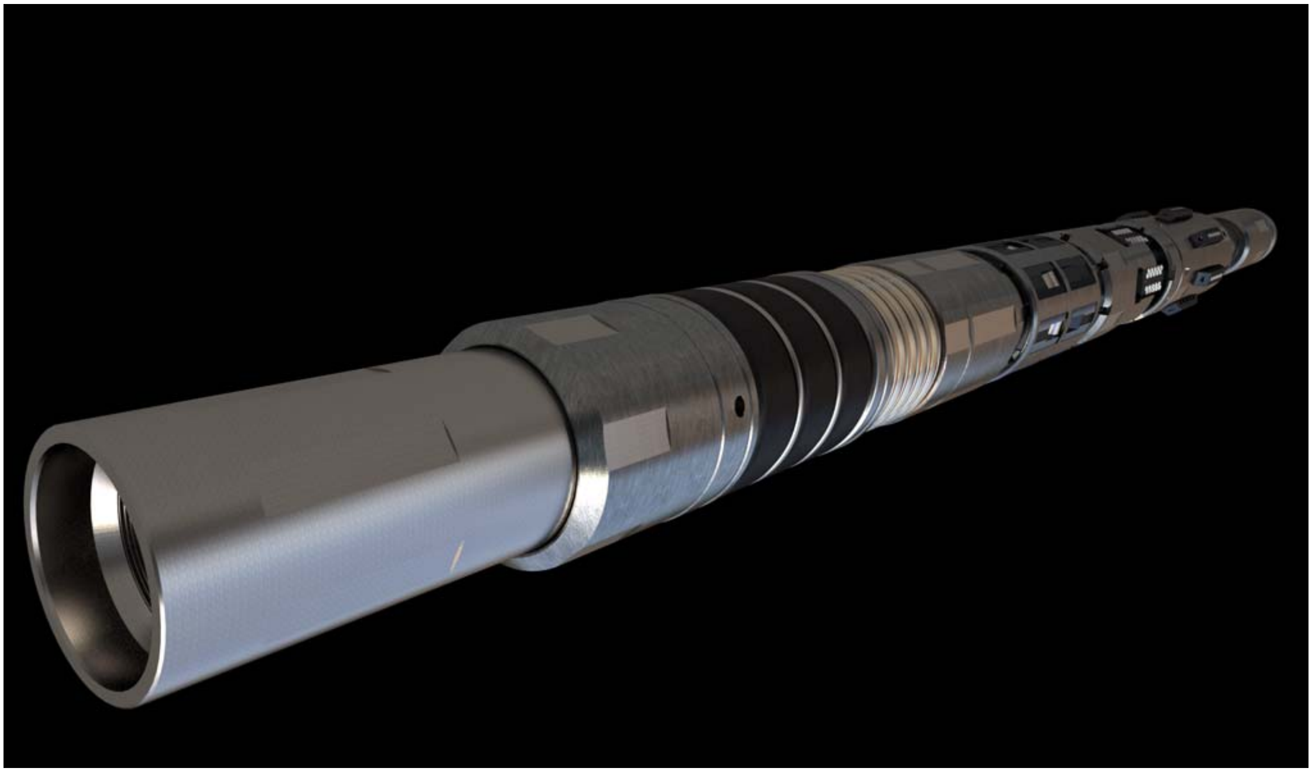
02

Retrievable Service Tools



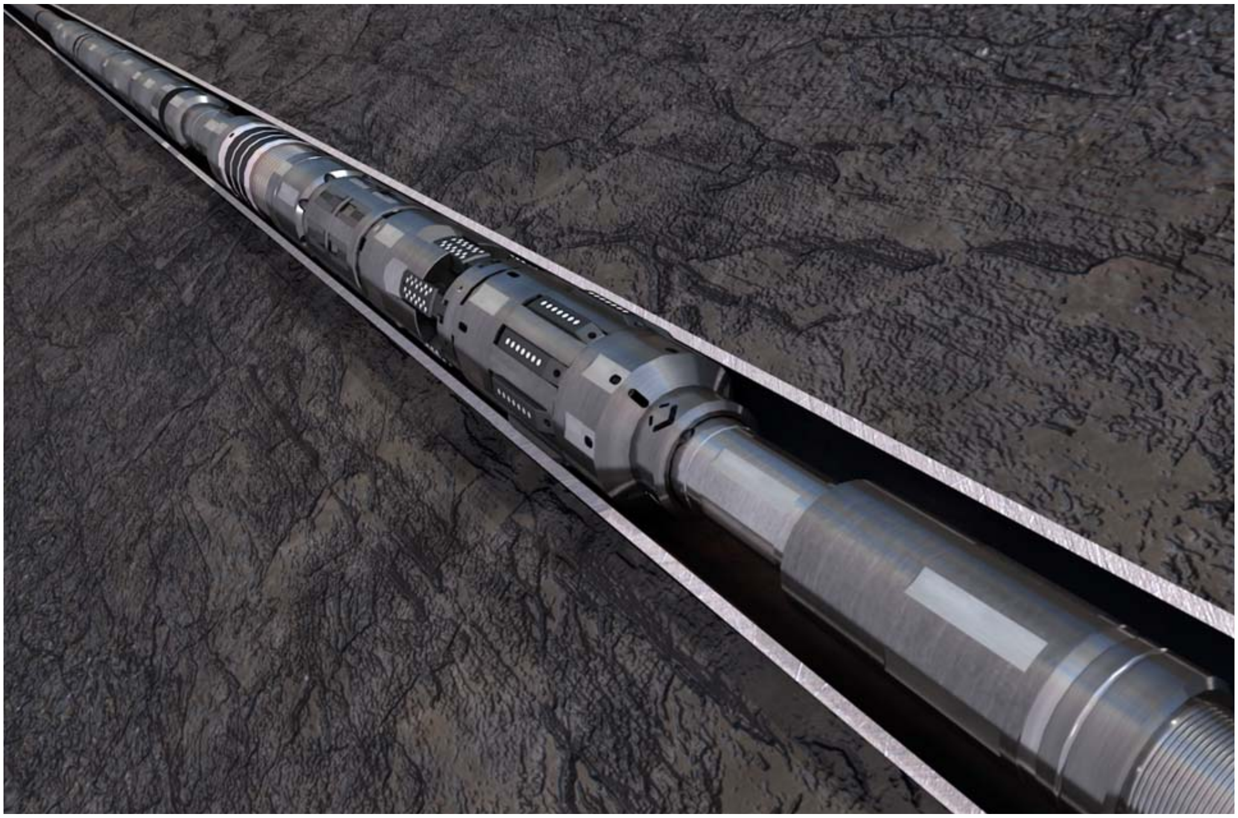
Introduction

Halliburton is dedicated to providing top-quality equipment and service. This section contains information about our Retrievable Service Tool solutions and related accessories.

Halliburton maintains strict standards and well-documented processes and procedures to help ensure excellence and dependability in our Retrievable Service Tools equipment.

No matter what your downhole situation, you can count on your Halliburton representative to look beyond the tool and develop a cost-effective engineered solution that can produce savings far greater than any difference in tool cost.

Isolation Barrier Solutions



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Isolation barrier systems are a critical component in a variety of well applications. During the well construction phase, operators are often required to isolate the well to perform various operations, such as scheduled blowout preventer (BOP) testing and repairs. When drilling and completing an entire field, operators might intermittently delay completion operations to begin drilling another well. Failure to keep a wellbore sealed can lead to a loss of well control and worse — unplanned release of hydrocarbons to the environment. This can be detrimental for operators and hazardous to the environment. Regulatory organizations and operators require a reliable, robust solution to this industry challenge.

Suspending the well to keep it stable and safe is particularly critical when performing temporary abandonment activities.

These barrier systems help address the following operational challenges:

- BOP qualification testing and maintenance
- Unscheduled wellhead maintenance
- Short- to long-term well suspension
- Casing integrity testing
- Emergency suspension caused by weather or adverse conditions
- Temporary barriers during batch drilling operations

Halliburton is able to meet these challenges with several temporary isolation barrier solutions, including:

- Intercept® retrievable bridge plug
- RTTS® packer combined with a subsurface control (SSC) valve
- Model 3L™ retrievable bridge plug

Intercept® Retrievable Bridge Plug

Failure to maintain a gas-tight seal in a wellbore can lead to a loss of well control and an unplanned release of hydrocarbons to the environment. This can be detrimental for operators and hazardous to the environment. Regulatory organizations and operators require a solution to this industry challenge.

The Halliburton Intercept® retrievable bridge plug is a gas-tight, well-suspension plug ideal for dual-barrier applications and is designed to handle a wide range of well conditions. The plug solves the industry regulatory requirements of having an API 11D1/ISO 14310 V0-qualified well barrier to provide wellbore isolation. Suspending the well and keeping it stable and safe are particularly critical when performing activities, such as:

» Blowout preventer qualification testing and maintenance
» Wellhead maintenance
» Short- and long-term well suspension
» Casing testing
» Emergency suspension because of weather or adverse conditions

The Intercept retrievable bridge plug is unique because it does not require hang weight below to set, which saves the rig time required to deploy drillpipe before running the plug. Should well operations require it, the plug can handle significant pipe weight below, saving trip time and reducing costs while enhancing safety. Additionally, the plug does not require left-hand rotation, which reduces the risk of accidental disconnection of the workstring or bottomhole assembly. When the operation is complete, the plug can be retrieved quickly and safely.

The Intercept plug can be run reliably in a variety of applications, from ultra-deepwater to inland waters, and sets with simple workstring manipulation.

The ball valve can be opened and closed as often as desired without pipe rotation. The workstring can then be released from the plug, which remains in place until operations are complete. To retrieve the plug, the workstring is relatched, and the ball valve is opened to monitor pressure below. The plug is then released with right-hand rotation. The plug consists of packer-type, high-performance sealing elements, bi-directional mechanical slips, and a ball valve module. When set, the Intercept retrievable bridge plug provides a reliable barrier in the casing, regardless of pressure reversals. The lower portion of the plug can be run as a conventional service-type packer without the ball valve module.

Features and Benefits

» API 11D1/ISO 14310 V0 qualified
» No hang weight required below
» Ball valve module can be opened at maximum differential pressure without rotation
» Industry-proven RTTS® packer mechanical slips provide positive anchor for setting
» Ability to support tensile loads up to 400,000 lb (181 440 kg)
» Meets industry requirement for gas-tight barrier
» Quick and easy operating procedure with no left-hand rotation required
» Tripping tailpipe not required, saving rig time and costs

Intercept®
Retrievable Bridge Plug

RTTS® Packer

The RTTS® packer has been one of the most used and well-known service packers in the industry for more than 60 years. These packers have been run successfully in more than 100,000 jobs in nearly every country where oil and gas is produced. Their reputation for reliability and durability is why operators ask for RTTS packers by name — some are still in wellbores that have been working continuously for as long as 30 years. For barrier applications, the RTTS packer is run with an SSC valve to provide a trusted seal in the wellbore. This combination allows the workstring to be released and retrieved from the well while further operations are performed on the wellhead.

The RTTS packer is a full-opening, hookwall packer used for testing, treating, and squeeze operations. In most cases, the tool runs with a circulating valve assembly. The packer body includes a J-slot mechanism, mechanical slips, packer elements, and hydraulic slips. Large, heavy-duty slips in the hydraulic holddown mechanism help prevent the tool from being pumped uphole.

Features and Benefits

- Full-opening design of the packer mandrel bore allows large volumes of fluid to pump through the tool
  - Tubing-type guns and other wireline tools can be run through the packer
- Packer can be set and relocated as many times as necessary
- Tungsten carbide slips provide greater holding ability and improved wear resistance in high-strength casing
- Optional integral circulating valve locks into open or closed position during squeezing or treating operations and opens easily to allow circulation above the packer

RTTS® Packer

RTTS® V3 Packer

The RTTS® V3 full-opening, hookwall packer is used for well suspension, testing, and treating operations. The assembly is qualified to API 11D1/ISO 14310 Grade V3 requirements. In most cases, the tool is run with a subsurface control valve (SSC) assembly to allow for fast, reliable well suspension without having to fully recover the drillstring or bottomhole assembly (BHA). The RTTS V3 packer can be unset and retrieved by simply moving the workstring upward.

Features and Benefits

- Full-opening design of the packer mandrel bore allows large volumes of fluid to pump through the tool
- Tubing-conveyed perforating guns and wireline equipment can be run through the packer
- Packer can be set and relocated as many times as necessary with simple tubing manipulation*
- Tungsten carbide slips provide greater holding capacity and improved wear resistance in high-strength casing
- Pressure through the tubing activates the slips in the hydraulic holddown mechanism
- Assembly tensile strengths greater than 1 million pounds available
- Can be run with multiple accessories, such as RTTS circulating and SSC valves, to cover multiple operations on location
- Suspends the well without the need to recover the drilling BHA, minimizing downtime by allowing operations to continue without the need to rerun the complete drilling assembly
- Qualified and proven to industry API and ISO standards

*Specific operational information must be considered before multiple sets are conducted.

RTTS®
V3 Packer

Subsurface Control Valves

Halliburton Subsurface Control (SSC) valves provide reliable barriers for use in a variety of applications from regular blowout preventer (BOP) maintenance and integrity validation to casing and liner-top testing to longer-term applications, such as batch drilling. When combined with the strength and durability of the industry-standard RTTS® packer, SSC valves allow operators to perform workover operations as well as minimize disruptions caused by weather or wellbore containment emergencies.

Using SSC valves, operators can secure the drillstring downhole to provide more efficient abandonment of the installation. Because the drillstring is left in place, minimal effort is required to bring the well back online. Well security and personnel safety are improved, and operations can resume quickly after a workover or storm.

Solutions for a Range of Applications

The SSC valve product line includes SSC I, SSC II, SSC III, and the newest addition to the line, the SSC IV valve. Each of these valves offers specific features to suit a variety of wellbore construction scenarios.

The SSC I valve is a combination sliding sleeve and backoff joint ideal for situations in which a well needs to be closed in without pulling the complete workstring.

The SSC II valve is a ball valve and release mechanism, which allows operators to isolate a wellbore without having to fully recover the workstring. The release mechanism requires only right-hand rotation to disconnect the workstring and is re-latched by simply setting down weight.

The SSC III valve is a ball valve and release mechanism that requires minimal rotation with high hang-weight capability. It supports up to 1 million pounds of drillstring weight hanging off the valve.

The SSC IV valve encompasses all the benefits of the SSC III, along with a gas-tight qualification to meet the industry needs for a secure barrier during well operations.

Capabilities

SSC valves use the industry-standard RTTS packer to support workstring weight. The packer seals inside the casing (surface pipe or intermediate casing string), and the SSC valve seals the workstring ID. Because SSC valves include a release mechanism, the workstring above can be removed from the well and then reconnected when operations resume.

To take advantage of the SSC III and IV valves' high-load capabilities, special high-strength RTTS packer assemblies have been developed for use in conjunction with these valves to support the workstring weight.

By opening and closing the valve, the operator can check for pressure buildup before unsetting the packer. The SSC II, III, and IV valves can handle large volumes of drilling fluids to recondition the mud system before the packer and valve are removed and normal drilling operations resume.

Subsurface Control (SSC) Valve

Model 3L™ Retrievable Bridge Plug

The Model 3L™ retrievable bridge plug consists of packer-type sealing elements, mechanical slips, and a large area bypass.

The sealing elements are less susceptible to damage while running in the hole because they are not in contact with the casing. When set, the Model 3L bridge plug does not move up or down the casing, regardless of pressure reversals.

This plug can be run alone on tubing or run below the RTTS® or CHAMP® IV packer. The tool is run in the hole, set, and released from the tubing or packer. It remains in place until the tubing or packer is relatched, the bypass valve is opened, and the slips are released.

The bridge plug is retrieved when the tubing is lowered and the overshot engages the lugs on the plug-retrieving head. Torque is applied and the tubing is pulled up. It might be necessary to apply weight if pressure is trapped below the tool. As the torque is applied and the tubing is pulled up, the bypass ports open, and the mechanical slips are retracted to release the bridge plug.

Features and Benefits

» Rugged, packer-type sealing elements and slips
» Wide range of pressure and temperature capabilities
» Simple operation
» Superior zonal isolation and protection
» Can temporarily plug the wellbore
» Contains bypass ports that reduce swab and surge effects and relieve pressure during retrieval
» Can be used with or without other retrievable tools
» Easily removed

*Model 3L™
Retrievable Bridge Plug*

Isolation Barrier Solutions Tables

Following are the specifications tables for the Isolation Barrier Systems. The values of tensile, burst, and collapse strength are calculated with new tool conditions, Lame's formulas with von Mises Distortion Energy Theory for burst and collapse strength, and stress area calculations for tensile strength.

These ratings are guidelines only. For more information, consult your local Halliburton representative.

Intercept® Retrievable Bridge Plugs

Size in.	Packer Main Body OD in. (mm)	Plug ID in. (mm)	Weight lb/ft	Temperature °F (°C)	Minimum Casing ID in. (mm)	Maximum Casing ID in. (mm)	Tensile Rating lb (kg)	Maximum Working Pressure psi (MPa)	API/ISO Validation
9 5/8	8.15 (207)	3.00 (76.2)	47 to 53.5	38 to 275 (3.3 to 135)	8.403 (213.4)	8.821 (224.1)	400,000 (181 437)	7,500 (51.71)	V0
10 3/4	9.125 (231.8)	3.00 (76.2)	60.7 to 65.7	38 to 275 (3.3 to 135)	9.415 (239.1)	9.818 (249.4)	400,000 (181 437)	7,500 (51.71)	V0
			85.3				300,000 (136 078)	10,000 (68.95)	
13 3/8	12.06 (306.3)	3.00 (76.2)	68 to 72	38 to 195 (3.3 to 90.6)	12.203 (310)	12.623 (320.6)	400,000 (181 437)	7,500 (51.71)	V0
13 5/8	12.06 (306.3)	3.00 (76.2)	86.5 to 88.2	38 to 195 (3.3 to 90.6)	12.203 (310)	12.623 (320.6)	400,000 (181 437)	7,500 (51.71)	V0
14	12.06 (306.3)	3.00 (76.2)	114	38 to 195 (3.3 to 90.6)	12.203 (310)	12.623 (320.6)	400,000 (181 437)	7,500 (51.71)	V0

RTTS® Packers

Casing Size in.	Packer Main Body OD in. (mm)	Packer ID in. (mm)	Nominal Casing Weight lb/ft	Minimum Casing ID in. (mm)	Maximum Casing ID in. (mm)	Tensile Rating* lb (kg)	Maximum Working Pressure psi (MPa)
2 3/8	1.81 (46)	0.6 (15.2)	4.60	1.93 (49.0)	2.029 (51.5)	28,700 (13 018)	10,000 (68.95)
2 7/8	2.22 (56.4)	0.75 (19.1)	6.50	2.372 (60.3)	2.493 (63.3)	38,300 (17 373)	10,000 (68.95)
	2.1 (53.3)	0.6 (15.2)	7.9 to 8.7	2.172 (55.2)	2.353 (59.8)	54,463 (24 704)	10,000 (68.95)
3 1/2	2.93 (74.4)	0.62 (15.7)	5.70	3.15 (80)	3.197 (81.2)	63,800 (28 940)	10,000 (68.95)
	2.7 (68.6)	0.62 (15.7)	9.2 to 10.2	2.842 (72.2)	3.037 (77.1)	63,800 (28 940)	10,000 (68.95)
	2.5 (63.5)	0.62 (15.7)	13.30	2.668 (67.8)	2.809 (71.4)	63,800 (28 940)	10,000 (68.95)
4	3.18 (80.8)	1.12 (28.4)	9.5 to 11.6	3.35 (85.1)	3.599 (91.4)	73,959 (33 584)	10,000 (68.95)
	3.06 (77.7)	0.875 (22.2)	12.5 to 15.7	3.144 (79.9)	3.441 (87.4)	63,200 (28 667)	10,000 (68.95)
4 1/2	3.89 (98.8)	1.8 (45.7)	9.50	3.941 (100.1)	4.154 (105.5)	77,077 (34 962)	10,000 (68.95)
	3.75 (95.3)	1.8 (45.7)	11.6 to 13.5	3.852 (97.9)	4.041 (102.6)	77,077 (34 962)	10,000 (68.95)
	3.55 (90.2)	1.8 (45.7)	15.1 to 17.1	3.657 (92.9)	3.903 (99.1)	107,059 (48 562)	10,000 (68.95)
5	4.25 (108.0)	1.8 (45.7)	11.5 to 13	4.43 (112.5)	4.56 (115.8)	84,649 (38 397)	10,000 (68.95)
	4.06 (103.1)	1.8 (45.7)	15 to 18	4.194 (106.5)	4.486 (113.9)	86,026 (39 021)	10,000 (68.95)
	3.89 (98.8)	1.8 (45.7)	21.40	4.031 (102.4)	4.219 (107.2)	77,077 (34 962)	10,000 (68.95)
	3.78 (95.3)	1.8 (45.7)	23.20	3.945 (100.2)	4.145 (105.3)	77,077 (34 962)	10,000 (68.95)

RTTS® Packers

Casing Size in.	Packer Main Body OD in. (mm)	Packer ID in. (mm)	Nominal Casing Weight lb/ft	Minimum Casing ID in. (mm)	Maximum Casing ID in. (mm)	Tensile Rating* lb (kg)	Maximum Working Pressure psi (MPa)
5 1/2	4.55 (115.6)	1.9 (48.3)	13 to 20	4.694 (119.2)	5.102 (129.6)	142,344 (64 567)	10,000 (68.95)
	4.4 (111.8)	1.8 (45.7)	20 to 23	4.577 (116.3)	4.867 (123.6)	84,649 (38 397)	10,000 (68.95)
	4.25 (107.9)	1.9 (48.3)	23 to 26	4.444 (112.9)	4.765 (121)	84,649 (38 397)	10,000 (68.95)
5 3/4	4.89 (124.2)	1.9 (48.3)	14 to 18	5.1 (129.5)	5.365 (136.3)	133,208 (60 423)	10,000 (68.95)
6	5.06 (128.5)	1.9 (48.3)	15 to 23	5.151 (130.8)	5.599 (142.2)	142,344 (64 567)	10,000 (68.95)
	4.89 (124.2)	1.9 (48.3)	20 to 26	5.034 (127.9)	5.388 (136.9)	133,200 (60 419)	10,000 (68.95)
6 5/8	5.65 (143.5)	2.38 (60.3)	17 to 20	5.799 (147.3)	6.551 (166.4)	160,810 (72 943)	10,000 (68.95)
	5.43 (137.9)	1.9 (48.3)	24 to 32	5.567 (141.4)	5.98 (151.9)	133,208 (60 423)	10,000 (68.95)
7	5.65 (143.5)	2.38 (60.3)	17 to 38	5.799 (147.3)	6.551 (166.4)	160,810 (72 943)	10,000 (68.95)
	5.25 (133.4)	2.00 (50.8)	49.50	5.384 (136.8)	5.701 (144.8)	133,208 (60 423)	10,000 (68.95)
7 5/8	6.35 (161.3)	2.38 (60.3)	24 to 39	6.509 (165.3)	7.129 (181.1)	160,810 (72 943)	10,000 (68.95)
	6.16 (156.4)	2.38 (60.3)	29.7 to 45.3	6.43 (163.3)	6.901 (175.3)	158,238 (71 777)	10,000 (68.95)
7 3/4	6.16 (156.4)	2.38 (60.3)	33.2 to 50	6.43 (163.3)	6.901 (175.3)	158,238 (71 777)	10,000 (68.95)
8 5/8	7.31 (185.7)	3.00 (76.2)	24 to 49	7.381 (187.5)	8.207 (208.5)	237,218 (107 602)	7,500 (51.71)
9 5/8	8.25 (209.6)	3.75 (95.3)	36 to 53.5	8.403 (213.4)	9.049 (229.9)	379,267 (172 036)	7,500 (51.71)
	7.8 (198.1)	3.00 (76.2)	58.4 to 71.8	7.958 (202.1)	8.587 (218.1)	237,200 (107 592)	7,500 (51.71)
10 3/4	9.4 (238.8)	3.75 (95.3)	40.5 to 55.5	9.631 (244.6)	10.189 (258.9)	444,600 (201 667)	5,000 (34.48)
	8.85 (224.8)	3.75 (95.3)	60.7 to 85.3	8.976 (228.0)	9.818 (249.4)	444,600 (201 667)	5,000 (34.48)
11 3/4	10.6 (269.2)	3.75 (95.3)	47 to 54	10.756 (273.2)	11.223 (285.1)	444,600 (201 667)	5,000 (34.48)
	10.1 (256.5)	3.75 (95.3)	60 to 71	10.438 (265.1)	10.934 (277.7)	444,600 (201 667)	5,000 (34.48)
12 3/4	11.1 (281.9)	3.75 (95.3)	57 to 81	11.5 (292.1)	11.884 (301.9)	444,600 (201 667)	3,000 (20.69)
13 3/8	11.94 (303.3)	3.75 (95.3)	54.5 to 72	12.203 (310.0)	12.783 (324.7)	651,300 (295 425)	5,000 (34.48)
	11.5 (292.1)	3.75 (95.3)	72 to 98	11.76 (298.7)	12.403 (315.0)	651,300 (295 425)	5,000 (34.48)
14	12.25 (311.2)	3.75 (95.3)	82.5 to 98	12.449 (316.2)	13.067 (331.9)	651,300 (295 425)	5,000 (34.48)
16	14.43 (366.5)	3.75 (95.3)	55 to 65	15.115 (383.9)	15.564 (395.3)	651,300 (295 425)	2,500 (17.24)
	14.18 (360.2)	3.75 (95.3)	84 to 109	14.509 (368.5)	15.215 (386.5)	651,300 (295 425)	2,500 (17.24)
	13.62 (345.9)	3.75 (95.3)	109 to 146	13.968 (354.8)	14.688 (373.1)	651,300 (295 425)	2,500 (17.24)
18 5/8	16.87 (428.5)	3.75 (95.3)	78 to 118	17.257 (438.3)	17.98 (456.7)	651,300 (295 425)	2,500 (17.24)

RTTS® Packers

Casing Size in.	Packer Main Body OD in. (mm)	Packer ID in. (mm)	Nominal Casing Weight lb/ft	Minimum Casing ID in. (mm)	Maximum Casing ID in. (mm)	Tensile Rating* lb (kg)	Maximum Working Pressure psi (MPa)
20	17.87 (453.9)	3.75 (95.3)	94 to 133	18.535 (470.8)	19.213 (488.0)	1,000,000 (453 592)	2,500 (17.24)
	17.25* (438.2)	4.14 (105.2)	133 to 187	17.257 (438.3)	17.98 (456.7)	1,000,000 (453 592)	2,500 (17.24)
	17.25 (438.2)	3.75 (95.3)	169 to 204	17.951 (456.0)	18.65 (473.7)	1,000,000 (453 592)	2,500 (17.24)

*High-expansion packer

RTTS® V3 Packers

Casing Size in.	Packer Main Body OD in. (mm)	Packer ID in. (mm)	Nominal Casing Weight lb/ft	Minimum Casing ID in. (mm)	Maximum Casing ID in. (mm)	Tensile Rating* lb (kg)	Maximum Working Pressure* psi (MPa)
10 3/4	9.280 (235.7)	3.50 (88.9)	65.7	9.415 (239.1)	9.723 (247.0)	350,000 (158 757)	6,500 (44.82)
	8.875 (225.4)	3.50 (88.9)	73.2 to 85.3	8.976 (228.0)	9.577 (243.3)	350,000 (158 757)	6,500 (44.82)
13 3/8	11.94 (303.28)	2.44 (62.0)	54.5 to 72.0	12.203 (320.0)	12.783 (324.7)	1,000,000 (453 592)	8,000 (55.16)
13 5/8	11.94 (303.28)	2.44 (62.0)	86.0 to 88.2	12.203 (320.0)	12.783 (324.7)	1,000,000 (453 592)	8,000 (55.16)
14	11.94 (303.28)	2.44 (62.0)	103.5 to 113.0	12.203 (320.0)	12.783 (324.7)	1,000,000 (453 592)	8,000 (55.16)
16	14.18 (360.2)	3.00 (76.2)	95.0 to 97.0	14.684 (373.0)	15.079 (383.0)	1,000,000 (453 592)	7,500 (51.71)

*Please consult your Halliburton representative to determine maximum hang-off and pressure test requirements.

Subsurface Control (SSC) Valves

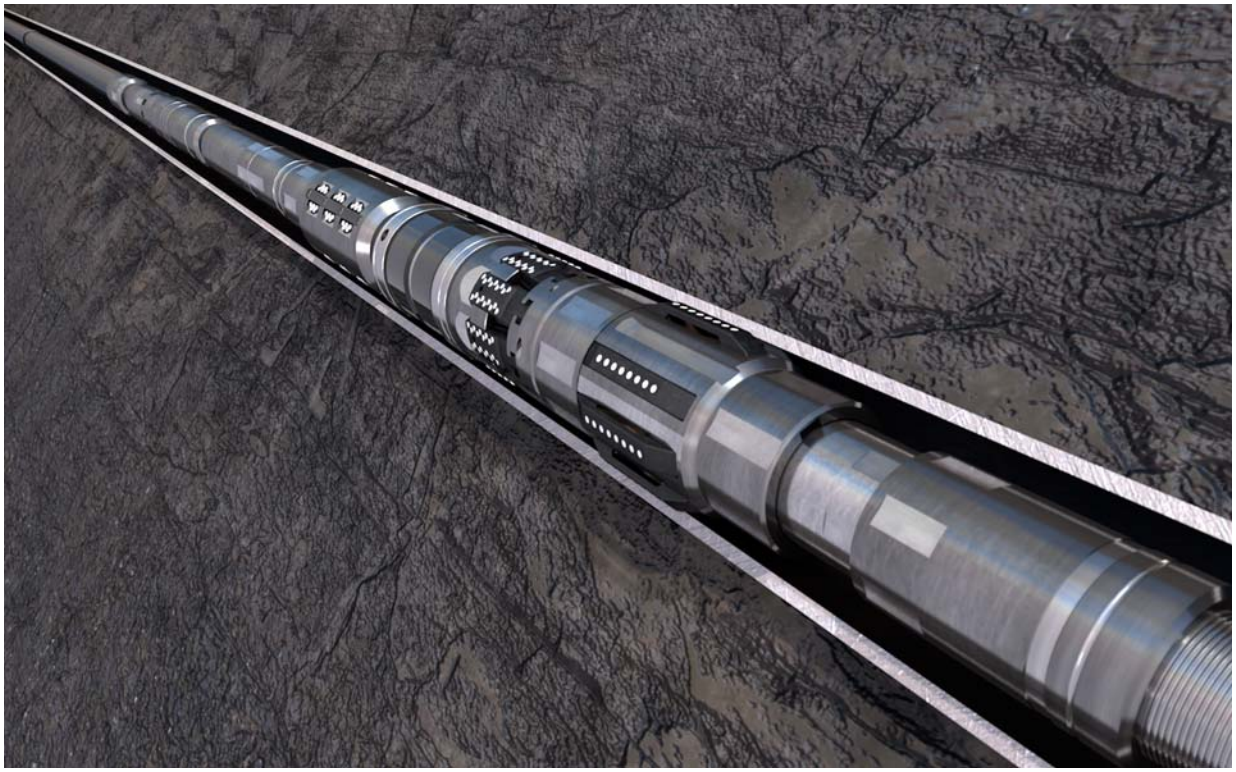
Type	Assembly OD in. (mm)	RTTS® Size Range in.	Maximum Working Pressure psi (MPa)	Tensile Rating lb (kg)	Valve Type
SSC I	3.72 (94.5)	4 1/2 to 5 1/2	8,000 (55.16)	218,306 (99 022)	Sliding
	4.87 (123.7)	6 5/8 to 7 5/8	6,200 (42.75)	335,811 (152 321)	Sliding
	6.25 (158.8)	8 5/8 to 20	10,000 (68.95)	598,040 (271 266)	Sliding
SSC II	4.75 (120.7)	6 5/8 to 7 5/8	10,000 (68.95)	186,946 (84 797)	Ball
	4.75* (120.7)	6 5/8 to 7 5/8	15,000 (103.42)	302,449 (137 188)	Ball
	6.5 (165.1)	8 5/8 to 20	10,000 (68.95)	452,092 (205 066)	Ball
SSC III	8.5 (215.9)	10 3/4 to 20	8,000 (55.16)	1,038,600 (471 101)	Ball
SSC IV	8.0 (203.2)	9 5/8 to 20	8,000 (55.16)	400,000 (181 437)	Ball
	8.5 (215.9)	10 3/4 to 20	8,000 (55.16)	1,058,487 (480 121)	Ball

*This SSC II valve has a 1.50-in. ID to increase the pressure and tensile rating.

Model 3L™ Retrievable Bridge Plugs

Casing Size in.	Main Body OD in. (mm)	Nominal Casing Weight lb/ft	Minimum Casing ID in. (mm)	Maximum Casing ID in. (mm)	Tensile Rating lb (kg)	Maximum Working Pressure psi (MPa)
4 1/2	3.75 (95.3)	9.5 to 13.5	3.920 (99.6)	4.090 (103.9)	65,200 (29 574)	10,000 (68.95)
5	4.35 (110.5)	11.5	4.560 (115.8)	4.778 (121.4)	65,200 (29 574)	10,000 (68.95)
	4.25 (107.9)	13 to 15	4.408 (112.0)	4.494 (114.2)	65,200 (29 574)	10,000 (68.95)
	3.93 (99.8)	18 to 21.4	4.126 (104.8)	4.276 (108.6)	65,200 (29 574)	10,000 (68.95)
5 1/2	4.60 (116.8)	13 to 20	4.778 (121.4)	5.044 (128.1)	65,200 (29 574)	10,000 (68.95)
	4.35 (110.5)	20 to 23	4.560 (115.8)	4.778 (121.4)	65,200 (29 574)	10,000 (68.95)
6 5/8	5.43 (137.9)	24 to 32	5.675 (144.2)	5.921 (150.4)	65,200 (29 574)	10,000 (68.95)
7	5.65 (143.5)	17 to 38	5.920 (150.4)	6.538 (166.1)	65,200 (29 574)	10,000 (68.95)
7 5/8	6.35 (161.3)	20 to 39	6.625 (168.3)	7.125 (181.0)	65,200 (29 574)	10,000 (68.95)
8 5/8	7.04 (178.8)	49 to 56	7.313 (185.8)	7.511 (190.8)	117,800 (53 433)	7,500 (51.71)
9 5/8	8.15 (207.0)	29.3 to 53.5	8.535 (216.8)	9.063 (230.2)	117,800 (53 433)	7,500 (51.71)
10 3/4	9.40 (238.8)	32.75 to 55.5	9.760 (247.9)	10.192 (258.9)	117,800 (53 433)	7,500 (51.71)
	8.85 (224.8)	60.7 to 80.8	9.250 (235.0)	9.660 (245.4)	117,800 (53 433)	7,500 (51.71)

Testing and Treating Solutions



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Well servicing and workover is used to extend the economically viable productive life of a well. This is accomplished through performance of several zonal treatment procedures, such as high-pressure acidizing, fracturing, perforation washing, and squeezing.

Testing potential producing zones is accomplished by placing the formation into temporary production conditions. This requires the use of a robust service packer that isolates the zone so the pressure at the formation can be reduced to bring flow into the wellbore and ultimately build pressure back up, indicating it can produce hydrocarbons.

Halliburton testing and treating systems provide the following:

» Negative and positive test for well integrity — locates problems then squeeze cement fixes the leak
» Multiple operations in one trip
» Custom tool combinations

RTTS® Straddle Packer

The RTTS® straddle packer allows selected sections of the wellbore to be isolated and serviced. Based on the industry-proven RTTS packer, the RTTS straddle packer allows operators to test and treat selected zones and can be further tailored by adjusting the straddle distance between the upper and lower elements.

The RTTS straddle packer is a hookwall packer used for testing, treating, and squeeze operations. The packer body includes an upper and lower packer with spacer tubing and an integral bypass and ball seat. The lower packer incorporates a J-slot mechanism, mechanical slips, packer elements, and a bypass. Large, heavy-duty slips in the hydraulic holddown mechanism are contained in the upper packer to help prevent the tool from being pumped uphole. Drag blocks operate the J-slot, and automatic J-slot sleeves are standard equipment on all Halliburton RTTS straddle packers.

Features and Benefits

» Optimized flow areas allow for a high volume of fluid to be pumped through the tool
» Straddle intervals can be tailored utilizing industry-standard tubular and pipe connections
» Packer can be set and relocated as many times as necessary
» Tungsten carbide slips provide greater holding ability and improved wear resistance in high-strength casing
» Integral bypass ensures pressure equalization across the packer, when required
» A ball and seat allows isolation of the wellbore below the tool for targeted treatments

RTTS®
Straddle Packer

RTTS® Circulating Valve

The RTTS® circulating valve is a multi-function valve that serves as both a circulating valve and bypass. The clearance between an RTTS packer and the casing ID is relatively small. To reduce the effect of fluid-swabbing action when the tool is run in or pulled out of the hole, a packer bypass is used.

The RTTS circulating valve automatically moves to the closed position when the packer is set. During testing and squeezing operations, the ability to lock the valve in the closed position helps prevent it from being pumped open. A straight J-slot in the locked-open position can be used with the straight J-slot (optional) in the packer body. This combination helps eliminate the need to turn the tubing to close the circulating valve or reset the packer after the tubing is displaced with cement.

Features and Benefits

» Valve can be locked closed when the packer is unset to reverse fluid around the bottom of the packer
  – A lower circulating point allows fluid to circulate farther down the wellbore, if required

» Full opening allows tubing-type guns and other wireline equipment to pass

» Rugged seal system provides highly reliable isolation between workstring and annulus

RTTS®
Circulating Valve

Model 2 RTTS® Circulating Valve

The Model 2 RTTS® circulating valve provides an efficient, safe method of performing inflow/negative tests and can be deployed as a means of general circulation and fluid positioning. This locked-open valve serves as both a circulating valve and a bypass valve and is held closed by internal pressure and/or pipe weight.

A straight J-slot in the circulating valve allows the valve to be used with a straight J-slot in the packer assembly. This combination helps eliminate the need to rotate the tubing to close the circulating valve or reset the packer after the tubing has been displaced with alternative fluids. A straight spline option allows the valve to be opened and closed without string rotation.

Features and Benefits

» Well control is maintained while monitoring pressure at the packer
» Fluid can be circulated to kill the well while maintaining packer seal integrity
» Valve can be manipulated between open and close without removing weight set on the packer
» Valve can be used in conjunction with the RTTS packer

Model 2 RTTS®
Circulating Valve

RTTS® Safety Joint

The RTTS® safety joint is a recommended backoff device that helps prevent unintentional operations. In the event that the lower string becomes stuck during operations, the safety joint will release the workstring and tools.

The RTTS safety joint is run immediately above the RTTS packer to allow for optimized recovery of the workstring.

Before the safety joint can be used, a tension sleeve located on the bottom of the lug mandrel must first be parted by pulling up on the workstring. This tension sleeve should be considered whenever additional tools or workstring are run below the packer. Excessive weight below the packer can cause unexpected parting of this sleeve during the tool makeup process.

After the tension sleeve has parted, the safety joint is released by right-hand torque while the workstring is reciprocated a specified number of cycles.

By incorporating the RTTS safety joint in the workstring, operators can help ensure that even if the bottomhole assembly becomes stuck in the well, it can be recovered safely and efficiently with minimum downtime.

Features and Benefits

- Positive sequence of operation helps prevent premature release
- Tools above the safety joint can be retrieved when string is stuck, preventing tools from being lost in the well, sidetracked, or redrilled

RTTS®
Safety Joint

CHAMP® IV Packer

The CHAMP® IV packer is a hookwall retrievable packer with a concentric bypass that can be used as a stimulation or testing packer. The CHAMP IV packer is well suited for tubing-conveyed perforating (TCP) applications where the firing head assembly is easily incorporated, as well as horizontal applications because of its limited rotational requirements and integrated bypass. Just a quarter-turn is required at the tool to set the packer and close the bypass. A straight upward pull opens the bypass and unseats the packer.

To control setting of the packer, the tool is lowered into the hole where a J-slot holds the bypass open. When the packer is set, the bypass closes as weight is applied by the workstring. After the packer is set, a balancing piston activated by tubing pressure holds the bypass closed.

Each tool assembly includes a J-slot mechanism, mechanical slips, packer elements, hydraulic slips, and a bypass. Round, piston-like slips used in the hydraulic holddown mechanism prevent the tool from being pumped uphole. The bypass allows fluids to pass around the bottom of the tool when it is removed from the hole. This design helps eliminate accidentally opening a conventional bypass during circulation around the bottom of the packer.

Circulation around the CHAMP IV packer is not interrupted if the packer element seals unintentionally, as when it passes through points of interference in the casing.

Features and Benefits

- Ideal for highly deviated wells or where pipe manipulation is difficult
- Picking the packer straight up (no torque required) opens the bypass
- Easily relocated in multiple zones during a single trip for treating, testing, or squeezing
- Concentric bypass has a larger bypass flow area to allow for high circulation rates
- Used with a retrievable bridge plug for straddling zones during various operations
- Tool of choice where positive circulation below the packer is required, such as:
  - Drillstem testing
  - TCP applications using tailpipe for shallow service
  - Liner tools

CHAMP® IV Packer

CHAMP® IV Non-Rotational Retrievable Packer

The CHAMP® IV non-rotational packer is ideal for deepwater, extended-reach situations where achieving sufficient torque downhole to manipulate the toolstring can be challenging, particularly when running with multiple umbilicals, such as drillstem test applications. This tool has the same basic features as the standard CHAMP IV packer, but with the added feature that it does not require rotation to set. The CHAMP IV non-rotational packer consists of a hookwall retrievable packer with a concentric bypass and a continuous indexing J-slot. This J-slot allows the packer to be run in the casing, set, and unset without applying any rotation to the workstring. The packer can cycle from the run-in-hole (RIH) to the set and pull-out-of-hole (POOH) positions simply by reciprocating the workstring in the wellbore.

A J-slot position locking mechanism keeps the packer in the RIH configuration until the desired depth is reached and the locking mechanism is deactivated. The position locking mechanism is deactivated using a rupture disk, which is set to rupture at a predetermined pressure. The deactivation pressure can be either wellbore hydrostatic at a certain depth or pump pressure applied to the annulus at surface. The locking mechanism allows the packer to be run on jointed pipe without cycling through the positions in the J-slot as each joint of pipe is being made up at the surface.

The concentric bypass allows fluids to circulate around the bottom of the tool when it is removed from or moved uphole in the wellbore. Therefore, circulation as the packer assembly is passed through tight spots, where packer elements might unintentionally achieve a temporary seal, remains uninterrupted. The bypass valve is also designed to be pressure balanced with applied pressure. This prevents the unintentional opening of the bypass during treatment applications.

Features and Benefits

- Easily operated in extended-reach or highly deviated wellbores
- No rotation required to set packer
  - Picking the packer straight up (no torque required) opens the bypass
- Will not set until the hydrostatic pressure at a predetermined depth is reached or annulus pressure is applied
- Easily relocated to multiple zones during a single trip for treating, testing, or squeezing
- Concentric bypass allows a larger bypass flow area with positive circulation below the packer and tailpipe
- Temperature rating of 400°F (204.4°C)

CHAMP® IV Non-Rotational Retrievable Packer

CHAMP® IV Non-Rotational Restricted-Set Retrievable Packer

The CHAMP® IV non-rotational restricted-set packer is ideal for deepwater, extended-reach applications on floating, heaving vessels where obtaining sufficient torque downhole to manipulate the toolstring can be challenging, particularly when running with multiple umbilicals, such as drillstem test applications with subsea equipment. This packer has the same basic features as the standard CHAMP IV packer, but with the added feature that it does not require rotation to set and can be reset a predetermined number of times.

The CHAMP IV non-rotational packer is a hookwall retrievable packer with a concentric bypass and a continuous indexing J-slot that incorporates a lock-out mechanism. The packer can cycle from the run-in-hole (RIH) to the set and pull-out-of-hole (POOH) positions simply by reciprocating the workstring in the wellbore. After the packer has been set the required number of times, it can be mechanically locked out to prevent any further setting operations during toolstring recovery from the wellbore.

Each assembly includes an indexing lock-out J-slot mechanism, mechanical slips, packer elements, hydraulic slips, and a concentric bypass. Hydraulic piston-type slips in the hydraulic holddown mechanism prevent the packer from being pumped uphole.

A J-slot position locking mechanism keeps the packer in the RIH configuration until the desired depth is reached and the locking mechanism is deactivated. The position locking mechanism is deactivated using a rupture disk, which is set to rupture at a pressure that is predetermined during the job calculations. The deactivation pressure can be either wellbore hydrostatic at a predetermined depth or pump pressure applied to the wellbore at surface.

The locking mechanism allows the packer to be run without cycling through the positions in the J-slot, as each joint of pipe is made up at the surface.

The J-slot lock-out mechanism prevents the packer from setting after the operation is complete and allows the string to move freely, even in significant heave situations on floating vessels.

Features and Benefits

- Easily operated in extended-reach or highly deviated wellbores
- No rotation required to set packer
  - Picking the packer straight up (no torque required) opens the bypass
- Will not set until the hydrostatic pressure at a predetermined depth is reached or annulus pressure is applied
- Easily relocated to multiple zones during a single trip for treating, testing, or squeezing
- Sets up to eight times continuously before locking out
- "Locked out" mechanically to allow recovery from the wellbore in significant heave
- Concentric bypass allows a larger bypass flow area with positive circulation below the packer and tailpipe
- Temperature rating of 400°F (204.4°C)

CHAMP® IV Non-Rotational Restricted-Set Retrievable Packer

CHAMP® V Packer

The CHAMP® V packer is a 15K-psi rated hookwall retrievable packer with a concentric bypass and is ideally suited for high-pressure/high-temperature (HP/HT) wells. The packer's higher-grade materials and elastomers are supported with backup rings and an element package. As the tool is lowered into the hole, a J-slot holds the bypass open and controls the setting of the packer. When the packer is set, a balancing piston activated by tubing pressure holds the bypass closed, preventing accidental communication with the annulus.

Each tool assembly includes a J-slot mechanism, mechanical slips, packer elements, hydraulic slips, and a bypass. Round, piston-type slips are used in the hydraulic holddown mechanism to help prevent the tool from being pumped uphole. The CHAMP V 15K packer has additional holddown mechanisms to help keep it in place because of the higher loads caused by high pressure. The bypass allows the fluids to pass around the bottom of the tool when it is removed from the hole. This design helps eliminate accidental opening of a conventional bypass during circulation around the bottom of the packer. Additionally, circulation around the packer is uninterrupted when it passes through points of interference in the casing.

Features and Benefits

- Ideal for highly deviated wells or where pipe manipulation is difficult
- Simply picking the packer straight up (no torque required) opens the bypass, saving time and costs
- Easily relocated in multiple zones during a single trip for treating, testing, or squeezing
- Large bypass area allows for higher circulation rates
- Ideal for HP/HT testing, tubing-conveyed perforating, or stimulation applications
- High-strength construction makes it extremely durable and reliable
- Rugged tungsten carbide slips allow multiple sets in the hardest casings

CHAMP® V Packer

CHAMP® V 15K Non-Rotational Retrievable Packer

The CHAMP® V 15K non-rotational packer is ideal for deepwater, extended-reach situations where achieving sufficient torque downhole to manipulate the toolstring can be challenging. It is made up of a hookwall retrievable packer with a concentric bypass and a continuous indexing J-slot.

The CHAMP V 15K non-rotational packer is constructed with higher-grade materials, and all elastomers are supported with backup rings. The J-slot enables the packer to be run in the casing, set, and unset without applying any rotation to the workstring. The packer can cycle from the run-in-hole (RIH) to the set and pull-out-of-hole (POOH) positions simply by lifting or lowering the drillpipe or tubing in the wellbore.

Each assembly includes an indexing J-slot mechanism, mechanical slips, packer elements, hydraulic slips, and a concentric bypass. Round, piston-type slips are used in the hydraulic holddown mechanism to help prevent the tool from being pumped uphole. It also contains additional holddown mechanisms to help keep it in place because of the higher loads.

A J-slot position locking mechanism keeps the packer in the RIH configuration until the required depth is reached and the locking mechanism is deactivated. The position locking mechanism is deactivated using a rupture disk, which is set to rupture at a predetermined pressure. The deactivation pressure can be either wellbore hydrostatic at a certain depth or pump pressure applied to the annulus at surface.

The locking mechanism enables the packer to be run on jointed pipe without cycling through the positions in the J-slot as each joint of pipe is made up at the surface.

The concentric bypass enables fluids to circulate around the bottom of the tool when it is removed from or moved uphole in the wellbore. Therefore, circulation as the packer assembly is passed through tight spots, where packer elements might unintentionally achieve a temporary seal, remains uninterrupted. The bypass valve is also designed to be pressure balanced with applied pressure. This prevents unintentional opening of the bypass during treatment applications.

Features and Benefits

- Easily operated in extended-reach or highly deviated wellbores
- No rotation required to set packer
- Locked in the RIH position until the hydrostatic pressure at a predetermined depth is reached or annulus pressure is applied
- Easily relocated to multiple zones during a single trip for treating, testing, or squeezing
- Concentric bypass enables a larger bypass flow area with positive circulation below the packer and tailpipe
- Rated up to 15,000-psi (103.42-MPa) working pressure with a temperature rating of up to 400°F (204.4°C)

CHAMP® V 15K Non-Rotational Retrievable Packer

PinPoint Injection (PPI) Packer

The PinPoint Injection (PPI) packer is a retrievable, treating straddle packer that features 1 ft of spacing between packer elements. This spacing helps ensure that the maximum number of perforations within a long producing interval can be broken down to accept stimulation fluids uniformly. Once the entire zone is broken down individually, a large-scale treatment can be performed more effectively.

Adapters are provided to run tubing for spacer if intervals greater than 1 ft (30.48 cm) are required. A typical PPI packer toolstring consists of the following tools (top to bottom):

» RFC® retrievable fluid control valve
» RTTS® circulating valve
» PPI packer
» Collar locator

The PPI packer has a straight J-slot drag-block body. The collar locator, if used, can be run either above or below the PPI packer. The RFC valve retains acid used to break down perforations in the tubing as the PPI packer is moved to the next setting point.

Fluid passage through the center of the bottom packer is closed off with the retrievable plug or ball included in the conversion kit. The retrievable plug or ball can be run in place with the PPI packer or can be dropped from the surface after the tools are run in.

After the RFC valve is removed, the retrievable plug passes through the RFC valve seats. If a ball is used, it must be reversed out or brought out with the toolstring.

Features and Benefits

» Spacing between packer and elements
» RTTS packer reliability built into the PPI packer
» Adapters allow for spacing intervals greater than 1 ft
» Provides more thorough stimulation of the producing interval
» Allows for the collection of more detailed formation data for planning the main treatment
» Can perform treatments through the same tool with one trip in the hole

PinPoint Injection (PPI) Packer

Testing and Treating Solutions Tables

Following are the specifications tables for the Testing and Treating Systems. The values of tensile, burst, and collapse strength are calculated with new tool conditions, Lame's formulas with von Mises Distortion Energy Theory for burst and collapse strength, and stress area calculations for tensile strength.

These ratings are guidelines only. For more information, consult your local Halliburton representative.

RTTS® Straddle Packers

Casing Size in.	Packer Main Body OD in. (mm)	Packer ID in. (mm)	Nominal Casing Weight lb/ft	Minimum Casing ID in. (mm)	Maximum Casing ID in. (mm)	Tensile Rating lb (kg)	Maximum Working Pressure psi (MPa)
4 1/2	3.89 (98.8)	1.8 (45.7)	9.50	3.941 (100.1)	4.154 (105.5)	77,077 (34 962)	10,000 (68.95)
	3.75 (95.3)	1.8 (45.7)	11.6 to 13.5	3.852 (97.9)	4.041 (102.6)	77,077 (34 962)	10,000 (68.95)
	3.55 (90.2)	1.8 (45.7)	15.1 to 17.1	3.657 (92.9)	3.903 (99.1)	107,059 (48 562)	10,000 (68.95)
5 1/2	4.55 (115.6)	1.9 (48.3)	13 to 20	4.694 (119.2)	5.102 (129.6)	142,344 (64 567)	10,000 (68.95)
	4.4 (111.8)	1.8 (45.7)	20 to 23	4.577 (116.3)	4.867 (123.6)	84,649 (38 397)	10,000 (68.95)
	4.25 (107.9)	1.9 (48.3)	23 to 26	4.444 (112.9)	4.765 (121)	84,649 (38 397)	10,000 (68.95)
7	5.65 (143.5)	2.38 (60.3)	17 to 38	5.799 (147.3)	6.551 (166.4)	160,810 (72 943)	10,000 (68.95)
	5.25 (133.4)	2.00 (50.8)	49.50	5.384 (136.8)	5.701 (144.8)	133,208 (60 423)	10,000 (68.95)
7 5/8	6.35 (161.3)	2.38 (60.3)	24 to 39	6.509 (165.3)	7.129 (181.1)	160,810 (72 943)	10,000 (68.95)
	6.16 (156.4)	2.38 (60.3)	29.7 to 45.3	6.43 (163.3)	6.901 (175.3)	158,238 (71 777)	10,000 (68.95)
9 5/8	8.25 (209.6)	3.75 (95.3)	36 to 53.5	8.403 (213.4)	9.049 (229.9)	379,267 (172 036)	7,500 (51.71)
	7.8 (198.1)	3.00 (76.2)	58.4 to 71.8	7.958 (202.1)	8.587 (218.1)	237,200 (107 592)	7,500 (51.71)
10 3/4	9.4 (238.8)	3.75 (95.3)	40.5 to 55.5	9.631 (244.6)	10.189 (258.9)	444,600 (201 667)	5,000 (34.48)
	8.85 (224.8)	3.75 (95.3)	60.7 to 85.3	8.976 (228.0)	9.818 (249.4)	444,600 (201 667)	5,000 (34.48)

RTTS® Circulating Valves

Size in.	OD in. (mm)	ID in. (mm)	Tensile Rating lb (kg)	Maximum Working Pressure psi (MPa)
2 3/8	1.68 (42.7)	0.68 (17.3)	31,900 (14 451)	9,900 (68.25)
2 7/8	2.15 (54.6)	1.00 (25.4)	37,500 (17 009)	7,800 (53.77)
3 1/2	2.37 (60.1)	1.00 (25.4)	52,500 (23 813)	10,000 (68.95)
4	3.06 (77.7)	1.50 (38.1)	92,200 (41 821)	8,100 (55.84)
4 1/2 to 5	3.60 (91.4)	1.80 (45.7)	85,000 (38 505)	10,100 (69.63)
5 1/2 to 6 5/8	4.18 (106.2)	1.99 (50.5)	150,700 (68 356)	10,000 (68.95)
7 to 7 5/8	4.87 (123.7)	2.44 (61.9)	148,800 (67 606)	10,000 (68.95)
8 5/8 to 20	6.12 (155.4)	3.00 (76.2)	311,400 (141 200)	10,500 (72.39)

Model 2 RTTS® Circulating Valves

Size in.	Casing Weight lb/ft	Maximum OD in. (mm)	Minimum ID in. (mm)	Tensile Rating lb (kg)	Maximum Working Pressure psi (MPa)
8 5/8	24 to 49	6.50 (165.1)	2.00 (50.8)	322,998 (146 817)	10,000 (68.95)
9 5/8	40 to 71.8	6.50 (165.1)	2.40 (61.0)	322,998 (146 817)	10,000 (68.95)
	29.3 to 53.5	6.50 (165.1)	2.40 (61.0)	322,998 (146 817)	10,000 (68.95)
10 3/4	32.75 to 81	6.50 (165.1)	2.40 (61.0)	322,998 (146 817)	10,000 (68.95)
11 3/4	38 to 71	6.50 (165.1)	2.40 (61.0)	322,998 (146 817)	10,000 (68.95)
13 3/8	48 to 98	6.50 (165.1)	2.40 (61.0)	322,998 (146 817)	10,000 (68.95)
16	75 to 109	6.50 (165.1)	2.40 (61.0)	322,998 (146 817)	10,000 (68.95)
18 5/8	78 to 118	6.50 (165.1)	2.40 (61.0)	322,998 (146 817)	10,000 (68.95)
20	94 to 204	6.50 (165.1)	2.40 (61.0)	322,998 (146 817)	10,000 (68.95)

RTTS® Safety Joints

Size in.	OD in. (mm)	ID in. (mm)	Tensile Rating lb (kg)	Maximum Working Pressure psi (MPa)
2 3/8	1.81 (46.0)	0.68 (17.3)	32,000 (14 500)	9,600 (66.20)
2 7/8	2.15 (54.6)	1.00 (25.4)	24,300 (11 022)	5,000 (34.47)
3 1/2	2.37 (60.1)	0.75 (19.0)	65,700 (29 801)	12,200 (84.11)
4	3.34 (84.8)	1.50 (38.1)	92,100 (41 775)	12,900 (88.94)
4 1/2 to 5	3.68 (93.5)	1.90 (48.3)	88,600 (40 272)	9,900 (68.28)
5 1/2 to 6 5/8	4.06 (103.1)	2.00 (50.8)	127,400 (57 789)	10,200 (70.33)
7 to 7 5/8	5.00 (127.0)	2.44 (61.9)	148,800 (67 606)	10,900 (75.10)
8 5/8 to 20	6.12 (155.4)	3.12 (79.2)	271,900 (123 600)	10,400 (71.70)

Note: Although other sizes might be available, these sizes are the most common.

CHAMP® IV Retrievable Packers

Casing Size in.	Packer OD in. (mm)	Packer ID in. (mm)	Nominal Casing Weight lb/ft	Minimum Casing ID in. (mm)	Maximum Casing ID in. (mm)	Tensile Rating lb (kg)	Maximum Working Pressure psi (MPa)
4 1/2	3.87 (98.3)	1.80 (45.7)	9.5 to 10.5	4.044 (102.7)	4.090 (103.9)	71,200 (32 300)	8,400 (57.92)
	3.75 (95.2)	1.80 (45.7)	11.6 to 13.5	3.852 (97.8)	4.068 (103.3)	71,200 (32 300)	8,400 (57.92)
5	3.98 (98.3)	1.80 (45.7)	18 to 20.8	4.156 (105.6)	4.276 (108.6)	71,200 (32 300)	8,400 (57.92)
	4.18 (106.2)	1.80 (45.7)	11.5 to 15.0	4.408 (112.0)	4.560 (115.8)	71,200 (32 300)	8,400 (57.92)
5 1/2	4.55 (115.6)	2.00 (50.8)	13 to 20	4.694 (119.2)	5.120 (130.0)	99,600 (45 177)	8,400 (57.92)
	4.38 (111.3)	1.80 (45.7)	20 to 23	4.670 (118.6)	4.778 (121.4)	71,200 (32 300)	8,400 (57.92)

CHAMP® IV Retrievable Packers

Casing Size in.	Packer OD in. (mm)	Packer ID in. (mm)	Nominal Casing Weight lb/ft	Minimum Casing ID in. (mm)	Maximum Casing ID in. (mm)	Tensile Rating lb (kg)	Maximum Working Pressure psi (MPa)
6 5/8 or 7	5.25 (133.4)	2.00 (50.8)	6 5/8: 28 to 32 7: 41 to 49.5	5.384 (136.8)	5.947 (151.1)	97,600 (44 270)	10,000 (68.95)
7	5.65 (143.5)	2.37 (60.2)	17 to 38	5.920 (150.4)	6.538 (166.1)	148,600 (67 404)	10,000 (68.95)
7 5/8	6.35 (161.3)	2.37 (60.2)	20 to 39	6.509 (165.3)	7.224 (183.5)	148,500 (67 385)	10,000 (68.95)
7 3/4	6.22 (158.0)	2.37 (60.2)	46.1	6.694 (170.0)	6.427 (163.2)	148,500 (67 358)	10,000 (68.95)
8 5/8	7.04 (178.8)	2.62 (66.5)	44 to 56	7.313 (185.8)	7.625 (193.7)	215,640 (97 813)	7,500 (51.71)
	6.75 (171.4)	2.37 (60.2)	58.7 to 68.1	7.001 (177.8)	7.251 (184.2)	313,600 (142 247)	7,500 (51.71)
9 5/8	8.15 (207.0)	2.87 (72.9)	36 to 53.5	8.403 (213.4)	9.049 (229.8)	407,400 (184 794)	7,500 (51.71)
	7.80 (198.1)	2.87 (72.9)	40 to 71.8	8.125 (206.4)	8.835 (224.4)	341,900 (155 083)	7,500 (51.71)
10 3/4	9.07 (230.4)	3.00 (76.2)	55.5 to 80.8	9.250 (235.0)	9.760 (247.9)	524,600 (237 955)	5,000 (34.47)
11 3/4	10.40 (264.2)	3.00 (76.2)	47 to 71	10.438 (265.1)	11.151 (283.2)	524,600 (237 955)	5,000 (34.47)
13 3/8	11.94 (303.3)	3.75 (95.2)	54.5 to 72	12.203 (310.0)	12.783 (324.7)	651,300 (295 424)	3,000 (20.68)
	11.50 (292.1)	3.75 (95.2)	72 to 98	11.937 (303.2)	12.347 (313.6)	651,300 (295 424)	3,000 (20.68)

Note: Although other sizes might be available, these sizes are the most common.

CHAMP® IV Non-Rotational Retrievable Packers

Casing Size in.	Packer OD in. (mm)	Packer ID in. (mm)	Nominal Casing Weight lb/ft	Minimum Casing ID in. (mm)	Maximum Casing ID in. (mm)	Tensile Rating lb (kg)	Maximum Working Pressure psi (MPa)
7	5.65 (143.5)	2.37 (60.2)	26 to 35	6.004 (152.5)	6.538 (166.1)	148,600 (67 403)	10,600 (73.08)
7	6.00 (152.4)	2.30 (58.4)	26	6.276 (159.4)	6.276 (159.4)	131,900 (59 829)	10,000 (68.95)
9 5/8	8.25 (209.6)	2.87 (72.8)	36 to 53.5	8.535 (216.8)	8.921 (226.6)	345,000 (156 489)	8,700 (59.98)
9 5/8	7.80 (198.1)	2.87 (72.8)	58.4 to 71.8	8.125 (206.4)	8.435 (214.2)	345,000 (156 489)	7,500 (51.71)

CHAMP® IV Non-Rotational Restricted-Set Retrievable Packer

Casing Size in.	Packer OD in. (mm)	Packer ID in. (mm)	Nominal Casing Weight lb/ft	Minimum Casing ID in. (mm)	Maximum Casing ID in. (mm)	Tensile Rating lb (kg)	Maximum Working Pressure psi (MPa)
7	5.75 (146.1)	2.30 (58.4)	26 to 35	6.004 (152.5)	6.276 (159.4)	131,915 (59 835)	10,000 (68.95)

CHAMP® V Retrievable Packers

Casing Size in.	Packer OD in. (mm)	Packer ID in. (mm)	Nominal Casing Weight lb/ft	Minimum Casing ID in. (mm)	Maximum Casing ID in. (mm)	Tensile Rating lb (kg)	Maximum Working Pressure psi (MPa)
7	5.75 (146.1)	2.25 (57.2)	29 to 35	6.004 (152.5)	6.201 (157.5)	163,330 (74 085)	15,000 (103.42)
7 5/8	6.00 (152.4)	2.25 (57.2)	47.1 to 51.2	6.251 (158.8)	6.375 (161.9)	163,330 (74 085)	15,000 (103.42)
	6.25 (158.8)	2.25 (57.2)	39 to 42.8	6.501 (165.1)	6.625 (168.3)	163,330 (74 085)	15,000 (103.42)
9 5/8	8.165 (207.4)	3.00 (76.2)	47 to 61.1	8.231 (209.1)	8.681 (220.5)	340,000 (154 221)	15,000 (103.42)

CHAMP® V Retrievable Packers

Casing Size in.	Packer OD in. (mm)	Packer ID in. (mm)	Nominal Casing Weight lb/ft	Minimum Casing ID in. (mm)	Maximum Casing ID in. (mm)	Tensile Rating lb (kg)	Maximum Working Pressure psi (MPa)
9 7/8	8.165 (207.4)	3.00 (76.2)	62.8	8.480 (215.4)	8.632 (219.3)	340,000 (154 221)	15,000 (103.42)
10 3/4 HW	8.165 (207.4)	3.00 (76.2)	91.2 to 109	8.434 (214.2)	9.032 (229.4)	340,000 (154 221)	15,000 (103.42)

Note: Although other sizes might be available, these sizes are the most common.

CHAMP® V 15K Non-Rotational Retrievable Packers

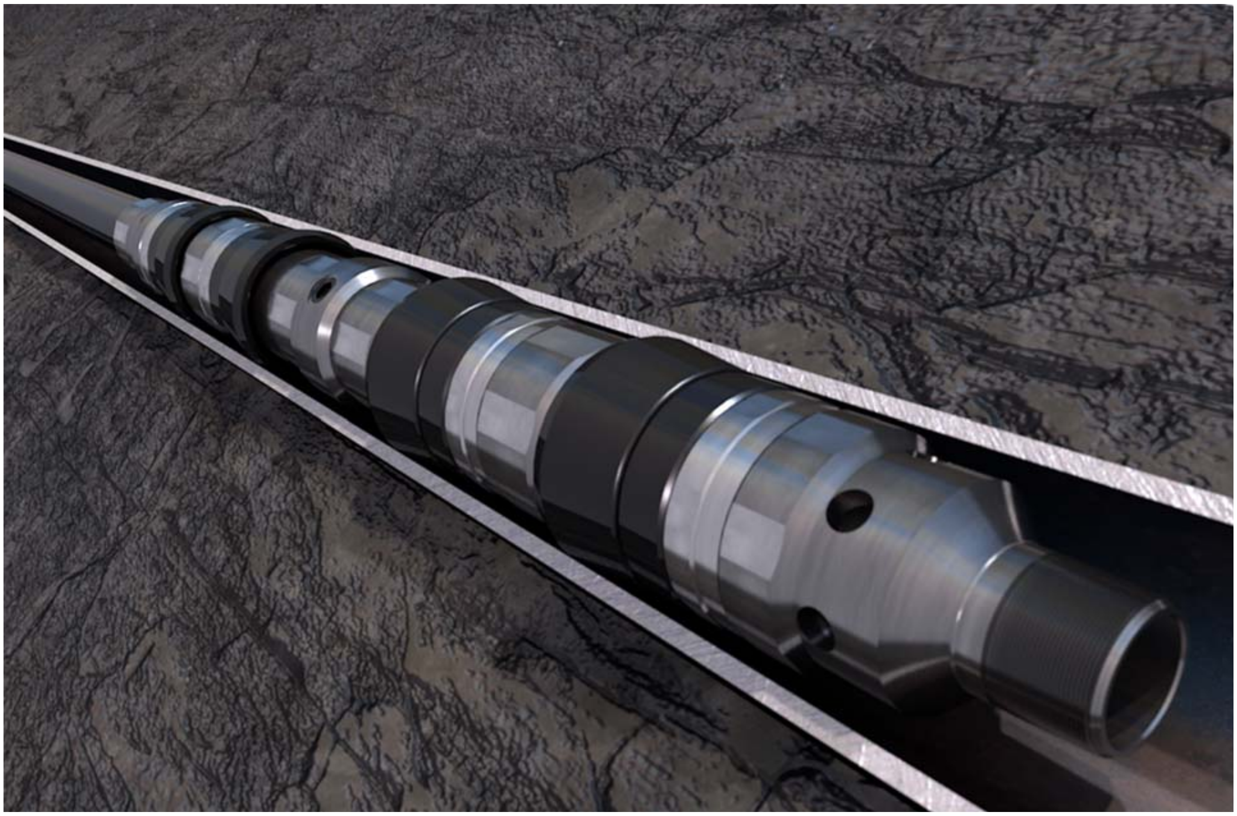
Casing Size in.	Packer OD in. (mm)	Packer ID in. (mm)	Nominal Casing Weight lb/ft	Minimum Casing ID in. (mm)	Maximum Casing ID in. (mm)	Tensile Rating lb (kg)	Temperature Rating °F (°C)	Maximum Working Pressure psi (bar)	Absolute Pressure psi (bar)
7	5.75 (146.1)	2.00 (50.8)	29 to 35	6.004 (152.5)	6.184 (157.1)	150,000 (68 038)	400 (204.4)	15,000 (1034)	25,000 (1724)
7 5/8	6.62 (161.8)	2.25 (57.2)	29.7 to 39	6.625 (168.3)	6.875 (174.6)	150,000 (68 038)	400 (204.4)	15,000 (1034)	25,000 (1724)
9 5/8	8.165 (207.4)	3.00 (76.2)	47 to 61.1	8.231 (209.1)	8.681 (220.5)	340,000 (154 221)	400 (204.4)	15,000 (1034)	25,000 (1724)
9 7/8	8.165 (207.4)	3.00 (76.2)	62.8	8.480 (215.4)	8.632 (219.3)	340,000 (154 221)	400 (204.4)	15,000 (1034)	25,000 (1724)
10 3/4 HW	8.165 (207.4)	3.00 (76.2)	91.2 to 109	8.434 (214.2)	9.032 (229.4)	340,000 (154 221)	400 (204.4)	15,000 (1034)	25,000 (1724)

Note: Although other sizes might be available, these sizes are the most common.

PinPoint Injection (PPI) Packers

Casing Size in.	Main Body OD in. (mm)	Packer ID in. (mm)	Nominal Casing Weight lb/ft	Minimum Casing ID in. (mm)	Maximum Casing ID in. (mm)	Tensile Rating lb (kg)	Maximum Working Pressure psi (MPa)
4	3.18 (80.8)	0.805 (20.4)	9.5 to 11.6	3.350 (85.1)	3.599 (91.4)	73,959 (33 584)	10,000 (68.95)
4 1/2	3.89 (98.8)	1.50 (38.1)	9.5	3.941 (100.1)	4.154 (105.1)	77,077 (34 962)	10,000 (68.95)
	3.75 (95.3)	1.50 (38.1)	11.6 to 13.5	3.852 (97.9)	4.041 (102.6)	77,077 (34 962)	10,000 (68.95)
	3.55 (90.2)	1.50 (38.1)	15.1 to 17.1	3.657 (92.9)	3.903 (99.1)	107,059 (48 562)	10,000 (68.95)
5	4.25 (108.0)	1.50 (38.1)	11.5 to 13	4.430 (112.5)	4.560 (115.8)	84,649 (38 397)	10,000 (68.95)
	4.06 (103.1)	1.50 (38.1)	15 to 18	4.194 (106.5)	4.486 (113.9)	86,026 (39 021)	10,000 (68.95)
	3.89 (98.8)	1.50 (38.1)	21.4	4.031 (102.4)	4.219 (107.2)	77,077 (34 962)	10,000 (68.95)
	3.78 (95.3)	1.50 (38.1)	23.2	3.945 (100.2)	4.145 (105.3)	77,077 (34 962)	10,000 (68.95)
5 1/2	4.55 (115.6)	1.50 (38.1)	13 to 20	4.694 (119.2)	5.102 (129.6)	142,344 (64 567)	10,000 (68.95)
	4.40 (111.8)	1.50 (38.1)	20 to 23	4.577 (116.3)	4.867 (123.6)	84,649 (38 397)	10,000 (68.95)
	4.25 (107.9)	1.50 (38.1)	23 to 26	4.444 (112.9)	4.765 (121.0)	84,649 (38 397)	10,000 (68.95)
6 5/8	5.65 (143.5)	1.50 (38.1)	17 to 20	5.799 (147.3)	6.551 (166.4)	160,810 (72 943)	10,000 (68.95)
7	5.65 (143.5)	1.50 (38.1)	17 to 38	5.799 (147.3)	6.551 (166.4)	160,810 (72 943)	10,000 (68.95)
	5.25 (133.4)	1.50 (38.1)	49.5	5.384 (136.8)	5.701 (144.8)	133,208 (60 423)	10,000 (68.95)
7 5/8	6.35 (161.3)	1.50 (38.1)	24 to 39	6.509 (165.3)	7.129 (181.1)	160,810 (72 943)	10,000 (68.95)
8 5/8	7.31 (185.7)	1.50 (38.1)	24 to 49	7.381 (187.5)	8.207 (208.5)	237,218 (107 602)	7,500 (51.71)
9 5/8	8.25 (209.6)	1.50 (38.1)	36 to 53.5	8.403 (213.4)	9.049 (229.9)	379,267 (172 036)	7,500 (51.71)

Specialty Tools



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Specialty Tools have unique features and characteristics because they are designed as a unique solution for a designated customer or group of customers. These tools have been developed to meet specific requirements or certain market demands.

Specialty Tools are generally run in conjunction with other Halliburton service tools to improve overall job quality or lower overall job costs.

Selective Injection Packer (SIP) Tool

Used most often in mature fields and conventional wells, the Selective Injection Packer (SIP) tool's main purpose is to open clogged or restricted perforations to re-establish communication with the producing formation.

The tool has opposing cups that isolate perforations for chemical treatments or perforation washing. Normal spacing between the cups is 1 ft; however, spacing can be expanded, if required.

Some methods, such as a ball-and-seat or ball valve, must be used to close off the center opening below the tool and force treating or washing fluid through ports between the cups.

A concentric bypass built into the SIP tool allows pressure to equalize from the annulus above to the annulus below the bottom cup. Fluid flows through the bypass, under the tool, and pushes the ball up.

Circulating valves are designed specifically for use with SIP tools. These ball-drop valves require approximately 1,350 psi (93.08 MPa) pressure to open.

Features and Benefits

- Opens restricted perforations
- Removes near-wellbore damage
- Helps return well to maximum production
- Optimizes total recovery
- Ball-and-seat arrangement or optional ball valves that close off the bottom of the tubing below the SIP tool assembly
- Reversing valve that drains the tubing when tools are removed from the well (either a ball-drop circulating valve or an RTTS®-type circulating valve)
- Treating packer and/or RFC® III valve, either of which is useful during chemical treatment processes

Selective Injection Packer (SIP) Tool

RFC® III Valve

The RFC® III retrievable fluid control valve controls the amount of fluid pumped into a formation, allowing treatment of a completed well without pulling the tubing. The valve is preset to operate at a specific pressure and allows precise amounts of fluid to be pumped through tubing into a formation.

The RFC III valve can be used for various purposes including:

- Scale removal operations
- Chemical treatment
- Acidizing with jet tools on long openhole intervals or multiple sets of perforations

The RFC III valve can be run in and retrieved on sandline, wireline, and slickline, or it can be dropped directly into the tubing for simplicity and ease of operation. If the shoe and seal ring are changed, then one tool can be used in either 2 3/8-in. EUE or 2 7/8-in. EUE tubing, making it more versatile.

When used in low-fluid-level wells, the RFC III valve prevents the loss of excess chemicals, reducing both waste and costs. The valve also allows for the removal of the final displacement fluid after a treating job, without subjecting the formation to the displacement fluid. Should scale or other downhole conditions cause difficulty with the tool, it can be removed and replaced without pulling the tubing string.

Features and Benefits

- Full range of closing pressures from 1,500 to 7,100 psi
- Hardened ball and seat to minimize fluid cutting issues
- Can be used to wash openhole sections below tubing
- Adjustable operating pressure feature allows controlled opening for various depths and fluid weights
- Can be used separately or in conjunction with packers or Hydra-Jet™ tools
- Can be run in, removed, and replaced without pulling the tubing string

RFC® III Valve

Indicating Ball Catcher System

Cement/scale buildup in the workstring and inaccurate fluid placement have continuously caused problems during industry operations. The plugging of bits or downhole assemblies and over-displacement are examples of such issues. Costs of replacing a workstring and reaming out cement sheaths can be significant, particularly for offshore operations. The Halliburton Indicating Ball Catcher System helps minimize these issues.

Features and Benefits

- Reduces costs through accurate fluid placement
- Provides positive surface indication of displacement
- Reduces costly cement/ scale cleanup
- Capable of multiple squeeze jobs without tripping pipe
- Separates incompatible fluids in the workstring and highly deviated or horizontal wells
- Enables wiping of tapered tubing string
- Reduces over-displacement occurrence
- Compatible with circulation and reverse circulation
- Can be run with retrievable or drillable packers
- Configuration includes ball catcher, launching and retrieving head, and rubber wiper balls

Ball Catcher

The indicating ball catcher is designed to provide a positive indication of displacement volume and can retain multiple balls. This tool incorporates a reduced orifice at the top of the ball catcher to produce the pressure indication. Once the wiper ball is pumped through the orifice restriction, it enters the larger-diameter retaining chamber.

The retaining chamber is designed with a lower orifice that retains the wiper balls and enables continued circulation and/or reverse circulation. Rates in excess of 5 bbl/min (3.15 m^3/min) with a pressure drop less than 500 psi (3.45 MPa) have been achieved during field operations. Currently, the ball catcher is available in 2 3/8-in. (60.3-mm) through 6 5/8-in. (168.3-mm) sizes.

Launching and Retrieving Head

The launching and retrieving head facilitates wiper ball placement into the smaller-diameter workstring. A ported nipple within the head enables wiper ball retrieval at the surface if reverse circulation is required before the ball reaches the indicating ball catcher. As a result, the cement slurry can be reversed out of the workstring without shutdown.

Wiper Ball

The wiper ball consists of a 50-durometer nitrile compound. This compound provides the flexibility and durability necessary for proper workstring wiping. The wiper balls are available in 2.50-in. (63.5-mm) through 6.3-in. (160-mm) sizes.

Indicating Ball Catcher System

Specialty Tools Tables

Following are the specifications tables for the Specialty Tools. The values of tensile, burst, and collapse strength are calculated with new tool conditions, Lame's formulas with von Mises Distortion Energy Theory for burst and collapse strength, and stress area calculations for tensile strength.

These ratings are guidelines only. For more information, consult your local Halliburton representative.

Selective Injection Packer (SIP) Tools

Casing Size in.	Casing Weight lb/ft	ID in. (mm)	Cup OD in. (mm)	Packer Rings OD in. (mm)
3 1/2	9.20	2.992 (76.0)	3.03 (77.0)	2.62 (66.5)
3 1/2	10.20	2.992 (76.0)	3.03 (77.0)	2.62 (66.5)
4 1/2	9.50	4.090 (103.9)	4.10 (104.1)	3.78 (96.0)
4 1/2	10.50	4.052 (102.9)	4.10 (104.1)	3.78 (96.0)
4 1/2	11.60	4.000 (101.6)	4.10 (104.1)	3.78 (96.0)
4 1/2	13.50	3.920 (99.6)	3.95 (100.3)	3.62 (91.9)
4 1/2	15.10	3.826 (97.2)	3.95 (100.3)	3.62 (91.9)
5	11.50	4.560 (115.8)	4.60 (116.8)	4.25 (107.9)
5	13.00	4.494 (114.1)	4.60 (116.8)	4.25 (107.9)
5	15.00	4.408 (112.0)	4.45 (113.0) 4.31 (109.5)	4.00 (101.6) 3.90 (99.1)
5	18.00	4.276 (108.6)	4.45 (113.0) 4.31 (109.5)	4.00 (101.6) 3.90 (99.1)
5	21.00	4.154 (105.5)	4.45 (113.0) 4.31 (109.5)	4.00 (101.6) 3.90 (99.1)
5 1/2	15.50	4.950 (125.7)	4.98 (126.5)	4.62 (117.3)
5 1/2	17.00	4.892 (124.3)	4.98 (126.5)	4.62 (117.3)
5 1/2	20.00	4.778 (121.4)	4.81 (122.2)	4.42 (112.3)
5 1/2	23.00	4.670 (118.6)	4.81 (122.2)	4.42 (112.3)
5 1/2	13.00	5.044 (128.1)	5.04 (128.0)	4.60 (116.8)
5 1/2	14.00	5.012 (127.3)	5.04 (128.0)	4.60 (116.8)
5 1/2	15.50	4.950 (125.7)	4.98 (126.5)	4.60 (116.8)
5 1/2	17.00	4.892 (124.3)	4.98 (126.5)	4.60 (116.8)
5 1/2	20.00	4.778 (121.4)	4.808 (122.1)	4.60 (116.8)
7	17.00	6.538 (166.1)	6.578 (167.1)	6.00 (152.4)
7	20.00	6.456 (164.0)	6.578 (167.1)	6.00 (152.4)
7	23.00	6.366 (161.7)	6.416 (163.0)	6.00 (152.4)
7	26.00	6.276 (159.4)	6.306 (160.2)	5.75 (146.0)
7	29.00	6.184 (157.1)	6.306 (160.2)	5.75 (146.0)

Selective Injection Packer (SIP) Tools

Casing Size in.	Casing Weight lb/ft	ID in. (mm)	Cup OD in. (mm)	Packer Rings OD in. (mm)
7	32.00	6.094 (154.8)	6.124 (155.5)	5.65 (143.5)
	35.00	6.004 (152.5)		
	38.00	5.920 (150.4)		
7 5/8	26.40	6.969 (177.0)	7.055 (179.2)	6.50 (165.1)
	29.70	6.875 (174.6)	6.905 (175.4)	6.35 (161.3)
	33.70	6.675 (169.5)		
	39.00	6.625 (168.3)	6.655 (169.0)	6.20 (157.5)
9 5/8	29.30	9.063 (230.2)	9.113 (231.5)	8.50 (215.9)
	32.30	9.001 (228.6)		
	36.00	8.921 (226.6)	8.951 (227.4)	8.50 (215.9)
	40.00	8.835 (224.4)		
	43.50	8.755 (222.4)	8.785 (223.1)	8.18 (207.8)
	47.00	8.681 (220.5)		

RFC® III Valve

Casing Size in.	Main Body OD in. (mm)	Retrieving Head OD in. (mm)	Length		
			Zero Auxiliary Spring Assemblies in. (mm)	One Auxiliary Spring Assembly in. (mm)	Two Auxiliary Spring Assemblies in. (mm)
2 3/8 to 2 7/8	1.52 (38.6)	0.625 (15.9)	46.08 (1170.4)	58.28 (1480.3)	70.48 (1790.2)

Indicating Ball Catcher System

Tubing/ Casing Size in.	Maximum OD in. (mm)	ID (Ball Passage) in. (mm)	End Connections	Ball Size (Capacity) in.
2 3/8	3.63 (92.2)	1.10 (27.9)	2 3/8-in. 8 RD EU	2.50 (7 ea)
2 7/8	3.63 (92.2)	1.40 (35.6)	2 7/8-in. 8 RD EU	3.00 (4 ea)
3 1/2	4.75 (120.7)	1.75 (44.5)	3 1/2-in. API IFTJ	3.50 (3 ea)
3 1/2	4.75 (120.7)	2.00 (50.8)	3 1/2-in. API IFTJ	3.50 (10 ea)
4 1/2	5.35 (133.4)	2.00 (50.8)	4 1/2-in. XT-M40	4.50 (7 ea)
4 1/2	6.25 (158.8)	2.00 (50.8)	4 1/2-in. API IFTJ	4.50 (3 ea)
5 1/2	7.25 (184.2)	2.50 (63.5)	5 1/2-in. HT-55 TJ	5.00 (4 ea)
5 1/2	7.25 (184.2)	2.50 (63.5)	5 1/2-in. XT-57 TJ	5.00/5.50/6.3 (4 ea/3 ea/2 ea)
6 5/8	8.50 (215.9)	3.25 (82.6)	6 5/8-in. FHTJ	6.3 (4 ea)
6 5/8	8.50 (215.9)	3.25 (82.6)	6 5/8-in. FHTJ	6.3 (10 ea)