Table C.4 – Initial Pressure Testing, Surface BOP Stacks

Component to be Tested	**Pressure Test – Low Pressure**[a,c] psi (MPa)	**Pressure Test – High Pressure**[a,c] psi (MPa)	
		Change Out of Component, Elastomer, or Ring Gasket	**No Change Out of Component, Elastomer, or Ring Gasket**
Annular Preventer[b]	250 to 350 (1.72 to 2.41)	RWP of annular preventer	MASP or 70% of annular RWP, whichever is lower
Fixed pipe, variable bore, blind, and BSR preventers[b,d]	250 to 350 (1.72 to 2.41)	RWP of ram preventer or wellhead system, whichever is lower	ITP
Choke and kill line and BOP side outlet valves below ram preventers (both sides)	250 to 350 (1.72 to 2.41)	RWP of side outlet valve or wellhead system, whichever is lower.	ITP
Choke manifold – upstream of chokes[e]	250 to 350 (1.72 to 2.41)	RWP of ram preventer or wellhead system, whichever is lower	ITP
Choke manifold – downstream of chokes[e]	250 to 350 (1.72 to 2.41)	RWP of valve(s), line(s), or MASP for the well program, whichever is lower	
Kelly, kelly valves, drill pipe safety valves, IBOPs	250 to 350 (1.72 to 2.41)	MASP for the well program	

[a] Pressure test evaluation periods shall be a minimum of five minutes.
No visible leaks.
The pressure shall remain stable during the evaluation period. The pressure shall not decrease below the intended test pressure.

[b] Annular(s) and VBR(s) shall be pressure tested on the largest and smallest OD drill pipe to be used in well program.

[c] For pad drilling operations, moving from one wellhead to another within the 21 days, pressure testing is required for pressure-containing and pressure-controlling connections when the integrity of a pressure seal is broken.

[d] For surface offshore operations, the ram BOPs shall be pressure tested with the ram locks engaged and the closing and locking pressure vented during the initial test. For land operations, the ram BOPs shall be pressure tested with the ram locks engaged and the closing and locking pressure vented at commissioning and annually.

[e] Adjustable chokes are not required to be full sealing devices. Pressure testing against a closed choke is not required.

Table C.5 – Subsequent Operational Pressure Testing, Surface BOP Stacks

Component to be Pressure Tested	Pressure Test – Low Pressure[a] psi (MPa)	Pressure Test – High Pressure[a] psi (MPa)	Frequency
Annular Preventer[b]	250 to 350 (1.72 to 2.41)	MASP for the hole section, or 70% of annular RWP, whichever is lower.	Not to exceed 21 days
BOP side outlet valves above pipe ram preventers (wellbore side)	250 to 350 (1.72 to 2.41)	MASP for the hole section, or 70% of annular RWP, whichever is lower.	Not to exceed 21 days
BOP side outlet valves above pipe ram preventers (non-wellbore side)	250 to 350 (1.72 to 2.41)	MASP for the hole section	Not to exceed 21 days
Fixed and variable bore pipe ram preventers[b]	250 to 350 (1.72 to 2.41)	MASP for the hole section	Not to exceed 21 days
Choke and kill line and BOP side outlet valves below pipe ram preventers (both sides)	250 to 350 (1.72 to 2.41)	MASP for the hole section.	Not to exceed 21 days
Choke manifold – upstream of chokes[c]	250 to 350 (1.72 to 2.41)	MASP for the hole section	Not to exceed 21 days
Choke manifold - downstream of chokes[c]	250 to 350 (1.72 to 2.41)	RWP of valve(s), line, or MASP for the hole section, whichever is lower	Not to exceed 21 days
Kelly, kelly valves, drill pipe safety valves, IBOPs	250 to 350 (1.72 to 2.41)	MASP for the hole section	Not to exceed 21 days
Blind and BSR preventers	250 to 350 (1.72 to 2.41)	Casing test pressure	At casing points

[a] Pressure test evaluation periods shall be a minimum of five minutes.
No visible leaks
The pressure shall remain stable during the evaluation period. The pressure shall not decrease below the intended test pressure.

[b] Annular(s) and VBR(s) shall be pressure tested on the smallest OD drill pipe expected to be used in the next 21 days.

[c] Adjustable chokes are not required to be full sealing devices. Pressure testing against a closed choke is not required.

Table C.6 – Operating Chamber Pressure Testing, Surface BOP Stacks

Component to be Pressure Tested	**Pressure Test – Low Pressure**[a] psi (MPa)	**Pressure Test – High Pressure**[a] psi (MPa)	**Frequency**
Annular Preventer open and closing operating chambers	Not required	RWP as specified by equipment manufacturer	Every 12 months
BOP choke and kill valve open and closing operating chambers	Not required	RWP as specified by equipment manufacturer	Every 12 months
Ram preventer open and closing operating chambers	Not required	RWP as specified by equipment manufacturer	Every 12 months
Casing shear ram open and closing operating chambers	Not required	RWP as specified by equipment manufacturer	Every 12 months

[a] Pressure test evaluation periods shall be a minimum of five minutes.
No visible leaks
The pressure shall remain stable during the evaluation period. The pressure shall not decrease below the intended test pressure.

[b] If the BOP is in operation, the test is to be conducted during the BOP next planned maintenance.

Table C.7 – Pre-deployment Function Testing, Subsea BOP Stacks

System Component	Function Test Description	Test Acceptance Criteria
Secondary Control Systems		
Acoustic System	Critical functions tested by activation through acoustic control unit. Each shear ram CLOSE One pipe ram CLOSE Ram locks LOCK LMRP connector UNLATCH	Verification of intended operation may be in the form of visual inspection, flowmeter volume count, pressure testing, or applicable means Response times to meet 6.4.6.2
ROV Intervention	Function test of critical functions through intervention circuit Each sealing shear ram CLOSE and LOCK Each non-sealing shear ram CLOSE One pipe ram CLOSE and LOCK LMRP connector UNLATCH	Verification of intended operation may be in the form of visual inspection, flowmeter volume count, pressure testing, or other applicable means Response times to meet 6.4.6.2
Emergency Control Systems		
Deadman circuit test[ad]	All modes function tested by removing electric power and hydraulic supply to the stack	Completed in 90 seconds or less[c] Verification of intended operation/sequence may be in the form of visual inspection, flowmeter volume count, pressure testing, or other applicable means
Autoshear circuit test[ad]	All modes function tested by activation of trigger	Completed in 90 seconds or less[c] Verification of intended operation/sequence may be in the form of visual inspection, flowmeter volume count, pressure testing, or other applicable means
Primary Control Systems		
Control stations[e]	Function test of all control stations and remote panels	Positive verification of intended operation
BOP stack operators, valves, and pods	BOP functions tested from installed pods (to include ram operators, annular operators, connectors, stack mounted valves, stabs, cylinders, pod specific functions, high-pressure circuits, secondary circuits).	Visual verification of no leaks Verification of intended operation may be in the form of visual inspection, flowmeter volume count, pressure testing, or other applicable means Response time to meet 6.4.6.2 Flowmeter volume count to be within equipment owner's criteria
BOP gas bleed and side outlet valves	Valve closure to be function tested with springs only (no hydraulic assist)	Verification valve shifts to fully closed state by visual inspection, pressure testing, flowing through valves, or other applicable means
Main accumulator system HPU pumps	Drawdown test per 6.4.15 Cumulative output capacity of pump systems to be timed, charging the main accumulator after drawdown test to system RWP	Verification that the final accumulator pressure is greater than the MOP specified in system accumulator sizing Verification that system RWP is achieved within 15 minutes

Table C.7 – Pre-deployment Function Testing, Subsea BOP Stacks (continued)

System Component	Function Test Description	Test Acceptance Criteria
BOP stack hydraulic circuits	The integrity of the BOP stack hydraulic circuits to be verified at maximum pressures expected for well control operations Test duration to be per equipment owner requirements	Visual verification of no leaks
Emergency disconnect sequence (dry test)	All modes function tested Each EDS activation location function tested with at least one mode	Verification at data logger that functions were commanded per sequence
Emergency disconnect sequence (wet test)	The mode that consumes the largest volume of hydraulic fluid function tested by activation at control station	Verification at data logger that functions were commanded per sequence Verification of intended operation may be in the form of visual inspection, flowmeter volume count, pressure testing, or other applicable means
BOP stack	BOP to be drifted with a minimum diameter tool or drift as determined by the equipment owner and user requirements	Pass completely through BOP stack after BOP pre-deployment pressure and function testing (API 16A acceptance criteria to drift within 30 minutes not applicable)

[a] Securing the well includes closing rams, valves, and locks and does not include disconnects or other functions that may subsequently be employed after the well has been secured.

[b] Autoshear systems that are initiated by removal of electric power and hydraulic supply to the stack do not require a separate test from the deadman system.

[c] Minimal time requirement to secure the wellbore does not include functions after well has been secured.

[d] Power fluid may be supplied from surface accumulators or an alternative source.

[e] Maintenance panels excluded.

Table C.8 – Initial Function Testing, Subsea BOP Stacks

System Component	Function Test Description	Test Acceptance Criteria
Secondary Control Systems		
Acoustic System	Close one ram BOP	Verification of intended operation may be in the form of visual inspection, flowmeter volume count, pressure testing, or applicable means Response times to meet 6.4.6.2
ROV Intervention	Close one ram BOP	Verification of intended operation may be in the form of visual inspection, flowmeter volume count, pressure testing, or other applicable means Response times to meet 6.4.6.2
Emergency Control Systems		
Dedicated emergency accumulators Deadman circuit test	One mode function tested by removing control and hydraulic supply to the activation device	Completed in 90 seconds or less[c] Positive verification of intended operation may be in the form of visual inspection, flowmeter volume count, pressure testing, or other applicable means Verification that components actuated per design Final accumulator pressure greater than the MOP to secure the well
Primary Control Systems		
BOP rams, annulars, choke and kill valves	BOP functions tested from the control station through the installed pods[c]	Verification of intended operation may be by recovery of system pressure, flowmeter readback, or other applicable means Response tie to meet 6.4.6.2 Flowmeter volume counts to be within equipment owner's criteria
High-pressure casing shear rams and high-pressure BSRs close circuits	Function tested from install pods from designated control stations[a]	Verification of intended operation may be by recovery of system pressure, flowmeter readback, or other applicable means Response tie to meet 6.4.6.2 Flowmeter volume counts to be within equipment owner's criteria
Main accumulator system (only required on systems that rely on LMRP accumulators to meet sizing requirements)	Drawdown test per 6.4.15	Verification that the final accumulator pressure is greater than the MOP specified in system accumulator sizing
BOP stack	BOP to be drifted with a minimum diameter tool or drift as determined by the equipment owner and user's requirements	Pass completely through BOP stack after BOP initial pressure and function testing (API 16A acceptance criteria to drift within 30 minutes not applicable)
Drill Floor Safety Valves		
Valves	Function test	Verification of intended operation
Choke Manifold		
Adjustable chokes	Function test	Verification of intended operation

[a] Securing the well includes closing rams, valves, and locks and does not include disconnects or other functions that may subsequently be employed after the well has been secured

[b] Minimal time requirement to secure the wellbore does not include functions after well has been secured.

[c] Maintenance panels excluded.

Table C.9 – Subsequent Operational Function Testing, Subsea BOP Stacks

System/Component	Function Test Description	Test Acceptance Criteria	Frequency
	Secondary Control Systems		
Acoustic	Battery Check	Verification of communication	Not to exceed 21 days
	Emergency Control Systems		
Dedicated emergency accumulators	Drawdown test With charging system isolated, discharge the volume of the greatest consuming emergency system mode	Accumulator pressure greater than the MOP to secure the well	Not to exceed 180 days
	Primary Control Systems		
BOP rams, annulars, and choke and kill valves (excluding shear rams)	Function tested through one pod from one designated control station[a] Pods to be alternated between tests Control stations to be alternated according to equipment owner's schedule	Verification of intended operation may be by recovery of system pressure, flowmeter readback, or other applicable means Response time to meet 6.4.6.2 Flowmeter volume counts to be within equipment owner's criteria	Not to exceed 7 days
Casing shear rams and BSRs	Function tested through one pod from one designated control station[a] Pods to be alternated between tests Control stations to be alternated according to equipment owner's schedule	Verification of intended operation may be by recovery of system pressure, flowmeter readback, or other applicable means Response time to meet 6.4.6.2 Flowmeter volume counts to be within equipment owner's criteria	Not to exceed 21 days
High-pressure casing shear ram circuit and high-pressure BSRs close circuit	Function tested through one pod from one designated control station[a] Pods to be alternated between tests Control stations to be alternated according to equipment owner's schedule	Verification of intended operation may be by recovery of system pressure, flowmeter readback, or other applicable means Response time to meet 6.4.6.2 Flowmeter volume counts to be within equipment owner's criteria	Not to exceed 90 days
Main accumulator system HPU pumps	Drawdown test per 6.4.15 Cumulative output capacity of pump systems to be timed, charging the main accumulator after drawdown test to system RWP	Verification that the final accumulator pressure is greater than the MOP specified in system accumulator sizing Verification that system RWP is achieved within 15 minutes	Not to exceed 180 days[b]
	Drill Floor Safety Valves		
Valves	Function test	Verification of intended operation	Daily
	Choke Manifold		
Adjustable chokes	Function test	Verification of intended operation	Daily

[a] Maintenance panels excluded

[b] Temperature variations can affect the usable volume in the accumulator system. An accumulator usable volume calculation or a drawdown test may be used to verify usable fluid when extreme temperature variations occur at the accumulator.

Table C.10 – Scheduled Function Testing, Subsea BOP Stacks			
System/Component	**Function Test Description**	**Test Acceptance Criteria**	**Frequency**
Secondary Control Systems			
ROV	Function test of all functions through intervention circuit and valves Testing to be conducted during pre-deployment testing with BOP on surface	Positive verification of intended operation may be in the form of visual inspection, flowmeter gallon count, pressure testing, or other applicable means Response time to meet 6.4.6.2	Not to exceed 12 months
Primary Control Systems			
EDS	The mode that consumes the largest volume of hydraulic fluid function tested by activation at control station Testing to be conducted with BOP latched to the wellhead	Verification at data logger that functions were commanded epr sequence Positive verification of intended operation may be in the form of ROV inspection, flowmeter gallon count, pressure testing, or other applicable means	Not to exceed 5 years
UPS battery test	Two-hour UPS system function test (the main UPS electrical supply isolated) with the BOP control system powered in routine drilling mode Testing to be conducted with BOP on surface	Verification of the UPS battery system by operation of a single BOP stack function after two hours	Not to exceed 12 months
Control fluid reservoir (if applicable)	Control fluid reservoir mixing operation and level alarms	Verification that appropriate visual and/or audible alarm is received from each tank fluid level Verification of automatic mixing system functionality	Not to exceed 12 months
HPU pumps	HPU pump systems start and stop pressures	Verification that primary pump system automatically starts before system pressure has decreased to 90% of the system RWP, and automatically stops at system RWP ±2% Verification that the secondary pump system automatically starts before system pressure has decreased to 85% of the system RWP and automatically stops between 95% and 100% of the system RWP	Not to exceed 12 months
[a] Testing not to be conducted during operations			

Table C.11 – Pre-deployment Pressure Testing, Subsea BOP Stacks			
Component to be Tested	**Pressure Test – Low Pressure**[ac] psi (MPa)	**Pressure Test – High Pressure**[ac] psi (MPa)	
		Change Out of Component, Elastomer, or Ring Gasket	**No Change Out of Component, Elastomer, or Ring Gasket**
Annular Preventer[b]	250 to 350 (1.72 to 2.41)	RWP of annular preventer	MASP or 70% of annular RWP, whichever is lower
BOP side outlet valves below annular and above ram preventers (wellbore side)	250 to 350 (1.72 to 2.41)	RWP of annular preventer	MASP or 70% of annular RWP, whichever is lower
BOP side outlet valves below annular and above ram preventers (non-wellbore side)	250 to 350 (1.72 to 2.41)	RWP of ram preventers	PDTP or 5000 psig, whichever is higher
Fixed pipe, variable bore, blind, and BSR preventers[bd]	250 to 350 (1.72 to 2.41)	RWP of ram preventer	PDTP or 5000 psig, whichever is higher
LMRP and wellhead connectors[bc]	250 to 350 (1.72 to 2.41)	Same as BOP above connector	Same as BOP above connector
Choke and kill line and BOP side outlet valves below ram preventers (both sides)	250 to 350 (1.72 to 2.41)	RWP of ram preventers	PDTP or 5000 psig, whichever is higher

[a] Pressure test evaluation periods shall be a minimum of five minutes.
No visible leaks.
The pressure shall remain stable during the evaluation period. The pressure shall not decrease below the intended test pressure.

[b] Annular(s) and VBR(s) shall be pressure tested on the largest and smallest OD drill pipe to be used in well program.

[c] Ram-type BOPs shall be pressure tested with the locks engaged and the closing and locking pressure vented.

Table C.12 – Initial Pressure Testing, Subsea BOP Stacks

Component to be Tested	**Pressure Test – Low Pressure**[ac] psi (MPa)	**Pressure Test – High Pressure**[ac] psi (MPa)
Annular Preventer[b]	250 to 350 (1.72 to 2.41)	MAWHP or 70% of annular RWP, whichever is lower
BOP side outlet valves below annular and above ram preventers (wellbore side)	250 to 350 (1.72 to 2.41)	MAWHP or 70% of annular RWP, whichever is lower
BOP side outlet valves below annular and above ram preventers (non-wellbore side)	250 to 350 (1.72 to 2.41)	MAWHP for the well program
Fixed pipe, variable bore, blind, and BSR preventers[bd]	250 to 350 (1.72 to 2.41)	MAWHP for the well program
LMRP and wellhead connectors[bc]	250 to 350 (1.72 to 2.41)	Same as BOP above connector
Choke and kill line and BOP side outlet valves below ram preventers (both sides)	250 to 350 (1.72 to 2.41)	MAWHP for the well program
Choke manifold – upstream of chokes[de]	250 to 350 (1.72 to 2.41)	MAWHP for the well program
Choke manifold – downstream of chokes[de]	250 to 350 (1.72 to 2.41)	RWP of valve(s), line(s), or MAWHP for the well program, whichever is lower
Kelly, kelly valves, drill pipe safety valves, IBOPs[e]	250 to 350 (1.72 to 2.41)	MAWHP for the well program

[a] Pressure test evaluation periods shall be a minimum of five minutes.
No visible leaks.
The pressure shall remain stable during the evaluation period. The pressure shall not decrease below the intended test pressure.

[b] Annular(s) and VBR(s) shall be pressure tested on the largest and smallest OD drill pipe to be used in well program.

[c] Ram-type BOPs shall be pressure tested with the locks engaged and the closing and locking pressure vented.

[d] Adjustable chokes are not required to be full sealing devices. Pressure testing against a closed choke is not required.

[e] Pressure testing can be conducted before the BOP is latched to the wellhead.

Table C.13 – Subsequent Operational Pressure Testing, Subsea BOP Stacks

Component to be Pressure Tested	**Pressure Test – Low Pressure**[a] psi (MPa)	**Pressure Test – High Pressure**[a] psi (MPa)	**Frequency**
Annular Preventer[b]	250-350 (1.72-2.41)	MAWHP or 70% annular RWP, whichever is lower	Not to exceed 21 days
BOP side outlet valves above pipe ram preventers (wellbore side)	250-350 (1.72-2.41)	MAWHP or 70% annular RWP, whichever is lower	Not to exceed 21 days
BOP side outlet valves above pipe ram preventers (non-wellbore side)	250-350 (1.72-2.41)	MAWHP for the hole section	Not to exceed 21 days
Fixed and variable bore pipe ram preventers[b]	250-350 (1.72-2.41)	MAWHP for the hole section	Not to exceed 21 days
Choke and kill line and BOP side outlet valves below pipe ram preventers (both sides)	250-350 (1.72-2.41)	MAWHP for the hole section	Not to exceed 21 days
Choke manifold – upstream of chokes[c]	250-350 (1.72-2.41)	MAWHP for the hole section	Not to exceed 21 days
Choke manifold – downstream of chokes[c]	250-350 (1.72-2.41)	RWP of valve(s), line(s), or MAWHP for the hole section, whichever is lower	Not to exceed 21 days
Kelly, kelly valves, drill pipe safety valves, IBOPs	250-350 (1.72-2.41)	MAWHP for the hole section	Not to exceed 21 days
BSR preventers	250-350 (1.72-2.41)	Casing test pressure	At casing points

[a] Pressure test evaluation periods shall be a minimum of five minutes.
No visible leaks
The pressure shall remain stable during the evaluation period. The pressure shall not decrease below the intended test pressure.

[b] Annular(s) and VBR(s) shall be pressure tested on the smallest OD drill pipe expected to be used in the next 21 days.

[c] Adjustable chokes are not required to be full sealing devices. Pressure testing against a closed choke is not required.

Table C.14 –Operating Chamber Pressure Testing, Subsea BOP Stacks

Component to be Pressure Tested	**Pressure Test – Low Pressure**[a] psi (MPa)	**Pressure Test – High Pressure**[a] psi (MPa)	**Frequency**[b]
Annular Preventer open and closing chambers	Not required	RWP as specified by equipment manufacturer	Every 12 months
LMRP connector latch and unlatch operating chambers	Not required	RWP as specified by equipment manufacturer	Every 12 months
BOP choke and kill valve open and closing operating chambers	Not required	RWP as specified by equipment manufacturer	Every 12 months
Ram preventer open and closing operating chambers	Not required	RWP as specified by equipment manufacturer	Every 12 months
Casing shear ram open and closing operating chambers	Not required	RWP as specified by equipment manufacturer	Every 12 months
Wellhead connector latch and unlatch operating chambers	Not required	RWP as specified by equipment manufacturer	Every 12 months

[a] Pressure test evaluation periods shall be a minimum of five minutes.
No visible leaks
The pressure shall remain stable during the evaluation period. The pressure shall not decrease below the intended test pressure.

[b] If the BOP is in operation, the test is to be conducted when the BOP is retrieved to surface for the next planned maintenance.