Cased Hole Wireline Pressure Control Equipment and Systems

API STANDARD 16WL

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Introduction

This document provides information on the assembly and operation of wireline pressure control equipment and systems during cased hole operations. Cased hole wireline pressure control practices rely on mechanical barriers as the primary means for pressure control.

API 6A and API 16B establish equipment-level design and manufacturing requirements for pressure control components referenced in this document. This recommended practice addresses system-level considerations and provides operational guidance for the application of such equipment.

Manufacturers and integrators may design, manufacture, and supply individual components independent of overall system requirements. The end user or system integrator is responsible for system engineering, including system design and operation. System engineering is important to support the proper design, fabrication, operation, and maintenance of well intervention systems and their components throughout their intended service life.

This document provides guidance on job planning, equipment readiness and inspection, common equipment and system configurations, implementation and testing, system monitoring and maintenance, roles and responsibilities, and contingency planning.

1. Scope

This document covers cased-hole wireline pressure control equipment, including its function and operation, with emphasis on establishing and maintaining an effective seal at the wireline interface to prevent the flow of liquid or gas. Two external surface types for wireline have been identified: slick and braided.

Examples for each external surface type are shown in Table 1.

Table 1 - Wireline External Surface Examples

Slick External Surface	Braided External Surface
Slickline	Braided line
Coated slickline	Mono cable / Mono conductor
Polymer embedded cables	Electric line / e-line / conductor line

This document covers wireline pressure control equipment systems and cased hole operations guidance for wireline operations when the wireline pressure control equipment is installed on:

a) a production tree.
b) a surface flow head or surface test tree.
c) a surface pressure head assembly.
d) tubing, casing, drill pipe, work string located on the drilling, completion, or service unit rig floor.
e) an open water intervention riser system (OWIRS).
f) a through BOP intervention riser system (TBIRS).

This document does not cover wireline pressure control equipment assemblies and operations for slickline, braided line, or electric line if the following applications apply:

a) open-hole wireline operations.
b) drill pipe or work string conveyed wireline operations.
c) open water riserless wireline operations.
d) operations where well bore fluid is being used as a barrier.

2. Normative References

The following referenced documents are indispensable in the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any addenda) applies.

API Specification 6A, *Specification for Wellhead and Christmas Tree Equipment, 21st edition, November 2018*

API Specification 7HU2, *Oilfield Hammer Unions, 1st Edition March 2022*

API Specification 16B, *Coiled Tubing, Snubbing, and Wireline Well Intervention Equipment, 1st Edition, May 2025*

API Specification 16D, *Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment, 3rd Edition, November 2018*

API Recommended Practice 500, *Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division 1, and Division 2, 4th Edition, June 2023*

API Recommended Practice 505, *Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Zone 0, Zone 1, and Zone 2, 3rd Edition, January 2025*

ASME B31.3, *Process Piping*

ASTM D5720-95, *Standard Practice for Static Calibration of Electronic Transducer-Based Pressure Measurement Systems for Geotechnical Purposes,*

3. Terms & Definitions and Abbreviations

3.1 Terms and Definitions

For the purposes of this document, the following terms and definitions apply

3.1.1
accumulator bank
A group of interconnected hydraulic accumulators that store pressurized fluid volume and energy to operate pressure control equipment when the pump system is not running.

3.1.2
adiabatic heating
The rapid temperature rise of trapped wellbore fluids or gases caused by fast compression without time for heat to escape, potentially damaging wireline equipment and creating a safety risk.

3.1.3
ball check
A valve that permits fluid to flow freely in one direction and contains a mechanism to automatically prevent flow in the reverse direction (also known as a flow check device).

3.1.4
bleed subs
bleed port
Pressure-rated component with dedicated ports used to safely remove trapped gas or fluid and equalize pressure in the lubricator or pressure control stack, helping to minimize adiabatic heating.

3.1.5
braided line
Wireline made of multiple strands of wire twisted together in a rope formation with a solid "non-conductor" center core.

3.1.6
braided line ram
A wireline ram designed to be used with braided line.

3.1.7
chemical injection sub
A pressure-rated subassembly with ports that allow controlled injection of treatment or inhibiting chemicals into the wellbore or pressure control stack.

3.1.8
closing ratio
The ratio of the effective ram piston area to the differential area exposed to wellbore pressure, used to determine the hydraulic pressure required to close a ram or shear-seal device at MASP.

3.1.9
coated slickline
A thin, nonelectric, single strand cable with a thin exterior protective coating.

3.1.10
conductor line
Wireline made of multiple strands of wire twisted together in a rope formation with a limited number of conductor cables within its core.

3.1.11
contingency operations
Field operations executed under pre-planned contingency procedures to regain or maintain pressure control or safe conditions following an abnormal event.

3.1.12
contingency planning
The process of identifying, documenting, and preparing procedures, equipment, and responsibilities for responding to abnormal conditions or loss of pressure control.

3.1.13

control fluid reservoir
A tank or vessel that stores hydraulic control fluid for the accumulator and operating systems.

3.1.14

control panel
The operator interface that houses gauges, valves, actuators, and indicators used to monitor and control the pressure control operating system.

3.1.15

control system
The combination of control panels, valves, instrumentation, and logic used to operate and monitor the pressure control stack components.

3.1.16

crossover connections
Pressure-containing pieces of equipment having OEC end connections with different sized end connections or different OEC types.

3.1.17

dedicated shear & seal device
A shear-seal component with its own operating circuit or accumulator capacity specifically provided to shear wireline and seal the wellbore independently of the primary ram system.

3.1.18

drawdown test
A functional test of an accumulator system in which operating cycles are performed to confirm that required components can be operated with sufficient pressure and volume remaining in the bank.

3.1.19

dual packoff
A pressure control device with two elastomeric sealing elements used to create a static seal around the wireline, as opposed to a “single packoff”, which contains one independent sealing elements

3.1.20

dynamic pressure controlling device
A pressure sealing device to contain fluid and pressure escaping from the wellbore while wireline is in motion.

3.1.21

Electric Line / E-Line
Wireline made of multiple strands of wire twisted together in a rope formation with armor and multiple conductor cables within its core.

3.1.22

Equipment Owner's Maintenance System
The documented program, procedures, and records used by the equipment owner to inspect, maintain, and verify fitness for service of pressure control equipment.

3.1.23

equalizing device

A device to equalize pressure between ram cavities across each pressure-sealing ram prior to opening the rams.

3.1.24

fire-resistant control hose
A control hose qualified to maintain integrity and function for a specified duration when exposed to fire, used for operating critical pressure control components.

3.1.25

Fit for Service
A determination, based on inspection and evaluation, that equipment has sufficient integrity to operate safely within its rated limits and specified service conditions.

3.1.26

flow cross
A pressure-containing cross-shaped fitting with multiple outlets used to route pump-in, kill, or circulation fluids into the wellbore or pressure control stack.

3.1.27

greasehead
A pressure control device that consists of a set of grease and flow tubes designed to create a dynamic seal around wireline by using injected wireline grease.

3.1.28

head catcher
A mechanical device installed at the top of the pressure control stack to catch and retain the tool string, preventing it from falling back into the wellbore.

3.1.29

hydraulic control fluid
The filtered, compatible fluid used in the hydraulic operating system for transmitting power to pressure control components.

3.1.30

hydraulic quick latch
A hydraulically actuated quick latch that provides rapid connection and disconnection of the lubricator or WPCE to the wellhead while maintaining pressure integrity and structural support.

3.1.31

independent accumulator bank
An accumulator bank that is hydraulically isolated from other banks and dedicated to a specific set of pressure control components, such as a shear-seal device.

3.1.32

inverted ram
A ram configured to contain pressure from above, used in combination with a standard ram to allow wireline grease injection between the rams at an OEM-recommended pressure to prevent wellbore fluid and effluent migration between the armors of braided or electric line.

3.1.33

inverted ram
A ram configured to contain pressure from above, used in combination with a standard ram to allow wireline grease injection between the rams at an OEM-recommended pressure to prevent wellbore fluid and effluent migration between the armors of braided or electric line.

3.1.34

jacketed cable stuffing box
A pressure control device that provides an elastomeric dynamic seal during jacketed cable operations.

3.1.35

kill line inlet
An inlet to allow pumping below the lowermost pressure control stack component and above the lowermost PCB.

3.1.36

line of fire area
The physical space where a person could be struck or harmed by moving objects or released hazardous energy.

3.1.37

line of fire risk
The risk of personnel injury arising from being positioned in the path of moving equipment, pressure releases, or ejected objects during operations.

3.1.38

line wiper
A device used to wipe excess fluid from the wireline as it exits the pressure control equipment.

3.1.39

liquid seal stuffing box
A pressure control device that provides a wireline grease dynamic seal during slickline operations.

3.1.40

lubricator
An assembly of pressure-control tubular sections installed above the uppermost well control stack-sealing valve or ram and is typically used to house the tool string.

3.1.41

manifold
A pressure-rated piping assembly that distributes hydraulic control fluid from the accumulator bank and pumps to various operating circuits and components.

3.1.42

maximum anticipated wellhead pressure
The highest wellhead pressure expected at surface under the planned operating and contingency conditions for the operation.

3.1.43

mono cable / mono conductor
Wireline made of multiple strands of wire twisted together in a rope formation with a conductor cable within its core.

3.1.44

nitrogen pre-charge
The initial nitrogen gas pressure charged into an accumulator before hydraulic fluid is introduced, establishing the stored energy level for operation.

3.1.45

Non-Shearables
Components or sections of the tool string or wireline that cannot be reliably sheared by the shear rams or shear-seal device at the specified MASP.

3.1.46

Pack-off
A pressure control device used to create a static seal around the wireline using an elastomer element.

3.1.47

packoff and Auxiliary Tool Sub Circuit
A dedicated hydraulic circuit used to operate packoffs and auxiliary subs such as bleed, vent, or injection subs within the pressure control stack.

3.1.48

passive safety device
A passively actuated device that provides an element of pressure control in specific conditions.

3.1.49

polymer embedded cables
A thin, electric, single strand cable with a thick exterior protective polymer coating.

3.1.50

power fluid
The pressurized hydraulic fluid used in the operating system to actuate valves, rams, and other pressure control components.

3.1.51

pre-charge pressure
The measured nitrogen pressure in an accumulator at thermal equilibrium before the accumulator is placed in hydraulic service.

3.1.52

pressure control equipment operating system
The integrated hydraulic and pneumatic system, including accumulators, pumps, controls, and lines, used to operate pressure control stack components.

3.1.53

pressure control head
The uppermost pressure control device that provides an effective pressure seal between the wireline pressure control equipment and the moving wireline to contain wellbore fluids and pressure.

3.1.54

pressure-dealing device lock
The locking system on the pressure sealing device (Shear/Seal Device) locks the device closed and maintains the pressure seal after the removal of the operating hydraulic actuator pressure.

3.1.55

prime mover
The primary mechanical or pneumatic driver, such as an electric motor or air motor, that powers the hydraulic pump for the operating system.

3.1.56

primary rams
The main set of ram components in the pressure control stack that provide the primary means of isolating or sealing the wellbore during normal operations.

3.1.57

pump in sub
A device that allows the pumping of fluids into pressure-control equipment.

3.1.58

pump system
The assembly of pump, prime mover, reservoirs, and associated controls used to pressure and circulate hydraulic control fluid within the operating system.

3.1.59

quick latch
A mechanically or hydraulically actuated connector that enables fast attachment and release of the lubricator or WPCE from the wellhead with repeatable alignment and load capacity.

3.1.60

quick latch systems
An engineered assembly that provides rapid, remote-controlled connection and disconnection of the lubricator or pressure control equipment to the wellhead while maintaining structural support, alignment, and pressure integrity.

3.1.61

quick test sub
A pressure-control sub installed at the routinely broken lubricator or WPCE connection

that allows only that connection's seal area to be pressure tested through an external test port, eliminating the need to retest the entire pressure control stack between runs.

3.1.62

quick unions
Mechanical end connectors that allow rapid make-up and break-out of pressure control equipment while maintaining alignment, seal integrity, and pressure ratings.

3.1.63

ram injection port
A port that gives the ability to inject wireline grease between an inverted ram and a designated upper ram.

3.1.64

ram locking device
A mechanism that mechanically locks a ram in the closed position and maintains the seal in the absence of hydraulic closing pressure.

3.1.65

ram position indicator
A device to provide a visual position indication of the ram position for a ram component.

3.1.66

shear ram
A ram designed to seal the wellbore and isolate pressure when the bore of the ram is obstructed.

3.1.67

shear-seal device
A device specifically designed to actively shear wireline and subsequently isolate well pressure and effluents from the atmosphere during wireline operations.

3.1.68

single packoff
A packoff device with one elastomeric sealing element used to create a static seal around the wireline, as opposed to a dual packoff, which contains two independent sealing elements.

3.1.69

slickline
A thin, nonelectric, single strand cable.

3.1.70

slickline ram
A wireline ram is designed to be used with slickline.

3.1.71

slickline stuffing box
A pressure control device that provides an elastomeric dynamic seal during slickline operations.

3.1.72

Spacer Spool
Pressure-containing pieces of equipment having flanged end connections which serve to space out the well control stack components with equal sized end connections.

3.1.73

stabilized operating pressure
The steady hydraulic pressure observed in an accumulator bank and manifold after sufficient time has elapsed for temperature and pressure to reach equilibrium.

3.1.74

static pressure controlling device
A pressure sealing device to contain fluid and pressure escaping from the wellbore while wireline is static.

3.1.75

Stop Work Authority
The authority granted to any person on location to halt operations they believe present an unsafe or environmentally unsound condition until the risk is assessed and addressed.

3.1.76

support structure
A structural frame or arrangement used to support, brace, or guy the pressure control stack and associated equipment to maintain alignment and stability during operations.

3.1.77

tool trap
A mechanism at the bottom of the lower lubricator section that will trap the tool string from below and not allow it to fall back into the wellbore.

3.1.78

variable bore ram
A wireline ram designed to be used with a range of wireline OD's.

3.1.79

vent or injection sub
A pressure-rated subassembly with ports used to vent, inject, or circulate fluids into or out of the pressure control stack at a controlled location.

3.1.80

Well Handover
The formal transfer of operational responsibility and control of the well between drilling, production, and well intervention or wireline teams.

3.1.81

well hopping
The practice of performing consecutive wireline jobs on multiple wells in a campaign-style sequence to maximize equipment utilization and minimize rig-up, rig-down, and travel time between wells.

3.1.82

wireline pressure control equipment
Equipment designed to allow wireline services to be safely performed within the rated working pressure of the equipment.

3.1.83

wireline pressure controlling barrier
A tested mechanical component or combination of tested mechanical components that provide pressure containment and does not require constant monitoring to perform its intended function.

3.1.84

wireline pressure controlling device
A device or system that provides pressure containment and requires constant monitoring and operational control to provide its intended function.

3.1.85

wireline ram
A wireline ram designed to isolate pressure between the wireline OD surface and the inside diameter ID of the pressure control stack bore.

3.1.86

wireline valve
The pressure control equipment assembly used during wireline operations to seal off the wellbore and maintain control. This assembly may contain one or more hydraulically or manually operated ram or ball valve assemblies.

3.2 Abbreviations

For the purposes of this Recommended Practice, the following abbreviations apply.

API	American Petroleum Institute
BHA	Bottom Hole Assembly
BSL	Bolting Safety Level
CR	Closing Ratio
CO2	Carbon Dioxide
COS	Certificate of Service
CRA	Corrosion Resistant Alloy
ESD	Emergency Shutdown Devices
FFS	Fit For Service
FMEA	Failure Mode and Effects Analysis
H2S	Hydrogen Sulfide
HSE	Health, Safety and Environmental
Hz	Hertz
ID	Inside Diameter
LM	Lower Master Valve
LOPC	Loss of Pressure Containment
MAOP	Maximum Anticipated Operating Pressure
MASP	Maximum Anticipated Surface Pressure
MFG	Manufacturing
MTR	Material Test Report
N/A	Not Applicable
NDE	Non-Destructive Examination
OD	Outside Diameter
OEC	Other End Connector
OEM	Original Equipment Manufacturer
PC-0	Pressure Category Zero
PC-1	Pressure Category One
PC-2	Pressure Category Two
PC-3	Pressure Category Three
PC-4	Pressure Category Four
PCB	Pressure Controlling Barrier
PCD	Pressure Controlling Device

PCE	Pressure Control Equipment
PCH	Pressure Control Head
POOH	Pull Out of Hole
PPE	Personal Protective Equipment
PSI	Pounds Per Square Inch
PSIG	Pounds Per Square Inch Gauge
QA	Quality Assurance
QTS	Quick Test Sub
RGD	Rapid Gas Decompression
RWP	Rated Working Pressure
SBR	Shear Blind Ram
SDS	Safety Data Sheets
SITP	Shut In Tubing Pressure
Spec	Specification
UM	Upper Master Valve
WL	Wire Line
WLV	Wireline Valve
WPCE	Wireline Pressure Control Equipment

4. Wireline Pressure Control Equipment

4.1 General

Wireline pressure control equipment (WPCE) is designed to allow wireline services to be safely performed within the rated working pressure (RWP) of the equipment.

The following shall apply:

a) WPCE conforms to either API 6A or API 16B where applicable.

b) The selection of pressure control equipment for a given application is to be consistent with the manufacturer’s recommendations and this document.

c) Pressure control equipment to be selected, installed, tested, and used to maintain control of the well surface pressure during wireline services.

d) The following is to be reviewed and understood to ensure conformance with this requirement (including but not limited to):

   1) Maximum Anticipated Surface Pressure (MASP).

   2) Maximum Anticipated Operating Pressure (MAOP).

3) ambient temperatures.

4) bore size, rated working pressure (RWP), and connections of pressure control equipment.

5) pressure controlling barriers.

6) wireline pressure control categories.

7) wellbore temperature, fluids, and effluents.

8) pressure control stack configurations.

4.2 Wireline Pressure Controlling Devices (PCD)

A wireline pressure controlling device is defined as a device or system that provides pressure containment and requires constant monitoring and operational control to provide its intended function.

4.2.1 Dynamic Pressure Controlling Device

Provides a pressure seal to contain fluid and pressure escaping from the wellbore while wireline is in motion. The following are dynamic PCD's

a) Greasehead
b) Slickline Stuffing Box
c) Liquid Seal Stuffing Box
d) Jacketed Cable Stuffing Box.

For Greaseheads and Liquid Seal Stuffing Boxes the following shall apply:

a) have at least one injection port and one return port.

b) have a flow check device installed between injection port and the external pump to prevent well bore fluid and effluents from flowing back to the pump.

c) The wireline grease properties are compatible with the prescribed service.

4.2.2 Static Pressure Controlling Device

Provides a pressure seal to contain fluid and pressure escaping from the wellbore while wireline is static.

Included components, but not limited to are:

a) Pack-off – A pressure control device used to create a static seal around the wireline using an elastomer element.

   1) The pack-off shall be remotely operated.

   2) The location of the pack-off should not restrict the ability to fully retrieve the WL BHA above the uppermost ram in the pressure control stack.

b) Wireline Ram - The wireline ram is designed to isolate pressure between the wireline OD surface, and the inside diameter ID of the pressure control stack bore.

   1) Braided Line Ram - The braided line ram is a wireline ram designed to be used with braided line.

   2) Slickline Ram - The slickline ram is a wireline ram designed to be used with slick line.

   3) Variable Bore Ram - A multi-line ram is a wireline ram designed to be used with a range of wireline OD's.

c) Inverted Ram - An inverted ram is configured to contain pressure from above (standard ram configuration holds pressure from below) in order to have wireline grease injected between a standard and inverted ram to prevent well bore fluid and effluent migration between the armors of braided line. The injection pressure shall not exceed the rated working pressure of the ram assembly.

During wireline conveyance, while pressure controlling barriers (PCB) are open, a dynamic pressure controlling device (PCD) shall be used for primary pressure control. For pressure categories 1,2,3, and 4, a minimum of 2 additional static PCD's should be available in the event of loss of dynamic pressure control or during contingency operations listed in (Annex A).

4.3 Wireline Pressure Controlling Barriers (PCB)

A wireline pressure controlling barrier is defined as a tested mechanical component or combination of tested mechanical components that provides pressure containment and does not require constant monitoring to perform its intended function.

Tested barrier elements incorporated in the pressure control stack shall demonstrate reliable and repeatable pressure control performance through mechanical testing prior to being used for the prescribed service.

Wireline Pressure Controlling Barriers include but not limited to:

4.3.1 Shear Blind Ram (SBR) - The SBR is a combination ram which incorporates two ram functions into a single pressure control ram component. The following shall apply:

a) Shearing and sealing to be achieved in a single operation.

b) The SBR be capable of shearing the wireline at the MASP of the well.

c) Upon completion of the SBR actuation, the ram seals will isolate the wellbore without requiring the movement of the wireline.

d) The SBR blades and required components to be replaced after each wireline shearing operation as soon as practically possible.

4.3.2 Shear-Seal Device - A device specifically designed to actively shear wireline and subsequently isolate well pressure and effluents from the atmosphere during wireline operations. The following shall apply:

a. Shearing and sealing to be achieved in a single operation.

b. The Shear-Seal Device be capable of shearing the wireline at MASP of the well.

c. Upon completion of the device actuation, the device seals will isolate the wellbore without requiring the movement of the wireline.

d. The shearing blades and required components to be replaced after each wireline shearing operation as soon as practically possible.

(NOTE 1) Additional pressure controlling barriers include but not limited to gate valves and ball valves. Their qualification as a barrier is outside the scope of this document.

4.4 Additional Wireline Ram Assembly Components

4.4.1 Ram Position Indicator - Each ram type pressure control component should be equipped with a visual position indicator to determine the ram position for each ram component.

4.4.2 Ram locking device - All pressure sealing pressure control stack ram components shall have a system for locking the rams in the closed position, be capable of holding the rams in the closed position and conform with the individual performance requirements in the absence of closing pressure applied by the closing system.

4.4.3 Equalizing Device - A pressure control stack shall have a means for equalizing pressure between cavities across each pressure-sealing ram prior to opening the rams.

4.4.4 Ram Injection Port - When an inverted ram is installed, the pressure control stack shall have a port that gives the ability to inject wireline grease between inverted ram and designated upper ram.

4.4.5 Kill Line Inlet - A kill line inlet shall be installed below the lower most pressure control stack component, and above the lower most PCB.

4.4.6 Passive Safety Device - A passively actuated device that provides an element of pressure control in specific conditions. (non-tested) **i**ncludes but is not limited to,

a) ball check device;

b) slick line stuffing box;

c) blow out plugs.

4.5 WPCE During Running Operations

The following shall apply:

a) PCB’s to either be independently controlled, or the operating control system to have capacity, closing ratio, and operating pressure to close and open all other connected PCB’s and PCD’s at MASP.

b) A qualified wireline shear device .

c) All rams in the stack including Shear-Blind rams and shear-seal devices to be able to close and seal in 30 seconds.

4.6 Wireline Pressure Control Categories

Table 2 contains the pressure control categories, and the required minimum number of PCD and PCB’s.

Table 2 - Pressure Categories

Pressure Category	Minimum Stack RWP psig	Min # of Static PCD	Min # of PCB
PC-0(a, d, e)	3000	1	1
PC-1(b, c, d, e)	5000	3	1
PC-2(b, c, d, e)	10000	3	1
PC-3(b, c, d, e)	12500	3	1
PC-4(b, c, d)	15000	4	1

a) PC-0 applies to those wells demonstrated as incapable of unassisted flow to surface (based on local regulatory agency guidelines)
b) PC-1 – PC-4 The minimum RWP of the stack shall be equal to or greater than MAOP including grease injection pressure for a stuffing box or grease head if applicable.
c) Braided/e-line line requires an inverted ram below the standard wireline ram with the ability to inject wireline grease between the standard and inverted ram in order to be considered a pressure control device (PCD).
d) One inverted and two standard configured rams, if all rams are within the same body, are considered two PCDs.
e) All PCD's and at least one PCB shall be remotely operated.

A pack-off is a single PCD, each additional pack-off is considered an additional PCD.

Example stack arrangement diagrams for the different types of wireline (slickline, braided line, and jacketed line) and pressure control levels (PC0 to PC4) can be found in annex B.

Table 3, 4, and 5 state the minimum stack up requirements that shall be followed.

Table 3 -Braided Line Minimum Stack Up Requirements

WL Pressure Control Component		PC-0	PC-1	PC-2	PC-3	PC-4
1	Single Packoff	Required	N/A	N/A	N/A	N/A
2	Dual Packoff	Optional	N/A	N/A	N/A	N/A
3	Single Packoff Grease Head Assembly	Optional	Required	Required	N/A	N/A
4	Dual Packoff Grease Head Assy (b)	Optional	Optional	Optional	Required	Required
5	Flow Check Device	Optional	Required	Required	Required	Required
6	Tool Catcher (a)	Optional	Optional	Optional	Optional	Optional
7	Lubricator	Optional	Required	Required	Required	Required
8	Bleed Port	Required	Required	Required	Required	Required
9	Tool Trap (a)	Optional	Optional	Optional	Optional	Optional
10	Quick Test Sub	Optional	Optional	Optional	Optional	Optional
11	Wireline Ram – Standard configuration (b)	Optional	1 Required	1 Required	1 Required	2 Required
12	Wireline Ram – Inverted Configuration	Optional	1 Required	1 Required	1 Required	1 Required
13	Shear/Seal Device	Required	Required	Required	Required	Required
14	Kill Line Inlet (including but not limited to a pump in sub or Flow cross)	Required	Required	Required	Required	Required
15	Wellhead Adaptor	Required	Required	Required	Required	Required

a) One of either the tool catcher or tool trap shall be required for PC-1, PC-2, PC-3, & PC-4.
b) Either a dual pack-off or additional standard ram for PC-2 is required.

Table 4 – Slickline Minimum Stack Up Requirements

WL Pressure Control Component		PC-0	PC-1	PC-2	PC-3	PC-4
1	Hydraulic Slickline Stuffing Box	Required	Required	Required	Required	Required
2	Liquid Seal Stuffing Box	Optional	Optional	Recommended (b)	Required	Required
3	Flow Check Device	Required	Required	Required	Required	Required
4	Tool Catcher (a)	Optional	Optional	Optional	Optional	Optional
5	Lubricator	Optional	Required	Required	Required	Required
6	Bleed-Port	Required	Required	Required	Required	Required
7	Tool Trap (a)	Optional	Optional	Optional	Optional	Optional
8	Quick Test Sub	Optional	Optional	Optional	Optional	Optional
9	–Wireline Ram - Standard	1 Required	2 Required	2 Required	2 Required	3 Required
10	Shear/Seal Device	Required	Required	Required	Required	Required
11	Kill Line Inlet (including but not limited to a pump in sub or Flow cross)	Required	Required	Required	Required	Required
12	Wellhead Adaptor	Required	Required	Required	Required	Required

a) One of either the tool catcher or tool trap shall be required for PC-1, PC-2, PC-3, & PC-4.
b) A liquid seal stuffing box should be used for PC-2 configurations.

Table 5 – Jacketed Cable Minimum Stack Up Requirements

WL Pressure Control Component		**PC-0**	**PC-1**	**PC-2**	**PC-3**	**PC-4**
1	Single jacketed cable Stuffing Box	Required	Required	N/A	N/A	N/A
2	Dual jacketed cable Stuffing Box	Optional	Optional	Required	Required	Required
3	Triple jacketed cable Stuffing Box	Optional	Optional	Optional	Recommended (b)	Recommended (b)
4	Flow Check Device	Required	Required	Required	Required	Required
5	Tool Catcher (a)	Optional	Optional	Optional	Optional	Optional
6	Lubricator	Optional	Required	Required	Required	Required
7	Bleed Port	Required	Required	Required	Required	Required
8	Tool Trap (a)	Optional	Optional	Optional	Optional	Optional
9	Quick Test Sub	Optional	Optional	Optional	Optional	Optional
10	Wireline Ram Standard config	1 Required	2 Required	2 Required	2 Required	3 Required
11	Shear/Seal Device	Required	Required	Required	Required	Required
14	Kill Line Inlet (including but not limited to a pump in sub or Flow cross)	Required	Required	Required	Required	Required
17	Wellhead Adaptor	Required	Required	Required	Required	Required

4.7 Rated Working Pressure and Connections of Pressure Control Equipment

4.7.1 General

The following shall apply:

a) End connectors and outlet connectors in the pressure control stack to be in accordance with API 6A and API 16B as applicable.

b) All bolting, including applicable torque values with flanges, to conform with the requirements of API 6A and/or 16B as applicable.

c) Ring gaskets to conform with the requirements of API 6A.

d) Ring gaskets not to be reused.

4.7.2 Connections - Specified Pressure Categories

a) PC-0
The following shall apply:

(1) All connections shall have a minimum rated working pressure rating of 3000 psig.

b) PC-1
The following shall apply:

(1) All end connectors from the tree to the uppermost required ram component in the pressure control stack configuration to have a minimum pressure rating of 5000 psig.

(2) Flanged or other connection types used above the uppermost ram component to have a minimum pressure rating of 5000 psig.

(3) Where surface wellhead and tree construction prevent the use of a flange connector, an installation plan for use of other end connectors (OEC)s to be available and reviewed.

(4) For tree construction with a threaded connection only, the threaded connection to meet the minimum pressure rating of 5000 psig and should be restricted to the connection between the tree and pressure control stack.

c) PC-2, PC-3, & PC-4
The following shall apply:

a) All end connectors from the tree to the uppermost required ram component in the pressure control stack configuration should be flanged and to have a minimum pressure rating per the table in 4.7.

b) Flanged or other connection types used above the uppermost ram component have a minimum pressure rating per the table in 4.7.

c) Where surface wellhead and tree construction prevent the use of a flange connector, an installation plan for use of other end connectors (OEC)s to be available and reviewed.

4.8 Pressure Isolation Protection Below the Pressure Control Stack Equipment

For PC-1 to PC-4, as far as practicable, reservoir pressure shall be isolated from the environment to establish safe operating conditions in order to install WPCE.

Where rig up onto drill pipe or a jointed tubing work string is required the drill pipe, or work string, shall be isolated by at least one mechanical PCB rated for the pressure end load (such as full open safety valve, gate valve, etc.) with a risk assessment performed to evaluate onsite conditions and determine the most appropriate means for providing a secondary pressure isolation device.

Where the isolation valve on the tree immediately below the WPCE connection is designed to be directional (seals pressure from below only), a separate two-way sealing valve should be installed above the tree-directional-sealing valve to allow for proper pressure testing of the WPCE.

4.9 Flow Tube Selection for Braided Wireline Products.

Grease heads should have a minimum of three flow tubes linked by couplings required with an entry point for grease injection, and an outlet point for grease return.

Flow tubes should be between .002”-.008” above the maximum OD or sizing die of intended cable at working depth. Larger clearance between flow tube and cable can be allowed for polymer injected cables.

Table 6 provides guidance in determining the minimum recommended number of concentric flow tubes installed above the lowest injection point in a braided line grease head. This section is not intended to replace OEM specifications or recommendations.

Table 6 – Flow Tube Recommendations

MASP (PSI)	Fluid	Min # of flow tubes above the lowest injection point	Min number of injection points
0 - 5,000	Liquid	3	1
0 - 5,000	Gas	4	1
5,001 - 7,500	Liquid	4	1
5,001 – 7,500	Gas	5	2
7,501 – 10,000	Liquid	5	2
7,501 – 10,000	Gas	7	2
10,001 – 11,666	Liquid	6	2
10,001 – 11,666	Gas	8	2
11,667– 12,500	Liquid	7	2
11,667 – 12,500	Gas	9	2

Flow tube requirements are calculated using the pressure drop across the flow tube, along with grease viscosity at ambient temperature.

The number of flow tubes shall be compatible with the prescribed service.

Additional flow tube, or alternative means of restriction, is required below the lowest injection point to impede the flow of grease into the well bore.

4.10 Spacer Spools, Adaptor Spools, Crossover Connectors, Wireline Adaptors

The following shall apply:

a) The spacer spools, adaptor spools, and crossover connections to meet or exceed all requirements stipulated in API 6A, with fasteners and bolting conforming with requirements of API 16B Section 4.3.3.

b) Spacer Spools, adaptor spools and crossover connections to be capable of withstanding the applied loads and combination of loads shown below (as a minimum):

   1) compression loads generated by the pressure control equipment on top of the assembly;

   2) bending loads including but not limited to those generated by the wireline back tension, dynamic motion, and wind loads;

   3) loads due to internal pressure.

   4) Where the bending loads cannot be completely mitigated, the flanged connections to be subjected to derating as per API 6AF2.

4.11 Periodic Maintenance and Inspection

The following shall apply:

a) The inspection and maintenance of the pressure control equipment to be performed in accordance with the equipment owner's maintenance system. The equipment owner's maintenance system to meet or exceed the OEM's maintenance recommendations.

b) The equipment owner's maintenance system to address the inspection (e.g. internal/external, visual, dimensional, NDE, etc…) of pressure control components.

c) The maintenance of PCE and parts within each component to be performed by a competent person.

d) Elastomeric components and the finishes of their seal surfaces to be inspected when the equipment is disassembled.

e) Replacement parts (consumables) to be in conformance with the relevant API standards and satisfy the design/operating requirements as specified by the OEM.

f) The pressure control equipment is to be inspected at least every 5 years.

   1) The inspection frequency period to begin using one of the following criteria:

   2) The date the equipment owner accepts delivery of the pressure control component(s) unless placed into storage in accordance with **4.15**

   3) The date the inspected equipment is placed into service, where preservation and storage records in accordance with **4.15.**

   4) The date of the last inspection for the equipment, if preservation and storage records in accordance with **4.15** are not available.

g) A record of maintenance or repair history for each pressure control stack component to be retained by serial number or unique identification number available for review by the user

h) Records of maintenance/testing/inspections to be retained for the life of the equipment.

i) The maintenance records (either hard copy or electronic storage) to be available onsite for the selected pressure control equipment.

4.12 Equipment Preservation

4.12.1 Pressure control equipment should be stored in a manner that prevents degradation of the equipment's integrity in accordance with the equipment owner's or manufacturer's requirements.

4.12.2 Before returning to service, the components shall be inspected and tested in accordance with the original manufacturer's requirements and specifications.

4.12.3 Elastomer seals found to be outside of the manufacturer's recommended shelf-life expiration date shall not be installed in pressure control equipment systems

4.12.4 Sealing areas and threads should be protected from corrosion and damage.

4.12.5 Thread protectors should be used, when possible, to protect the equipment.

4.12.6 External equipment surfaces should be painted or coated for corrosion resistance as needed.

4.13 Pressure Control Elastomers

4.13.1 General

Degradation of the elastomers' physical and mechanical properties can result in loss of pressure containment.

The following shall apply:

a) Elastomers and seals used in pressure control equipment to be selected based on liquids, gasses, pressures, and temperatures anticipated to be encountered.

b) The service provider of the pressure control equipment to document that recommended elastomers and seals are installed.

c) The OEM or elastomer manufacturer to be consulted regarding selection of the elastomer for a prescribed service.

d) Elastomer selection criteria to at least include the following performance parameters:

(1) rapid gas decompression (RGD);

(2) chemical compatibility;

(3) temperature performance range;

(4) extrusion resistance;

(5) abrasion/erosion resistance; and

(6) pressure rating.

NOTE The listed criteria are not exclusive and are interrelated. See API 6J for additional information on the testing of oilfield elastomers. See API 16B for additional information on the validation of elastomers.

4.13.2 Rapid Gas Decompression

Some elastomers are more resistant to the effects of RGD than others. Seal performance in RGD is highly dependent on both the materials and seal geometries (seal assembly and seal gland) employed. It should be noted that while special decompression resistant grades of material are commercially available, some seal geometries (e.g. exposed and relaxed seals on rams) are always susceptible to damage by RGD.

The decompression rate is critical, below 1000 psig as most seal damage will occur below this pressure. Unless otherwise recommended by the manufacturer, the decompression rate should not exceed 75 psig per minute when the pressure within the pressure control stack is below 1000 psig. The depressurization rate to 1000 psig should not exceed a rate that contributes to mechanical damage of the seal assembly.

NOTE Carbon Dioxide (CO2) and other impurities can increase susceptibility to RGD damage in some materials.

4.13.3 Chemical Compatibility

Incompatibility issues may result in degradation of performance of the sealing elements. Incompatibility with fluids may lead to softening or hardening depending on the fluid and material involved. The use of solvents normally leads to softening and the potential for mechanical damage, including extrusion. Elevated temperatures will increase chemical activity.

Operational procedures may be used to minimize the detrimental effects of chemical exposure to elastomers within the pressure control stack. These options include, but are not limited to the following:

a) continuous injection of inert fluids or inhibitors across the pressure control stack rams to displace chemically active fluids;
b) operational procedures that prevent chemically active fluids from entering the pressure control stack;

c) application of a protective coating.

4.13.4 Temperature Performance Range

The elastomers shall perform across the range of temperatures encountered during operations.

Exceeding the temperature capability of an elastomer can result in softening or hardening, and/or other changes in physical properties. Changes at low temperature are typically reversible physical changes, while those at elevated temperature are normally chemical and irreversible.

Temperature changes may arise from, but are not limited to, the following:

a) ambient temperature extremes before, during and after the operations;

b) wellbore temperatures;

c) bleed down operations causing cooling due to the Joule-Thompson effect;

d) heated treatment fluids;
e) cryogenic fluids.

Operational procedures may be used to keep the elastomers within the OEM temperature range limits. These options include:

a) continuous injection of cooling fluids (in hot environments) or heated fluids (in cold environments) across the pressure control stack rams and piping, and;

b) controlling the external operating environment of the pressure control stack and piping.

4.13.5 Extrusion Resistance

For some seal glands, the seal geometry requires mechanical support from either thermoplastic or metallic anti-extrusion devices, as per the manufacturer's recommendations, to avoid extrusion damage.

4.13.6 Abrasion/Erosion Resistance

Abrasion and erosion issues can compromise the sealing integrity of the elastomers. To minimize the effects of abrasion/erosion:

a) ensure that the pressure control stack rams are retracted and out of the fluids flow path when not closed;

b) select an elastomer material appropriate for the operating conditions;

c) consider abrasion by pumped fluids when using elastomer-lined piping systems (high-pressure pump line hoses).

4.13.7 Pressure Rating

The elastomers shall be suitable for the pressure rating of the equipment component in service.

4.13.8 Exposure

If the pressure control stack elastomers have been exposed to conditions which exceed the limits of the elastomers (e.g. RGD, temperature, chemical), the pressure-sealing components with the exposed elastomers should be replaced at the earliest opportunity.

4.13.9 Fatigue Life of Pressure Control Stack Ram Packers

The fatigue life of the elastomers is determined using API 16B (operational characteristics test procedure: fatigue test). The fatigue life of the ram elastomers should exceed the anticipated cycle frequency during the well operation.

Durometer

The durometer of the elastomers should be appropriate for the well conditions during operations.

4.13.10 Age Control and Storage of Non-metallic Seals

All elastomers shall be stored in their original opaque and sealed packaging as per OEM recommendations to avoid exposure to oxygen, ultraviolet light, heat and ozone which are damaging to some types of elastomers. For storage of elastomers, the following should apply:

a) age control;

b) indoor storage;

c) maximum temperature and humidity not to exceed OEM storage recommendations;

d) protected from direct natural light;

e) stress conditions (see text below);

f) stored away from contact with liquids;

g) protected from ozone and radiographic damage.

Packaging and storage of nonmetallic seals shall not impose tensile or compressive stresses sufficient to cause permanent deformation or other damage.

The elastomer manufacturer should provide written requirements for preservation of nonmetallic seals in storage.

4.13.11 Product Marking

Manufacturers' marking on well control elastomers or packaging should include the following:

a) manufacturer;

b) durometer hardness;

c) generic type of compound;

d) date of manufacture (cure date);

e) part number, and

f) shelf life.

When replacing the elastomeric seals, the packaging identification shall be compared with the OEM documentation to ensure that the replacement seals conform with the OEM requirements.

4.13.12 Equipment in Storage

Elastomers can degrade while in stored equipment. Stored equipment shall be tested before each use and elastomers to be replaced upon failed test.

5. Pressure Control Equipment Operating System

5.1 General

The pressure control equipment operating system typically provides a source of pressurized hydraulic control fluid (power fluid) to operate the pressure control equipment requirements. The design of the operating system, equipment and circuitry varies in accordance with the application and environment.

a) The Pressure Control Equipment Operating System is able to function all applicable equipment in the pressure control stack. The pressure control equipment is sorted into 3 main categories.

   1) Primary Rams
      i. Wireline Rams
      ii. Blind Ram
      iii. Primary Shear Ram
      iv. Primary Shear-Blind Ram

   2) Dedicated Shear & Seal Device

   3) Pack-Offs & Auxiliary Tools
      i. Pack-Off / Stuffing Box
      ii. Tool Trap
      iii. Tool-Catcher
      iv. Vent or Injection Sub
      v. Hydraulic Quick Latch
      vi. Auxiliary Valves or Tools

b) The pressure control equipment operating system shall be an independent system dedicated exclusively to the operation of pressure control equipment.

   NOTE An Independent system includes a dedicated power source, prime mover(s), pump system(s) and control system.

c) The pressure control operating system for any of the main pressure control equipment categories can be an independent unit or can be combined into a single unit as per the operator's preference

d) If the pressure control operating system is designed as a single unit to control all 3 main categories it shall be configured to include at minimum, three independent sub-circuits that make up the independent hydraulic system and be isolated from one another. The minimum three independent sub-circuits are as follows:

   1) Primary Ram Control Sub Circuit: Hydraulic sub-circuit that is solely used to operate the primary rams in the pressure control stack. An independent and isolated accumulator bank and control circuit shall be used

   2) Dedicated Shear & Seal Device Control Sub Circuit: Hydraulic sub-circuit that is soley used to operate the required dedicated shear & seal device in the pressure control stack. An independent and isolated accumulator bank and control circuit shall be used

3) Packoff and Auxiliary Tool Sub Circuit: Hydraulic sub-circuit that is soley used to operate the packoff(s) and all other Auxiliary Tools used in the pressure control

stack. Any type or form of independent and isolated control circuit may be used. This may include an accumulator bank circuit, manual pump circuit, or dedicated pump circuit as applicable.

e) The Pressure Control Equipment Operating System shall be capable of running in all possible environments and temperatures required for the intended operation. This includes any hazardous location requirements.

f) The pressure control operating system may also contain the Grease Injection Operating System if applicable as additional sub circuits. See Section 5.5 for the specific requirements

A risk assessment shall be performed if the pressure control operating system does not comply with section 5.1

5.2 Primary Ram & Dedicated Shear & Seal Device Control Requirements

The Pressure Control Equipment Operating System for the Primary Rams and/or Dedicated Shear & Seal Device shall contain the following components at minimum:

a) Power Source
b) Prime mover (Powers the pump system)
c) Pump system (pressurizes the hydraulic control fluid)
d) Accumulator bank (stores power fluid)
e) Fluid Reservoir
f) Control panel, manifold and hoses (for transmission of power fluid to pressure control stack components)
g) Hydraulic control fluid
h) Visual and Audible Alarm systems.

NOTE When pressurized, hydraulic control fluid is referred to as power fluid.

5.2.1 Power Source

Power sources include the means to power the operating system(s) as well as the means to power the Prime Mover, pump systems and other individual pressure control components,

There should be a method to disconnect or isolate the Pressure Control Equipment Operating System from the Power Source while the Power Source is operational. Loss of any power source shall not immediately cause the loss of control of any Pressure Control Equipment.

The restoration of power to Pressure Control Equipment Operating System shall not result in the automatic operation of any control system function.

The Pressure Control Equipment Operating System only requires the capability to connect to a minimum of one power source at a time. If only a single power source is used, a secondary power source shall be available on site and be able to integrate with the Pressure Control Equipment Operating System.

If the Pressure Control Operating System for the Primary Ram and Dedicates Shear & Seal Device are combined into a single unit, the power source(s) used to drive the Primary Ram Control Sub Circuit & Dedicated Shear & Seal Device Control Sub Circuit may be the same.

A Power source may be one of the following:

a) Internal Combustion Engine
b) Electrical Generator
c) Utility or Shore Power Connection
d) Air Compressor
e) Battery Bank that is capable of being charged on site
f) Other suitable options are permitted if they meet the intended operating requirements.

5.2.2 Prime Mover

The prime mover is powered by the power source and drives the pump system

A minimum of one prime mover is required per pump system

The prime movers shall be powered or connected so the failure of one prime mover does not impair the function of the other prime mover and pump system

A prime mover may be one of the following.

a) Internal Combustion Engine
b) Electric Motor
c) Compressed Air Motor
d) Other suitable options are permitted if they meet the intended operating requirements.

5.2.3 Pump System

The pump system(s) provide power fluid to their respective pressure control equipment components. The following shall apply:

a. A minimum of two pump systems installed (Primary Pump System and Secondary Pump System(s)); a pump system may consist of one or more pumps.

b. If the Pressure Control Operating System for the Primary Ram and Dedicated Shear & Seal Device are combined into a single unit, each individual sub-circuit can be powered by the same pump system(s) if a dedicated and isolated accumulator bank is used in each sub-circuit.

c. The pump systems connected so that the loss of any one pump system does not impair the operation of any other pump systems, including pump suction lines (valve and Y strainer) and discharge lines (discharge check valves).

d. Each pump system shall be capable of providing a discharge pressure at least equivalent to the RWP of the Pressure Control Operating System

e. The cumulative output capacity of the pump systems sufficient to charge all independent accumulator banks from pre-charge pressure toa minimum 97% of the system RWP within 15 minutes.

f. With the loss of one pump system, the remaining pump systems are to have the capacity to charge all independent accumulator banks from pre-charge pressure to 97% to 100% of the system RWP within 30 minutes.

g. When applicable, the primary pump system is to automatically start before system pressure has decreased to 90% of the system RWP and automatically stop pumping fluid between 97% to 100% of the RWP

h. When applicable, the secondary pump system is to automatically start before system pressure has decreased to 85% (of the system RWP and automatically stop between 95% to 100% of the system RWP.

i. Each pump system to be protected from over pressurization by a minimum of two devices as follows:

j. i. one device to limit the pump discharge pressure so that it will not exceed the RWP of the Pressure Control Operating Systems.

k. Ii. the second device, such as a relief valve, to limit the unit pressure to not more than 10% above system RWP.

l. Iii. Devices used to prevent pump system over pressurization to be installed directly in the pump discharge line and not have isolation valves or any other means that defeat their intended purpose. Rupture discs or relief valves that do not automatically reset are not to be used.

m. If air-actuated hydraulic pumps are used, the air actuated hydraulic pumps be capable of charging the system to 97% to 100% RWP with 75-psig minimum air pressure supply.

n. If applicable, the Pump Systems to have the means to isolate the pump(s) from one another to allow online maintenance if required

o. The secondary pump system may be external to the unit if properly integrated into the hydraulic system.

p. Manually Operated Pumps not to be used as the Primary or Secondary Pump Systems only as tertiary pump systems if applicable

5.2.4 Accumulator Bank General Requirements

The following shall apply:

a. Each accumulator bank to have two or more accumulators that store hydraulic fluid under pressure. The stored energy within each accumulator bank is used to function pressure control components, independent of the pump system.

b. Each accumulator bank to have a means to bleed and drain the accumulator power fluid back to the fluid reservoir

c. The accumulator bank piping to have the means to isolate the accumulator(s) from the accumulator bank manifold line. Isolation is to be set up so the loss of an individual accumulator does not cause the loss of more than 50% of the independent accumulator bank volume

d. Each independent accumulator bank to be protected by at least one pressure relief valve set at a pressure no greater than 10% of the RWP of the hydraulic circuit.

e. Pressure relief valve(s) to be installed directly in the accumulator banks manifold circuit downstream of the pump line check valves and not have isolation valves or any other means that defeat their intended purpose. Rupture discs or relief valves that do not automatically reset are not allowed.

f. No accumulator bottle are to be operated at a pressure greater than its RWP.

g. The accumulator(s) bladder used are to meet the temperature requirements of the system

h. Accumulators are to be mounted in the orientation specified by the accumulator(s) OEM.

5.2.5 Accumulator Capacity Requirements

The accumulator capacity requirements (ACR) of each applicable independent accumulator bank (Primary Ram Accumulator Bank and Dedicated Shear & Seal Device Accumulator Bank) shall meet or exceed the required Functional Volume Requirements (FVR) indicated below. The ACR shall be met with pumps inoperative. Accumulator sizing calculations shall follow the requirements outlined in Annex C or another appropriate real gas calculation technique**.**

Primary Ram Control Sub Circuit:

a) Complete a drawdown test that consists of a Close-Open cycle of each Primary Ram set and still have 200 psi above pre-charge pressure.

b) Close each Primary Ram in the stack and verify that sufficient accumulator bank pressure is available to:

1) Close the Ram at MAWP and establish a proper seal.

2) If a shearing ram is included in the Primary circuit, the pressure required to

shear the maximum line diameter expected during operations at MAWP and form a seal if applicable.

3) If the Primary Rams have different volumes or closing pressure requirements all orders and combinations of closure must be analyzed.

Dedicated Shear & Seal Device Control Sub Circuit:

a) Complete a drawdown test that consists of a Close-Open cycle of the Dedicated Shear & Seal Device and still have 200 psi above pre-charge pressure

b) Complete a Shear & Seal close cycle and have enough pressure to shear the maximum line diameter used in operations at MAWP and form a seal.

5.2.6 Accumulator Pre-Charge

The accumulator pre-charge pressure provides the minimum stored potential energy needed to propel the power fluid from within the accumulators.

A pre-charge pressure shall be used to provide the required ACR as described above in the applicable operating environment, without exceeding the RWP of the accumulator. The calculations listed in Annex C can be used to help determine the required pre-charge for the applicable operating environment.

Pre-charge practices shall conform to the following:

a) The accumulator to be pre-charged with inert gas only.
b) Pre-charge pressure to be at least 25% of RWP of the Hydraulic Operating System

5.2.7 Fluid Reservoir

The following shall apply:

a. The hydraulic fluid reservoir to be at least two-times the stored hydraulic fluid capacity of the operating system, which may include accumulator bank(s), control valve manifolds and all pressure control equipment components.

b. If the Pressure Control Operating System for the Primary Ram and Dedicated Shear & Seal Device are combined into a single unit, the fluid reservoir used to supply the Primary Ram Control Sub Circuit and Dedicated Shear & Seal Device Control Sub Circuit may be the same.

c. The hydraulic fluid reservoir to be equipped with at minimum the following:

1) Pressure relief valves or vents to avoid over-pressurization.

2) Inspection/cleanout Port

3) A means to determine hydraulic control fluid level

4) Pump suction port(s) with a valve(s) to isolate the supply. Each pump system to have its own suction port and isolation valves.

5) Fluid return port(s) from the pressure control stack components and, accumulator bank(s**).**

d. Control fluid reservoirs are to be cleaned, flushed of contaminants, and have vents inspected before fluid is introduced in accordance with the equipment owner's maintenance system

5.2.8 Operating System Response Time

The Operating System response time is measured from initial component actuation to confirmed closure of the component and establishment of an effective pressure seal. The function of a Pressure Control component may be confirmed through observation of the visual position indicator (closed or opened), or when recovery of the decrease in operating system pressure due to frictional pressure losses in the control lines is observed.

If confirmation of pressure seal off is required, a pressure test below the ram component or across the valve shall be performed.

The following shall apply:

a. The Pressure Control Equipment Operating System to have a response time capable of closing the Primary Ram within 30 seconds or less. When multiple Primary Rams are installed, each subsequent ram are to fully close within 30 seconds or less following closure of the previous Primary Ram.

b. The Pressure Control Equipment Operating System to have a response time capable of closing the Dedicated Shear & Seal Device in 30 seconds or less.

5.2.9 Control Panel, Control System, Manifold and Hoses

The following shall apply:

a. The pressure control equipment operating system to be equipped with one or more control panels to control all required functions.

b. Any control circuitry to be designed such that a leak or failure in one circuit does not cause the unintended operation of another function.

c. If a digital, or non-manually operated control system is utilized, a formal risk assessment (e.g., FMEA) to be conducted to verify that the control system responds appropriately under all intended operating conditions and credible failure modes.

d. If a digital or non-manually operated control system is utilized, an accessible method to manually operate all Primary Ram and Dedicated Shear & Seal Device control valves to be available in case of control system failure.

e. All control valves, manifolds and hoses to be sized to operate all Primary Rams and Dedicated Shear & Seal Devices as per the response time requirements of section 4.5.

f. The control panel to provide the following:

1) Two-step operations to function all Primary Rams and Dedicated Shear & Seal Device to avoid unintentional operation.

2) All Primary Ram and Dedicated Shear & Seal Device valves are to be clearly marked to indicate:

   I. the pressure control component operated, and

   II. the position of the pressure control component actuators - open, close, and if applicable neutral.

3) Controls to operate all prime movers and pump systems

4) Displays to monitor all independent accumulator banks pressure, pressure control component pressure (open and close), and pump supply air pressure (for all systems using air-operated pumps and air operated panels).

c. All valves, fittings, piping, flexible lines, hoses, and other pressure retaining components such as pressure switches, transducers, transmitters, etc., to have a RWP at least equal to the RWP of the circuit in which it is installed.

5.2.10 Piping

5.2.11 Pipe and tubing shall conform to specifications of ASME B31.3 or an equivalent recognized national or international standard.

5.2.12 External Hoses Connected to Pressure Control Equipment

The following shall apply:

a) All external hoses used to operate the Primary Ram and Dedicated Shear & Seal Device Control System, assembled in the pressure control stack to comply with the following:

b) All hoses to be appropriately sized for the equipment component in service to minimize frictional pressure losses due to expected fluid flow and rated for the working pressure of the system, as installed, to meet the closing time requirements as per section 4.5

c) The hose assemblies to have a minimum burst pressure of 1.5 times the RWP.

d) Dedicated Shear & Seal Device hoses directly connected to the pressure control stack PCB components located in a division one (1) area, as defined by API 500 or a Zone 1 area as defined by API 505, to comply with the fire test requirements of API 16D.

e) The minimum length of each fire-resistant control hose directly connecting to the Dedicated Shear & Seal Device to be determined by API 500 or API 505.
f) The end connection joining the fire-resistant hose to the remainder of conventional hydraulic control hose to be through a fitting having fire-resistant qualification.

5.3 Hydraulic Control Fluid

5.3.1 General

The following shall apply:

a. The hydraulic control fluid to comply with the recommendations of the equipment manufacturer and meet or exceed local requirements for environmental safety.

b. The control fluid to be maintained to prevent freezing when necessary.

5.3.2 Hydraulic Fluid Filtration

The following shall apply:

a. The hydraulic fluid to be continually filtered to ensure proper operation in accordance with the Pressure Control Operating Systems manufacturers requirements

b. Filters may permit manual or automatic bypassing of clogged elements rather than interrupting system operation. If automatic bypass is utilized, a bypassing indicator is to be included.

c. Filter housings to be mounted in an accessible location to facilitate maintenance

5.3.3 Alarm Systems

The following shall apply:

a. Tank(s) used to serve as a hydraulic fluid reservoir to be equipped with fluid level alarms to indicate a “low fluid level condition”.

b. Each independent accumulator bank to be equipped with a low-pressure alarm to indicate a “low power-fluid pressure” condition

c. If applicable, each air-actuated hydraulic pump system to be equipped with a low-pressure alarm to indicate a “low air pressure” condition.

d. All alarm systems described are to provide both visual and audible alert devices to identify the Pressure Control Operating System experiencing the defined alarm conditions

5.4 Packoff and Auxiliary Tool Hydraulic Circuit Requirements:

5.4.1 A minimum of one hydraulic pump shall be provided for each pack-off and auxiliary tool circuit unless an accumulator bank is incorporated into the system.

5.4.2 When an accumulator bank is utilized, all pack-off and auxiliary tool functions may be supplied from a common hydraulic pump.

Acceptable pump types include:

a) manually operated hydraulic pumps;

b) air-actuated hydraulic pumps;

c) regulated hydraulic pumps;

d) accumulator banks charged by a hydraulic pump.

e) Alternative pressure delivery systems that meet OEM performance requirements and have been risk assessed

The following shall apply:

a. Each pump to be capable of delivering a discharge pressure not less than the RWP of the pressure-control equipment operating system.

b. When an accumulator bank is utilized, no minimum accumulator volume is prescribed; however, the accumulator system is to be sized to ensure all required functional and performance requirements are met under all expected operating conditions.

c. Each pack-off and auxiliary tool to have a means to individually control and monitor all required functions.

d. When the pack-off and auxiliary tool circuits are combined as a sub-circuit with the primary ram circuit, a common pump or pump system may be used, provided that an isolated, independent accumulator bank is installed for the pack-off/auxiliary circuit. The accumulator bank requirements of 5.2.4 to be met.

e. When the pack-off and auxiliary tool circuits are combined as a sub-circuit with the primary ram circuit, a common fluid reservoir may be used

5.5 Operating & Functional Testing Requirements

5.5.1 Operating Requirements

The following shall apply:

a. Each ram control actuator to remain in the open or close position (not the neutral position) during well service operations.

b. All pressure control equipment operating hoses and monitoring cables to be supported though bridles or brackets which are secured to the stack to eliminate axial tensile loading on the end connections during any stage of well intervention service.

c. All pressure control stack operating hoses and monitoring cables to remain connected throughout the well intervention operation and be pre-deployed in a manner where movement of the pressure control stack does not require changes in any of the mechanical components or connections providing hydraulic flow or signal communication (hose reels, points of severe turns, bending or kinking of lines, etc.).

5.5.2 Functional Testing Requirements

The following functional tests shall be performed prior to the start of any job to ensure the complete system including the Pressure Control Equipment and Pressure Control Equipment Operating System are properly functioning.

a. The function of a pressure control component may be confirmed through observation of the visual position indicator (closed or open), or when recovery of the decrease in operating system pressure due to frictional pressure losses in the control lines is observed.

b. Confirmation of pressure seal-off shall be required. A pressure test below the ram component or across the valve to be performed.

c. The operating system for all pressure control stack ram components to provide a response time of 30 seconds or less for closure and completion of function.

d. The closing time using only the accumulator system (pumps disabled) to be confirmed through testing onsite, at atmospheric pressure, and evaluated to determine whether the closing time is appropriate for the intended service (see annex D for an example WL accumulator drawdown test form).

e. Pressure Control Equipment Operating System Pressure Test – Hook-up all control hoses to their applicable PCE as will be conducted during the job - Pressure up hydraulics and set all PCE Control Valves to the Close Position and Hold for 15 minutes after stabilization. Re-conduct the test with the valves in the open position. Acceptance Criteria – No Visible Leakage.

f. Pressure Control Equipment Operating System Fill Time Test – Starting with all hydraulic system bled off use all pumps to fill accumulator to Max Rated Hydraulic Working Pressure. The time to fill the accumulator to be less than 15 minutes.

g. The pre-charge pressure and body temperature of the record to be taken after the accumulator has reached thermal equilibrium (typically 30 minutes) after pre-charge activities.

5.6 Grease Injector Operating System

5.6.1 The grease-injector operating system, delivers controlled, pressurized grease to the Pressure Control Equipment, forming the dynamic and static seal necessary to maintain wellbore pressure integrity of applicable wireline types during operations for the grease head, liquid seal stuffing box or between closed wireline rams.

5.6.2 The operating controls shall be located either on or adjacent to the grease injector system and operated through the control circuit described below.

5.6.3 The grease injector control system shall conform to the following:

a) Two independent pressure delivery systems. Manually powered pressure delivery systems shall not be used unless as a tertiary back-up.

b) Examples of grease delivery systems include

1) Air Driven Grease Delivery Systems

2) Dual Medium Intensifier Grease Delivery Systems

c) Two independent power sources

d) Each pressure delivery system shall be capable of providing sufficient wireline grease volume at the RWP of the Pressure Control Equipment of the well at the grease-head or wireline ram assembly.

e) Hoses of sufficient length, size and pressure/chemical ratings for the prescribed services and required flowrates.

f) A sufficient volume of wireline grease (see section 6.9)

g) A means to monitor grease pressure and control the delivery of grease to the required Pressure Control Equipment component

h) A means to control the output pressure of the supplied grease.

5.6.4 If built as a sub circuit into the Pressure Control Operating Control System the same power sources and prime movers may be utilized (stacking of pumps) if individual pumps are utilized for the grease delivery system and two individual dedicated power sources are used. (One power source to power each prime mover). Figure 1 shows an example circuit configuration diagram

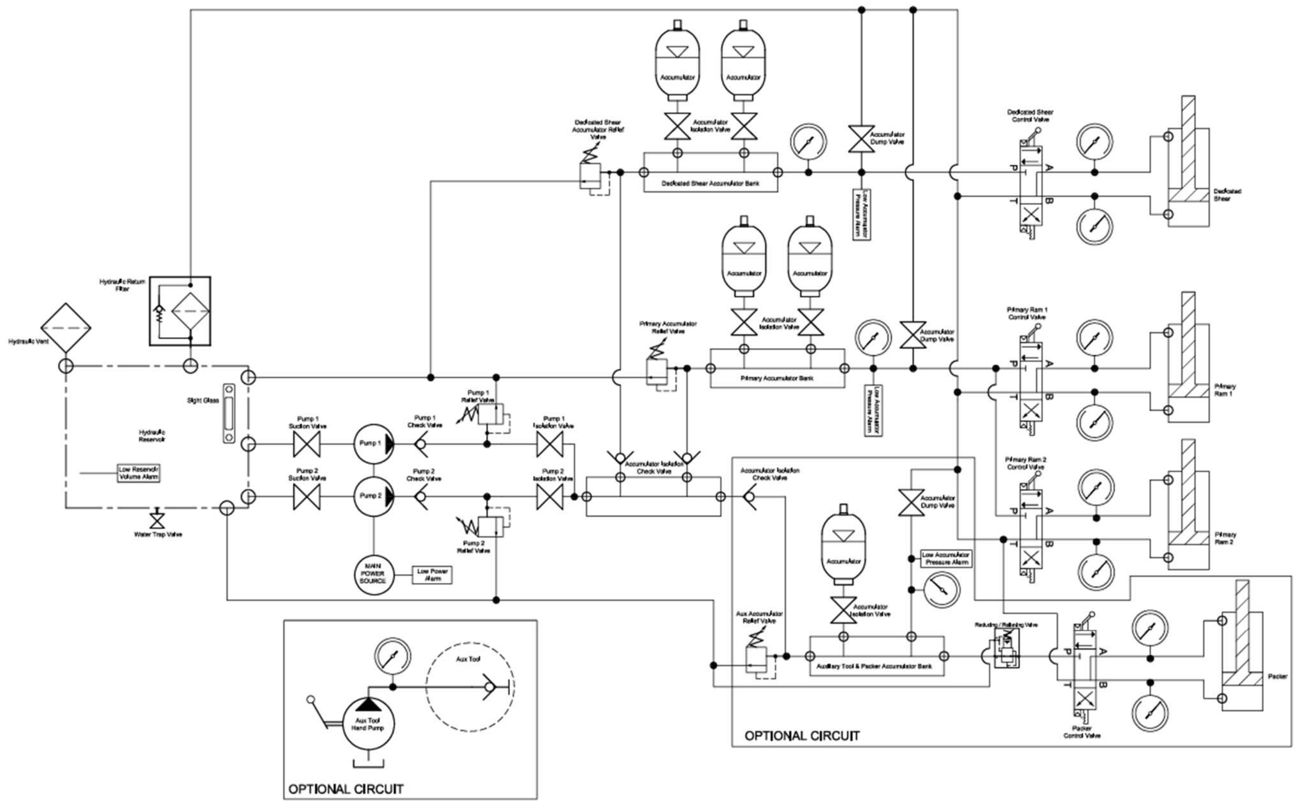

Figure 1: Example circuit configuration diagram

6. Pre-Mobilization Planning

6.1 General

A planning meeting should be held with parties to clearly define operational objectives. The scope of work, services, required equipment, materials, and well intervention procedures should be outlined. A health, safety and environmental (HSE) plan should be developed to cover items such as well site orientation, hazard identification, safety data sheets (SDSs), and Contingency Planning

The information from 6.2 through 6.9 should be considered in preparation for wireline intervention service applications.

6.2 Job Planning Deliverables, Criteria,

The job plan should include the following:

a) Operational objectives

b) Scope of Work

c) Services, equipment and Personnel required

d) Identify Well characteristics Listed in 6.2 and 6.3

e) General tool string parameters (length, wt, specific / detail) OD. Fishing neck, cable head, weak link, releases…... centralizer, roller boogies, tractors, ………… Listed in 6.4

f) Identify wireline, (type, size alloy, temp specifications……) Listed in 6.4

g) Winch requirements based on well geometry (i.e. capstan) (will require conveyance simulations) See 6.5

h) Run sequence, (i.e. gauge run, dummy, etc.), See 6.5

i) Operational parameters (running speeds, tension limits, etc.) See 6.5

~~j)~~ Identify Personnel requirements/qualifications, and number of personnel needed.

k) Identify WPCE (include stackup specs, lubricator lengths, elastomers, grease selection, accumulator sizes, connections, & interfaces)

l) Identify Logistical requirements (availability of people, material, equipment, supplies, transportation, location etc…)

m) Emergency / contingency procedures contingency materials and equipment)

6.3 Wellbore—Physical Characteristics

Wellbore physical characteristics should include the following:

a) Tubing/casing sizes, weights, grades, depths, and connection type

b) Dimensions, depths, and description of downhole completion components

c) Directional survey

d) Fluid type, composition, levels, and density in the well (H2S, Co2, Gas, Liquid, Etc.)

e) Description of current completion including wellbore diagram

f) Location and dimension of obstructions or restrictions (lost tool-strings, junk, corkscrewed pipe/tubing, etc...)

g) Specifications of wellhead and related surface equipment, including wellhead interface connections.

h) Location and type of wellbore safety devices

i) Known wellbore problems, including corrosion, mechanical damages, etc.…

j) Current casing and/or tubing pressure capacities

k) Well history (workovers, wireline work, issues, etc.)

l) Fluid temperature (minimum and maximum)

6.4 Reservoir—History and Current Parameters

Reservoir history and current parameters should include the following:

a) Reservoir type and characteristics
b) Reservoir temperatures
c) Description and location of all zones communicating with the wellbore
d) Initial and current static and flowing tubing pressures
e) Initial and current static and flowing bottomhole pressures
f) Maximum potential shut-in pressure
g) Type(s) of produced fluids and maximum potential production rates
h) Conditions which can promote erosion, corrosion, scale, asphaltene, or other issues
i) Known field issues

6.5 Wireline and Tool String-

Identify all the parameters for the wireline and the tool string:

a) Tool String length with detailed information (OD's, centralizers, roller stems, tractors etc.)
b) Tool string weights
c) Cablehead weak points
d) Fishing Neck Profile
e) Wireline being used, to include (Type, size, alloy, temperature limits, etc.)

6.6 Wireline Operations-

Identify all the operating parameters for the wireline operations:

a) Cable Requirements
b) Winch Requirements (Capstan, etc.)
c) Run sequence (Gauge Run, Dummy Run, plug Setting, Logging, etc.)
d) Running Speeds
e) Tension limits
f) Conveyance analysis
g) Contingency operations (see Annex A)

6.7 Location—Physical, Environmental, and Regulatory Factors

The location factors should include:

a) type of facility (land, floating, fixed platform, etc.…)
b) location layout and operational constraints
c) crane capacity and reach
d) pollution prevention and containment
e) other operations in near proximity, including non-petroleum activities such as farming, fishing, hunting, tourism, as well as other environmental concerns
f) handling and disposal of fluids and materials
g) logistical support
h) governmental and regulatory agency regulations
i) property owner concerns
j) Access to emergency services.

6.8 Location—Equipment Layout and Requirements

Location equipment layout considerations should include the following:

a) location constraints (load limit, overhead obstructions, and site dimensions);
b) identification and classification of hazardous areas
c) dimensions and weights of service equipment
d) placement and orientation of equipment
e) location and description of remote-control operator panels and emergency shutdown devices (esd)
f) escape routes and accessibility
g) tiedown locations
h) “line of fire area” for personnel and equipment access, movements, or locations
i) simultaneous operations

6.9 Pressure Control and Wireline Equipment

Pressure control equipment considerations (to be based on criteria from sections 4.1 – 4.7) should include the following:

— type, size, configuration, and pressure rating of pressure control equipment required (see section 4);

— personnel assignments and responsibilities (see section 8);

— pump in sub (kill port) pressure ratings, and configurations (see section 4);

— consideration of corrosive fluids;

— hydrate prevention considerations (i.e., glycol or methanol water mix);

— wireline type requirements and tensile rating, configuration, and history;

— test pump unit requirements, pressure rating and configuration;

— review of on-site pressure testing procedure (see section 7);

— tree connection, spacer spools, and crossover spool requirements (see section 4) note: include WPCE connection;

— control system power source, capacity, pressure, and closing time requirements (see section 5);

— seal and elastomer compatibility with pumped and reservoir fluids;

— shearing capabilities;

— ambient temperatures;

— WPCE service type (standard, H_2S);

— Wireline grease compatibility and volumes.

6.10 In environments where hydrate formation is possible the capability to inject glycol, methanol-water mixtures, other fluids, equipment and/or operational procedures that prevent freezing or the formation of hydrates should be used.

6.11 In environments where freezing (i.e. fluids in wireline grease return line freezing) is possible, you shall have the means to prevent it from occurring.

6.12 External supports (e.g. guide wires, crane, support structure) should be used to reduce bending and transmitted loads from the equipment onto the connections.

6.13 An appropriately sized crane or support structure is the primary means of minimizing loads within the pressure control stack and shall be capable of supporting these loads. Visual inspections shall be done to verify the pressure control stack and rig up are maintained as inline and straight with the tree as is practical.

7. Pressure Control Equipment Testing

7.1 General

a) The pressure control equipment including, but not limited to, the pressure control stack, flow lines, kill lines, manifolds, valves and spacer spool segments, shall be tested in accordance with 7.4 to 7.8

b) A WPCE testing plan shall be developed to verify and develop the following:

— The WPCE's previous pre-job shop performance testing and documentation.

— The planned pressure and function testing protocols to be followed and documented at the well site.

7.2 Pre-Job Shear/Seal Device and Shear-Blind Shearing and Pressure Test

a) The performance tests for the shear/seal device and SBR shall be reviewed and available to confirm that the pressure control component is fit for purpose.

b) The shear/seal device and SBR shall demonstrate the ability to seal the ID bore of the well control stack to the equipment's RWP l. The shear/seal device and SBR pressure test protocol, frequency and performance requirements shall be in accordance with Section 7.4 to 7.8

7.3 Pre Job Pressure-sealing Device and Ram Locks

The following shall apply:

a) The ram locking system on the pressure sealing rams (Shear/Seal and SBR) to be performance tested to confirm that the rams remain closed and maintain the pressure seal to the established test criteria after removal of hydraulic actuator pressure applied to the rams.

b) The ram locking performance tests to be conducted at a minimum test frequency of 365 days to the RWP of the ram component.

c) Records documenting the performance pressure tests using only the ram locking system to be available for review.

7.4 Pressure Testing Criteria

All pressure control equipment components shall be pressure tested. The pressure test sequence consists of a low-pressure test, followed by a high-pressure test.

The pressure test fluid should be water or some other solids-free liquid with a flash point greater than 100 °F.

7.5 Low-Pressure Test Criteria

The following shall apply:

a) Pressure control components to be subjected to a low-pressure test (250 psig to 350 psig).

b) The pressure is to be maintained at stabilized pressure with no visible leakage for at least five minutes.

c) Any initial pressure above 350 psig is to be bled back to a pressure between 250 psig and 350 psig before starting the test.

d) If the initial pressure exceeds 500 psig, the pressure is to be bled back to zero and the test reinitiated.

NOTE: A pressure of 500 psig or greater could energize a seal that may continue to hold pressure after bleeding down and, therefore, not be representative of an acceptable low-pressure test.

7.6 High-Pressure Test Criteria

The following shall apply:

a) Pressure control components to be subjected to a pressure, equal to MAOP or MASP, plus 500 psig, whichever is greater.

b) The allowable test pressure tolerance above RWP not to exceed 5% of RWP or 500psi, whichever is less.

c) The pressure shall not decrease below the intended test pressure.

d) The pressure is to be stabilized with no visual leakage for a minimum of 5 minutes.

e) When using pressure decay evaluation algorithm software for pressure testing, the pressure drop will satisfy the documented criteria with a stable pressure or decreasing decay rate during the evaluation period.

7.7 Types of Pressure Control Equipment Tests – At Well Site

The following are descriptions of the types of pressure tests that should occur at the well location.

a) Pressure control barriers, example Shear-Seal Ram: a pressure integrity test used to verify the ability of the pressure control component to maintain the designated pressure seal(s) when closed.

b) System pressure test: a full-body pressure integrity test used to verify the pressure sealing capability of all pressure containment components assembled for the operation. The Greasehead/Stuffing box assembly typically serves as the upper pressure containment device for the system pressure test.

c) Connection/QTS pressure test: a pressure integrity test used to confirm the pressure-sealing integrity of one or more connections within the system. This type of test shall only be used during subsequent wireline runs after a full system pressure test (see above) has been performed and that only the connection being tested has been used for breaking containment.

7.8 Conventional WL Pressure Control Equipment Pressure Test Frequency

7.8.1 Pressure test frequency, at the well site, for the pressure control equipment shall be as follows:

a) Ram/valve pressure test:

— initial installation of the pressure control equipment and hydraulic pressure control system, and at least once every fourteen days

— following any action compromising the pressure seals.

b) System pressure test: initial installation of the pressure control equipment and hydraulic pressure control system on each designated well, and at least once every fourteen days.

c) Connection pressure test:

— initial installation of the pressure control equipment if not included in the ram/valve pressure test, and at least once every seven days

— following any action that requires disconnecting a pressure seal.

7.8.2 A period of more than fourteen days between tests should be allowed when well operations (such as, but not limited to, stuck WL) lasting more than fourteen days prevent testing. However, the pressure tests are to be performed at the earliest opportunity following the fourteen day period.

7.9 Pressure Control Hydraulic System Test

This test is required to demonstrate the ability and verify the pressure integrity of the prime mover hydraulic system to actuate the individual well control component(s) as designed.

The following shall apply:

a) Each component is to be actuated and the actuation visually confirmed. This test is to be performed on location prior to commencing the job and be documented on the job log.

b) The minimum pressure of the well control equipment operating system is to be that required to perform the specified ram function at atmospheric pressure plus that required to overcome the wellbore pressure (based on the ram piston balance pressure).

c) The accumulator response time test (see 5.3.6) is to be performed on location and shall be documented on the job log.

d) A hydraulic system will supply the volume required to operate the well control stack functions at MASP.

7.10 Frequency of Actuation Test

An actuation test of a pressure control component consists of a close and open sequence. The test of the pressure control component shall be performed and be documented on the job log:

a) Upon initial installation of the pressure control equipment and hydraulic pressure control system;

b) Following any action compromising the integrity of the hydraulic control system connected to the specific component;

c) At least once every fourteen days.

7.11 "Well Hopping" Wireline Pressure Control Equipment Pressure Test Frequency

In campaign programs where several concentric well intervention operations are planned, the grouping of wells within close proximity of each other provides a unique opportunity in performing safe and effective pressure testing in a time-efficient manner by "well hopping", generically defined in Section 3.

This document's "well hopping" guidance applies to the practice of conducting well intervention operations within a group of wells where the objective of the intervention program within a given wellbore is completed within the 14 day pressure test frequency as recommended in 7.8 item b) and the wireline pressure control stack is then moved to an adjacent wellbore and well intervention operations are conducted with pressure testing requirements following 7.8 item c) only.

Where "well hopping" operations are anticipated, see Annex E for the testing process which will conform with the pressure testing frequency recommendations of this standard.

7.12 Test Documentation

The following applies to test records.

a) All pressure control equipment test activities, including test results, remedial actions taken and testing sequence shall be documented on the daily operations log and recorded in a separate pressure test log.

b) The results of all pressure control equipment pressure tests should be recorded using an analog chart recorder or digital data acquisition system and include as a minimum:

— the pressure control component(s) incorporated within the pressure test;
— the stabilized pressure observed for the low-pressure test and duration of each test;

- the stabilized pressure observed for the high-pressure test and duration of each test;
- resulting outcome of the pressure test (passed or failed);
- resolution of failed pressure tests (repairs implemented and or replacement of components).

c) The WPCE owner should be informed of pressure control equipment failures in the field. The WPCE owner should alert the manufacturer.

7.13 General Pressure Testing Considerations

All on-site personnel should be alerted when pressure test operations are conducted. Only necessary personnel should remain in the test area. The following considerations should be noted:

a) Only personnel authorized by the equipment user or designee to go into the test area to inspect for leaks when the pressure control equipment is under pressure;

b) Repairs or any other work is to be performed only after pressure has been released and potential trapped pressure has been bled at every available outlet;

c) Pressure should be released through pressure release (bleed-off) lines, tree, or production system.

7.14 Pressure Test Acquisition Devices

Pressure gauges, chart recorders, and/or data acquisition equipment shall be used to record the pressure test of the pressure control equipment.

For all pressure tests, pressure measurements made with bourdon tube-type pressure measurement devices shall be made at not less than 25 % and not greater than 75 % of the full pressure span of the gauge or device.

The graduations of the test gauge scale should have sufficient resolution for conducting the pressure test.

Where chart recorders are used, the chart recorder time clock should be set for a four-hour period or less.

For recording pressure tests using a digital data acquisition system, the pressure sensor accuracy shall be equal to or better than ±0.5 % of the full range of the sensor.

The monitoring system shall be at least as accurate as the sensor.

The update (scan) rate of the monitoring system shall be equal to or faster than 1 Hz and calibrated in accordance with ASTM D5720-95.

8. Personnel Roles, Responsibilities, and Requirements

This recommended practice establishes the job descriptions of personnel needed to safely operate cased hole wireline pressure control equipment and systems and additionally defines their roles and responsibilities.

8.1 Personnel Requirements

Personnel that supervise or operate (or both supervise and operate) pressure control equipment shall have role and level specific accredited training and documented competencies in the following areas, at a minimum:

— Pressure Control / Well Control
— Personal Protective Equipment
— Health, Safety, and Environment

8.2 Personnel Roles and Responsibilities

8.2.1 Wellsite Leader

The WSL functions as the owner/operator's designated representative for each well during cased hole wireline operations.

The wellsite leader's, or designee's responsibilities should include but are not limited to:

a) Verify that operations are carried out as stated in the approved well program, and in accordance with technical safety requirements, environmental policies, and procedures.

b) If a deviation from the approved plan is necessary, initiate all required managements of change.

c) Has knowledge of location, wellsite, and emergency response protocols.

d) Participate in daily meetings; record, review, and authorize daily work instructions. Note: e.g. attend pre-job toolbox talks, safety meetings, risk assessments, and update relevant parties on deviations to work scope.

e) Oversee pressure control operations and drills.

f) Distribution of operational reports.

g) Confirm personnel have received training in accordance with 8.1.

h) Confirm all well intervention pressure control equipment conforms to Section 4.

i) Verify well services interfaces are in place with the ongoing operations teams, including technical or operational issues that may affect safety and the environment.

j) Confirm that the formal transfer of control of the well from drilling or production to well servicing team and back (well-handover documentation) is prepared, communicated, and distributed.

k) Exercise and promote stop work authority at all levels.

8.2.2 Wireline Supervisor

The wireline supervisor reports directly to the WSL. In the event the Wellsite Leader is not present, a Wireline Supervisor with training in accordance with 8.2.1 shall assume Wellsite Leader's roles and responsibilities.

The wireline supervisor's responsibilities should include at a minimum:

a) Responsible for wireline pressure control operations.

b) Comply with approved processes, procedures, and best practices.

c) Responsible that wireline and pressure control equipment is fit for purpose prior to and during operations.

d) Verify personnel operating pressure control equipment have received the appropriate training in accordance with 8.1.

e) Verify equipment certifications adhere to regulatory and operator requirements.

f) Ensure attendance of relevant personnel at toolbox talks, safety meetings, and risk assessments.

g) Identify issues that may impact the operation, stop the job if necessary, and communicate such to Wellsite Leader and immediate supervisor.

h) Complete and distribute operations reports and QA checks as required.

i) Ensure shift handover conversation is conducted and signed off.

j) Have knowledge of equipment functionality, troubleshooting skills, wellhead knowledge, and scope of operations.

k) Exercise and promote stop work authority at every level.

l) Actively promote safety within every aspect of the operation.

8.2.3 Wireline Operator and WPCE Operator

The wireline and WPCE operator(s) should at a minimum:

a) Report directly to the Wireline Supervisor.

b) Comply with all approved processes, procedures, and best practices.

c) Take action to maintain pressure control during all cased hole wireline operations.

d) Prior to and during operations, verify equipment is fit for service per Section 4 and meets job requirements.

e) Attend all operational relevant meetings, toolbox talks, shift handover, safety meetings and actively contribute.

f) Take part in or review risk assessment meetings prior to operations or during changes in work scope.

g) Identify issues that may impact the operation, communicate such to Wellsite Leader and immediate supervisor.

h) Complete and distribute all company reports and QA checks as required.

i) Have general knowledge of equipment functionality, troubleshooting skills, wellhead knowledge, and scope of operations.

j) Exercise and promote stop work authority at all levels.

k) Actively promote safety within all aspects of the operation.

9. Pressure Control Operational Considerations

9.1 General

The information from 9.2 through 9.4 should be considered in preparation for wireline intervention service applications.

9.2 Rig Up

a) Prior to rigging up, all personnel involved directly or indirectly on location shall review and confirm the information obtained during pre-job planning (section 6).

b) The information should include but not limited to the following.

   1) identification of the on-site representative in charge.

   2) written job procedure with roles and responsibilities of all personnel.

   3) expected hazards including chemicals, flammable fluids, H_2S, CO_2, energized fluids, contingencies;

   4) type and location of required PPE, emergency response equipment, and egress routes.

5) emergency and contingency pressure control equipment-operating procedures. Consideration should be given to Annex A

6) hazardous areas designations.

7) Unexpected environment and weather conditions impacting operating limitation of utilized equipment.

8) anticipated surface pressure.

9) procedure for pressure and function testing of pressure control equipment.

10) project and site-specific hazards and risks. May include weather conditions, obstacles, crane or overhead limitations, ground or deck conditions, line of fire areas, and simultaneous operations in the area.

c) Prior to breaking containment to well bore the following should be considered:

(1) Verify well bore pressure and amend test plan and operational plan as required.

(2) OEM instructions for opening and closing valves including recording the number of turns needed.

(3) Ensure well bore barriers are in place and sealed.

(4) Ensure there is no trapped pressure at the tree crown cap or WPCE interface location. (Monitor for any pressure build up for a minimum of 5 minutes after bleeding to zero).

d) During the WPCE installation:

1) Prevent damage to wireline and cable head while lowering the PCE on the well
2) Prevent wireline tools from falling by using a head catcher, tool trap, bottom plug, or specific procedure.

9.3 Pressure Test WPCE

Minimize adiabatic heating caused by rapid compression of trapped air in lubricator by utilizing a purge/bleed sub installed below the greasehead/stuffing box or other means of removing the air during filling.

Once test/equalizing pressure is applied to the lubricator, due to fluid displacement of the wireline, the tool string will not be able to move until the well has been opened.
The PCE should be filled at a rate that will minimize rapid compression of trapped air (see 9.2.d)
In the event that wireline rams are closed under pressure, the pressure above and below the rams shall be equalized prior to opening the rams.

NOTE: Rapidly bleeding off the PCE can damage the PCE seals.

Perform pressure test per written procedure developed in the Pre-Job Planning (see Section 7) using specified pressure test fluid.

Record all high and low pressure tests.

Records to be maintained at work site until all wireline work has been completed and equipment rigged down.

Quick Test Sub. – Ensure QTS port is not clogged prior to use. A QTS pressure test is a quick visual test (via pressure gauge) to verify the QTS union seal has pressure integrity. Any testing performed with the QTS should be documented

Once pressure test validates no leaks of WPCE or lubricator, equalize pressure in lubricator and WPCE to well bore pressure.

9.4 Additional Operational Considerations

9.4.1 Pressure Control Heads

Pressure control heads (PCH) provide effective pressure control between the WPCE and the wireline. The following, but not limited to should be considered:

a. Prior to starting operations ensure that actual well parameters match those determined during pre-job planning (section 6) and that the PCH configuration (determined using section 4) is compatible.

b. The location of the greasehead or stuffing box should not restrict the ability to fully retrieve the wireline BHA above, at a minimum, the uppermost Pressure Controlling Barrier in the pressure control stack.

c. When bottom hole assemblies are too long to be contained within the pressure control stack, alternate methods or processes conforming with the barrier requirements listed in the Section 4 tables #3, #4, and #5 are acceptable. Alternate methods may include the usage of quick test subs, remote actuated connectors, etc...

d. During operations, PCH equipment performance to be monitored to determine when inspections are to be performed to ensure that the PCH will perform properly throughout the wireline operation.

e. Inspections to include at a minimum, but not limited to, visual inspection for wear and condition, of the following components:

   - Packings
   - Upper and lower packing glands
   - Passive Safety Device
   - Control lines and fittings

9.4.2 Slickline Stuffing Box

Ensure, if applicable, any integrated (part of the stuffing box) wireline sheaves are free to turn and rotate when running wire.

Inspection of the packings and flow check device should occur at the first time the lubricator is laid down and periodically as determined in pre-job planning.

If applicable inspect grease injection points and components and ensure that a check valve is properly installed at the injection port.

9.4.3 Liquid Seal Stuffing Box

Grease circulation pressure at the grease tubes should be greater than shut in tubing pressure SITP of the well and below equipment rated working pressure.

Grease circulation through the flow tubes must be maintained whenever the wire is moving, or when wire is stopped, and pack offs are not energized.

Inspection of the packings and flow check device should occur at the first time the lubricator is laid down and periodically as determined in pre-job planning.

Inspect grease injection points and components and ensure that a check valve is properly installed at the injection port.

Ensure, if applicable, any integrated (part of the stuffing box) wireline sheaves are free to turn and rotate when running wire.

9.4.4 Electric and Braided Wireline Grease Heads

Grease circulation pressure at the grease tubes should be greater than SITP of the well and below equipment rated working pressure.

Grease circulation through the flow tubes must be maintained whenever the wire is moving, or when wire is stopped, and pack offs are not energized.

Packing should not be energized unless the wire is stopped. Excess drag caused by the packings on braided wire can damage the wire by loosening the outer strands.

Dedicated line wipers may be energized on a running cable while pulling out of the hole (POOH).

Inspection of the packings and flow check device should occur at the first time the lubricator is laid down and periodically as determined in pre-job planning.

Inspect grease injection points and components and ensure that a check valve is properly installed at the injection port.

9.4.5 Jacketed Cable Stuffing Boxes (Greaseless)

An interval for inspecting and/or changing elements should be predetermined prior to the first run.

Avoid over-energizing the rubber elements of the head.

Lubricants used shall be compatible with the prescribed line.

Adequate volume of lubricant shall be available.

9.4.6 Sheaves

The diameter of the sheaves and the groove size of the wheels shall meet the prescribed cable's requirements.

The sheaves and any tie off points shall be sufficient to handle the max pull of the prescribed cable.

The sheaves shall be visibly monitored for rotation and twisting while the cable is running in and out of the well.

The top sheave should be aligned to the control head to prevent side loading and excessive rubbing of the cable to help extend control head packing life.

9.4.7 Lubricators

When possible the lubricator length should be sufficient to cover the longest wireline tool string.

OEM recommendations on maximum length of lubricator to be picked up/laid down to/from a horizontal position shall be followed.

When picking up or laying down the lubricator to/from a horizontal position, bending loads of the lubricator should be minimized.

Ensure that the lubricator is able to be drained/bled off and that the bleed/drain point is at or below the lowest joint of the lubricator.

9.4.8 Quick Unions

Quick unions should be visibly marked or secured to ensure that the union collar doesn't back off.

Quick unions shall be made up completely without partially backing them off and stay in that position for the duration of the wireline run(s).

The transition of the union ID's should allow the wireline tool to move unimpeded.

Some quick unions with different RWP's can be made up together, the RWP of all unions in the PCE stack shall meet the PCE minimum pressure category requirements.

9.4.9 Pump in subs

Ensure that side port is capable of handling the weight of the valves and/or equipment that is going to be connected to it.

Consideration of the side port ID should be used when determining the max pumping rate required.

Side port unions shall not be mixed and be verified that they are compatible and have the same RWP.

The side port hammer unions shall meet API spec 7HU2 requirements.

9.4.10 Head Catchers (also known as a tool catcher)

The catching mechanism shall be able to properly catch and release the planned wireline fishing neck.

It should be designed to be in the catch position without any intervention and is released by it's operating mechanism.

While running in and out of the hole the head catcher should be in catch position.

Care should be taken to prevent sand/dirt accumulation on the wireline which can prevent the head catcher from operating as expected.

The head catcher shall be rated to hold the weight of the heaviest planned wireline tool string.

The head catcher shall be remotely operated.

9.4.11 Tool Traps

The tool trap should not be functioned while the wireline tool string is sitting on the tool trap flapper(s).

The tool trap should remain in the closed (trap) position without any intervention, allow the wireline tool to pass freely up through the flapper, and is opened by it’s operating mechanism.

The tool trap shall have an external visual indicator to show the position of the tool trap flapper.

While running in and out of the hole, with the entire tool string below the tool trap, the tool trap should be in the closed (trap) position to catch the tools once they are above the tool trap.

The tool trap should, at a minimum of one time, be able to withstand the maximum force imposed by the dropping tools while preventing tools from falling below the tool trap. The tool trap shall be inspected after each drop event.

The tool trap should be remotely operated.

9.4.12 Bleed/Vent/Purge Subs

The vent/purge sub ports should be located at the highest point possible in the PCE stack.

The bleed sub ports should be located at the lowest point possible in the PCE stack.

Any subs utilizing needle valves in ports shall have two needle valves per port, and the outer most needle valve is the working valve.

The vent/purge sub should be remotely operated and remain in the closed position without intervention, and is opened by it’s operating mechanism.

The hoses attached to subs shall be rated to MASP.

The hoses attached to the subs shall be secured to a fit for purpose container.

Special consideration should be taken when bleeding gas from the PCE stack.

9.4.13 Chemical injection

The chemical injection sub is used to pump hydrate prevention fluids into the PCE stack.

When utilized, the chemical injection port should be located as high as possible within the PCE stack.

Any chemical injection port shall have a check valve rated to equal to or greater than the PCE RWP.

The chemical injection pump should be able to pump pressures equal to MASP.

The chemical injection hose(s) shall be rated to MASP.

The chemical injection hose(s) should have an manually operated isolation valve located at the chemical injection pump in the event of check valve failure.

Consideration should be given to the fluid volumes required for the chemical injection.

Use glycol or other ice / hydrate inhibitor chemicals

9.4.14 Wireline Ram Assembly

Ram blocks and seals shall be correctly sized for the prescribed wirelines.

The elastomer and seals shall be compatible with the wellbore fluids and well surface temperatures.

The elastomers and seals shall be inspected for damage and/or wear). In the event, during contingency operations, the wireline is stripped through the ram seals, a risk assessment, prior to stripping, shall be performed and the seals shall be inspected before continuing operations.

Ensure rams can close and seal at the MASP of the well.

Ensure Shear/Seal Device can shear and seal on the prescribed wireline.

Wireline rams should be tested and meet all API 16B validation requirements.

9.4.15 Pressure Control Equipment Operating System

Verify the following:

a) Hose sizes, type, lengths.
b) Volumes, pressures, power supply
c) Controls in open position, secondary retention on controls
d) Control placement (in relation to the well and equipment)
e) Alarms
f) Function draw/down testing
g) Fluid selection based on environment and ambient temperatures

9.4.16 Quick Latch Systems

The following shall apply:

a) Ensure hose and cable, if applicable, length and size can reach all of the wells within the operation.
b) The latch to have a means to visually verify that it is latched and sealed.
c) After latching, prior to opening the well, a pressure test (either at the latch itself or across the entire PCE stack) to be performed to verify that the latch is closed and sealed.
d) Contingency procedures/methods to be available to operate the latch in the event that it becomes unable to open.
e) The latch is to have a fail/safe function preventing it from being opened/removed while under pressure.
f) All personnel involved to be competent in utilizing and operating the latch system.

ANNEX A- Contingency Operations
(Informative)

A.1 Intentionally Shear Wireline w/ Shear Ram, Pressure control maintained

STEP	Activity	WL Supervisor	WL Operator	WPCE Operator
1	Ensure the depth of non-shearable and determine if it is across the shear ram or barriers.	X		
2	If non-shearable is across the barriers or shear ram and cannot be moved. Follow operator's well control contingency for non-shearables while maintaining pressure control.	X		
3	Secure approval(s) from well operator and wireline service leadership.	X		
4	Perform JSA and Pre-Job meeting	X	X	X
5	Clear personnel, flag and secure area due to wire ejected from PCH and / or potential high pressure leaks.	X	X	X
6	Adjust wireline tension to neutral free hanging weight	X		
7	Close Wireline Rams (blind) around thewireline ,			X
8	Bleed pressure from lubricator			X
9	Energize stuffing box(es)/pack-offs at pressure control head.			X
10	Verify all personal are clear of area	X		
11	Shear wireline with shear, blind-shear, or shear/seal device			X
12	Close barriers below wireline valve (gate valve or tree valve). Ensure barriers are fully closed.		X	X
13	Shut down grease injection to PCH if applicable			X
14	Bleed pressure from WLV and between Rams. Remove all trapped pressure.			X
15	Remove Lubricator and Wire.		X	X

A.2 Loss of Pressure Containment: Leak above WLV and below top of PCH, wireline in well bore

STEP	Activity	WL Supervisor	WL Operator	WPCE Operator
1	Clear area of all unnecessary personnel due to potential high pressure leaks	X	X	X
2	Stop wireline movement	X	X	
3	Record wireline surface tension and surface pressure	X		
4	Ensure wireline tools are below the wireline ram assembly.			X
5	Close Wireline ram assembly and create seal around the wireline	X		
6	Inject grease in WRA if applicable , depending on configuration.			X
7	Once seal at wireline ram assembly is established, lock rams in closed position using manual back up.			X
8	bleed down lubricator pressure above rams			X
9	If applicable, reduce the grease injection to the flowtubes to zero			X
10	Visually monitor PCE for a *minimum of 5 minutes* to ensure that leak has stopped.			X
11	Release PCH pressure	X		X
12	If required, release and lift lubricator. Clamp the wireline ensuring wireline remains stationery			X
13	Proceed with remedial work to repair the leak	X	X	X
14	As required re-assemble pressure control equipment rig up	X	X	X
15	Follow pre-deployment rig up and pressure testing procedure while keeping WRA closed		X	X
16	Re-stablish line tension as previously recorded and adjust lubricator pressure to equal wellhead pressure. Ensure, utilizing ram equalizers, that the pressure above and below each ram is equalized.	X	X	X
17	Back off manual locks and open WRA	X	X	X
18	De-energise pack offs and verify cable is moving freely			X
19	Resume operations		X	X

A.3 Loss of Pressure Containment - Below WRA / WPCE

STEP	Activity	WL Supervisor	WL Operator	WPCE Operator
1	Clear area of all unnecessary personnel due to potential high pressure leaks	X	X	X
2	Stop wireline movement	X		
3	Confirm wireline tools are below the wireline rams.	X		
4	If leak is able to be contained then wire may be able to be recovered safely to the lubricator and UM / LM closed.	X		
5	If leak is not able to be contained then emergency procedures to be executed.	X	X	X
6	shear the wire with the shear seal.		X	X
7	Pull wire to surface.	X		
8	Close all barriers.		X	X

A.4 Loss of Pressure Containment - Grease Head

STEP	Activity	WL Supervisor	WL Operator	WPCE Operator
1	Stop wireline	X		
2	Engerize Pack-offs			X
3	Close grease head return line			X
4	Increase grease pressure until leak stops			X
5	Open grease head return line			X
6	Confirm grease head is working correctly. If grease seal is unable to be regained, go to A.2 steps 6 - 20			X
7	De-energize Pack-offs			X
8	Continue running wireline	X		

Annex B
(Informative)

Wireline Pressure Control Stack Arrangements for Designated Pressure Categories

The following figures show the various Recommended Pressure Control Stack Equipment Configuration for the different types of wireline (slickline, braided line, and jacketed line) and pressure control levels (PC0 to PC4).

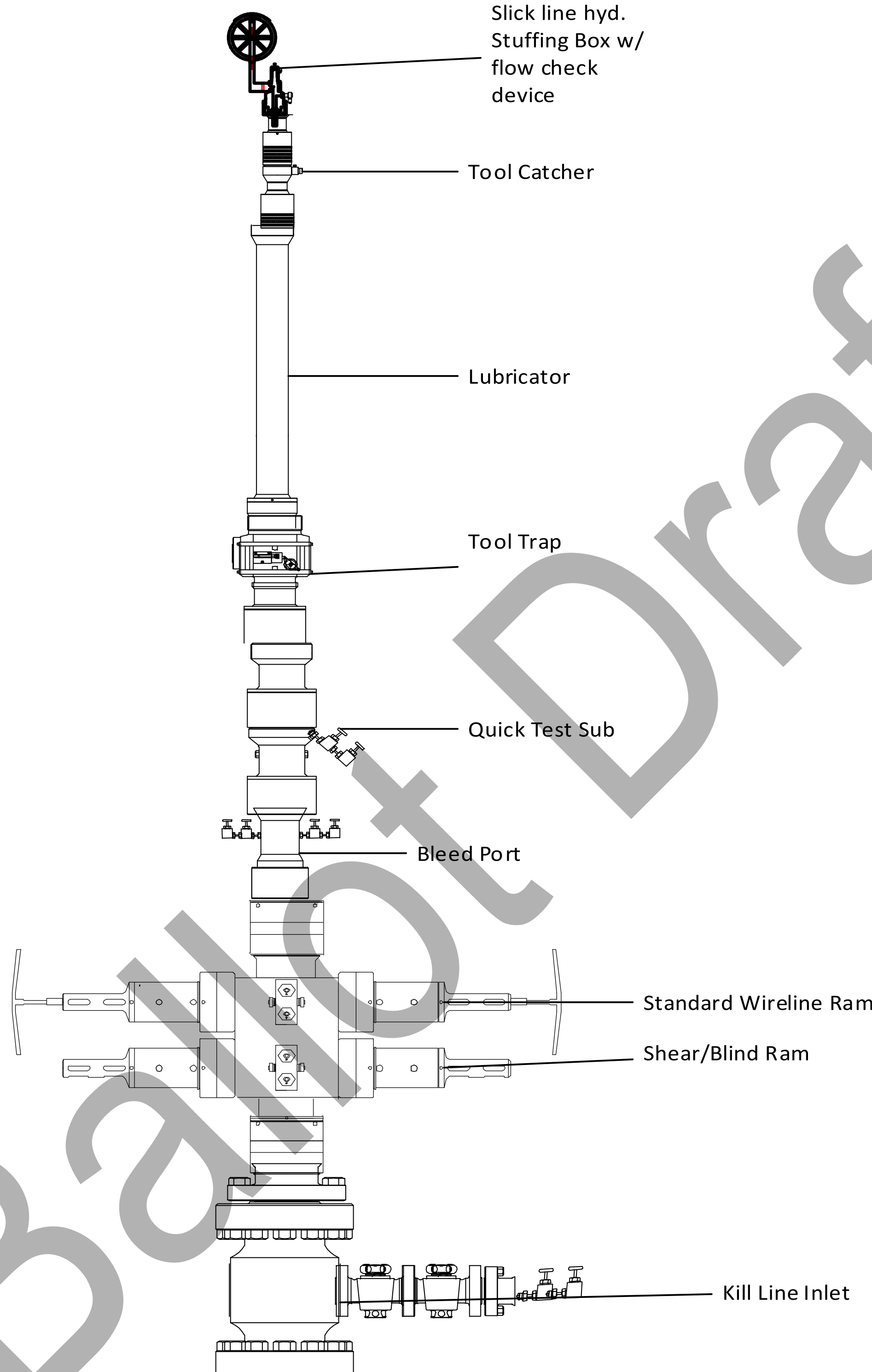

Figure B.1 – Recommended Slickline Pressure Control Stack Equipment Configuration (PC-0)

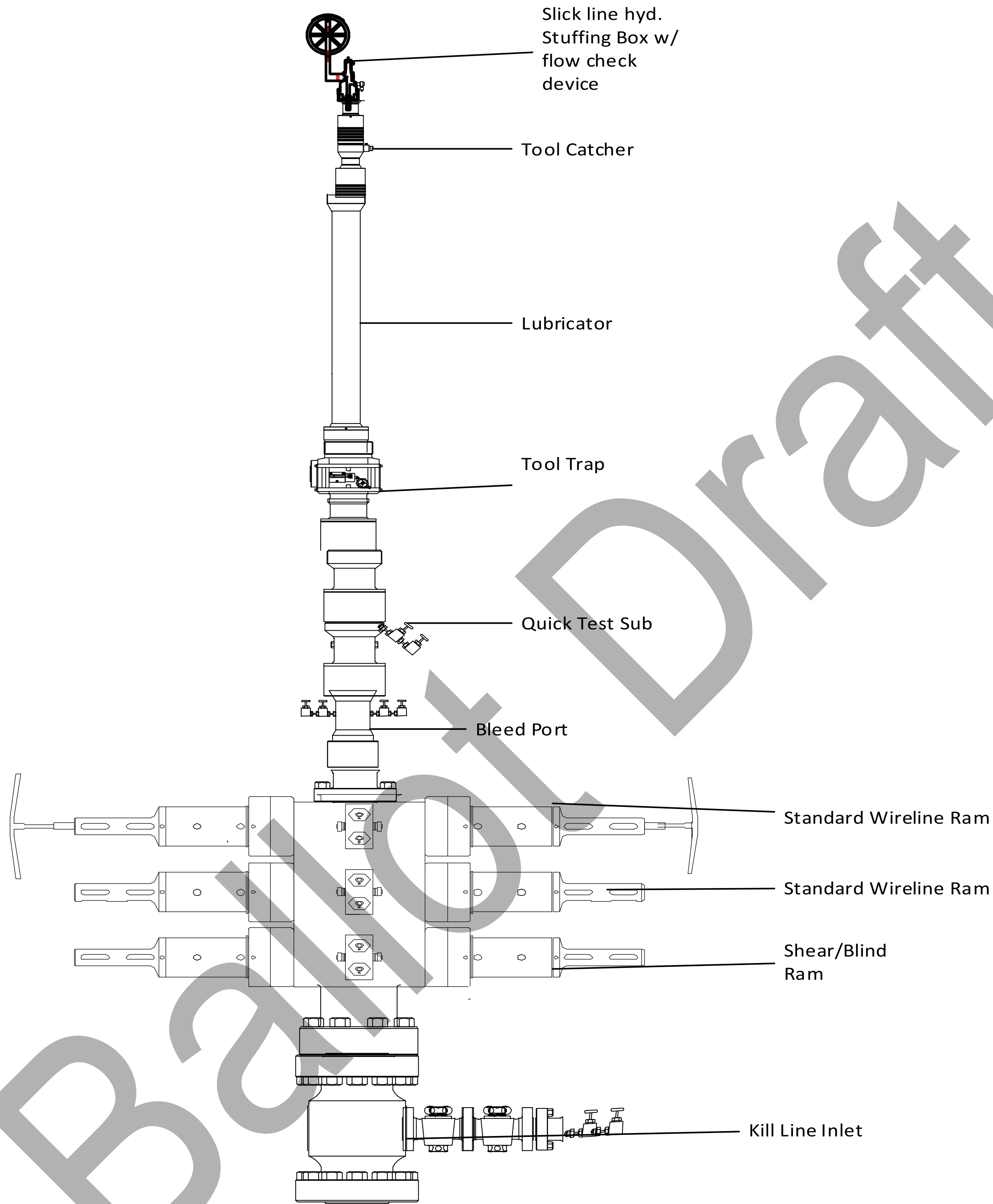

Figure B.2 Recommended Slickline Pressure Control Stack Equipment Configuration (PC-1,PC-2)

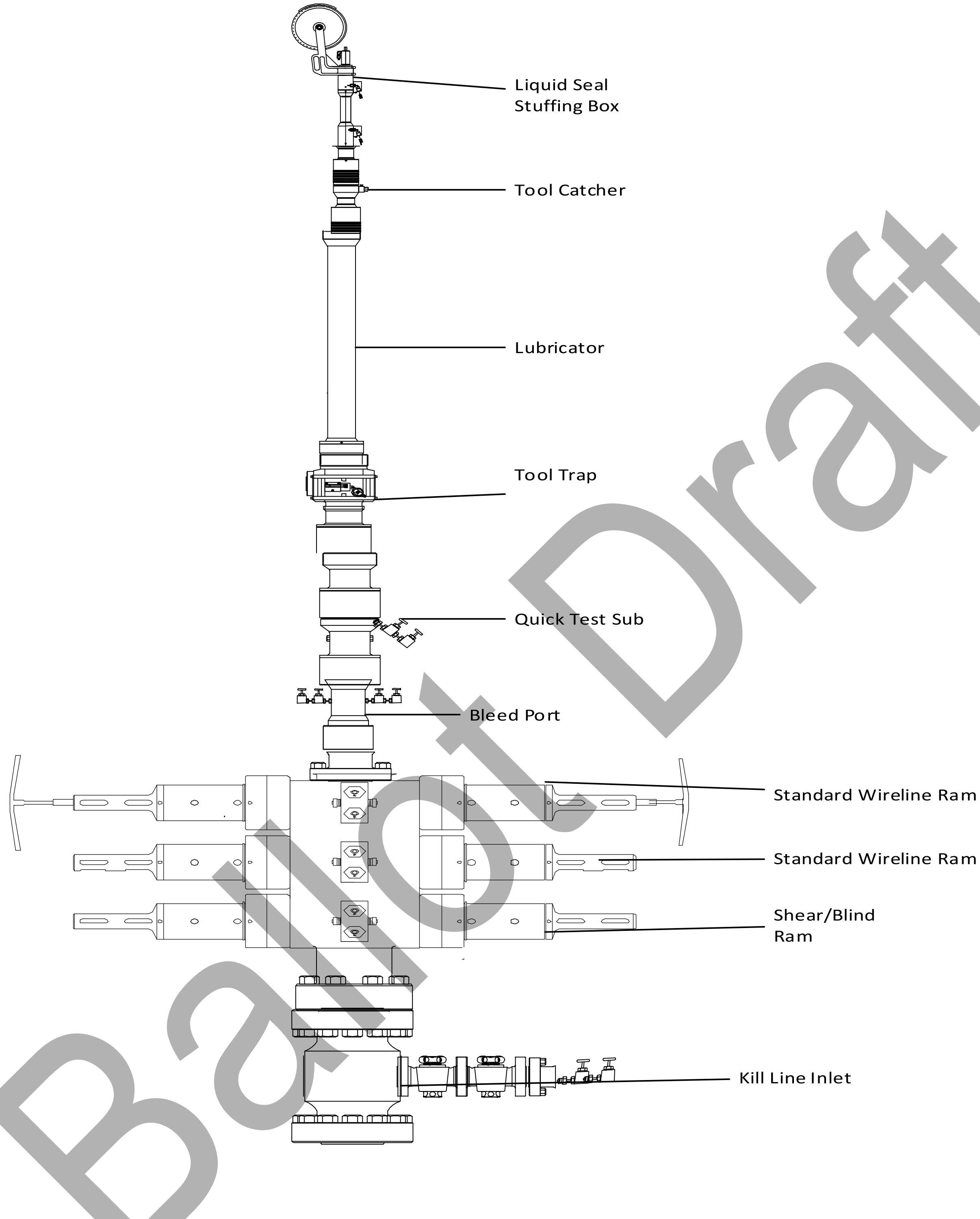

Figure B.3 Recommended Slickline Pressure Control Stack Equipment Configuration (PC-3)

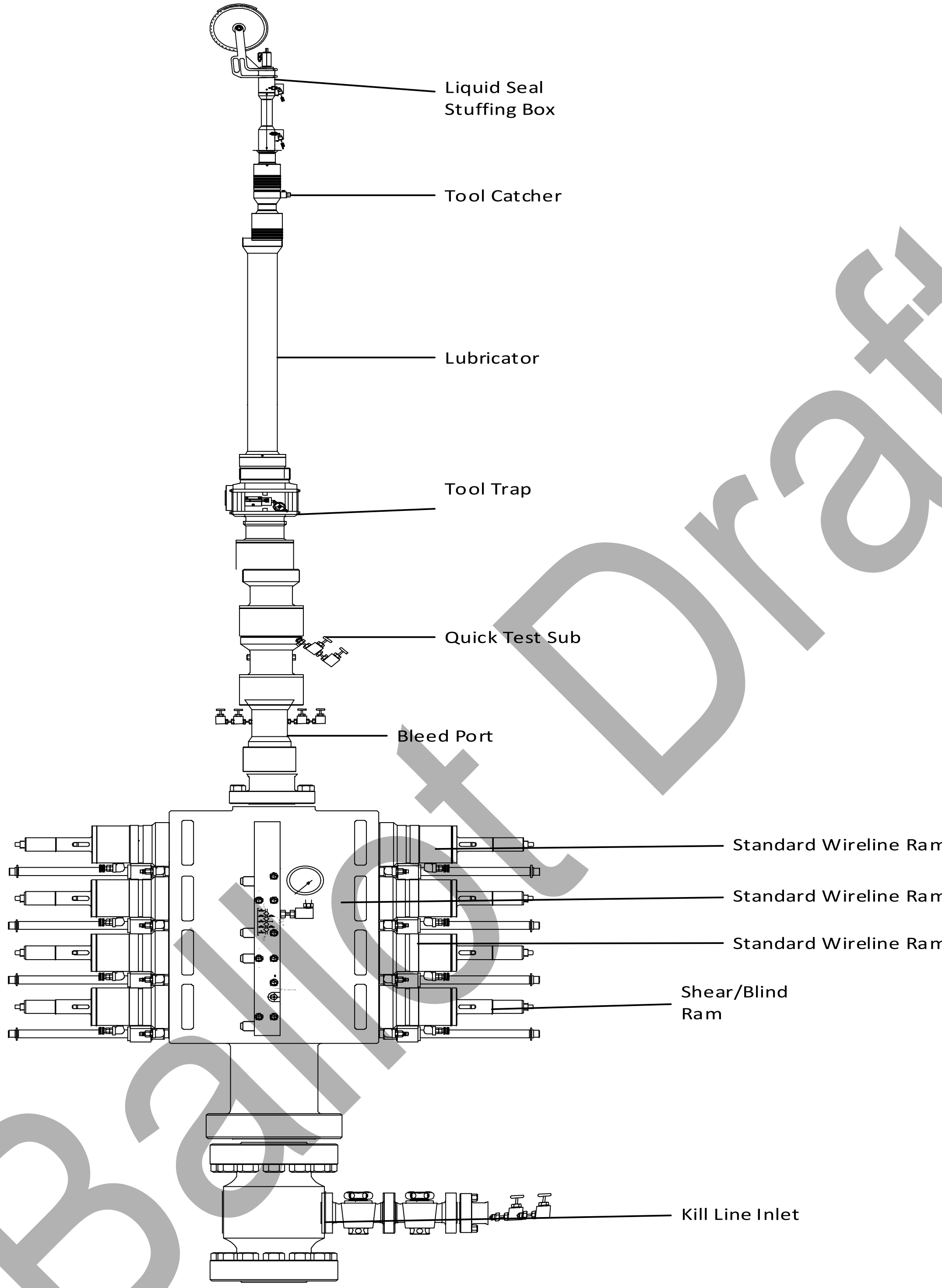

Figure B.4 Recommended Slickline Pressure Control Stack Equipment Configuration (PC-4)

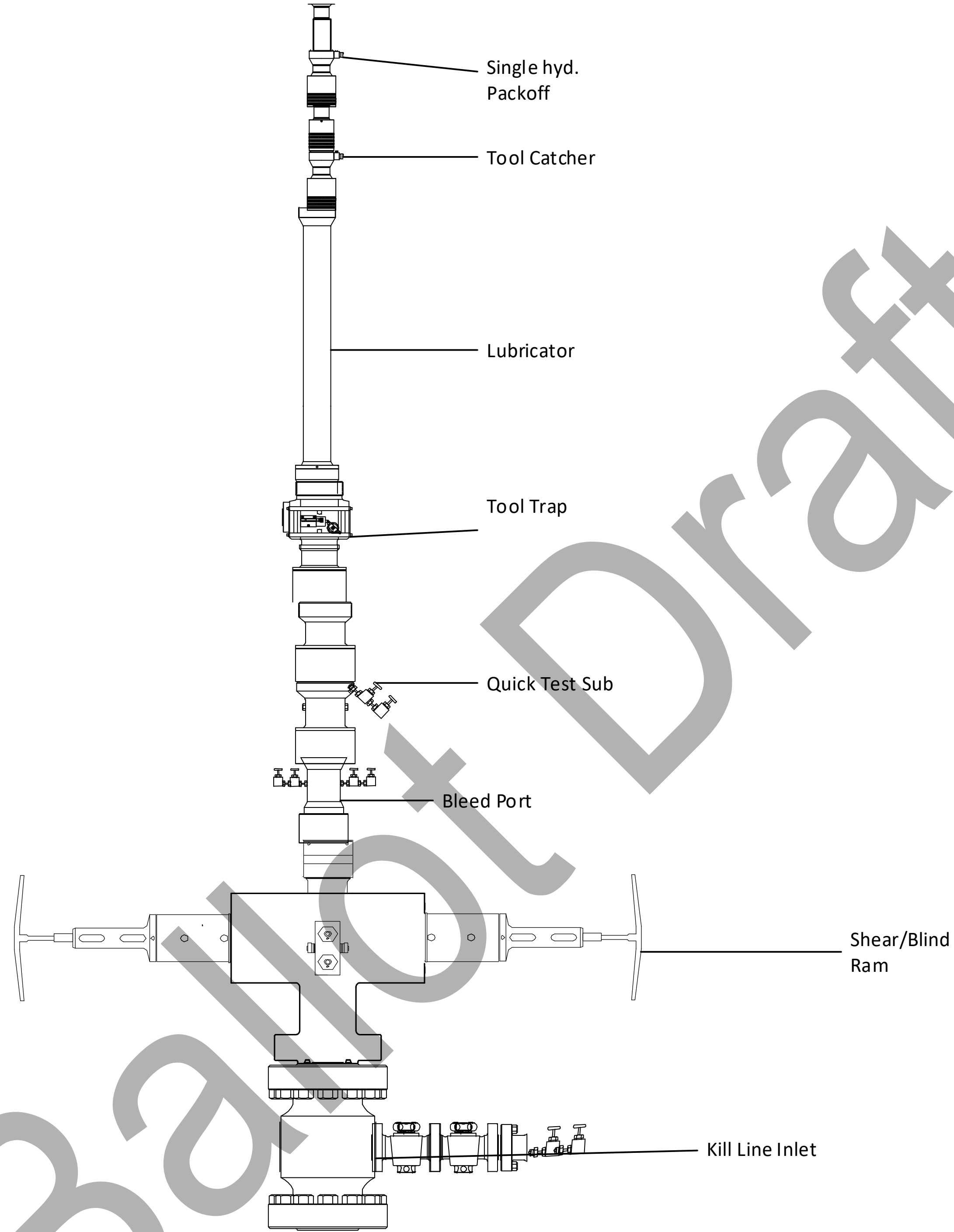

Figure B.5 Recommended Braided Line Pressure Control Stack Equipment Configuration (PC-0)

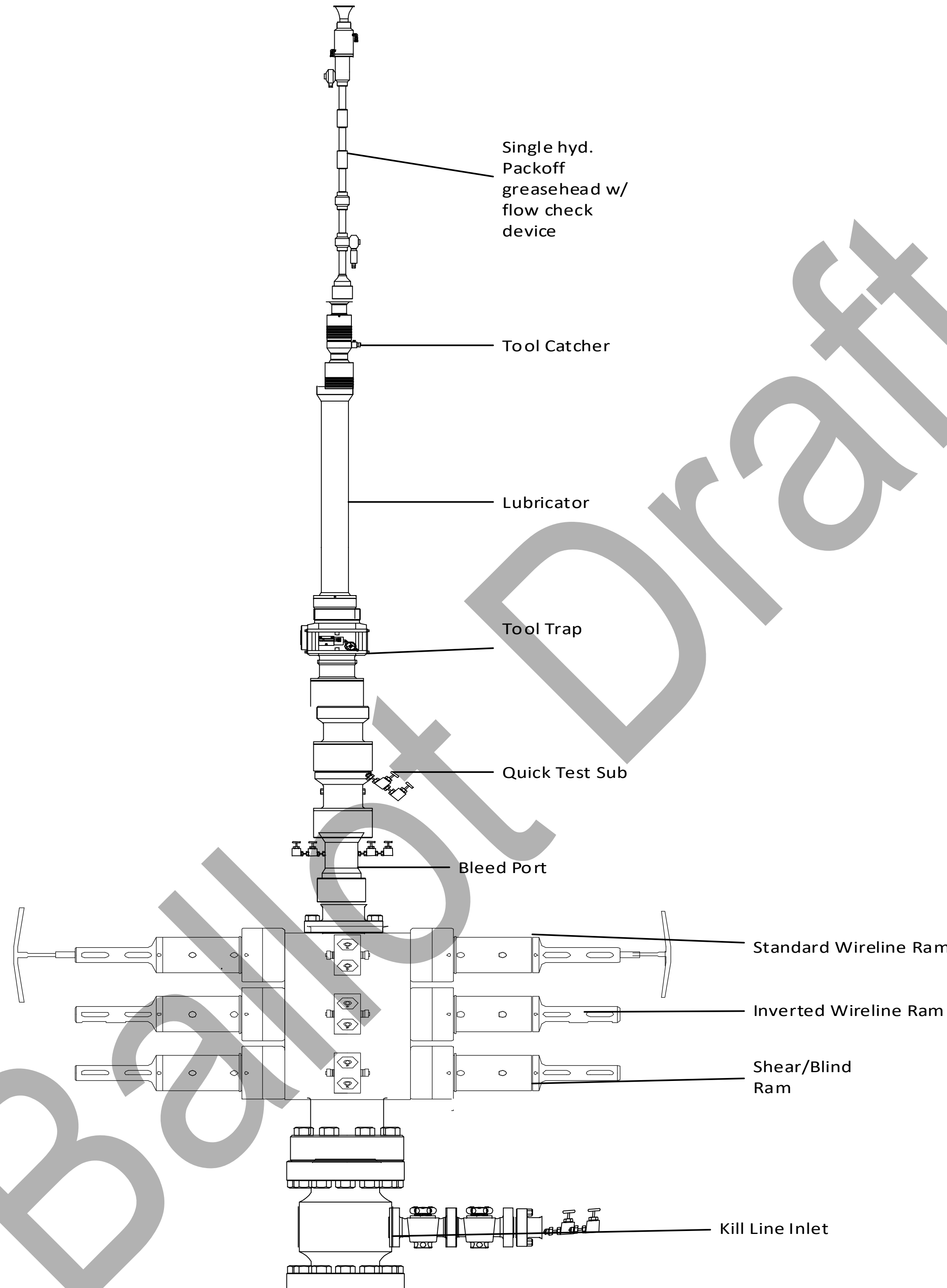

Figure B.6 Recommended Braided Line Pressure Control Stack Equipment Configuration (PC-1)

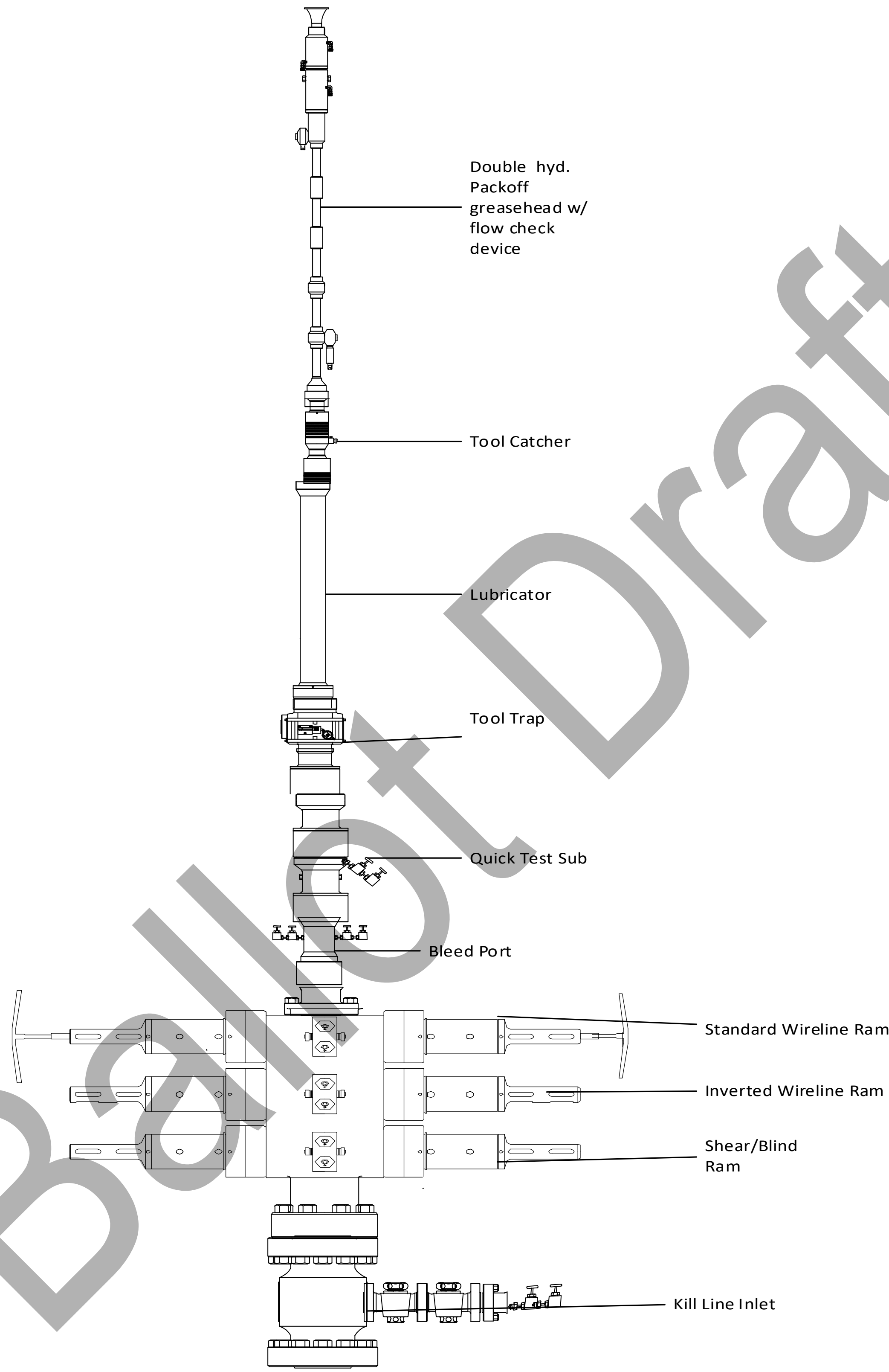

Figure B.7 Recommended Braided Line Pressure Control Stack Equipment Configuration (PC-2, PC-3)

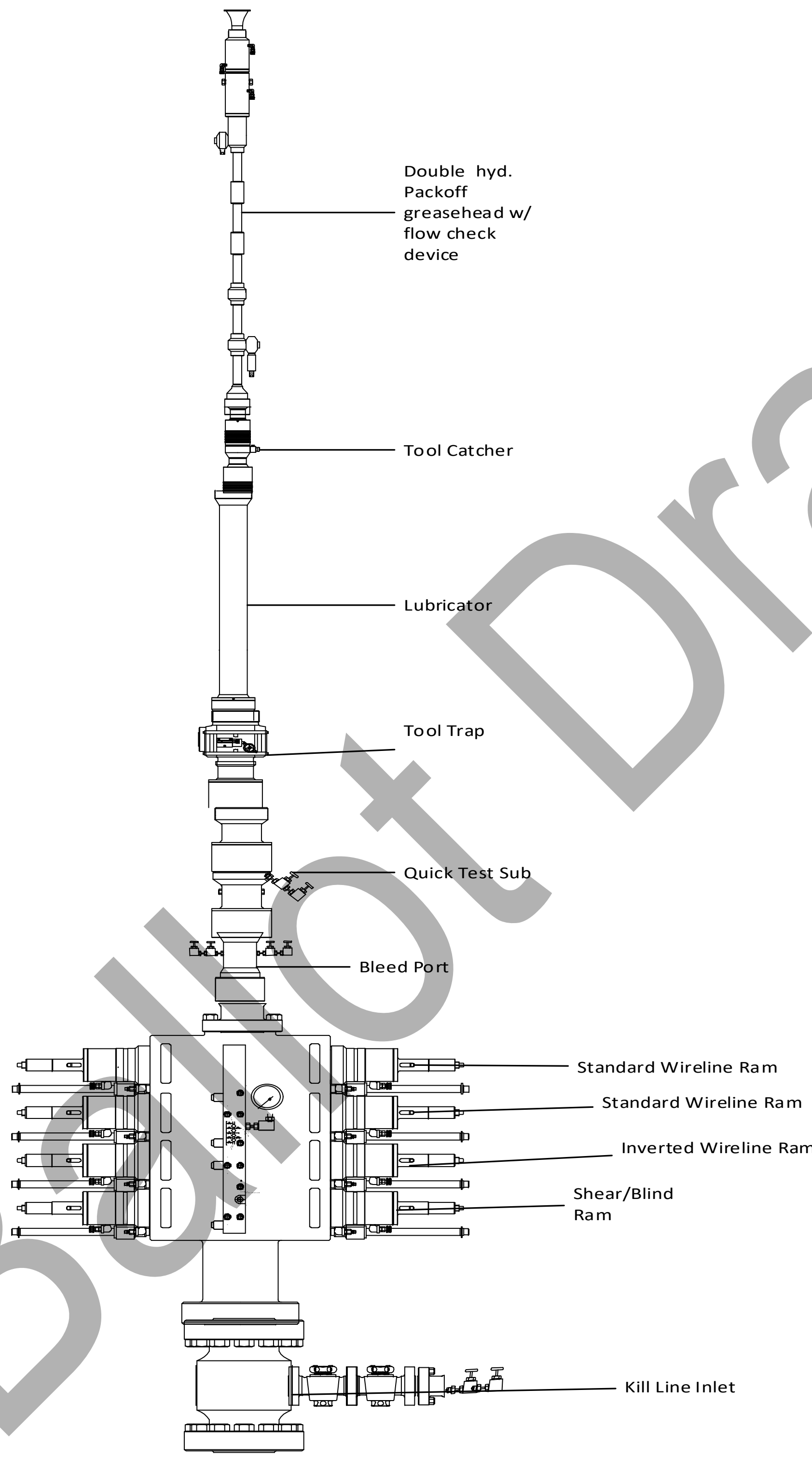

Figure B.8 Recommended Braided Line Pressure Control Stack Equipment Configuration (PC-4)

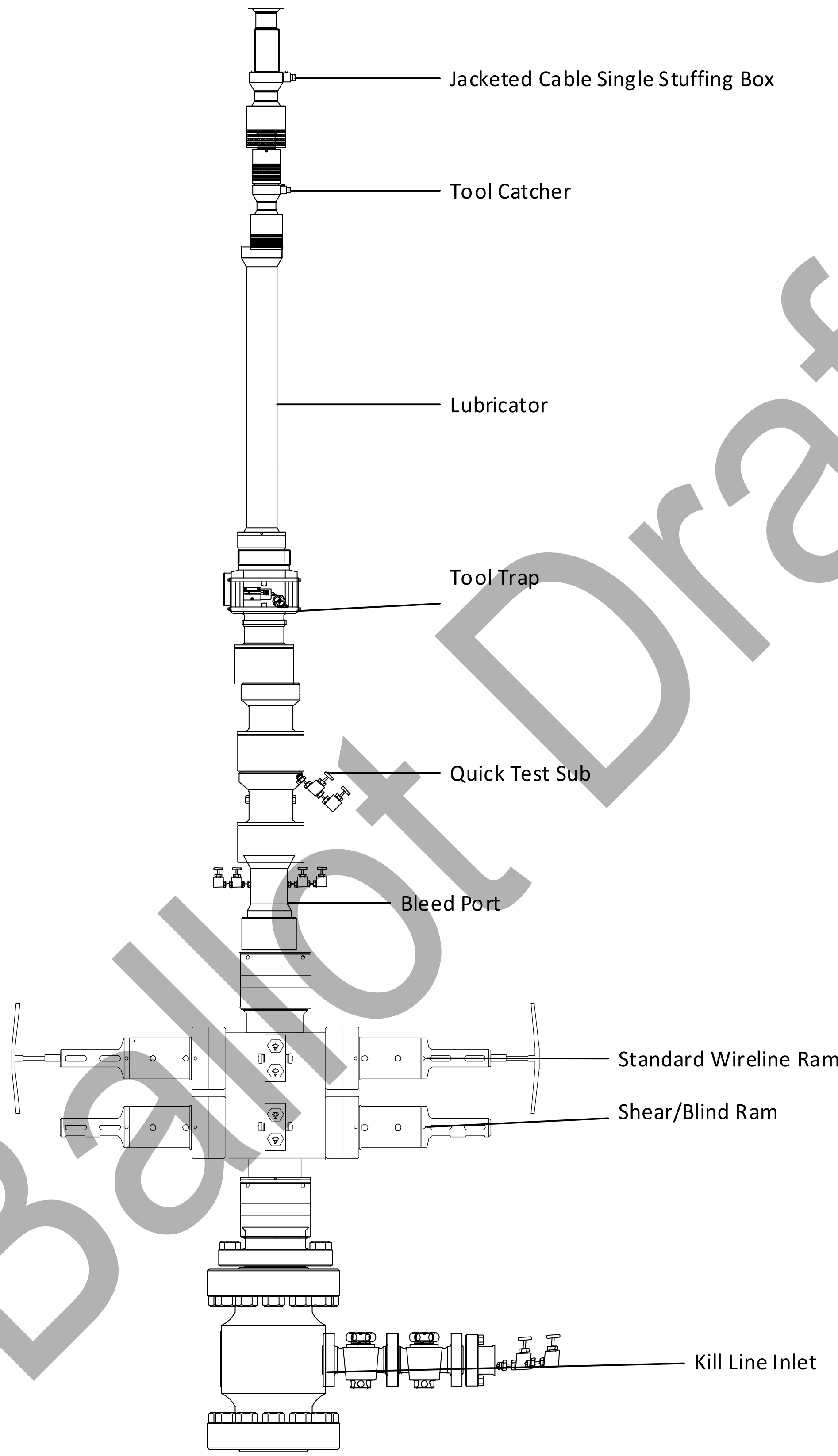

Figure B.9 Recommended Jacketed Line Pressure Control Stack Equipment Configuration (PC-0)

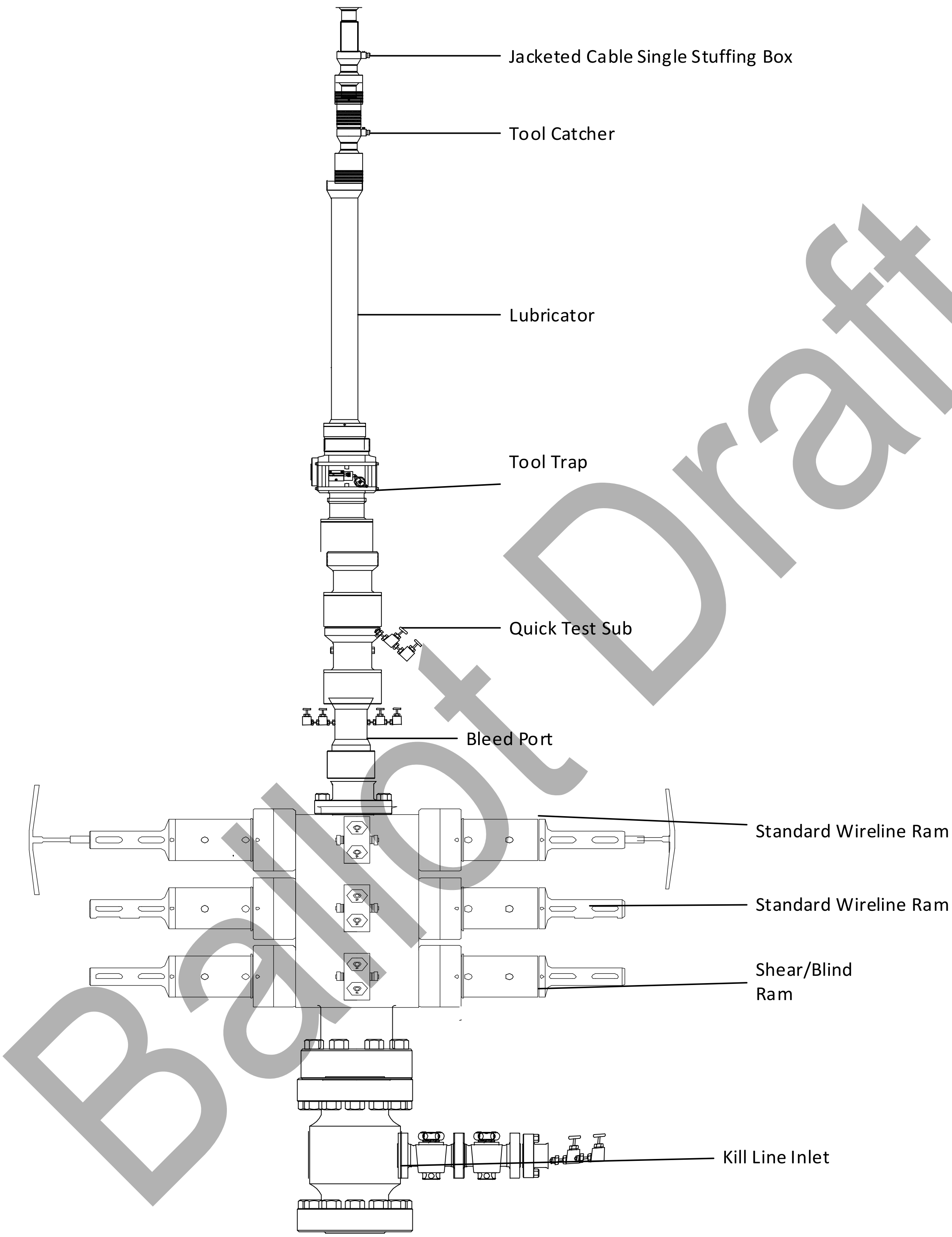

Figure B.10 Recommended Jacketed Line Pressure Control Stack Equipment Configuration (PC-1)

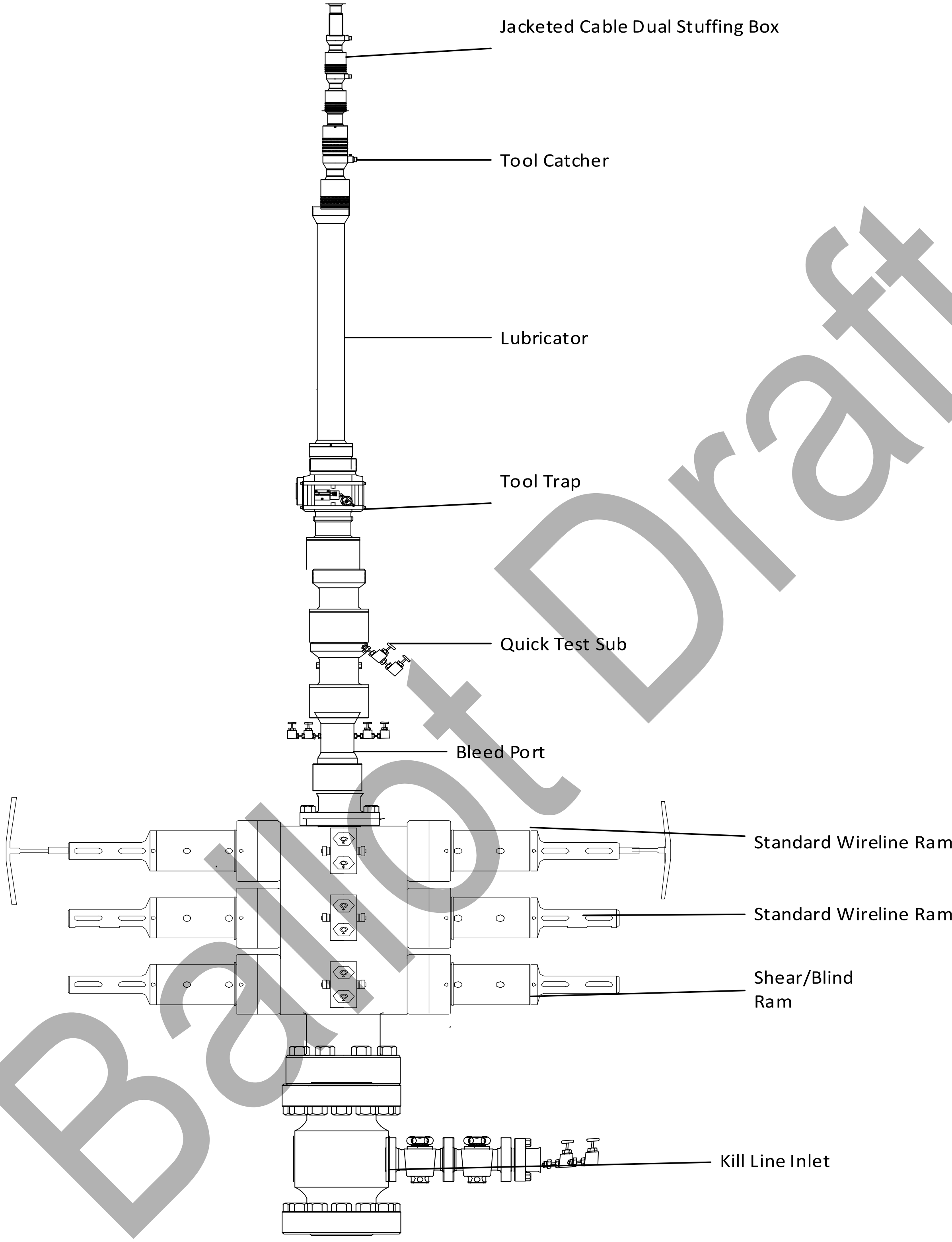

Figure B.11 Recommended Jacketed Line Pressure Control Stack Equipment Configuration (PC-2, PC-3)

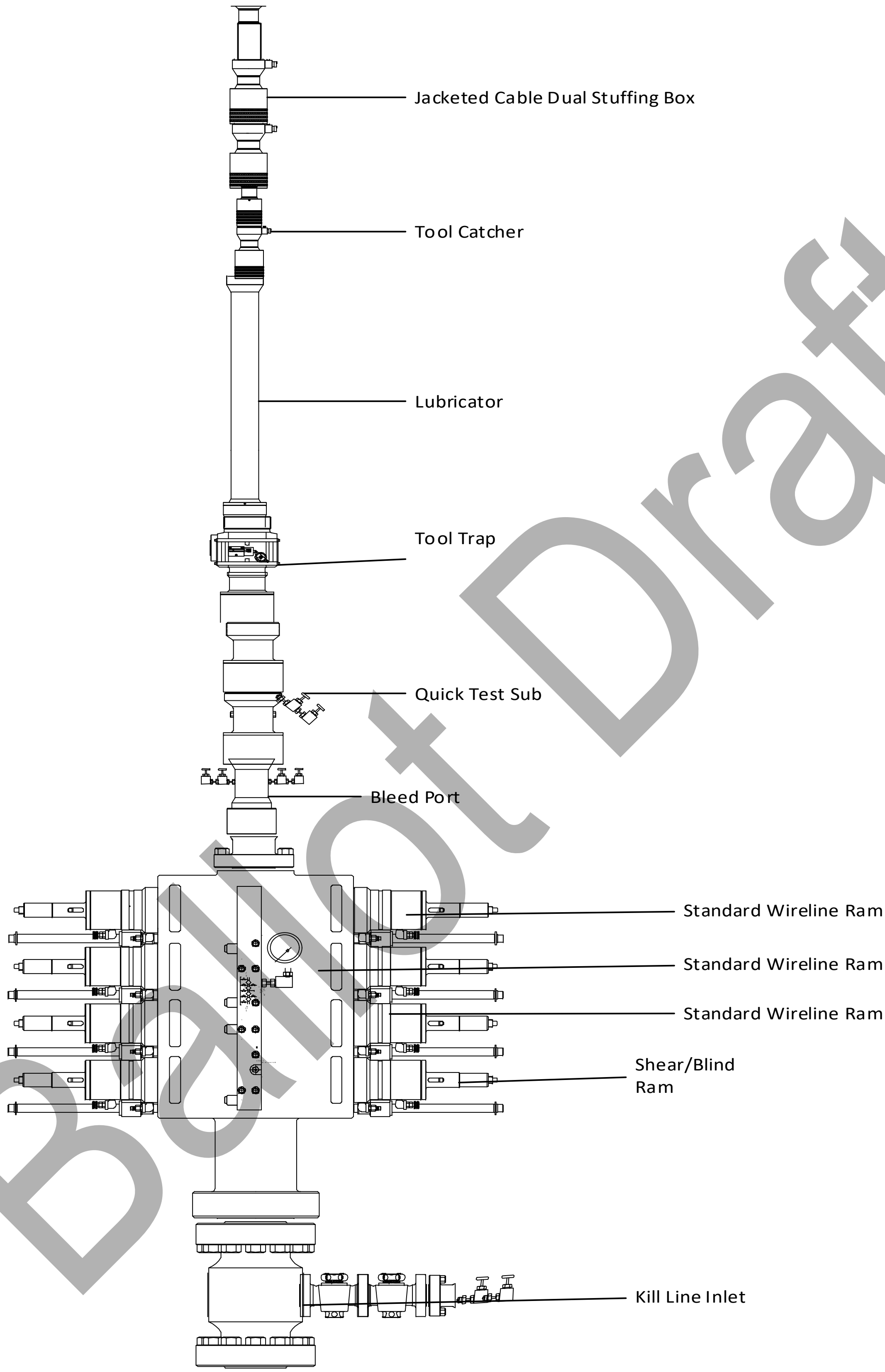

Figure B.12 Recommended Jacketed Line Pressure Control Stack Equipment Configuration (PC-4)

Annex C
Accumulator Sizing Calculations

(Informative)

C.1 General

The accumulator sizing calculations provided in this Annex are intended to guide the user in determining or verifying the required accumulator bank capacity necessary to meet the requirements of this document for both Primary and dedicated accumulator systems. This Annex also provides a method for determining the low accumulator pressure alarm setpoint.

The methods presented may be applied to either Primary or Dedicated accumulator banks; however, the input parameters shall be selected to represent the applicable accumulator bank being evaluated.

These calculations evaluate two limiting design cases: the Volume Limiting Case and the Pressure Limiting Case. The accumulator system should be sized such that both cases are satisfied. The governing accumulator bank capacity should be the greater of the requirements determined from these two cases.

C.2 Volume Limiting Case:

C.2.1 Definition: The Volume Limiting Case is the condition in which the accumulator bank is sized based on the hydraulic fluid volume required to perform the specified operating sequence (close–open) of all applicable pressure control components, while maintaining a minimum residual pressure of precharge + 200 psi within the accumulator system.

C.2.2 Purpose: The purpose of the Volume Limiting Case is to ensure that the accumulator system contains sufficient useable hydraulic fluid volume to complete an entire drawdown test as described in Annex D without loss of functional capability.

C.2.3 Design Criteria: The total useable hydraulic fluid volume stored in the applicable accumulator bank must be greater than the hydraulic fluid volume required to complete a drawdown test.

C.3 Pressure Limiting Case:

C.3.1 Definition: The Pressure Limiting Case is the condition in which the accumulator system volume is sized based on its ability to maintain sufficient hydraulic pressure to perform the required pressure control sequence under worst-case conditions in a well-control event after hydraulic fluid volume is discharged to perform the pressure control device's function. The minimum hydraulic pressures for the required pressure control device's function include the following depending on the specific device used.

a. **Wireline Ram**: Minimum hydraulic pressure required to achieve and maintain a seal at MASP
b. **Shear & Seal Device**: Minimum hydraulic pressure required to shear the specified wireline and subsequently achieve a seal at MASP
c. **Shear Ram**: Minimum hydraulic pressure required to shear the specified wireline at MASP

Note: All factors influencing the required hydraulic operating pressure to perform the required function should be considered in determining the minimum pressure required, including but not limited to: Shearing force requirements, Minimum operating pressure for sealing (e.g., MOPFLPS), Wellbore pressure effects, Closing ratio (CR), etc

C.3.2 Purpose: The purpose of the Pressure Limiting Case is to ensure that the accumulator system maintains sufficient hydraulic pressure after the required hydraulic fluid volume has been discharged to perform the intended pressure control sequence in a well control event.

C.3.3 Design Criteria: The pressure remaining in the accumulator system after all required pressure control sequences are completed in a well control event is greater than critical pressure required to complete the last pressure control device function

C.4 Calculation Disclaimer / Limitations

The calculations provided in the Annex are intended for design verification and preliminary sizing of accumulator systems. A safety margin (SM) should be applied to account for uncertainties not explicitly included in these calculations. The results are subject to the following assumptions and limitations:

a. Calculations are based on conservation of the applicable inert gas mass and assume quasi-static conditions.
b. The applicable inert gas properties used in the calculations shall be determined using real-gas data (e.g., NIST). Interpolation between tabulated values may be required.
c. Transient thermodynamic effects, including adiabatic compression/expansion and heat transfer, are not explicitly modeled. Therefore, the results for rapid discharge or rapid filling of the accumulator bank such as the Pressure Limiting Case may provide non-conservative results
d. Hydraulic fluid is assumed to be incompressible.
e. Ambient temperature is used as an approximate for accumulator gas temperature. The use of minimum and maximum temperatures is intended to bound system performance; actual operating conditions may vary.
f. Results should be verified by functional testing where required to ensure conforming real-world performance

C.5 Required Initial Inputs needed to complete calculations

The following input parameters in Table C.1should be defined by the user to perform the calculations. The calculations presented in this Annex should be treated as an iterative process. If the selected input parameters do not satisfy the required criteria, the inputs should be revised and the calculations repeated until compliance is achieved.

Table C.1- Input Parameters

P_p	Average inert gas pre-charge pressure of the applicable accumulator bank
P_{p+200}	Inert gas pressure at 200 psi above the pre-charge pressure of the applicable accumulator bank
$P_{C.VL}$	Inert gas pressure at the charged condition of the applicable accumulator bank for the Volume Limiting Case; equal to the lesser of the maximum hydraulic system pressure or pump stop pressure

$P_{C.PL}$	Inert gas pressure at the charged condition of the applicable accumulator bank for the Pressure Limiting Case; equal to the automatic pump start (kick-in) pressure
$P_{Critical}$	Minimum hydraulic pressure required at the final stage of the pressure control sequence in a well control event, equal to the minimum operating pressure required for the final pressure control device to complete its intended function.
T_{Min}	Minimum expected ambient temperature during operation
T_{Max}	Maximum expected ambient temperature during operation
T_{Pre}	Ambient temperature at the time of accumulator pre-charge
V_{Open}	Hydraulic fluid volume required to open a pressure control device. Each applicable pressure controlling device requires a volume to be determined
V_{Close}	Hydraulic fluid volume required to close a pressure control device. Each applicable pressure controlling device requires a volume to be determined

C.6 Volume Limited Case Calculations

These calculations determine the minimum accumulator bank volume required to satisfy the Volume Limiting Case using the selected input variables for the applicable accumulator bank. The equations presented in this section are rearranged to solve for the required accumulator bank volume and are derived from the governing relationships shown below based on conservation of mass of the inert gas. The derivation of these calculations are not included in this Annex and are based upon API 16D principles.

$$V_{Use.VL} \geq V_{CO} \quad (C.1)$$

$$V_{Use.VL} = V_{@P_{C.VL}} - V_{@P_{P+200}} \quad (C.2)$$

Where

$V_{Use.VL}$	Usable hydraulic fluid volume in the applicable accumulator bank for the Volume Limiting Case
V_{CO}	Total cumulative hydraulic fluid volume required to complete the specified close–open sequence of all applicable pressure control devices operated through the applicable accumulator bank
$V_{@P_{C.VL}}$	Hydraulic fluid volume in the applicable accumulator bank at the charged condition corresponding to an accumulator pressure equal to $P_{C.VL}$
$V_{@P_{P+200}}$	Hydraulic fluid volume in the applicable accumulator bank when the accumulator pressure is equal to P_{p+200}

The total cumulative hydraulic fluid volume required to operate the applicable pressure control devices through a close–open cycle shall be calculated using Equation C.3. This volume defines the minimum usable hydraulic fluid volume required for the applicable accumulator bank in the Volume Limiting Case. For the Primary accumulator bank, all applicable pressure control devices should be included. For a dedicated accumulator bank, only the dedicated shear and seal device should be considered

$$V_{CO} = \sum V_{Close} + \sum V_{Open} \quad (C.3)$$

Where

$\sum V_{Close}$	Total cumulative hydraulic fluid volume required to close all applicable pressure control devices operated through the applicable accumulator bank
$\sum V_{Open}$	Total cumulative hydraulic fluid volume required to open all applicable pressure control devices operated through the applicable accumulator bank
$\sum V$ = Sum of the hydraulic fluid volumes for all applicable pressure control devices (i.e., Volume of Device 1 + Volume of Device 2 + ...)	

Once the total hydraulic fluid volume required to operate all applicable pressure control devices through the close–open sequence has been determined, the minimum accumulator bank volume required to satisfy the Volume Limiting Case can be calculated using Equation C.4.

$$V_{Bank.VL} = \frac{V_{CO}}{\rho_{@P_p}\left(\frac{1}{\rho_{@P_{P+200}}} - \frac{1}{(\rho_{@P_{C.VL}})}\right)} \quad \text{(C.4)}$$

Where

$V_{Bank.VL}$	Minimum total accumulator bank volume required for the applicable accumulator bank to satisfy the Volume Limiting Case
$\rho_{@P_p}$	Inert gas density at P_p and T_{Pre} of the applicable accumulator bank
$\rho_{@_{Pp+200}}$	Inert gas density at P_{p+200} and the lesser of T_{Min} or T_{Pre} for the applicable accumulator bank
$\rho_{@P_{C.VL}}$	Inert gas density at $P_{C.VL}$ and T_{Max} for the applicable accumulator bank

The density of the applicable inert gas for the various pressures at the temperature of interest can be found in the NIST Chemistry WebBook .

C.7 Pressure Limited Case Calculations

These calculations determine the minimum accumulator bank volume required to satisfy the Pressure Limiting Case using the selected input variables for the applicable accumulator bank. The equations presented in this section are rearranged to solve for the required accumulator bank volume and are derived from the governing relationships shown below based on conservation of mass of the inert gas. The derivation of these calculations are not included in this Annex and are based upon API 16D principles.

$$V_{Use.PL} \geq V_{PCOS} \quad \text{(C.5)}$$

$$V_{Use.PL} = V_{@P_{C.PL}} - V_{@P_{Critical}} \quad \text{(C.6)}$$

Where

$V_{Use.PL}$	Usable hydraulic fluid volume in the applicable accumulator bank for the Pressure Limiting Case
V_{PCOS}	Total cumulative hydraulic fluid volume required to perform the worst-case pressure control operating sequence in a well control event
$V_{@P_{C.PL}}$	Hydraulic fluid volume in the applicable accumulator bank at the charged condition corresponding to an accumulator pressure equal to $P_{C.PL}$

$V_{@P_{Critical}}$	Hydraulic fluid volume in the applicable accumulator bank at the charged condition corresponding to an accumulator pressure equal to $P_{Critical}$

The total cumulative hydraulic fluid volume required to operate the applicable pressure control devices through a pressure control operating sequence shall be calculated using Equation C.7. This volume defines the minimum usable hydraulic fluid volume required for the applicable accumulator bank to satisfy the Pressure Limiting Case.

To determine the required usable volume, all applicable pressure control operating sequences shall be evaluated.

In a well control event, the sequence of operations required to regain control will vary depending on the specific scenario and configuration of pressure control equipment in the stack. Because the exact sequence cannot be predetermined, all such applicable sequences shall be considered in the calculation.

The governing case shall be defined as the sequence that results in the most limiting condition based on the maximum hydraulic fluid volume requirement and the minimum pressure required at the final required operation. This governing condition defines the minimum usable hydraulic fluid volume required from the applicable accumulator bank to satisfy the pressure limiting case.

C.7.1 Application by Accumulator Bank

a. **Primary accumulator bank** — All pressure control devices that may be operated as part of any applicable pressure control sequence shall be included.
b. **Dedicated accumulator bank** — Only the dedicated shear and seal device shall be considered; however, it shall be evaluated under its own worst-case pressure and volume conditions.

$$V_{PCOS} = \sum V_{Sequence} \tag{C.7}$$

Where

$\sum V_{Sequence}$	Sum of the hydraulic fluid volumes for all applicable pressure control sequences (i.e., Volume of Sequence 1 + Volume of Sequence 2...)

Once the maximum hydraulic fluid volume required to operate all applicable pressure control devices for the worst-case pressure control operating sequence has been determined, the minimum accumulator bank volume required to satisfy the Pressure Limiting Case shall be calculated using Equation (C.8).

$$V_{Bank.PL} = \frac{V_{PCO}}{\rho_{@P_P}\left(\frac{1}{\rho_{@P_{critical}}} - \frac{1}{(\rho_{@P_{C.PL}})}\right)} \tag{C.8}$$

Where

$V_{Bank.PL}$	Minimum total accumulator bank volume required for the applicable accumulator bank to satisfy the Pressure Limiting Case
$\rho_{@P_p}$	Inert gas density at P_p and T_{Pre} for the applicable accumulator bank
$\rho_{@P_{critical}}$	Inert gas density at $P_{Critical}$ and the lesser of T_{Min} or T_{Pre} for the applicable accumulator bank
$\rho_{@P_{C.PL}}$	Inert gas density at $P_{C.PL}$ and T_{Max} for the applicable accumulator bank

The density of the applicable inert gas for the various pressures at the temperature of interest can be found in the NIST Chemistry WebBook

C.8 Minimum Accumulator Bank Volume Required

Once the minimum accumulator bank volumes for both the Volume Limiting Case and the Pressure Limiting Case have been determined, the required accumulator bank volume shall be taken as the greater of the two values. An appropriate safety margin (SM) may be applied to account for uncertainties and ensure the accumulator system meets all functional requirements under expected operating conditions. When these calculations are used to evaluate an existing accumulator system, compliance may be verified through functional testing. When these calculations are used for design, the inclusion of a safety margin reduces the potential for under sizing due to real-world effects not explicitly accounted for in the calculations. The total number of accumulator units should then be selected such that the accumulator bank capacity meets or exceeds the required volume in accordance with Equation (C.9).

$$N_A \cdot V_{@P_P} \geq Max(V_{Bank.VL}, V_{Bank.PL}) \cdot SM \qquad \text{(C.9)}$$

Where

N_A	The total cumulative number of single accumulators in the applicable accumulator bank
$V_{@P_P}$	The volume of inert gas in a single accumulator at P_p. This volume is equal to the OEM stated volume of a single accumulator
SM	The user selected Safey Margin (ie. 20% = 1.2)

NOTE Section 5 stipulates the requirement of a minimum of two accumulator

C.9 Minimum Accumulator Low Pressure Alaram Setting

After the user has selected an adequate accumulator bank volume to satisfy both the limiting cases, the required low accumulator pressure alarm can be determined. This alarm is intended to warn the user that, if accumulator pressure drops below the alarm setpoint and the pumps are inoperable, the accumulator bank may no longer have sufficient usable hydraulic volume or pressure to complete the required pressure control sequence.

To calculate the low accumulator alarm pressure, first calculate the nitrogen density at the alarm state using Equation C.10.The calculated nitrogen density is then used with the minimum expected ambient temperature to determine the corresponding nitrogen pressure from the NIST nitrogen property tables.

$$\rho_{@P_{Alarm}} = \frac{1}{\left(\frac{1}{\rho_{@P_{Critical}}} - \frac{1}{\rho_{@P_P}}\left(\frac{V_{PCO}}{N_A \cdot V_{@P_P}}\right)\right)} \qquad \text{(C.10)}$$

$$P_{Alarm} = Interp_{NIST}(\rho_{@P_{Alarm}}, T_{Min}) \qquad \text{(C.11)}$$

Where

$\rho_{@P_{Alarm}}$	Density of the inert gas at the alarm state pressure P_{Alarm} and T_{Min}
$\rho_{@P_p}$	Density of the inert gas at P_p and T_{Pre} of the applicable accumulator bank
$\rho_{@P_{critical}}$	Density of the inert gas at $P_{Critical}$ and the lesser of T_{Min} or T_{Pre} for the applicable accumulator bank

V_{PCOS}	Total cumulative hydraulic fluid volume required to perform the worst-case pressure control operating sequence in a well control event
P_{Alarm}	Pressure of the accumulator bank when the alarm should activate

The Pressure of the applicable inert gas for the given density at the temperature of interest can be found in the NIST Chemistry WebBook

C.10 EXAMPLE - Primary Accumulator Bank Sizing

C.10.1 General – Primary Accumulator Bank

A pressure control stack includes two wireline rams operated through the Primary accumulator bank. The Primary accumulator bank will be sized to satisfy both the Volume Limiting Case and the Pressure Limiting Case. The minimum accumulator low-pressure alarm setpoint will also be determined.

C.10.2 Equipment Overview and Required Technical Information – Primary Accumulator Bank

Using OEM-supplied data and applicable operating conditions, the required input parameters will be identified to complete the calculations as follows in Table C.10:

Table C.10 - OEM-supplied data and applicable operating conditions

Ram Set 1 Information	
Close Volume	0.55 gal
Open Volume	0.50 gal
Closing Ratio	11
Minimum Operating Pressure for Low Pressure Seal (MOPFLPS)	1300 psig
Ram Set 2 Information	
Close Volume	0.55 gal
Open Volume	0.50 gal
Closing Ratio	11
Minimum Operating Pressure for Low Pressure Seal (MOPFLPS)	1300 psig
Pressure Control Equipment Operating System	
Maximum Rated Hydraulic System Pressure	3000 psig
Pump Charge Stop Pressure	2950 psig
Automatic Pump Kick In / Start Pressure	2700 psig
Accumulator Pre-Charge Pressure	1200 psig
Accumulator Pre-Charge Gas	Nitrogen
Ambient Temperature During Pre-Charge	68°F
Operation Information	
Maximum Anticipates Surface Pressure (MASP)	8,000 psig
Maximum expected ambient pressure during operations	104°F
Minimum expected ambient pressure during operations	32°F
Well Control Operating Sequence	Step 1 – Close & Seal Ramset 1 Step 2 – Close & Seal Ramset 2

C.10.3 Determining Input Variables – Primary Accumulator Bank

Based on the gathered information, the required input variables will be assigned as follows in Table C.11.

Table C.11 - Required input variables

Input Variable	Assigned Value	Secondary Calculation
P_p	1,200 psig	N/A
P_{p+200}	1,400 psig	$P_{p+200} = P_p + 200\ psig$ $P_{p+200} = 1200\ psig + 200\ psig$ $P_{p+200} = 1400\ psig$
$P_{C.VL}$	2,950 psig	$P_{C.VL} = \min(3000\ psig, 2950\ psig)$
$P_{C.PL}$	2,700 psig	N/A
$P_{Critical}$	2027 psig	$P_{Critical} = MOPFLPS + \frac{MASP}{CR}$ $P_{Critical} = 1300\ psig + \frac{8000\ psig}{11}$ $P_{Critical} = 2027\ psig$ Note: Since both wireline rams are the same the order of operation doesn't change the critical pressure on the last sequence
T_{Min}	32°F	N/A
T_{Max}	104°F	N/A
T_{Pre}	68°F	N/A
V_{Open}	Ram Set 1 = 0.55 gal Ram Set 2 = 0.55 gal	N/A
V_{Close}	Ram Set 1 = 0.50 gal Ram Set 2 = 0.50 gal	N/A

C.10.4 Volume Limiting Case Calculations – Primary Accumulator Bank

The required hydraulic fluid volume to complete a drawdown test, including a close–open sequence for the two wireline rams, will be calculated as follows:

$$V_{CO} = \sum V_{Close} + \sum V_{Open}$$

$$V_{CO} = \left(V_{Close_{Ramset\ 1}} + V_{Close_{Ramset\ 2}}\right) + \left(V_{Open_{Ramset\ 1}} + V_{Open_{Ramset\ 2}}\right)$$

$$V_{CO} = (0.50\ gal + 0.50\ gal) + (0.55\ gal + 0.55\ gal)$$

$$V_{CO} = 2.1\ gal = 0.281\ ft^3$$

From the NIST Chemistry WebBook

Where

Variable	Looked Up Value	Description
$\rho_{@P_p}$	5.87 lbm/ft^3	Density of nitrogen at 1200 psig and 68°F
$\rho_{@P_{p+200}}$	7.50 lbm/ft^3	Density of nitrogen at 1400 psig and 32°F
$\rho_{@P_{C.VL}}$	11.2 lbm/ft^3	Density of nitrogen at 2950 psig and 104°F

With the required variables established, the minimum accumulator bank volume required to meet the Volume Limiting Case can be calculated as follows:

$$V_{Bank.VL} = \frac{V_{CO}}{\rho_{@P_P}(\frac{1}{\rho_{@P_{P+200}}} - \frac{1}{(\rho_{@P_{C.VL}})})}$$

$$V_{Bank.VL} = \frac{0.281\ ft^3}{5.87\ \text{lbm/ft3}(\frac{1}{7.50\ \text{lbm/ft3}} - \frac{1}{11.2\ \text{lbm/ft3}})}$$

$$V_{Bank.VL} = 1.085\ ft^3 = 8.12\ gal$$

C.10.5 Pressure Limiting Case Calculations – Primary Accumulator Bank

In the Pressure Limiting Case, the pressure control operating sequence consists of closing and sealing Ramset 1 at MASP, followed by closing and sealing Ramset 2 at MASP. The critical pressure is defined as the minimum hydraulic pressure required to close and achieve a seal for the final ramset at MASP.

The total hydraulic fluid volume required to complete this pressure control operating sequence in a well control event will be determined as follows:

$$V_{PCOS} = \sum V_{Close}$$

$$V_{PCOS} = (V_{Close_{Ramset\ 1}} + V_{Close_{Ramset\ 2}})$$

$$V_{PCOS} = (0.50\ gal + 0.50\ gal)$$

$$V_{PCOS} = 1.00\ gal = 0.134\ ft^3$$

From the NIST Chemistry WebBook

Where

Variable	Looked Up Value	Description
$\rho_{@P_p}$	5.87 lbm/ft^3	Density of nitrogen at 1200 psig and 68°F
$\rho_{@P_{critical}}$	9.40 lbm/ft^3	Density of nitrogen at 2027 psig and 32°F
$\rho_{@P_{C.PL}}$	10.60 lbm/ft^3	Density of nitrogen at 2700 psig and 104°F

With the required variables determined, the minimum accumulator bank volume to satisfy the Pressure Limited Case can be calculated as follows:

$$V_{Bank.PL} = \frac{V_{PCOS}}{\rho_{@P_P}(\frac{1}{\rho_{@P_{critical}})} - \frac{1}{(\rho_{@P_{C.PL}})})}$$

$$V_{Bank.PL} = \frac{0.134\ ft^3}{5.87\ \text{lbm/ft3}(\frac{1}{9.40\ \text{lbm/ft3}} - \frac{1}{10.60\ \text{lbm/ft3}})}$$

$$V_{Bank.PL} = 1.890\ ft^3 = 14.14\ gal$$

C.10.6 Minimum Accumulator Bank Volume – Primary Accumulator Bank

Based on the results of the Volume Limiting Case and Pressure Limiting Case, the minimum required accumulator bank volume shall be determined as the greater of the two calculated values. For this example, a safety margin (SM) of 20% is applied to ensure the accumulator system meets all functional requirements. The total number of nominal 10-gallon accumulators will then be selected to meet or exceed this required volume.

$$V_{Bank.VL} = 8.12\ gal$$

$$V_{Bank.PL} = 14.14\ gal$$

$$SM = 20\% = 1.2$$

$$N_A \cdot V_{@P_P}\ \geq\ Max(V_{Bank.VL}, V_{Bank.PL}) \cdot SM$$

$$N_A \cdot V_{@P_P}\ \geq\ Max(8.12\ gal, 14.14\ gal) \cdot 1.2$$

$$N_A \cdot V_{@P_P}\ \geq\ 14.14\ gal \cdot 1.2$$

$$N_A \cdot V_{@P_P}\ \geq\ 16.97\ gal$$

Using nominal 10-gallon individual accumulators, a minimum of two accumulators are required to satisfy the minimum required accumulator bank volume. This also meets the requirement for a minimum of two accumulators per bank. Therefore, the selected Primary accumulator bank volume will be 20 gallons.

C.10.7 Minimum Accumulator Low Pressure Alarm Setting – Primary Accumulator Bank

With the Primary accumulator bank volume selected to be 20 gallons (two nominal 10-gallon accumulators), the required minimum accumulator low-pressure alarm setpoint for the Primary accumulator bank will be determined as follows

$$\rho_{@P_{Alarm}} = \frac{1}{\left(\frac{1}{\rho_{@P_{Critical}}} - \frac{1}{\rho_{@P_P}}\left(\frac{V_{PCO}}{N_A \cdot V_{@P_P}}\right)\right)}$$

$$\rho_{@P_{Alarm}} = \frac{1}{\left(\frac{1}{9.40\ \mathrm{lbm/ft}} - \frac{1}{5.87\ \mathrm{lbm/ft}}\left(\frac{1\ gal}{20\ gal}\right)\right)}$$

$$\rho_{@P_{Alarm}} = 10.22\ lbm/ft3$$

From the NIST Chemistry WebBook

$$P_{Alarm} = \ Interp_{NIST}(10.22\ lbm/ft3\ , 32°\mathrm{F})$$

$$P_{Alarm} = 2350\ psig$$

The Primary accumulator bank low-pressure alarm will be set at 2350 psig. This setpoint ensures that, above this pressure, the accumulator system contains sufficient usable hydraulic volume and pressure to complete the required pressure control operating sequence during a well control event

C.11 EXAMPLE - Dedicated Accumulator Bank Sizing

C.11.1 General – Dedicated Accumulator Bank

A pressure control stack includes a Dedicated Shear & Seal Device operated through the Dedicated accumulator bank. The Dedicated Shear & Seal Device is required to shear & seal on the largest cable that will be used during operations. The Dedicated accumulator bank will be sized to satisfy both the Volume Limiting Case and the Pressure Limiting Case. The minimum accumulator low-pressure alarm setpoint will also be determined.

C.11.2 Equipment Overview and Required Technical Information – Dedicated Accumulator Bank

Using OEM-supplied data and applicable operating conditions, the required input parameters will be identified to complete the calculations as follows:

Dedicated Shear & Seal Device Information	
Close Volume	1.25 gal
Open Volume	1.50 gal
Closing Ratio	15
Minimum Operating Pressure for Low Pressure Seal (MOPFLPS)	1000 psig
Maximum Required Shear Pressure to shear wireline at atmospheric pressure	1200 psig
Pressure Control Equipment Operating System	
Maximum Rated Hydraulic System Pressure	3000 psig
Pump Charge Stop Pressure	2950 psig
Automatic Pump Kick In / Start Pressure	2700 psig
Accumulator Pre-Charge Pressure	1400 psig
Accumulator Pre-Charge Gas	Nitrogen
Ambient Temperature During Pre-Charge	68°F
Operation Information	
Maximum Anticipates Surface Pressure (MASP)	12000 psig
Maximum expected ambient pressure during operations	104°F
Minimum expected ambient pressure during operations	32°F
Well Control Operating Sequence	Actuate Shear & Seal Device

C.11.3 Determining Input Variables – Dedicated Accumulator Bank

Based on the gathered information, the required input variables will be assigned as follows.

Input Variable	Assigned Value	Secondary Calculation
P_p	1,400 psig	N/A
P_{p+200}	1,600 psig	$P_{p+200} = P_p + 200\ psig$ $P_{p+200} = 1400\ psig + 200\ psig$ $P_{p+200} = 1600\ psig$
$P_{C.VL}$	2,950 psig	$P_{C.VL} = \min\ (3000\ psig, 2950\ psig)$
$P_{C.PL}$	2,700 psig	N/A
$P_{Critical}$	2000 psig	$P_{Critical} = \max(P_{Shear}, P_{Seal})$

		$P_{Seal} = MOPFLPS + \frac{MASP}{CR}$ $P_{Seal} = 1000\,psig + \frac{12000\,psig}{15}$ $P_{Seal} = 1800\,psig$ $P_{Shear} = Shear\ Pressure + \frac{MASP}{CR}$ $P_{Shear} = 1200\,psig + \frac{12000\,psig}{15}$ $P_{Shear} = 2000\,psig$
T_{Min}	32°F	N/A
T_{Max}	104°F	N/A
T_{Pre}	68°F	N/A
V_{Open}	1.50 gal	N/A
V_{Close}	1.25 gal	N/A

C.11.4 Volume Limiting Case Calculations – Dedicated Accumulator Bank

The required hydraulic fluid volume to complete a drawdown test, including a close–open sequence for the Dedicated Shear & Seal Device, will be calculated as follows:

$$V_{CO} = \sum V_{Close} + \sum V_{Open}$$

$$V_{CO} = V_{Close} + V_{Open}$$

$$V_{CO} = 1.25\ gal + 1.50\ gal$$

$$V_{CO} = 2.75\ gal = 0.368\ ft^3$$

From the NIST Chemistry WebBook

Where

Variable	Looked Up Value	Description
$\rho_{@P_p}$	6.60 lbm/ft^3	Density of nitrogen at 1400 psig and 68°F
$\rho_{@_{Pp+200}}$	8.40 lbm/ft^3	Density of nitrogen at 1600 psig and 32°F
$\rho_{@P_{C.VL}}$	11.2 lbm/ft^3	Density of nitrogen at 2950 psig and 104°F

With the required variables established, the minimum accumulator bank volume required to meet the Volume Limiting Case can be calculated as follows:

$$V_{Bank.VL} = \frac{V_{CO}}{\rho_{@P_p}\left(\frac{1}{\rho_{@P_{P+200}}} - \frac{1}{(\rho_{@P_{C.VL}})}\right)}$$

$$V_{Bank.VL} = \frac{0.368\ ft^3}{6.60\ \text{lbm/ft3}(\frac{1}{8.40\ \text{lbm/ft3}} - \frac{1}{11.2\ \text{lbm/ft3}})}$$

$$V_{Bank.VL} = 1.873\ ft^3 = \ 14.01\ gal$$

C.11.5 Pressure Limiting Case Calculations – Dedicated Accumulator Bank

In the Pressure Limiting Case, the pressure control operating sequence consists of closing the Dedicated Shear & Seal Device. The critical pressure is defined as the minimum hydraulic pressure required to shear the wireline and achieve a seal at MASP.

The total hydraulic fluid volume required to complete this pressure control operating sequence in a well control event will be determined as follows:

$$V_{PCOS} = \sum V_{Close}$$

$$V_{PCOS} = V_{Close}$$

$$V_{PCOS} = 1.25\ gal$$

$$V_{PCOS} = 1.25\ gal = 0.167\ ft^3$$

From the NIST Chemistry WebBook

Where

Variable	Looked Up Value	Description
$\rho_{@P_p}$	6.60 lbm/ft^3	Density of nitrogen at 1400 psig and 68°F
$\rho_{@P_{critical}}$	9.20 lbm/ft^3	Density of nitrogen at 2000 psig and 32°F
$\rho_{@P_{C.PL}}$	10.60 lbm/ft^3	Density of nitrogen at 2700 psig and 104°F

With the required variables determined, the minimum accumulator bank volume to satisfy the Pressure Limited Case can be calculated as follows:

$$V_{Bank.PL} = \frac{V_{PCOS}}{\rho_{@P_P}(\frac{1}{\rho_{@P_{critical}}} - \frac{1}{(\rho_{@P_{C.PL}})})}$$

$$V_{Bank.PL} = \frac{0.167\ ft^3}{6.60\ \text{lbm/ft3}(\frac{1}{9.20\ \text{lbm/ft3}} - \frac{1}{10.60\ \text{lbm/ft3}})}$$

$$V_{Bank.PL} = 1.76\ ft^3 = \ 13.17\ gal$$

C.11.6 Minimum Accumulator Bank Volume – Dedicated Accumulator Bank

Based on the results of the Volume Limiting Case and Pressure Limiting Case, the minimum required accumulator bank volume shall be determined as the greater of the two calculated values. For this example, a safety margin (SM) of 20% is applied to ensure the accumulator system meets all functional requirements. The total number of nominal 10-gallon accumulators will then be selected to meet or exceed this required volume.

$V_{Bank.VL} = 14.01\ gal$

$V_{Bank.PL} = 13.17\ \ gal$

$SM = 20\% = 1.2$

$N_A \cdot V_{@P_P}\ \geq\ Max(V_{Bank.VL}, V_{Bank.PL}) \cdot SM$

$N_A \cdot V_{@P_P}\ \geq\ Max(14.01\ \ gal, 13.17\ gal) \cdot 1.2$

$N_A \cdot V_{@P_P}\ \geq\ 14.01\ gal \cdot 1.2$

$N_A \cdot V_{@P_P}\ \geq\ 16.81\ gal$

Using nominal 10-gallon individual accumulators, a minimum of two accumulators are required to satisfy the minimum required accumulator bank volume. This also meets the requirement for a minimum of two accumulators per bank. Therefore, the selected dedicated accumulator bank volume will be 20 gallons.

C.11.7 Minimum Accumulator Low Pressure Alarm Setting – Dedicated Accumulator Bank

With the Dedicated accumulator bank volume selected to be 20 gallons (two nominal 10-gallon accumulators), the required minimum accumulator low-pressure alarm setpoint for the Dedicated accumulator bank will be determined as follows

$$\rho_{@P_{Alarm}} = \frac{1}{\left(\frac{1}{\rho_{@P_{Critical}}} - \frac{1}{\rho_{@P_P}}\left(\frac{V_{PCO}}{N_A \cdot V_{@P_P}}\right)\right)} \tag{F.12}$$

$$\rho_{@P_{Alarm}} = \frac{1}{\left(\frac{1}{9.20\ \mathrm{lbm/ft3}} - \frac{1}{6.60\ \mathrm{lbm/ft3}}\left(\frac{1.25\ gal}{20\ gal}\right)\right)}$$

$$\rho_{@P_{Alarm}} = 10.08\ lbm/ft3$$

From the NIST Chemistry WebBook

$P_{Alarm} =\ Interp_{NIST}(10.08\ lbm/ft3\ , 32°\mathrm{F})$

$P_{Alarm} = 2240\ psig$

The Dedicated accumulator bank low-pressure alarm will be set at 2240 psig. This setpoint ensures that, above this pressure, the accumulator system contains sufficient usable hydraulic volume and pressure to complete the required pressure control operating sequence during a well control event

Annex D
Example Wireline Pressure Control Accumulator System Drawdown Test Form (Informative)

D.1 Introduction

The following forms (Figure D.1 and Figure D.2) are provided to offer guidance in conducting wireline pressure control equipment accumulator system drawdown tests and recording the performance data. The recommended test steps are intended to confirm that sufficient power fluid and actuator pressure are available to effectively perform the required ram function for the given wireline and wellbore pressure.

Figure D.1-Primary Pressure Control Stack Drawdown Test Form

Primary WL Accumulator System			**Date**
Number of Accumulator Bottles	Psig	Nominal Volume of Bottles	
Average Pre-charge Pressure	Psig		F
Maximum Pre-charge Pressure	Psig		F
30-minute Stabilized Operating Pressure Reading	Psig		F
Observed Operating Pressure Upon Open of Isolation	Psig		F

Component	**Status**	**Observed Pressure**	**Function Time**	**Comments**
Wireline Ram #1	Close	Psig	Seconds	
Wireline Ram #2	Close	Psig	Seconds	
Inverted Ram	Close	Psig	Seconds	
Wireline Ram	Open	Psig	Seconds	
Wireline Ram	Open	Psig	Seconds	
Inverted Ram	Open	Psig	Seconds	

Figure D.2-Dedicated Shear/Seal Device Drawdown Test Form

"Dedicated" WL Shear/Seal Device Accumulator System			**Date**
Number of Accumulator Bottles		Nominal Volume of Bottles	
Average Pre-chage Pressure	Psig	F	
Maximum Charge Pump Pressure	Psig	F	
30-minute Stabilized Operating Pressure Reading	Psig	F	
Observed Operating Pressure Upon Open of Isolation Valve	Psig	F	

Component	Status	Observed Pressure	Function Time	Comments
Shear/Seal	Close	Psig	Seconds	Compared with Shear Test Data
Shear/Seal	Open	Psig	Seconds	

Annex E
Wireline "Well-hopping" Pressure Control Stack Pressure Testing
(Informative)

E.1 General

"Well-hopping" pressure testing practices are intended to address WL operations conducted on platform drilled (offshore) or pad drilled (onshore) wells where the proposed WL well intervention operation will be completed prior to the fourteen-day pressure test frequency timeline (see 7.8 item b) and another WL well intervention operation is planned in a well adjacent to the initial well.
In WL well intervention applications where each well in the campaign is completed within a 12-hour to 36-hour period, there is a concern that rapid degradation of WL pressure control barrier elements will occur due to abrasion/ erosion of the elastomer seals and/or deformation of the sealing elements when subjected to a higher frequency of pressure testing than intended to confirm performance capability of the barriers.

The "well-hopping" pressure testing practices seen in this annex are to be conducted only where the closing unit and control lines are placed on location and remain in their original position, without being disconnected (not moved during the "well-hopping" well intervention campaign).

E.2 Recommended "Well-hopping" Pressure Control Stack Pressure Test Procedure

In order to meet the intent of safety and high confidence in pressure control stack component performance, the following process is recommended to be used when conducting Well Hopping pressure testing practices. The following steps are considered as minimum actions for conducting "well-hopping" operations and the actual operations employed should meet or exceed these steps based on a risk assessment.

E.2.1 In preparation for "well-hopping" operations, the initial pressure test of record for the pressure control stack components should be conducted to meet the highest MASP or MAOP conditions projected for the group of wells to be included in the fourteen-day test period protocol.

E.2.2 An assessment of the well intervention operations to be performed should be conducted to ensure that wellbore-wetted fluids in each wellbore within the specified "well hopping" group are compatible with the elastomeric seals installed in the pressure control equipment components to be used in the prescribed services.

E.2.3 If any pressure control components requires replacement due to failure or job scope, then the replaced component and all affected components should be pressure tested in accordance with 7.7 item b).

E.2.4 The "well-hopping" procedure should be conducted in the following manner to ensure the safe and effective pressure containment of the WL pressure control stack components when moved from the current wellbore to the subsequent wellbore in the program:

> **a)** The closing unit and control lines should be aligned with the wells within the intervention group such that there is no movement of the closing unit or control lines when disconnecting the WL pressure control stack on the current well and installation on the subsequent well.

b) Equipment used to raise the pressure control stack should be located in the optimum position to enable the lift equipment to reach each wellbore within the prescribed "well-hopping" group.

c) Disconnection of the pressure control stack from the current well installation should be limited to the connection located below all pressure control stack components, with minimal vibration or mechanical disturbance.

d) All pressure control stack operating hoses and monitoring cables should remain connected and be pre-deployed in a manner where movement of the pressure control stack does not require changes in any of the mechanical components or connections providing hydraulic flow or signal communication (hose reels, points of severe turns, bending or kinking of lines, etc.).

e) All pressure control equipment operating hoses and monitoring cables should be supported through bridles or brackets secured to the stack in a manner which prevents damages caused by loading on the end connections expected to occur during the move or during any stage of well intervention service.

f) Movement of the pressure control stack from the current tree to the subsequent tree should be provided by the dedicated lifting equipment and handled in a controlled environment which will ensure that no contact or collision with other equipment components can occur. The suspended hoses and cables should remain in a relaxed condition (as suspended from the bridles/brackets secured to the stack).

g) Post-installation pressure tests shall be conducted following 7.8 item c), as applicable.

E.2.5 The "well-hopping" procedural steps seen in Annex E.2 should be reported and recorded in the pressure test log, along with relevant documentation providing a layout of the "well-hopping" group of wells, location of the WL unit in relation to the group of wells and layout diagram for the pressure control equipment.

Annex F

Wireline Pressure Control Stack Mechanical Ram Performance Tests – Shear Seal Device (Normative)

F.1 Shear Ram Performance Testing

F.1.1 The shear ram performance tests shall be conducted using a segment of wireline which meets the same specifications as wireline to be used in the prescribed services. The shear ram test shall be performed with the ram ID bore at atmospheric pressure without tension applied to the WL specimen.

NOTE: Previous qualification of shearing capability is acceptable and new testing is not required.

F.1.2 At least one additional shear test shall be conducted with the WL specimen positioned off-center of the ID bore, perpendicular to the axis of the ram shaft at the edge of the shear blade cutting surface.

F.1.3 The test report data for each shear test shall include :

a) WL specimen data sheet;
b) description of each of the internal spoolable components and material yield strength(s) taken from MTR's;
c) manufacturer of shear ram assembly, including model, ID bore, RWP and serial number;
d) model of ram assembly actuator, including maximum allowable hydraulic operating pressure of actuator;
e) serial number or part number, or both, of shear blade, along with description of blade cutting profile;
f) observed shear ram hydraulic actuator "close" pressure applied to shear ram actuator at the point in time of the shearing event for each cut test;
g) observed shear ram hydraulic actuator "open" pressure at the point in time of the shearing event for each cut test;
h) condition of shear blade upon completion of each shearing test; and
i) digital record of hydraulic actuator pressure from start to end of each test, including peak WL shearing pressure.

F.1.4 The hydraulic actuator pressure shall be recorded using a digital data acquisition system. The pressure sensor accuracy shall be equal to or better than ±0.5 % of the full range of the sensor. The monitoring system shall be at least as accurate as the sensor. The update (scan) rate of the monitoring system shall be equal to or faster than 20Hz and operated in accordance with ASTM D5720-95.

F.2 Shear-Seal Device Performance Testing

F.2.1 The shear ram performance tests shall be conducted using a segment of wireline which meets the same specifications as wireline to be used in the prescribed services. The shear ram test shall be performed with the ram ID bore at atmospheric pressure without tension applied to the WL specimen.

F.2.3 Immediately following the initial Shear-seal device cut test, the shear=seal device shall remain closed and a pressure test conducted in accordance with 7.7 – 7.9 the hydraulic pressure applied to the SBR actuator for the pressure test shall be adjusted to represent the effective actuator pressure applied to the rams for the max RWP of the shear-seal device.

F.2.5 At least one additional shearing test shall be conducted with the WL specimen positioned off-center of the ID bore, perpendicular to the axis of the ram shaft at the edge of the SBR blade cutting surface.

F.2.6 Immediately following the second SBR cut test, the SBR shall remain closed and a pressure test conducted in accordance with 7.7 – 7.9. The hydraulic pressure applied to the SBR actuator for the pressure test shall be adjusted to represent the effective actuator pressure applied to the rams for the max RWP of the shear-seal device.

F.2.8 The test report data for each SBR cut and seal test shall include:

a) WL specimen OD, average wall thickness, material yield strength from MTR and designated grade of tube;
b) description of each of the internal spoolable components and material yield strength(s) taken from MTR's;
c) manufacturer of SBR assembly, including model, ID bore, RWP and serial number;
d) model of ram assembly actuator, including maximum allowable hydraulic operating pressure of actuator;
e) serial number or part number, or both, of SBR blade, along with description of blade cutting profile;
f) observed SBR hydraulic actuator "close" pressure applied to SBR actuator at the point in time of the shearing event for each cut test;
g) observed SBR hydraulic actuator "open" pressure at the point in time of the shearing event for each cut test;
h) condition of SBR blade upon completion of each shearing test;
i) digital record of hydraulic actuator pressure from start to end of each test, including peak WL shearing pressure;
j) post-shear pressure test record (circular charts or digital data acquisition).

F.2.9 The hydraulic actuator pressure shall be recorded using a digital data acquisition system. The pressure sensor accuracy shall be equal to or better than ±0.5 % of the full range of the sensor. The monitoring system shall be at least as accurate as the sensor. The update (scan) rate of the monitoring system for the shearing tests shall be equal to or faster than 20Hz and operated in accordance with ASTM D5720-95. The update (scan) rate of the monitoring system for the post-shear pressure tests to be equal to or faster than 1 Hz and operated in accordance with ASTM D5720-95.

ANNEX G
Management of Quick Unions
(Normative)

G.1 General

This annex provides guidance around the use of quick unions in wireline pressure control equipment covered by the scope of API 16WL to minimize the risk of loss of primary containment events during wireline operations.

G.2 Planning

The following shall be considered during the planning phase:

a) Minimize the number of quick unions below the wireline valve as practical as possible (removing any extra cross overs)
b) Utilize consistent sizes of quick unions through the stack avoiding smaller sized quick unions below a larger sized to decrease bending loads and deflection.
c) Support the PCE stack by applying tension from the top of the stack (utilizing a hoisting system with an anchoring point as close to the vertical as practical)
d) Minimize lateral/side loading on pressure control equipment by ensuring there is sufficient support for the PCE to maintain it in a vertical position.
e) When possible; obtain a documented operating envelope for functional and structural capacity taking into consideration forecasted weather conditions during operations
f) Monitor the applied tension to the pressure control equipment by using weight indicators (load cells) and defining maximum/ minimum tensions required.
g) Agree and document quick union make up procedures.

G.3 Equipment preparation

The following shall be considered during the equipment preparation for rig up:

a) Inspection of O-ring groove and seal surfaces
b) Change all elastomers on the assembly before each operation
c) Inspect threads making sure there is no damaged threads

G.4 PCE Stack make up

The following shall be considered during the PCE stack make up:

a) Ensure alignment during make up of quick unions in the vertical position to prevent seal damage
b) Verify that the pin is fully seated with the box before lowering the “nut” and making it up
c) Make up the quick union nut fully by hand this is to prevent connection backing off with any vibration
d) Mark the quick union vertically with a visible fluorescent marker to indicate any back off during operations (clean and remark any connections broken/made up)
e) Avoid taping any connections as this may mask leaks.
f) Apply and maintain tension to the PCE stack ensuring that all connections are under tension

G.5 During operations

The following shall be considered during operations:

a) Continuously monitor tension on the PCE stack to ensure that all connections are under tension.
b) Continuously monitor quick union marks for any signs of back off

c) Verify connections between runs or any time the lower part of the PCE(below the QTS) is left unsupported

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