (H_2S);
    b. Horizontal well control considerations;
    c. Off bottom kills;
    d. Underground blowouts;
    e. Combination thief and kick zones;
    f. False kick indicators;
    g. Pipe reciprocation during well kill (biaxial loading);
    h. Underbalanced drilling;
    i. Slim-hole well control considerations;
    j. Coiled tubing;
    k. Snubbing;
    l. New well control technology and equipment;
    m. High pressure/high temperature considerations;
    n. Tapered string/tapered hole;
    o. Wellhead component failure points;
    p. Shut-in and circulating kick tolerance;
    q. Small tubing unit; and
    r. Wireline.

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1.7 Course outline

PTTCO Drilling Well Control Course outline		
Subject Area	**Lecture (Hours)**	**Exercises (Hours)**
1. Introduction to drilling operations and Well Control Mathematics	1.0	
2. Government, Industry, and Company Rules, Orders and Policies, including as an Supervisor, appreciation of interrelationship between Petroleum operations and industrial operations related to drilling and maintenance of wells	1.5	
3. Well Planning	1.0	
4. Pressure Concepts and Calculations	1.5	
5. Gas Characteristics and Behavior	1.0	
6. Well Control Principles, including maintenance of wells	2.0	
7. Procedures	1.25	
8. Simulator Exercises	-	3.0
9. Well Control Equipment	2.0	
10. Actions Upon Taking A Kick	1.5	
11. Preparation & Prevention	1.5	
12. Well Control/Kill Techniques	2.0	
13. Simulator Exercises	-	3.0
14. Well Control Complications	1.25	
15. Specific Environments	1.0	
16. Subsea Operations	3.0	
17. Simulator Exercises	-	3.0
18. Special Situations	1.0	
19. Case Studies	1.0	
20. Simulator Exercises	-	
21. Written Exam.	2.0	
22. Simulator Exam.	-	2.5
Sub Total	25.5	14.5
Total	40.0 hours	

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1.8 Course goals and learning objectives

1. Introduction:
    a. Performance Objective: Students will understand the purpose and the objectives of the course and course procedures.
    b. Students will demonstrate understanding of the following:
2. Knowledge of the Government, Industry, and Company Rules, Orders and Policies, including:
    a. Knowledge of IWCF, IADC, API and ISO Practices, Standards and Bulletins pertaining to well control;
    b. Recognize Bridging Documents:
    c. (a) Describe how bridging documents can resolve differences between operator and contractor well control policies (e.g., shallow gas and diverter operations).
    d. Recognize Federal, Regional and / or local regulations where required;
    e. Knowledge of Polices & Practices;
    f. As an Supervisor, recognize the importance of interrelationship between petroleum operations and industrial operations related to drilling and maintenance of wells; and
    g. Recognize Crew's Responsibility During Well Control Operations;
3. Demonstrate the knowledge and skills of Well Planning, including:
    a. Formation Pressure;
    b. Formation Strength;
    c. Well Planning;
    d. Leak Off Test (LOT); and
    e. Formation Integrity Test (FIT).
4. Demonstrate the understanding of pressure concepts and calculations, including:
    a. Types of pressure, including:
        i. U-tube concept and hydrostatic column;
        ii. Define Pressure gradient;
        iii. Define Formation gradient;
        iv. Define and calculate Hydrostatic pressure;
        v. Define and calculate Bottomhole pressure;
        vi. Differential pressure;
        vii. Define Surface pressure and describe its effect on downhole pressures;
        viii. Explain System pressure losses (circulating friction pressure losses);
        ix. Estimate system pressure losses due to pump speed and/or fluid density changes;
        x. "Trapped" pressure;

xi. Casing shoe pressure;
xii. Surge and swab pressures;
xiii. Explain causes and effects of surge pressures on wellbore;
xiv. Calculate Hydrostatic pressure change due to loss of fluid levels and/or fluids with different mud densities (e.g., pills slugs, washes, spacers, etc.);
xv. Static and dynamic calculation of bottomhole pressure; and
xvi. Fracture pressure (leak-off pressure) as defined by API RP 59;

b. Knowledge of the Types of pressure Calculations;
c. Ability to perform the calculations, including:
i. Volume of tanks and pits;
ii. Volume of a cylinder as related to pump output;
iii. Displacement of open and closed pipe;
iv. Annular capacity per unit length;
v. Annular volume;
vi. Hydrostatic pressure
vii. Fracture pressure (as defined by API RP 59);
viii. Formation pressure;
ix. Conversion from pressure to equivalent fluid density;
x. Kill mud weight;
xi. Circulation time;
xii. Bottoms up time for normal drilling;
xiii. Total circulating time, including surface equipment;
xiv. Surface-to-bit time;
xv. Bit-to-shoe time;
xvi. Bottoms up strokes;
xvii. Surface-to-bit strokes;
xviii. Bit-to-shoe strokes;
xix. Total circulating strokes, including surface equipment;
xx. Pump output (look up from chart values only);
xxi. Equivalent circulating density based on annular pressure;
xxii. Relationship between pump pressure and pump speed;
xxiii. Relationship between pump pressure and mud density;
xxiv. Maximum allowable annulus surface pressure;
xxv. Effect of water depth on formation strength calculation;
xxvi. Gas laws PV=K;

xxvii. Weighting material required to increase density per volume;
xxviii. Volume increase due to increase in density;
xxix. Volume to be bled off, corresponding to pressure increase (volumetric method);
xxx. Initial circulating pressure;
xxxi. Final circulating pressure;
xxxii. Riser volume and fluid required to displace;
xxxiii. Choke and kill line volumes;
xxxiv. Choke and kill line strokes;
xxxv. Choke and kill line circulation time; and
xxxvi. Pressure drop per step

d. Understanding of Pressure versus Force calculations;
e. Understanding of Conversion of pressure to an equivalent mud weight:
    i. Required mud weight:
        A. Fluid density increase required to balance formation pressure;
    ii. Equivalent circulating density (ECD), including:
        A. ECD loss during flow check while drilling; and
        B. No ECD loss during tripping flow check.
    iii. Calculate fluid density increase required to balance formation pressure;
    iv. Calculate the effect of circulating friction pressure losses on surface and downhole pressures, including:
        A. Volume/Height relationship and effect on pressure;
        B. Calculate height of a given volume of fluid.
        C. Drop in pump pressure as fluid density increases during well control operations;
        D. Describe why pump pressure drops as fluid density increases during a constant bottomhole pressure method; and
        E. Maximum wellbore pressure limitations:
            - Surface (e.g., wellhead, BOP, casing);
            - Subsurface (e.g., perforations, casing shoe, open hole formation); and
            - Describe the consequences of exceeding maximum wellbore pressure limitations.
        F. Hydrostatic Pressure;

G. Formation Pressure;
H. Height of Influx;
I. Gradient of Influx;
J. Kill Mud Weight;
K. ICP;
L. FCP;
M. Strokes / Time;
N. Pump Strokes / Pressure Relationship; and
O. Mud Weight Change / Pressure Relationship.

5. The knowledge of Gas Characteristics and Behavior, including:
   a. Recognize Gas types, including:
      i. Hydrocarbon;
      ii. Toxic;
      iii. H_2S; and
      iv. CO2.
   b. Knowledge of Density, including:
      i. Gas;
      ii. Gas and mud mixtures;
      iii. Recognize the relatively low density of gas and its effect on the hydrostatic column;
      iv. Describe how the presence of gas affects; wellbore pressure;
      v. Explain the effect of gas cutting on bottomhole pressure and the use of pit level monitoring to recognize hydrostatic loss; and
      vi. Describe the conditions where gas cutting may have little effect on hydrostatic head and bottomhole pressure.
   c. Knowledge of Pressure/volume relationship:
   d. State Boyle's Gas Law and Knowledge of Accumulator Calculations:
   e. Knowledge of Migration & Gas bubble migration, including:
      i. If the well is left shut-in while gas is migrating;
      ii. If the well is allowed to remain open with no control;
      iii. If bottomhole pressure is controlled; and
      iv. Explain the consequences of gas migration.
   f. Knowledge of Gas Expansion and migration relationships, including:
      i. While in well;
      ii. Through surface equipment;
      iii. Explain the relationship between pressure and volume of gas in the wellbore;
      iv. Explain why a gas kick must expand as it is circulated out in order to keep bottomhole pressure constant; and

v. Explain the consequences of gas moving through the choke from a high pressure area to a low pressure area.

g. Knowledge of Pressure/Temperature/Compressibility Effects on Fluids/Gases and phase behavior, including:
   i. Hydrocarbon gas can enter the well in either liquid or gaseous form, depending on its pressure and temperature;
   ii. Hydrocarbon gas entering as a liquid may not migrate or expand until it is circulated up the wellbore;
   iii. Liquids can move down the annulus and come up the drillstring; and
   iv. Describe how hydrocarbon gas may not migrate and the consequences for well control.

h. Knowledge of Solubility of gases and solubility in mud, including:
   i. Combinations of gas and liquid in which solubility issues may apply:
      A. H_2S and water;
      B. CO2 and water;
      C. H_2S and OBM; and
      D. Methane and OBM.
   ii. CO2 and OBM;
   iii. Gases dissolved in mud behave like liquids;
   iv. Identify combinations of gas and liquid which may result in solubility issues (H_2S and water, CO2 and water, H_2S and OBM, methane and OBM, CO2 and OBM);
   v. Describe the difficulty of detecting kicks with soluble gases while drilling and/or tripping;
   vi. Describe how dissolved gas affects wellbore pressures when it comes out of solution; and
   vii. Describe the sequential consequences of gas evolving from the mud system.

6. Demonstrate the knowledge of Well Control Principles, including:
   a. Primary Well Control;
   b. Kick Fundamentals:
      i. Definition of a kick, including:
         A. Ability to define two types of kick: unintentional and intentional.
      ii. Recognize Causes of Kicks, including:
         A. Unintentional flow or "kick" from a formation;
            - Failure to keep hole full;
            - Swabbing effect of pulling pipe:

        - Hole and pipe geometry;
        - Well depth;
        - Mud rheology;
        - Hole conditions and formation problems;
        - Pipe pulling and running speed; and
        - BHA configuration;
    - Loss of circulation;
    - Insufficient density of drilling fluid, brines, cement, etc.;
    - Abnormally pressured formation;
    - Lowering pipe too rapidly into hole (surge);
    - Annular gas flow after cementing;
    - Identify causes of unintentional kicks;
    - Describe the piston effect (suction and how increased drag may be associated with swab);
    - Describe the effect of the items at left on surge and swab pressures; and
    - 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.

Intentional flow or "kick" from a formation:

- Drill stem test;
- Completion; and
- Identify causes of intentional kicks.

Kick Detection:

Knowledge of Kick indicators and Identify kick indicators; including:

- Gain in pit volume (rapid increases in fluid volume at the surface);
- Increase in return fluid-flow rate (with no pump strokes per minute increase);
- Well flowing with pump shut down;
- Hole not taking proper amount of fluid during trips; and

- Well monitoring and alarm devices:
    - Pit volume totalizers (PVT);
    - Relative flow increase.

Warning signals that indicate a kick may be occurring or is about to occur, including:

- Drilling rate change;
- Trip, connection, and background gas change;
- Gas-cut mud;
- Water-cut mud or chloride concentration change;
- Decrease in circulating pressure or increase in pump strokes; and
- Identify kick warning signals.

Indications of possible increasing formation pressure, including:

- Cuttings size and shape:
    - Torque;
    - Drag;
    - Fill;
    - Volume of cuttings; and
    - Appearance of sloughing shale.
- Temperature changes;
- Gas levels;
- Change in flow rate or mud properties of drilling fluid;
- Other pore pressure indicators;
- Rate of penetration increase; and
- Recognize and explain how the conditions listed above are associated with well control.

Importance of responding to kick indicators in a timely manner, including:

- Minimize:
    - Kick size;
    - Surface pressures; and
    - Lost operations time.
- Consequences of not responding:
    - Kick becomes blowout;
    - Release of poisonous gases;
    - Pollution; and

    - Fire
- Identify the importance of early detection and the consequences of not responding to a kick in a timely manner.

Distinguishing kick indicators and warning signals from other occurrences, including:

- Increases in pit level:
    - Surface additions; and
    - Flow from formation.
- Decreases in pit level:
    - Solids control;
    - Dumping mud; and
    - Lost circulation.
- Drilling rate changes:
    - Rate of penetration (ROP) as a function of weight on bit, formation type, RPM, and pump rate;
    - Drilling break (rapid increase in ROP);
    - Rapid decrease; and
    - Associate change in ROP with changes in formation.
- Gas cut mud and/or gas in drilled cuttings;
- Identify the causes of changes in pit level; and
- Identify drilling rate changes.

Tripping Practices;

Drilling Fluids:

Types of drilling fluids:

- Identify types of drilling fluids, including:
    - Water based mud;
    - Oil based mud (OBM), synthetic oil based mud (SOBM);
    - Cement; and
    - Completion fluids.

Explain how fluid properties affect pressure losses, including:

- Density;
- Viscosity; and
- Changes in mud properties due to contamination by formation fluids.

Fluid density measuring techniques:

- Mud balance;
- Pressurized mud balance; and
- Measure fluid density.

Mud properties following weight-up and dilution:

- Gel strengths;
- Plastic viscosity and yield point (PV and YP); and
- Explain the effects of weighting-up and diluting fluid on gel strength, PV and YP.

Secondary Well Control; and

Tertiary Well Control.

Demonstrate the knowledge of Procedures, including:

Knowledge of Set/Check Alarm limits:

High and low pit level;

Return flow sensor;

Trip tank level;

Others (i.e., H_2S and flammable/explosive gas sensors).

Demonstrate the procedures for setting well control monitoring indicators, including, where applicable, the items listed above.

Recognize Pre-recorded well control information, including:

Standpipe pressure at slow pump rates;

Well configuration;

Fracture gradient;

Maximum safe casing pressures:

Wellhead rating;

Casing burst rating;

Pipe/Tubing collapse; and

Subsurface weak zone (optional);

Identify appropriate pre-recorded information;

Record standpipe pressure at slow pump rate;

Read at choke console; and

Recognize an error in gauge readings based on discrepancies between readings.

Flow checks, including checks after cementing:

While drilling – normal flow back;

While tripping – well is hydrostatically balanced (no ECD loss considerations);

While drilling – normal flow back;

While drilling – abnormal flow back;

- Loss of equivalent circulating density (ECD) – pumps off;
- While tripping – well is hydrostatically balanced (no ECD loss considerations);
- Use and purpose of trip sheet;
- Describe the procedure to perform a flow check in the situations listed above;
- 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; and
- Demonstrate understanding that the primary indicator of influx is the trip sheet (hole fillup) rather than flow check.

Knowledge and skills for Shut-in, including:

- While drilling:
  - Individual responsibilities;
  - Pick up (with pump on);
  - Space-out;
  - Shut pump off;
  - Flow check;
  - Close-in BOP;
  - Close choke; and
  - Notify supervisor.
- While tripping:
  - Individual responsibilities;
  - Close off drillstring bore given variety of tubular used;
  - Close BOP; and
  - Notify supervisor.
- While running casing:
  - Individual responsibilities;
  - Install device to stop potential flow through casing;
  - Close appropriate BOP or divert as appropriate;
  - Close choke as applicable; and
  - Notify supervisor.
- While cementing:
  - Individual responsibilities;
  - Space out, including consequences of irregular tubular lengths;
  - Shut pump off;
  - Close BOP;
  - Close choke; and
  - Notify supervisor.
- During wireline operations:

Individual responsibilities; and
Close BOP with consideration for cutting/closure around wire.
During other rig activities:
Individual responsibilities;
Use of surface equipment to shut-in well;
Close choke; and
Notify supervisor.
Verification of shut-in:
Annulus:
- Through BOP;
- At the flow line.

Drillstring:
- Pump pressure relief valves;
- Standpipe manifold.

Wellhead/BOP:
- Casing valve (not applicable to subsea stack);
- Broaching to surface (outside of wellbore).

Choke manifold:
- Choke;
- Overboard lines.

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 above;

List differences between the Soft vs Hard methods of well control as defined by API RP 59 for both levels (see API RP 59); and

For any shut-in, verify well closure by demonstrating that the flow paths listed at above are closed.

Knowledge and skills for Well monitoring during shut-in, including:
Recordkeeping:
Time of shut-in;
Drillpipe and casing pressures:
- At initial shut-in; and
- At regular intervals.

Estimated pit gain;

Principles of bleeding volume from a shut-in well:

Trapped pressure:

- Causes;
- Relief of.

Pressure increase at surface and downhole from:

- Gas migration;
- Gas expansion.

Determining shut-in drillpipe pressure when using a drillpipe float;

Effects of density differences from gas, oil, or salt water kick on surface pressures;

Situations in which shut-in drillpipe pressure exceeds shut-in casing pressures:

Cuttings loading;

Inaccurate gauge readings;

Density of influx fluid greater than drilling fluid;

Flow through drill string; and

Blockage downhole.

Maximum safe annulus pressure;

Pressure between casing strings;

Explain or demonstrate recommended procedures to use for well monitoring during shutin;

Read, record, and report well shut-in recordkeeping parameters;

Identify at least two causes of trapped pressure;

Describe the effects of trapped pressure on wellbore pressure;

List two consequences on surface pressure resulting from shutting-in on a gas vs a liquid kick of equivalent volume;

Perform choke manipulation to achieve specific pressure or volume objectives;

Demonstrate procedure for relieving trapped pressure without creating underbalance;

If a float valve is in use (ported or non-ported), demonstrate the procedure to open the float to obtain shut-in drillpipe pressure;

List two situations in which shut-in drill pipe pressures would exceed shut-in casing pressures;

List hazards if closed-in annulus pressure exceeds maximum safe pressure;

Describe at least one method for controlling bottomhole pressure (BHP) while gas is migrating;

- Identify two causes of pressure between casing strings; and
- Describe potential hazard(s) of pressure trapped between casing strings and actions required.

Response to massive or total loss of circulation, including:

- During drilling, fill annulus with fluid in use;
- Notify supervisor immediately;
- Use of bridging materials (e.g., cement, gunk plugs, lost circulation materials, etc.);
- Elimination of overbalance;
- Identify at least two methods of responding to massive or total loss of circulation during a well kill operation; and
- Upon observing loss of circulation, perform the actions listed at above.

Tripping, including:

- Procedures used for keeping hole filled:
  - Using rig pump;
  - Using trip tank; and
  - Using recirculating trip tank (continuous fill).
- Methods of measuring and recording hole fill volumes;
- Procedure and line up to keep hole filled;
- Wet trip calculations:
  - Return to mud system;
  - No return to mud system.
- Dry trip calculations;
- Slugs;
- Trip margin:
  - Measure hole fill-up;
  - Recognize discrepancy from calculated fill-up;
  - Take appropriate action:
    - At flow, go to shut-in;
    - At no flow and short fill-up, go back to bottom.
- Procedure and line up to keep hole filled;
- Calculate correct fill volumes:
  - Wet trip;
  - Dry trip.
- Explain trip margin;
- Explain the effect of slugs on hole fill up;
- Measuring displacement volumes while tripping into hole:
  - With check valve in drillstring;
  - Without check valve in drillstring.
- Perform the items listed at above with regard to hole fill up on trips; and

Demonstrate, explain, or perform the actions listed at above with regard to tripping.

Well control drills (types and frequency), including:

Pit drills;

Trip drills;

Personnel evacuation;

Diverter drills as they relate to shallow gas hazards; and

Describe the steps involved in conducting the types of drills listed at above.

Formation competency, including:

Pressure integrity test (testing to a specific limit);

Leak-off test (testing to formation injectivity);

Interpret data from formation tests;

Effect of fluid density change as applicable:

Leak-off test (at least one method)

- Calculate equivalent mud weight for leak-off test pressure

Formation pressure integrity test

- With check valve in drillstring

Prepare the well for leak-off testing;

Describe or perform proper hook-up and procedures for conducting a formation leak-off test or competency test for a given configuration;

Identify from a plot the point at which leak-off begins;

Describe or perform the leak-off test and formation pressure integrity test; and

Describe how formation competency test results may be affected by fluid density change.

Stripping operations, including:

Line up for bleeding volume to stripping tank;

Stripping procedure through BOP;

Measurement of volume bled from well;

Calculations relating to volumes and pressures to be bled for a given number of drillstring stands run in the hole;

Stripping with/without volumetric control;

Define the following aspects of stripping: purpose, suitability, and method; and

Demonstrate stripping procedures listed at above.

Shallow gas hazards, including:

Mechanisms and timing of events;

Kill procedures:

Shut-in;

Use of diverters:

- With drillpipe;
- Running casing.

Riserless drilling.

Pilot holes;

During and after cementing conductor and surface casing;

Setting barite or cement plugs;

Explain why it is relatively easy to become underbalanced at shallow depths (e.g., hole sweeps, gas cutting, swabbing, lost circulation);

Explain the limited reaction time for kick detection;

Explain the well control procedural options available (i.e., shut-in vs. divert);

Explain the use of pilot holes;

Describe the technique or procedure for preparing and setting barite or cement plugs;

Describe the difference between diverting and conventional well kills;

Describe the difference between diverting and conventional well kills;

List at least two conditions under which the use of a diverter may be applicable; and

List at least two potential hazards when using a diverter.

Demonstrate the knowledge of the Well Control Equipment, including:

Knowledge for Well control related instrumentation, including:

Fluid pit level indicator;

Fluid return indicator;

Pressure measuring equipment and locations:

Locations:

- Standpipe pressure gauge;
- Drillpipe pressure gauge;
- Pump pressure gauge; and
- Casing pressure gauge (also referred to as choke manifold or annular pressure gauge).

Range and accuracy.

Mud pump/Stroke counter;

Mud balance and pressurized mud balance;

Gas detection equipment:
H_2S;
Flammable/Explosive gases.
Drilling recorder:
Pit volume (number of barrels of fluid in the pit);
Flow rate;
Rate of penetration (ROP);
Pressure;
Strokes per minute (SPM);
Mud weight; and
Depth recorder.
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.

Knowledge for BOP configuration, including:
Components (See API RP 53, most recent version):
Annular preventer;
Ram preventers/elements:
- Blind;
- Blind/Shear;
- Pipe;
- Variable bore pipe; and
- Ram elements.

Drilling spool or integral body; and
Valves.
Functions;
Demonstrate basic understanding of the use of ram and annular preventers;
Identify flow path for normal drilling operations;
Identify flow path for well control operations;
Identify areas exposed to high and low pressure during shut-in and pumping operations;
Identify and confirm line-up for equipment pressure testing, shut-in, and pumping operations;
Demonstrate ability to shut-in the well in the event of primary equipment failure;
Given a BOP stack configuration, identify potential flow paths for kill operations;

Given a BOP stack configuration, identify shut-in, monitoring, and circulation operations which are possible and those which are not; and

Given a BOP stack configuration, select an appropriate BOP to effect closure on a given tubular.

Knowledge of Manifolds and piping, including:

Standpipe;

Choke.

Knowledge of Valving, including:

BOP stack;

Drillstring:

Full opening valves (DPSV, kelly cock, Kelly valve);

Check valves; and

Float valves – advantages and disadvantages.

Choke manifold:

Adjustable choke:

- Hydraulic (remote operated);
- Manual.

Fixed choke; and

Valves to direct flow.

Mud pressure relief;

Describe opening and closing a full-opening safety valve;

Describe the difference in use between a full-opening safety valve and a check valve (e.g., inside BOP);

Be able to identify compatibility of thread types;

Distinguish the function of the choke from that of other valve types;

Define the function of a choke;

Describe the function of adjustable chokes, both manual and hydraulic; and

Identify changes in valve positions resulting from opening or closing the diverter.

Knowledge of Auxiliary well control equipment, including:

Mud/Gas separator:

Gas blow-through;

Vessel rupture.

Mud pits:

Suction pit;

Return pit;

Mixing equipment.

Degasser;

Trip tank:

Gravity feed;

Recirculating type.
Top drive systems:
Kelly valves, lower;
Spacing out;
Shutting-in;
Stripping.
Define function, operating principles, flowpaths, and components of mud-gas separators;
List two possible consequences of overloading the mudgas separator and explain the appropriate corrective actions;
Describe pit alignment during well control operations(e.g., vacuum degasser, flaring);
Describe the procedures for handling of gas in return fluids (e.g., vacuum degasser, flaring);
Describe the characteristics of a trip tank (e.g., small cross-section, accurate fluid volume measurements); and
Describe considerations when using top drive systems.
Demonstrate the knowledge and skills for BOP closing unit – function and performance:
Usable fluid volume test:
Gas blow-through;
Vessel rupture.
Closing time test;
Accumulator pressure:
Pre-charge pressure;
Minimum system pressure;
Operating pressure; and
Maximum system pressure.
Adjustment of operating pressure:
Manifold pressure regulator;
Annular pressure regulator.
Operating functions:
Regulator;
Unit/Remote switch;
By-pass valve; and
Accumulator isolator valve.
Demonstrate understanding of the function of the accumulator system, including an explanation of the consequences of losing nitrogen pre-charge pressure;
Identify major components of a BOP control system;
Describe the reasons and procedure for a usable fluid volume test;

State, for a 3000 psi system, the pre-charge pressure, minimum system pressure, normal regulated operating pressure, maximum system pressure;

List two reasons for adjusting regulated annular operating pressure;

Demonstrate the ability to operate the BOP from the driller's panel and the remote control panel; and

Diagnose simple functional problems.

Knowledge for Testing/Completion pressure control equipment, including:

Packers;

Lubricators;

Christmas trees;

Test trees; and

Explain use of testing and completion well control equipment.

Knowledge of Pressure and function tests, including:

Maximum safe working pressure:

Pressure ratings of all equipment;

Reasons for de-rating; and

Areas exposed to both high and low pressures during shut-in and pumping operations.

General emphasis on quality maintenance practices:

Correct installation;

Maintenance;

Wear and replacement requirements; and

Rings, flanges, and connectors.

Emphasis on quality testing practices;

Procedures for function and pressure testing all well control equipment:

Function and testing of high pressure well control equipment:

- BOP stack;
- Manifolds; and
- Auxiliary well control equipment.

Function and testing of low pressure well control equipment:

- Mud-gas separator;
- Fluid/Gas pathways.

Pressure or function testing of diverter systems;

Identify the maximum safe working pressure for a given set of well control equipment upstream and downstream of the choke;

List at least two reasons for possible de-rating of the working pressure of the well control equipment;

Describe correct installation, maintenance, wear, and replacement requirements, and describe rings, flanges, and connectors; and

Perform, explain, or demonstrate function and testing of high pressure well control equipment, low pressure well control equipment, and diverter systems.

Knowledge of Well control equipment arrangements, including:

General arrangements for BOP, valving, manifolds, and auxiliary equipment (applicable to both written and practical testing):

BOP, manifold plug, and valve line-up:

- For drilling operations;
- For shut-in;
- For well control operations; and
- For testing;

Identify the flow path for well control operations;

Identify areas exposed to high and low pressure during shut-in and pumping operations;

Identify and confirm line-up for equipment pressure testing, shut-in, and pumping operations;

Demonstrate ability to shut-in the well in the event of primary equipment failure;

Demonstrate the correct alignment of standpipe and choke manifold valves, including downstream valves for the the following conditions:

Drilling operations;

Shut-in;

Well control operations;

Testing.

Minimum BOP Requirements;

Minimum Diverter Requirements;

Closing Units and Accumulator Requirements;

Choke and Kill Manifold Requirements;

Other Well Control Equipment;

Well Control Equipment Testing Requirements;

Closing and Opening Ratios; and

Government Regulations.

Demonstrate the knowledge and the skills for Actions Upon Taking A Kick, including:

- Detecting a Kick;
- Containment as Early as Possible;
- Shut-in Procedures;
- Hang-off Procedure;
- Shut-in Period Prior to Well Kill;
- Gas Migration / Review Gas Law;
- Volume to Bleed to Maintain Constant BHP;
- MASP or MAASP; and
- MGS (Mud Gas Separator).

Demonstrate the knowledge and skills for the Preparation & Prevention, including:

- Preparation of Equipment and Materials;
- Well Control Drills;
- Pre-Recorded Information; and
- Kick Prevention During Operations.

Demonstrate the knowledge and skills for Well Control/Kill Methods/Techniques, including:

- Objectives of well control techniques, including:
  - Circulate kick safely out of the well;
  - Re-establish primary well control by restoring hydrostatic balance;
  - Avoid additional kicks; and
  - Avoid excessive surface and downhole pressures so as to prevent inducing an underground blowout.
- Techniques for controlling or killing a producing well;
- Preparing for well entry;
- No returns pumping technique(e.g. Bullheading);
- Volumetric method/ technique and lubricate & bleed;
- Principles of Constant bottomhole pressure(BHP) methods (forward or reverse circulation), including:
  - Shutting-in well will stop influx when bottomhole pressure (BHP) equals formation pressure:
    - Close choke and observe pressure gauges (SIDPP + SICP = 0 psi);
    - If hydrostatic balance is restored, open BOPs and check for flow;
    - Resume operations.
  - Circulating out a kick by maintaining enough choke back pressure to keep bottomhole pressure equal to or slightly greater than formation pressure;
  - 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;

Explain how pump and choke manipulation relates to maintaining constant bottomhole pressure;

Read, record and report drillpipe and annulus pressures; and

List the phases of at least one constant bottomhole pressure well control method.

Example steps for maintaining constant bottomhole pressure well control: Driller's Method & Wait and Weight Method:

Well control and kill – calculations and procedures:

Proficiency in both constant bottomhole pressure well control methods – Driller's and/or Wait & Weight Method:

- Bring pump up to slow kill rate while opening choke;
- Maintain surface pressure while circulating according to method;
- Increase mud weight in pits to kill weight;
- Line up pump to kill mud;
- Line up choke manifold and auxiliary well control equipment;
- Pump kill weight mud until kill mud completely fills the wellbore;
- Circulate until all kicks are removed from well;
- Shut off pumps;
- Close choke and observe pressure gauges (SIDPP + SICP = 0 psi);
- If hydrostatic balance is restored, open BOPs and check for flow; and
- Resume operations.

Preparing the killsheet:

- Organize the specific responsibilities of the rig crew during a well control/kill operation;
- Demonstrate proficiency in implementing both the Wait & Weight and Driller's Methods;

- Read, record and report drillpipe and annulus pressures;
- List the phases of at least one constant bottomhole pressure well control method;
- Explain how these steps relate to maintaining bottomhole pressure equal to or greater than formation pressure;
- 6. Demonstrate proficiency in at least one constant bottomhole pressure well control method (Driller to act under the direction of Supervisor); and
- Demonstrate or describe the process of organizing the specific responsibilities of the rig crew during the execution of a well kill operation.

Stripping;

Preparation of Well control kill worksheet, including:

Well control calculations:

- Drillstring and annular volumes;
- Fluid density increase required to balance increased formation pressure;
- Initial and final circulating pressure as appropriate for method(s) taught.

Maximum wellbore pressure limitations:

- Surface; and
- Subsurface.

Selection of a kill rate for pump:

- Allowing for friction losses;
- Barite delivery rate;
- Choke operator reaction time;
- Pump limitations; and
- Surface fluid handling capacity.

Correctly fill out a kill sheet for one well control method;

Determine weight up material required and corresponding volume increase;

Describe the consequences of exceeding maximum wellbore pressure at surface and subsurface; and

Identify factors affecting selection of kill rate for pump.

Well control procedures, including:

Procedure to bring pump on and off line and change pump speed while holding bottomhole pressure constant using choke:

Use of casing pressure gauge; and

Lag time response on drillpipe pressure gauge.

Initial circulation pressure:

Using recorded shut-in drillpipe pressure and reduced circulating pressure;

Without a pre-recorded value for reduced circulating pressure; and

Adjustment for difference in observed vs. calculated circulating pressure.

Choke adjustment during well kill procedure:

Changes in surface pressure as a result of changes in hydrostatic head or circulating rates:

- Drop in pump pressure as fluid density increases in drillstring during well control operations; and
- Increase in pump pressure with increased pump rate and vice versa.

Pressure response time:

- Casing pressure gauge (immediate); and
- Drillpipe pressure gauge (lag time).

Handling of problems during well control operations:

Pump failure;

Changing pumps;

Plugged or washed out nozzles;

Washout or parting of drillstring;

BOP failure:

- Flange failure;
- Weephole leakage;
- Failure to close; and
- Failure to seal.

Plugged or washed out choke;

Fluid losses;

Flow problems downstream of choke;

Hydrates;

            - Malfunction of remote choke system;
            - Mud/Gas separator;
            - Problems with surface pressure gauges; and
            - Annulus pack-off.
        - Considerations if using a diverter;
        - Demonstrate bringing pump on and off line and changing pump speed while holding bottomhole pressure constant using choke;
        - Determine correct initial circulating pressures;
        - Operate choke to achieve specific pressure objectives relative to selected constant bottomhole pressure methods;
        - Describe why pump pressure drops as fluid density increases during a constant bottomhole pressure method; and
        - Given a scenario detailing a well control problem, identify the problem and demonstrate or describe an appropriate.
    - Other well control methods, including:
        - Volumetric, including lubrication/bleed:
            - During drilling;
            - During well testing/completion.
        - Bullheading:
            - During drilling;
            - During well testing/completion.
        - Reverse circulation during well testing/completion;
        - Reasons for selecting the specific well control methods;
        - Assumptions and limitations of methods; and
        - Demonstrate proficiency in control/kill methods including volumetric with lubrication and bleeding, bullheading, etc.
- Demonstrate the knowledge and skills for Well Control Complications and Solutions, including:
    - Complications:
        - Trapped pressure:
            - Wireline plugs;
            - Subsurface safety valves (storm chokes);
            - Surface controlled subsurface safety valve;
            - Bridge plugs;
            - Sand bridges;
            - Paraffin;
            - Hydrates;
            - Beneath packer;

Identify sources of potential trapped pressure;
Determine potential pressures beneath various downhole plugs, valves, etc.; and
Describe procedure for resolving sources identified at left.

Pressure on casing:
Hole in tubing;
Hole in casing;
Seal or packer leak;
Pressure or temperature pulled seals out of seal bore;
Failed squeeze job or patch; and
Identify sources of pressure on casing and explain the well control implications.

Underground flow:
Based on surface parameters, identify underground flow and possible solutions.

Cannot circulate well (i.e., plugged workstring, etc.):
List three reasons why a well cannot be circulated and a solution for each.

Hydrates:
Describe the possible effects of hydrates on well control; and
Describe how hydrate formation may be prevented.

Lost circulation:
Identify signs of lost circulation; and
List at least two possible remedies to lost circulation.

Demonstrate the knowledge and skills for Specific Environments, including:
Deviated / Horizontal Well Control;
Shallow Gas / Diverting Procedures;
Hydrogen Sulphide;
HP/HT (High Pressure / High Temperature);
Lost Circulation;
Underbalanced Drilling;
Slim Hole; and
Government Regulations.

Demonstrate the knowledge for Subsea Operations, including:
Demonstrate the knowledge and skills for Subsea Well Control, including:
Subsea equipment:
Marine riser systems:

- Drilling with riser; and
- Drilling without riser.

BOP control systems:

- Block position;
- Pilot system; and
- Subsea control pods.

BOP stack:

- Lower marine riser package (LMRP);
- Configuration; and
- Ram locks.

Ball joint;
Flex joint;
Slip joint;
Riser dump valve;
Identify and describe the function of each system described at above;
State how to activate ram locks;
Describe reasons for drilling with and without riser; and
Describe operating principles of subsea BOP stack control system.

Diverter system:

Configuration and components;
Diverter line size and location;
Line-up for diversion:

- Valve arrangement and function;
- Valve operational sequence; and
- Limitations of the diverter system.

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

Kick detection issues:

Vessel motion;
With and without riser;
Riser collapse;
Water depth (BOP placement); and
Describe how the items listed at left affect kick detection.

Procedures:

Choke and/or kill line friction:

- Measurement of choke and/or kill line friction;
- Compensating for choke and/or kill line friction:
  - Static kill line;
  - Casing pressure adjustment.

Removing trapped gas from BOPs:

- Use of bleed lines;
- U-tubing of trapped gas.

Clearing riser:

- Gas in riser;
- Displacing riser with kill weight mud.

Hydrostatic effect of riser disconnects and re-connects;

Spacing and hang-off;

Effect of depth on formation competency;

Define or describe the effect of fluids of different densities in the choke and kill lines for both levels;

Explain consequences of trapped gas in subsea BOP system;

Describe specific procedure for removing trapped gas from the BOP stack following a kill operation;

Describe killing a subsea riser with kill mud and the consequences of failure to fill riser with kill mud after circulating out a kick;

Describe possible consequences of trapped gas removal in terms of well behavior or riser without riser margin; and

Describe steps necessary to space out drillpipe and hang-off using motion compensator, ram locks, etc.

Compensating for hydrostatic head changes in choke lines:

Demonstrate ability to adjust circulating pressures to compensate for choke line friction;

Demonstrate ability to adjust choke appropriately to compensate for rapid change in hydrostatic pressure due to gas in long choke lines.

Choke Line Friction Loss;

Gas in Choke Line / Riser;

Riser Margin;

Hydrates:

(a) Identify possible complications caused by hydrates.

Trapped Gas / Removal;

Deepwater Well Control; and

Government Regulations.

Demonstrate the knowledge regarding Shut-In for Subsea and Deepwater Wells:

- Shut-in for subsea wells:
  - Pre-kick preparation;
  - Hard shut-in vs. soft shut-in;
  - Annular shut-in vs. ram shut-in;
  - Shut-in while drilling;
  - Shut-in while tripping;
  - Shut-in while making a connection;
  - Shut-in with bit above BOPs;
  - Shut-in while running casing/liner;
  - Masking of choke pressure by high gel strength in C&K lines;
  - Reading shut-in drill pipe pressure;
  - Demonstrate the ability to shut in the well in a timely manner to minimize influx after observing positive flow indicators;
  - For any shut-in, verify well closure by demonstrating the flow paths are closed; and
  - Describe how choke pressure readings are affected in deepwater by the high gels of the mud in the choke and kill lines.

Demonstrate the knowledge and skills for Subsea and Deepwater Well Kill Considerations, including:

- Constant bottom hole pressure methods, including:
  - Driller's method;
  - Wait and weight method;
  - Demonstrate proficiency in implementing both the Wait & Weight and the Drillers Method;
  - Identify differences in using either of these methods in subsea environment.
- Bullheading, including:
  - Identify when bullheading should be used in lieu of constant bottom hole pressure methods;
  - Demonstrate proficiency in implementing a bullheading procedure.
- Number of choke and kill lines, including:
  - Explain how the number of choke and kill lines can affect circulating well kill methods.
- Volumetric method:
  - Explain differences in volumetric methods for subsea.

Dynamic lubrication methods:
Explain dynamic lubrication of gas below subsea BOP stack.

Demonstrate the knowledge and skills for Subsea and Deepwater Well Control–Shallow Flow (s), including:

Shallow flow(s) prior to BOP installation:
Shallow water flow;
Shallow gas;
Describe the mechanisms that can result in shallow flow; and
Discuss difficulty in controlling flows, emphasis must be placed on detection, prediction and prevention.

Shallow flow detection:
Shallow flow indicators;
Shallow flow detection methods and equipment;
Explain how shallow flows can be detected, e.g.:
during drilling;
while running casing; and
during/after cementing.

Shallow flow prevention technique, procedures and practices:
Describe ways to prevent shallow water and shallow gas flows.

Shallow flow well control methods:
Shallow water flow;
Shallow gas;
Lost circulation and formation breakdown;
Explain how to implement shallow water kill procedures;
Explain how to implement shallow gas kill procedures; and
Explain how to implement lost circulation and/or formation breakdown procedures.

Demonstrate the knowledge and skills for Subsea and Deepwater Well Control – Kick Prevention and Detection, including:

Knowledge of Kick Prevention & Detection, including:
Early kick detection:
- Drilling data analysis;
- Pressure detection services;
- Pressure transition management;
- General practices to managing pressure;
- Drilling fluid analysis;

- Simulated connections; and

Mud gas levels.

Tripping practices:

- Circulating trip gas.

Subsea Circulating Practices;

Connection and rotating practices;

Ballooning;

Explain why subsea kick detection is more difficult;

Describe how a leak-off test should be conducted in subsea operating environments;

Explain why early kick detection is necessary in deepwater operating environments;

Explain reasons for pressure transition problems in deepwater;

Describe how pressure detection services can detect kicks or lost circulation;

Describe "best practices" to managing pore and fracture pressures in deepwater drilling environments; and

Describe practices used to identify ballooning vs. wellkicks.

Knowledge of Riser gas considerations, including:

Danger of free gas in riser;

When to apply gas in riser procedures;

Considerations for handling gas in riser:

- Alternatives for handling riser gas;
- Riser circulation timing (1/4, ½, ¾, etc.).

Explains the risks and hazards of free gas in the riser;

Demonstrate proficiency in implementing procedures for handling riser gas;

Explain the usage of the diverter system in handling riser gas; and

Explain the benefits of having:

- riser mud gas separator, and
- riser boost lines.

Demonstrate the knowledge and skills for Subsea and Deepwater Well Control – BOP Arrangements:

- Subsea BOP Stack:
  - BOP Arrangements;
  - Placement of rams/outlets;
  - Moored and dynamic positioned rig;
  - Hang-off;
  - BOP instrumentation arrangements;
  - External loading of BOP equipment;
  - Hot stab requirements;
  - 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; and
  - Describe BOP instrumentation preferred for deepwater.
- Choke manifold system:
  - Overboard / mud gas separator bypass;
  - Strip tank tie-in;
  - Low pressure gauges;
  - Hydrate inhibition;
  - 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; and
  - Explain the importance of displacement fluids required to be displaced into choke/kill lines in deepwater.
- Subsea control systems:
  - Direct hydraulics;
  - Multiplex;
  - Acoustics;
  - 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; and

Explain “usable” fluid.

Diverter System – Floating Unit:

Configuration and components;

Diverter line size and location;

Line-up for diversion:

Valve arrangement and function;

Valve operational sequence; and

Limitations of the diverter system.

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

Demonstrate the knowledge and skills for Subsea and Deepwater Well Control – Riser System, including:

Riser considerations:

Design;

Operating characteristics;

Describe and identify key components required for a riser management system; and

Describe and identify riser design and operating characteristics:

- Collapse;
- Buoyancy; and
- Tension Loading.

Boost lines:

Explain how the use of boost lines affects the kick detection process.

Fill-up valves (dump valve):

Describe the purpose of a fill-up valve; and

List two situations where the use of a fill-up valve is required.

Demonstrate the knowledge and skills for Subsea and Deepwater Well Control – ROV INTERVENTIONS, including:

Minimum subsea BOP/ROV intervention functions:

Hot stab plug considerations;

ROV capabilities; and

Explain how an ROV can be used in well control intervention.

Common BOP override functions:

Identify common override functions and how they can be used to effect efficient well control.

Demonstrate the knowledge for Subsea and Deepwater Well Control – Drilling Fluids:

Subsea drilling fluid considerations, including:

Temperature effects;

Hydrates;

Identify how the drilling fluid properties affect:

- Losses and fracture propagation;
- Ballooning;
- Equivalent circulating densities;
- Temperature stability;
- Gas solubility (OBM, SBM);
- Leak-off tests (OBM, SBM);
- Fluid compressibility (OBM, SBM);
- Riser margin; and
- Hydrate formation, prevention and removal, e.g., glycol addition.

Explain the effect of the low temperature on the pressure losses in the choke and kill lines.

Fluid storage:

Weighted systems for shallow water flow kill;

Barite storage/mixing capacities and rates;

Kill weight mud; and

Describe how barite storage, kill weight mud storage, and the rig's mud mixing system can be used to control shallow water flows.

Demonstrate the knowledge and skills for Subsea and Deepwater Well Emergency Disconnect:

DP emergency disconnect considerations, including:

Yellow/Red alert considerations;

Emergency disconnect sequence functions;

Autoshear and deadman systems;

Acoustic back-up systems;

List two situations that would call for an emergency disconnect on a dynamically positioned rig; and

List the consequences of a Failure to Disconnect.

Demonstrate the knowledge and skills for Special Situations, including:

Hydrogen sulfide (H_2S):

Risks encountered in well control operations involving H_2S:

Toxicity;

Potential for explosion;

Corrosivity; and

Solubility.
Well control handling options:
Bullheading; and
Circulation with flaring.
Identify risks associated with H_2S;
Specify crew responsibilities; and
Identify well control options, including bullheading and circulation with flaring.
Horizontal well control considerations:
Influx detection;
Off bottom kill;
Special kill sheet;
Explain the following considerations related to horizontal well control:
Any kill sheet modifications;
Influx detection;
Procedure for off bottom kill;
Gas behavior in horizontal section; and
Pressurized drilling equipment.
Off bottom kills:
Explain off bottom kills.
Underground blowouts:
Indications of underground flow:
At shut-in;
During kill.
Demonstrate how to recognize loss of formation integrity during shut-in or circulation.
Combination thief and kick zones:
Thief zone on top, kick zone on bottom;
Kick zone on top, thief zone on bottom; and
Explain problems and procedural responses for combination thief and kick zone.
False kick indicators:
Kelly cut;
Background gas;
Bottoms up with OBM;
Fluid transfer; and
Describe false kick indicators.
Pipe reciprocation during well kill (biaxial loading):
Explain procedure for pipe movement during well kill.
Underbalanced drilling:
Producing while drilling;
Pressurized drilling equipment:
Rotating annular;
Rotating head.

Explain well control procedures for underbalanced drilling.

Slim-hole well control considerations:

Explain well control concerns during slim-hole drillling.

Coiled tubing:

Explain well control during coiled tubing operations.

Snubbing:

Explain well control during snubbing operations.

New well control technology and equipment;

High pressure/high temperature considerations;

Tapered string/tapered hole;

Wellhead component failure points:

- Casing hangers;
- Casing isolation seals; and
- Connections and fittings.

Shut-in and circulating kick tolerance;

Wireline; and

Small tubing unit.

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