From: Shaughnessy, John M.
Sent: Thu Jun 11 13:09:55 2009
To: Sprague, Jonathan D; Skelton, Jake
Subject: Well Control STP
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Attachments: GP 10-10 - Well Control STP June 11 09.doc

Jon, Jake,

Attached is what I would propose to roll out as our STP. The Group Practice is very perscritive. The 22 page document had 198 "Shall" commands/rules. Based on the way we work in the SPU I believe that 142 of those SHALLs should be changed to "Should". As is, we routinely operate outside the GP rules.

My modifications of the document left the shall in place, but crossed out and the "should" is shown in orange. I thought this made it easier to see what the GP intended, but where the SPU practices are in conflict.

Let me know if this approach seems reasonable or if you would like further editing.

I will be on vacation tomorrow until June 29.

John
Ext7254
<<...>>

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GP 10-10

Well Control

~~Group Practice~~
GOM DW STP

**BP GROUP
ENGINEERING TECHNICAL PRACTICES**

Foreword

This is the second issue of Engineering Technical Practice (ETP) BP GP 10-10. This Group Practice (GP) is based on parts of the BP Drilling and Well Operations Policy (BPA-D-001), and, for the subject matter covered herein, supersedes that document.

Table of Contents

Page

Foreword 2

Introduction 5

1. Scope 6

2. Normative references 6

3. Terms and definitions 6

4. Symbols and abbreviations 8

5. Well Control Training & Preparation 9
   - 5.1. General Requirements 9
   - 5.2. Training & Certification 9
   - 5.3. Well Control Preparation 9

6. Well Control Practices 10
   - 6.1. General Requirements 10

7. Conventional Well Control Equipment 11
   - 7.1. General Requirements 11
   - 7.2. Equipment Modifications, Changes & Repairs 12
   - 7.3. Configuration: Drilling Diverter Equipment 12
   - 7.4. Configuration: Surface Drilling, Completion, Conventional and Hydraulic Workover BOP Stacks 13
   - 7.5. Configuration: Subsea Drilling, Completion & Workover BOP Stacks 14
   - 7.6. Configuration: Rod Pump Pressure Control Equipment 15
   - 7.7. Other Well Control Equipment 15

8. Wireline Operations 17
   - 8.1. General Requirements 17
   - 8.2. Configuration: Well Control Equipment 17
   - 8.3. Well Control Processes 17

9. Coiled Tubing Operations 18
   - 9.1. General Requirements 18
   - 9.2. Configuration: Well Control Equipment 18
   - 9.3. Well Control Processes 18

10. Snubbing Operations 19
   - 10.1. General Requirements 19
   - 10.2. Configuration: Well Control Equipment 19
   - 10.3. Well Control Processes 19

11. Additional Considerations 20
   - 11.1. Coring 20

12. Pressure Testing 20
   - 12.1. General Requirements 20
   - 12.2. Pressure Testing of Well Control Equipment 20

Revision History........21

Introduction

Priorities for safety when planning and undertaking drilling and well operations shall be, in order of importance:

- Personnel
- Environment
- The Installation
- Reservoir Integrity
- Well Delivery

This ETP forms part of the contractual relationship between BP and its service providers.

Detailed statements are contained elsewhere within this document for specific activities.

1. Scope

This ETP covers the essential systems, practices and training requirements that comprise the BP well control standard. Methods and practices for detecting the flow of formation effluent into the well bore, shutting the well in, circulating out the unwanted formation effluent, diverting flow away from personnel and restoring the well to a stable operating condition are described. Industry and BP procedures that are considered to be best in class and essential practice for all personnel involved in drilling, completion and well work activities are presented in detail. In addition to basic well control techniques, specialized well control practices for wireline, coil tubing, snubbing, intervention operations and coring are included.

2. Normative references

The following normative documents contain requirements that through reference in this document constitute requirements of this GP. Requirements not referenced in this document are not requirements of this technical GP. Detailed guidance to practices for safe and effective well control is covered in the following BP Global documents:

BP

BPA-D-001	BP Drilling and Well Operations Policy
BPA-D-002	Well Control Manual
BPA-D-003	Casing Design Manual
GP 10-15	Pore Pressure Prediction
GP 10-16	Pore Pressure Monitoring
GP 10-20	Shallow Hazards
GP 10-35	Well Operations
GP 10-36	Breaking Containment
GP 10-40	Drilling Rig Audits and Rig Acceptance
GP 10-45	Working with Pressure
GP 10-60	Zonal Isolation Requirements during Drilling Operations and Well abandonment

API

API RP 53	Blowout Prevention Systems, 3rd Edition
API RP 59	Well Control Operations
API RP 64	Diverter Systems Equipment and Operations
API Spec 16C	Choke & Kill Systems
API Spec 16D	Control Systems for Drilling Well Control Equipment
API Spec 16R CD	Specification for Drill through Equipment – Rotating Control Devices

3. Terms and definitions

For the purposes of this GP, the following terms and definitions apply:

Safety Critical

Having the potential to cause personal injury, environmental damage, property damage or loss of reputation

Safety Critical Software

Software, the output of which is safety critical. For purposes of this document safety critical software is to include but not limited to all well control and well bore design software.

BOP

Blowout Preventer - a conditional surface / subsurface pressure barrier often consisting of a set of hydraulically operated rams containing equipment designed to grip pipe, seal around pipe, shear off pipe or seal an open hole during drilling or workover operations. The BOP components may include an annular preventer; ram type preventers, valves, spools and other specific pieces of equipment.

Tree

Christmas tree - the control sections that sit above the wellhead. It may contain hangers, master valves, annular valves, wing valves, and gauges or pressure, flow rate or monitoring equipment.

Wellhead

The part of the wellbore surface / subsurface equipment providing interface between the casing strings and annuli to the tree and casing/tubing outlets

Well Work

Well intervention operations performed after the initial completion, with a service, conventional or hydraulic workover rig and for the purpose of repairs, re-completions, workover, pulling rods for pumps, tubing change outs, etc., where hoisting and well control are essential.

Well Work Unit

Rigs with masts and hoisting capabilities for handling completion strings and jointed pipe

Coiled Tubing Unit

Coiled tubing is an upstream operations using specialized equipment, pipe and qualified personnel to control pressure and the movement a continuous string of pipe and tools in or out of the wellbore using a coiled tubing injector under or over balanced.

Snubbing Unit

Snubbing is an upstream operation using specialized equipment and qualified personnel to control pressure and the movement of jointed tubulars and tools in or out of wellbore using snubbing equipment while under-balanced.

Hydraulic Workover Unit (HWO)

HWO units shall be defined as specialized snubbing type units which are configured to perform the movement of tubulars and tools in or out of wellbore while employing conventional workover BOP configurations as the contingent barrier and a stable column of fluid to balance well pressures as the active barrier.

Contingent Barrier

During balanced drilling, conventional and hydraulic workover activities contingent barriers shall be defined as: blowout preventer equipment (BOPE). E.g. ram and annular / spherical type BOPE and down hole float equipment

During under-balanced drilling, wireline, snubbing and coiled tubing intervention activities contingent barriers shall be defined as: redundant blowout preventer equipment (BOPE) not required for stripping and tree. E.g. redundant ram and annular/spherical type BOPE configured to allow support primary means of pressure containment and conveyance of tools for required intervention.

Intervention
Activities that involves entering the pressure containing environment of the well. This includes drilling, well work, wireline, coiled tubing, snubbing, conventional and hydraulic workover operations, and tree and well head operations.

Active Barrier
During balanced drilling, conventional and hydraulic workover activities active barriers shall be defined as: a stable column of fluid equal to or greater than bottom hole pressure.

During under-balanced drilling, wireline, snubbing and coiled tubing intervention activities active barriers shall be defined as: dynamic mechanical sealing device. E.g. wireline packoff, grease injector, stripping rubber, rotating head, mechanically assisted differential sealing back pressure valve, annular or stripper rams – provided 100% redundancy is used.

4. Symbols and abbreviations

For the purpose of this GP, the following symbols and abbreviations apply:

AEUB	Alberta Energy and Utilities Board
API	American Petroleum Institute
BHA	Bottom Hole Assembly
BOP	Blow Out Preventer
BOPE	Blow Out Preventer Equipment
CT	Coiled Tubing
HPHT	High Pressure High Temperature
H_2S	Hydrogen Sulphide
HWO	Hydraulic Work Over
IWCF	International Well Control Forum
IADC	International Association of Drilling Contractors
MAR	Major Accident Risk
OC	Operating Centre
PM	Preventative Maintenance
SPA	Single Point of Accountability
TA	Technical Authority
VR	Valve Removal

5. Well Control Training & Preparation

5.1. General Requirements

Each BU shall designate a well control TA responsible for fulfilment of expectations set out in this ETP. Said TA is not required to reside within the respective BU and may be designated outward. Additionally, individual well control SPAs' may be designated within each PU as required by the BU. Each SPA [redacted] should notify the designated BU TA of any well control issues. Additionally, each BU TA [redacted] should notify and address all significant well control issues with the Segment TA.

5.2. Training & Certification

All BP drilling and well operations personnel, and personnel acting on behalf of BP, who are directly involved in planning and execution of BP drilling and well operations, plus any contractor personnel who may take control of well activities (such as toolpushers, drillers, assistant drillers, subsea engineers and service unit operators) shall have a valid and recognized well control certificate.

5.2.1 Valid and recognized well control certification authorities include IWCF, IADC, AEUB and others that may be designated by the Segment well control TA upon request by the BU.

5.2.2 Well control certifications shall be renewed at periods not exceeding twenty-four (24) months.

5.2.3 BUs shall be adequately prepared to remediate any well control event through the use of a Well Control Response Guide and the BP Well Control Manual. Framework of each well control response guide shall required endorsement of the Segment well control TA.

5.2.4 All BP personnel and personnel acting on behalf of BP, who are directly involved in the planning and execution of BP drilling and well operations, ~~shall~~ should be trained and competent in participation of a Well Control Response Guide.

5.3. Well Control Preparation

5.3.1 All drilling operations involving static fluid level designs; bore protectors or wear bushings ~~shall~~ should be installed in the wellhead during all drilling operations. The wellhead design ~~shall~~ should take this into account. If operations preclude the use of bore protectors or wear bushings this policy may be relaxed after completions of a documented risk assessment and BU well control TA or designate approval.

5.3.2 For conventional drilling operations, the kick tolerance of the weakest known point of the hole section being drilled ~~shall~~ should be updated continuously while drilling and reported on all BP daily drilling reports. This requirement for kick tolerance calculation applies to drilling of all hole sections after the first pressure containment string has been set.

5.3.3 Kick tolerance is defined as the maximum volume of kick influx that can be circulated out of the well without breaking down the formation at the open hole weak point. Kick tolerances are to be calculated as described in the Well Control Manual.

5.3.4 On all wells the design kick tolerance ~~shall~~ should be greater than 25 bbl based on maximum anticipated pore pressure and planned mud weights. This policy may be relaxed only after a documented risk assessment, approved by the BU well control TA or designate and conditional under the following conditions:

- Confirmation of a good cement job
- Open hole formations in infield drilling areas are known to be normally or sub-normally pressures based on established history
- Losses are expected in the target areas
- Where air or under balanced fluids are the primary circulating medium

- Before any unshearable component enters the BOP stack

5.3.5 The calculation updating requirement and the 25 bbl volume requirement may be relaxed after a documented risk assessment, and approval of the BU well control TA or designate and conditional upon indications of a good cement job, under any of the following conditions:

- Open hole formations in infield drilling areas are known to be normally or sub-normally pressured based on established history.
- Losses are expected in the target based on established history in infield drilling areas.
- Where air or under-balanced fluids are the primary circulating medium.

5.3.6 All drilling breaks ~~shall~~ should be flow-checked and reported to the BP designated company representative, based on criteria established between the BP designated company representative and the driller or service unit operator.

5.3.7 Balanced drilling and conventional and hydraulic workover operations, involving static fluid column designs, as a minimum, ~~shall~~ should be perform flow checks while tripping out of hole:

- Before pulling off bottom.
- After pulling into the casing shoe.
- Before the BHA enters the BOP stack.

5.3.8 Balanced drilling, conventional and hydraulic workover operations, involving static fluid level designs, trip sheets ~~shall~~ should be filled out by the driller / operator on every trip in and out of the hole. Any deviation from expected hole fill up volumes ~~shall~~ should be investigated based on criteria provided by the BP designated company representative.

5.3.9 Slow circulating rates ~~shall~~ should be taken every tour, each time a BHA change is made, when significant mud properties change and 500 feet of new hole is drilled. Choke line frictions will also be considered.

6. Well Control Practices

6.1. General Requirements

6.1.1 Tested BOPE shall be installed for drilling operations below the surface casing shoe.

6.1.2 The BOP stack and wellhead in place at any point during the course of the well, shall be of sufficient working pressure and temperature rating to contain the maximum allowable surface pressure and temperature from total depth of the current open hole section.

6.1.3 The maximum allowable wellhead pressure shall *be calculated based on accepted practices in the region taking all known offset information from the area drilling* ~~take~~ into account ~~a gas column to surface for exploration and appraisal wells, whilst for development wells reservoir fluid shall be used~~.

6.1.4 In balanced drilling, conventional and hydraulic workover operations involving static fluid column designs, the designated company representative shall be present prior to each trip to flow and loss check the well and then directly observe the trip until satisfied the wellbore fluid level is stable and the hole fill volume is correct.

6.1.5 In unconventional operations without static fluid levels, the designated company representative shall observe the pre-trip well conditions and assure themselves that the well will behave in accordance with expected norms for the planned operations.

6.1.6 After completing all well kills or well testing operations, the designated company representative shall be present to flow and loss check the well and directly observe the trip until such time as they are satisfied that the wellbore fluid level is stable and/or the hole is safe to trip prior to pulling out of the hole.

6.1.7 Kick detection, diverter, circulating, stripping, and shut-in drills ~~shall~~ should be held regularly until the designated company representative is satisfied that each crew demonstrates suitable BP standards.

6.1.8 Thereafter kick detection and shut-in drills ~~shall~~ should be performed at a minimum of once per week per crew and be reported in the Daily Report form.

6.1.9 A shut-in method ~~shall~~ should be established, communicated and practiced which minimizes influx and impact to the wellbore. Line and valve configurations ~~shall~~ should be planned, communicated and regularly checked by the driller or service unit operator and position confirmed with the BP well site leader or his designate.

6.1.10 The driller / operator is responsible for and authorized to shut the well in. The designated company representative shall be the only person authorized to initiate opening the well as part or conclusion of well control measures.

6.1.11 Except during under balanced drilling, a drilling well kick sheet ~~shall~~ should be maintained and updated for immediate use in the event of a well control event.

6.1.12 A well control incident report ~~shall~~ should be completed and documented within the Tr@ction reporting system following any well control incident.

6.1.13 At least one contingent barrier i.e. down hole float valve ~~shall~~ should be included on any casing string run through a hydrocarbon-bearing formation. *The need to run auto-fill casing where risks of lost circulation due to hole surge from a "closed" casing shoe is recognized as an advantage and will be accepted where necessary.*

6.1.14 Differential fill float equipment ~~shall~~ should not be used on casing strings which are to be run through potential hydrocarbon-bearing zones. This policy may be relaxed after a documented risk assessment and approval of the BU well control TA or designate.

6.1.15 Auto fill float equipment ~~shall~~ should be tripped prior to running through any hydrocarbon bearing zone, *except where a risk assessment has been performed and approved.*

6.1.16 For all exploration, HPHT and H2S appraisal wells a well specific Well Control Response Guide ~~shall~~ should be prepared.

6.1.17 A well control interface / bridging document ~~shall~~ should be prepared with the appropriate contractor to ensure there is clear understanding of responsibilities and which reference documents and procedures will be used in a well control situation.

6.1.18 Each BU ~~shall~~ should ensure that well control response guides are maintained in every supporting OC and base office and emergency drills regularly conducted and reported. These guides ~~shall~~ should address the availability of a means of quickly evacuating the well site and responding to an event.

6.1.19 During well construction and maintenance activities, operations ~~shall~~ should be conducted with one active barrier and one contingent barrier installed to address critical operational risks and contain the well. *Riserless drilling operations are an exception to this guideline.*

6.1.20 During conventional drilling, completions and well work activities the active barrier shall normally be a stable fluid column and the contingent barrier shall be the blowout preventer (BOP) equipment or tree. During under-balanced drilling, wireline, snubbing and coil tubing intervention activities, the active barrier shall normally be a dynamic mechanical sealing device and the contingent barrier shall be the BOP or tree.

7. Conventional Well Control Equipment

7.1. General Requirements

The requirements of this section ~~shall~~ should apply to all well control equipment used in drilling and well operations. They represent the general requirements to mitigate Major Accident Risk

(MAR) potential. These requirements ~~shall~~ should be exceeded for higher risk activities which may result, for example, from a combination of factors such as under-balanced drilling, coil tubing drilling, H2S, etc. Conversely and except in offshore operations, the requirements may warrant relaxation in lower risk activities or areas where the MAR is demonstrated to be below Group reporting limits and/or compliance with these requirements increases personal exposure to risk. Still other, special risk activities employed in several BP operating areas are not detailed in these requirements including air drilling, stripping, temporary stimulation tree/surface configurations

In either the high, low or special risk cases mentioned above, the operating unit ~~shall~~ should develop the relevant procedures based on risk assessment, the general context of these requirements and with reference to appropriate industry guidance and the BP Well Control Manual.

7.1.1 Systematic documented risk assessments and procedures ~~shall~~ should be required to confirm the suitability of all contingent barriers other than BOP's and trees. Such contingent barriers include but are not limited to cement plugs, packers and storm valves.

7.1.2 For all exploration and appraisal drilling operations, an independent recordable means of monitoring wellbore conditions ~~shall~~ should be used.

7.1.3 When conducting all offshore drilling and well operations, emergency power arrangements ~~shall~~ should be set up to enable operation of the cementing unit, the BOP control panel and ancillary services for well control contingency purposes. *This guideline is not intended for dynamic positioned vessels.*

7.1.4 All hammer-lock unions ~~shall~~ should be positively identified as to manufacturer, service and pressure rating prior to assembly and use. Additionally equipment ~~shall~~ should be able to demonstrate actual Preventative Maintenance (PM) performed. Controls ~~shall~~ should be in place to ensure direct interconnection of different types, pressure ratings and manufactures is avoided.

7.1.5 The BOP, choke manifolds and associated equipment (i.e., equipment that is flow wetted and pressure containing) ~~shall~~ should always be designed for an H2S environment in areas where the probability of any H2S exists, i.e., 'H2S trim'. In areas where the presence of H2S can not be determined H2S equipment ~~shall~~ should be employed.

7.2. Equipment Modifications, Changes & Repairs

7.2.1 All modifications, design changes or weld repairs to well control equipment ~~shall~~ should comply with appropriate API specifications, manufactures specifications or government regulations, whichever is more stringent.

7.2.2 Only original equipment manufacturers' designated spares ~~shall~~ should be used for blowout preventer equipment (BOPE) replacement parts. Where older, out-of-service equipment models dominate the industry in an operating area, after-market replacement parts that meet the original manufactures specifications are acceptable provided a documented risk assessment is completed and approved by the BU well control T A.

7.2.3 Ring joint gaskets with metal-to-metal sealing are preferred, but suitably qualified alternatives with elastomer backup are permissible where a documented risk assessment reveals no life-of-well integrity issues and approved by the BU well control TA or designate.

7.3. Configuration: Drilling Diverter Equipment

7.3.1 Diverter equipment ~~shall~~ should be installed and operational to manage shallow hazard potential as specified in GP 10-20 (Shallow Hazards). Diverter systems ~~shall~~ should only be considered as a means of controlling unexpected shallow hazards which have not been identified from site specific surveys. All offshore well locations ~~shall~~ should have a shallow hazard assessment. Where this survey identifies possible shallow hazards, the location ~~shall~~ should be moved to avoid the anomaly.

7.3.2 Where a riser and diverter system is to be used, the equipment ~~shall~~ should be evaluated and the diverter system shown to be adequate for the likely diversion scenario utilizing the possible pressure and fluid regime anticipated.

7.3.3 The pressure rating and sizing of all diverter system pipe work and valves ~~shall~~ should be shown to exceed anticipated pressures for a likely diversion scenario and to minimize the risk of broaching from the casing shoe.

7.3.4 Where a riser and diverter system is to be used, the formation strength at the casing shoe ~~shall~~ should be sufficient to avoid an underground flow.

7.3.5 The diverter control system shall be sequenced to ensure that a side outlet is open and the shale shaker valve is closed prior to the diverter element closing.

7.3.6 On closing the diverter element, flow shall be confined to the designated diverter lines only.

7.3.7 In cases where rupture discs are used, the diverter line valve, if installed, shall remain locked and tagged open.

7.3.8 The diverter control system shall operate all necessary valves and close the diverter element within 30 seconds for systems with a nominal bore of 20 inches or less. For systems with greater than 20 inch bore, the operating time shall not exceed 45 seconds.

7.3.9 The diverter control panel shall be located adjacent to the driller's / operator's position, with a second control panel located in a designated safe area.

7.3.10 Diverter lines shall be designed or audited to API RP-64. Diverter lines on offshore units shall have a minimum internal diameter of 12 inches. Diverter lines for onshore drilling operations shall have a minimum internal diameter of 8 inches. All diverter line valves and lines shall be full opening and designed as straight as possible. Where rig designs require, targeted turns will be allowed after a documented risk assessment is performed and approved by the BU well control TA or designate.

7.3.11 Upon installation and prior to drilling hole sections where diverting is the planned means of well control the diverter system shall be function tested and, subject to local environmental constraints, the diverter lines flushed. Thereafter, the diverter system ~~shall~~ should be function tested at least once every seven (7) days. Diverter lines with rupture discs ~~shall~~ should be inspected only and results recorded.

7.3.12 Offshore rigs ~~shall~~ should have dual diverter line systems.

7.3.13 Any diverter vent line ~~shall~~ should terminate in a safe location.

7.4. Configuration: Surface Drilling, Completion, Conventional and Hydraulic Workover BOP Stacks

7.4.1 As arranged from top to bottom, the minimum BOP configuration shall be required for wells where a wellhead pressure up to and including 3,500 psi is possible, is:

- One annular preventer
- Two ram type preventers, the upper most shall be blind or blind shear
- Outlets for choke and kill lines shall be positioned above the lower most set of pipe rams

7.4.2 As arranged from top to bottom, the minimum BOP configuration shall be required for wells where a wellhead pressure of over 3,500 psi is possible, is:

- One annular preventer
- Two ram type preventers, the lower of which shall be blind or blind shear
- Outlets for choke and kill lines
- One pipe ram

7.4.3 Stripper heads are an acceptable alternative to the annular preventer for onshore well work applications provided a documented risk assessment is completed and approved by the BU well control TA or designate. If used offshore for under balanced workovers, a stripper head shall be supplemental to an annular preventer.

7.4.4 For offshore operations sealing shear rams shall be installed.

7.4.5 All surface BOP stacks shall incorporate at least one choke line and one kill line which enter the stack above the lowermost set of pipe rams.

7.4.6 Kill and choke lines installed below the lowermost set of rams or wellhead other outlets shall be used for pressure testing or monitoring the well only.

7.4.7 The BOP stack shall contain a pipe ram that can close on every size of drill pipe, casing and tubing that comprises a significant length of the total string. Where tubular accessories (e.g. cables, clamps, screens etc) may compromise a shear ram or pipe ram seal, then appropriate procedures and contingencies shall be in place to mitigate this risk.

7.4.8 Where multiple similar rams are fitted, the lowermost ram shall be preserved as a master component and ~~shall~~ should only be used to close in the well when no other ram is available for this purpose or for the purpose of upper BOP repairs or re-configuration.

7.4.9 Dual, full-opening valves ~~shall~~ should be provided on each choke and kill line for all stacks. The outer valve on the choke line ~~shall~~ should be remotely activated. The outer valve on the kill line ~~shall~~ should either be a remotely operated or a non-return valve ~~shall~~ should be fitted.

7.4.10 Each ram type preventer ~~shall~~ should have a functional ram locking device fitted.

7.4.11 The standpipe manifold and cement manifold ~~shall~~ should have double valve isolation from the kill line.

7.4.12 Accumulator test ~~shall~~ should be carried out in accordance with the requirements set out in the well control manual.

7.5. Configuration: Subsea Drilling, Completion & Workover BOP Stacks

7.5.1 As arranged from top to bottom, the minimum BOP configuration ~~shall~~ should be required for wells where a wellhead pressure up to and including 5,000 psi is possible, is:

- One annular preventer that is retrievable on the lower marine riser package.
- Three ram type preventers.
- Outlets for choke and kill lines.

There shall be a minimum of one kill line and one choke line connected to the BOP stack.

7.5.2 As arranged from top to bottom, the minimum BOP configuration ~~shall~~ should be required for wells where a wellhead pressure of over 5,000 psi is possible, is:

- Two annular preventers, one of which is retrievable on lower marine riser package. ***Note the Discoverer Enterprise is equipped with only one annular. It does have two blind shear rams, one casing shear and three pipe rams. It is considered fit for purpose to work in the SPU.***
- Four ram type preventers.
- Outlets for choke and kill lines.

There shall be a minimum of three inlets/outlets. Where there are four inlets/outlets, one shall be below the lowermost ram. Where there are three inlets/outlets, the single kill or choke line connection shall not be below the lowermost ram.

7.5.3 A sealing shear ram shall be required. The limitations of its shearing capacity should be known and understood, and a documented risk assessment ~~shall~~ should be in place to address any such limitations.

7.5.4 Except in emergencies following the failure of the primary kill and choke lines, any outlets and lines installed below the lower most set of rams ~~shall~~ should be used for pressure testing and monitoring the well only.

7.5.5 The BOP stack shall contain a pipe ram that can close on every size of drill pipe and tubing that comprises a significant length of the total string. Where tubular accessories (e.g., cables, clamps, screens, etc) may compromise a shear ram or pipe ram seal, then appropriate procedures and contingencies shall be in place to mitigate this risk.

7.5.6 The lowermost ram ~~shall~~ should be preserved as a master component and only used to close in the well when no other ram is available for this purpose.

7.5.7 Ram type preventers ~~shall~~ should have remotely or automatically operated ram lock systems fitted.

7.5.8 Both the standpipe manifold and cement manifold ~~shall~~ should have double valve isolation from the kill line.

7.5.9 Opening and closing volumes of all BOPE functions ~~shall~~ should be monitored and recorded on subsea stacks.

7.5.10 Accumulator test ~~shall~~ should be carried out in accordance with the requirements set out in the well control manual.

~~7.6. Configuration: Rod Pump Pressure Control Equipment~~

~~7.6.1 This section applies to well servicing of wells with sucker rods, co-rod, drive shaft deliquification or similar through-tubing lifting systems where uncontrolled flow of well fluids cannot be sustained.~~

~~7.6.2 Prior to pulling rods, a manual single BOP shall be installed atop the flow tee.~~

~~7.6.3 A pump in connection point shall be available below the rod BOP.~~

7.7. Other Well Control Equipment

7.7.1 A full-open safety valve rated to the same pressure as the BOPs ~~shall~~ should be available and ready to install on the rig floor at all times. Crossovers ~~shall~~ should be available such that the full-open safety valve can be attached to any string of pipe to be run in the well. Contingencies for installing a safety valve and circulating casing at any time ~~shall~~ should *also be available for each string run in greater length than water depth.*

7.7.2 On surface wellheads during the drilling and well operations, a minimum of one casing spool side outlet to the casing string being drilled through or worked in ~~shall~~ should be equipped with double full-opening valves, companion flange and needle valve to allow installation of a pressure gauge. The principle of two full-opening valves is based upon using one as a master valve and one as a working valve when conducting pumping and circulating through the outlet.

7.7.3 The other side outlet(s) to this wellhead shall have either a valve removal (VR) plug or a full-opening valve and shall be equipped with a companion flange and needle valve installed to enable the installation of additional valves, if necessary.

7.7.4 Existing installed equipment which cannot meet the above design requirements based on lack of VR profile or based on outlet design ~~shall~~ should have two outlet valves. The full opening requirement may be relaxed after risk assessment. New wellheads ~~shall~~ should comply with the full-opening requirement.

7.7.5 On surface wellheads during the drilling and well operations, a minimum of one casing spool side outlet to any casing annulus ~~shall~~ should be equipped with a single full-opening valve, companion flange and needle valve to allow installation of a pressure gauge. This single valve ~~shall~~ should not be used to pump or flow through.

7.7.6 The opposing side outlet(s) to this wellhead ~~shall~~ should have either a VR plug or a full-opening valve and should be equipped with a companion flange and needle valve installed to enable the installation of additional valves, if necessary.

7.7.7 Existing installed equipment which cannot meet the above design requirements based on lack of VR profile or based on outlet design ~~shall~~ should have a single outlet valve companion flange and needle valve to allow installation of a pressure gauge. The full opening requirement may be relaxed after a documented risk assessment and approval of the BU well control TA or designate on existing well heads only. New wellheads ~~shall~~ should comply with the full-opening requirement.

7.7.8 Prior to the use of VR plugs a full risk assessment ~~shall~~ should be completed and a maintenance program established to monitor and evaluate VR plug conditions.

7.7.9 All drilling, offshore workover, service and offshore HWO units ~~shall~~ should have a BOP control system with two independent and operational hydraulic charging systems.

7.7.10 BOP control systems for onshore workover or service rigs and where uncontrolled flow of well fluids or gasses cannot be sustained ~~shall~~ should have an accumulator with at least one operational hydraulic charging system.

7.7.11 All drilling units, on and offshore, workover, service (excluding snubbing, CT and wireline equipment) and HWO units ~~shall~~ should be at least two operational control panels for all BOP functions one of which ~~shall~~ should be located adjacent to the driller's or operators position, with a second located in a designated safe area.

7.7.12 The primary hydraulic control unit, which may be considered as the second control panel, ~~shall~~ should be located in a designated safe area or protected by effluent well conditions.

7.7.13 On well service units where the operator works at ground level, a second panel is not necessary, provided that the primary hydraulic control unit is located in a designated safe area and immediately accessible to the operator within four (4) seconds.

7.7.14 The working fluid volume of BOP accumulators and the BOP closing times ~~shall~~ should comply with API RP 53 and the BP well control manual.

7.7.15 Choke manifolds are required on all drilling, conventional and hydraulic well work units and ~~shall~~ should incorporate a minimum of two adjustable chokes, one of which ~~shall~~ should be capable of remote operation.

7.7.16 Drilling unit choke lines, valves and the inlet side of manifolds ~~shall~~ should be sized 3 inches minimum internal diameter for surface and subsea stacks.

7.7.17 On and offshore workover, service, HWO, Snubbing and Coiled Tubing unit choke lines, valves and the inlet side of manifolds ~~shall~~ should be sized 2 inches minimum internal diameter for surface and subsea stacks.

7.7.18 Discharge lines and vessels from permanent and temporary choke manifolds ~~shall~~ should be properly secured and inspected to prevent any movement during highest anticipated flow rates and pressures. These systems ~~shall~~ should be assessed as being fit for purpose.

7.7.19 There ~~shall~~ should be calibrated choke manifold and standpipe gauges in close proximity to the choke controls and visible to the operator at all times.

7.7.20 Gauges suitable for accurately reading low drill pipe and casing pressures ~~shall~~ should be available along with a suitable manifold arrangement. Low pressure gauges ~~shall~~ should not remain plumbed into the well control system during normal operations or employ a means of isolation from the system during high pressure operations.

7.7.21 A pressure gauge ~~shall~~ should be mounted on the standpipe and choke manifolds. The gauge ~~shall~~ should be of the same nominal pressure rating as the equipment on which it is installed.

7.7.22 Conventional drilling and offshore workover operations with static fluid levels in the wellbore as the active barrier, a means of accurately monitoring fill-up and displacement volumes ~~shall~~ should be available to the driller / operator. A low volume trip tank ~~shall~~ should be installed and equipped with a volume indicator easily read from the driller's / operator's position.

7.7.23 During the well planning phase, a risk assessment ~~shall~~ should be made regarding the necessity of a stripping tank. If a stripping tank is installed a procedure for stripping using the equipment ~~shall~~ should be prepared and practiced. If a stripping tank is not installed an alternative method of stripping shall be defined and practiced.

7.7.24 In conventional drilling operations it ~~shall~~ should be possible at all times to disconnect from the string leaving a manually operated, full opening valve on the string.

7.7.25 During any top hole drilling operations prior to installing the BOP, a non-ported float valve ~~shall~~ should be run in the drill string Bottom Hole Assembly (BHA) as a protection against shallow gas influx up the drill string.

7.7.26 Connections rated 3,000 psi and above ~~shall~~ should not be threaded except as permitted in API RP53.

8. Wireline Operations

8.1. General Requirements

This section applies to well service operations performed with slickline, braided line or conductor line with or without a X-mas tree in service.

8.2. Configuration: Well Control Equipment

As arranged from top to bottom, the minimum BOP configuration for stacks used on wells where a surface pressure up to and including 5,000 psi is possible, ~~shall~~ should be:

- Rated high-pressure, pack-off, stripper, or grease head with line wiper.
- Lubricator of sufficient length to allow retrieval of the whole tool string, including items which may be retrieved from the well above the upper most tree valve or wireline BOP.
- One set of wireline valve rams for slickline, or dual wireline valve rams for braided and conductor line, suitable or sized for each diameter wire passing through the wireline valve.
- Pump-in sub or other means to kill the well while wireline valve rams are closed.

8.2.1 Where a surface pressure of over 5,000 psi is possible, the following additional equipment [redacted] should be required:

- An additional wireline valve ram.
- And, if the tree valve cannot cut and seal, a shear-seal BOP.
- A risk assessment should be conducted to determine the potential for gas escape past the lubricator stuffing box and methods employed to mitigate.

8.3. Well Control Processes

In the event that fished wireline or other tools of irregular size and shape are to be removed from the well, the number and size of the BOP's in the BOP stack up ~~shall~~ should be based on a risk assessment and operational requirements.

8.3.1 Logging and perforating operations conducted without the installation of wireline pressure control equipment ~~shall~~ should only be carried out under conditions where:

- The hole can be contained, monitored and controlled for the duration of the wireline operation.

- Drilling/completion fluid provides the necessary active barrier.
- Hole conditions are considered suitable for the tools that are to be run.

8.3.2 If the lubricator connection is broken above an already fully tested riser and BOP a retest of the lubricator connection above the BOP for 5 mins to the maximum anticipated wellhead pressure, is sufficient to confirm integrity.

9. Coiled Tubing Operations

9.1. General Requirements

This section applies to well service operations with a coiled tubing service unit with or with out a X-mas tree in service.

9.2. Configuration: Well Control Equipment

9.2.1 All pressure containing connections from the well head up to the BOP's ~~shall~~ should be flanged. Threaded connections may be used after a proper risk assessment and approval from the BU well control TA or designate on operations where surface pressures do not exceed 3,000 psi.

9.2.2 All annulus outlets ~~shall~~ should be double valved.

9.2.3 As arranged from top to bottom, the minimum BOP configuration for stacks used on wells where a surface pressure up to and including 5,000 psi is possible, ~~shall~~ should be:

- One high-pressure pack-off, stripper or annular type preventer.
- Lubricator of sufficient length to allow retrieval of the complete bottom hole assembly, including items which may be retrieved from the well.
- Hydraulically operated (with manual backup) triple - i.e. if triple is used one ram to be a dual purpose blind shear ram, quad or combination of BOP's with equivalent capacity and sized for the tubing to be used.

9.2.4 BOP's ~~shall~~ should have the following top down configuration:

- Blind rams.
- Shear rams.
- Slip rams.
- Pipe rams.

9.2.5 Where a surface pressure of over 5,000 psi is possible:

- An additional pipe ram ~~shall~~ should be installed and used as contingency equipment additionally, the additional pipe ram ~~shall~~ should only used in situations following failure of primary BOPE and not as an active barrier.
- Combi BOP's ~~shall~~ should not be installed
- A riser evaluation ~~shall~~ should be undertaken to ensure that the combined mechanical and pressure loadings are within the operating limits of the supplied equipment.

9.3. Well Control Processes

9.3.1 All relevant sections of this document ~~shall~~ should apply to all coiled tubing operations.

10. Snubbing Operations

10.1. General Requirements

10.1.1 This section applies to well service operations with a snubbing unit with or with out a X-mas tree in service. Additionally this section applies to stand alone, and rig assisted snubbing operations.

10.1.2 Requirements set forth in this document are minimums and do not include the full range of considerations needed for every snubbing installation. I.e. HPHT, sub-sea, H2S, fishing operations etc. Each BU will develop and maintain guidelines and requirements specific to each snubbing application and approved by the relevant BU well control TA or designate.

10.2. Configuration: Well Control Equipment

10.2.1 As arranged from top to bottom, the minimum BOP configuration for stacks used on wells where a surface pressure up to and including 5,000 psi is possible, and the tubulars to be snubbed are not tapered; ~~shall~~ should be:

- Stripper rubber or active stripper system, i.c. snubbing stripper bowl and rubber, annular or spherical type BOP
- Dual stripper rams equipped with a method to equalize and bleed off pressures between stripper ram components.

Note: an annular or spherical BOP ~~shall~~ be should not be required if dual strippers are included in the BOP configuration, however dual stripper rams ~~shall~~ should be required if an annular or spherical BOP is installed.

- An additional safety pipe ram ~~shall~~ should be installed and used as contingency equipment. Additionally, the additional pipe ram ~~shall~~ should only used in situations following failure of uppermost safety pipe ram and not as an active barrier.

Where a surface pressure of over 5,000 psi is possible and the probabilities of tapered tubulars are anticipated additional equipment ~~shall~~ should be installed:

- Blind or blind shear ram
- Flow / pump cross equipped with dual full opening valves on each choke and kill line for all stacks. The outer valve on the choke line ~~shall~~ should be remotely activated. The outer valve on the kill line ~~shall~~ should remotely operated and a non-return valve.
- An additional pipe ram for each tubular described ~~shall~~ should be installed and used as contingency equipment additionally, the additional pipe ram ~~shall~~ should only used in situations following failure of primary BOPE and not as an active barrier.

10.3. Well Control Processes

10.3.1 All relevant sections of this document ~~shall~~ should apply to all snubbing operations.

10.3.2 All snubbing unit hydraulic functions ~~shall~~ should not exceed the maximum operating tension loads of 80% and operating compression loads of 70% of minimum yield strengths for tubing string used.

10.3.3 Sufficient stack height ~~shall~~ should be used to cover all tools to be run in and out of the well above the upper most contingent barrier.

10.3.4 Snubbing unit tongs ~~shall~~ should be equipped with remote backups and safety snub line to secure and prevent tong movement during pipe make up and breakout.

10.3.5 Non-essential personnel ~~shall~~ should be minimized from the snubbing floor during "pipe light" conditions.

10.3.6 Work floor egress route ~~shall~~ should be predetermined and evacuation procedures practiced at regular intervals.

10.3.7 All relevant sections of this document ~~shall~~ should apply to all snubbing operations.

11. Additional Considerations

11.1. Coring

11.1.1 All coring tool strings ~~shall~~ should be equipped with a circulating sub above the core barrel.

12. Pressure Testing

12.1. General Requirements

12.1.1 All testing requirements not identified in this document remain as set forth in GP 10-45 Working with Pressure.

12.2. Pressure Testing of Well Control Equipment

12.2.1 In areas or fields where well design, hanger profile damage or tree leaks limit the use of plugs against which to test, the BOP's ~~shall~~ should be shop tested prior to installation. The testing company ~~shall~~ should provide the test charts and documentation. An additional shell test ~~shall~~ should be performed once installed. The required accumulator test and function test ~~shall~~ should be performed after rig up of well control equipment on the well and coincide with fourteen (14) day BOP pressure tests.

12.2.2 An accumulator test ~~shall~~ should be carried out in accordance with the Accumulator Closing Test worksheet of API RP53 and the BP well control manual. Accumulator pre-charge pressure ~~shall~~ should be recorded on the worksheet.

Revision History

Existing Clause	Revision	Date
5.3.2	Deleted - Duplication of Clause 8.4 in DWOP	15th October 2008
5.3.3	Deleted - Duplication of Section 16 requirements in DWOP	15th October 2008
5.3.4	Deleted - Duplication of Clause 8.1 in DWOP	15th October 2008
5.3.5	Deleted - Duplication of Clause 8.1 in DWOP	15th October 2008
5.3.10	Deleted - Duplication of Clause 8.2 in DWOP	15th October 2008
5.3.14	Deleted - Duplication of Clause 8.3 in DWOP	15th October 2008
5.3.15	Deleted - Duplication of Clause 9.3 in DWOP	15th October 2008
6.1.13	Deleted - Duplication of Clause 6.7 in DWOP	15th October 2008
6.1.14	Deleted - Duplication of Clause 6.7 in DWOP	15th October 2008
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10.3.2	Deleted - Duplication of Clause 20.5.10 in DWOP	15th October 2008
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Whole Document	Clause numbers corrected following above revisions	15th October 2008