Test Tools

Purpose of Well Tests

A properly conducted well test is a temporary completion of a well to acquire dynamic rate through time, pressure, and fluid property data. The well test often indicates how the well will perform when it is subjected to various flow conditions. An analysis is usually performed on the data to determine reservoir parameters and characteristics. Production decline maybe predicted using these parameters and characteristics. The production decline can be used to predict cash flow. Once cash flow is known, improved drilling, completion, and production decisions can be made on this well and other wells in the field. Well test objectives can be classified as short term or long term.

■ Short-term well test objectives typically involve gathering and analyzing sufficient well data to obtain a description of the reservoir system in the vicinity of the wellbore.

・Long-term well test objectives focus on gathering and analyzing data to obtain a complete description of the reservoir The test time required to satisfy the test objectives varies for each reservoir These test times are directly related to the testing costs and data needed. Therefore, testing times are a principal concern for the company conducting the test.

Downhole Testing Equipment

The well testing and sampling operation is typically accomplished with an assortment of test tools. The basic downhole test tools required for a well test include:

■ Reversing valve
■ Tester valve
■ Samplers
■ Gauges (pressure and temperature recorders)
■ Packer
・Tubing conveyed perforating guns

To determine the makeup of a test string, a test objective must be established and well defined. If the objective of the test is to perforate underbalanced and then test, only tools with a full opening should be used. A rule of thumb to observe when selecting the components of a test string is to keep the string as simple as possible. Avoid redundancy unless there is a real benefit to be gained. A variety of techniques and arrangements of test tools are used to handle diverse types of tests—from open hole to high- pressure/high temperature(HPHT) and underbalanced to name a few.

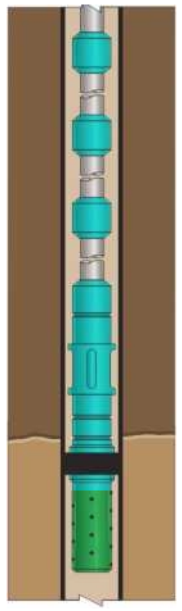
APR Annulus Pressure Response Test Tools

The APR annulus pressure response system of testing tools allows for a well test to be conducted with the blowout preventer (BOP) rams closed and without pipe manipulation or rotation to control the test. The APR tools are operated by simply applying and releasing annulus pressure. If there is a need to close the tester valve in an emergency, bleeding the annulus pressure off will close the tool, permitting corrective measures to be taken. If a leak in the work string should develop during the test to such an extent that annulus pressure cannot be bled off quickly enough to close the tester valve, the operator can then control the well by increasing the annulus pressure to the predetermined operating pressure of the APR rupture disk (RD) safety circulating valve.

This will lock the RD safety circulating valve ball in the closed position while opening the reversing ports to the annulus fluid. At this point, reversing out the string contents and conditioning mud can take place.

Two major applications for APR test tools are for wells drilled:

■ In directional holes where pipe manipulation is difficult.
■ From floating vessels.



Typical APR Annulus Pressure Response Cased Hole Testing String

Since these test tools are full opening, other tools can be run on wireline or coiled tubing to perforate, test, sample, treat the formation, and retest all in a single trip. In high-volume wells, the full-opening feature permits flow rates high enough to obtain more definitive test data, so test results are more reliable. The APR well testing method is safer; faster; and provides more reliable information than conventional methods used in the past.

Pre-Job Planning

Like all other operations required for drilling a well, pre-job planning is essential to ensure a safe and successful well test. This Management System serves as a preJob planning and execution guide to ensure that work is conducted in a professional, safe, and effective manner All personnel involved with the test must be informed of the different procedures needed to perform the test and must be prepared to react to changing well conditions during the job. Planning for a safe well test can be divided into two main events:

■ Pre-Job meeting
■ Well site preparation

Pre-Job Meeting

The following information should be discussed prior to the job.

Test Objectives

・ Pressure and temperature data

■ Flow rates

■ Downhole samples

・ lest duration

・ lest multiple zones

・ Type of data collection—surface readout, memory gauges

■ Analysis of collected data

Well Information

・ Expected bottom hole temperature

・- Elastomers required

■ - Data collection required

■ - Weight of annular fluid

・ Surface pressure

・- Pressure rating required for the surface equipment

■ Downhole pressure

■ - Pressure rating required for the downhole tools

■ - Packer required

■ - Type of cushion required

・- Data collection system required

■ - Tubulars required

■ Type of Production— rude, dry gas, H_2S, $CO_{2(}$ etc.

・- Elastomers required

-- Tools required

-- Surface equipment required

・- Test duration

・ Type of mud system—water based, oil based, brine

・- Elastomers required

-- Tools required

・ Casing or liner

- Size and weight—to determine size of tools

・- Pressure rating

-- Location of liner lap

・- Pressure rating of liner lap

・ Hole conditions

・- Total Measured Depth (MD)

・- True Vertical Depth (TVD)

・- Maximum deviation 一 can have an effect on what tools are used and if wireline is practical

・- Type of formation—will sand be produced?

・ Perforating

-- Tubing conveyed perforating—pressure activated, bar job

-- Perforating before test

-- Wireline guns through downhole tools

. Type of workstring

■ - Tubing 一 recommended for high pressure gas, HPHT

■ - Drill collars— rift needed for wireline passage

・- Landing string—for floating vessel

■ Drill pipe

-Cushion

-- Type of cushion— etermines type of elastomers required

-- Weight of cushion— etermines pressure differential across test tools and workstring

-- Method of cushion placement—spot, self-fill, fill at surface

Wellsite Preparation

Prior to testing, the following preparations need to be completed.

Equipment Preparation

・ Pressure test blowout preventers(BOP)

・ Pressure test subsea equipment

■ Pressure test surface equipment

, Function test downhole tools

- Pressure test downhole tools

・ Drift all equipment

■ Obtain work permits for pressure Testing

Note: All non-essential personnel should be restricted from area when pressure testing.

Personnel Preparation

・ Hold safety meeting before test

・- Know location of firefighting equipment

■ - Know evacuation procedures

・- Stress no smoking rule during test

・- No welding or open flames during testing

■ - No lifting over surface well test area

-- Use correct personal safety equipment

・ Instruct all essential personnel what procedures will be followed during testing.

・- Running in hole (RIH)

・- Firing tubing conveyed perforating (TCP) guns

.- Flowing well

■ - Shut-ins

・- Wireline procedures

■ - Sampling

■ - Killing well

-- Reversing out

・- Pulling out of hole (POOH)

・ Know when to abort test.

・- H2S detected over flowing limit—equipment not rated for H2S service

■ - Downhole tool malfunction

・- Subsea tool malfunction

■ - Surface leak that cannot be bypassed or repaired quickly

■ - Deteriorating weather conditions

■ -Leak in string, casing, tubing, etc.

■ Establish methods of communication.

■ - Voice

■ - Hand signals

■ - Hand radios

Conducting a Safe Well Test

During a test, there are numerous factors to be considered to help ensure a safe well test.

Picking Up Tools

■ Only qualified personnel to sling and direct crane operator

■ Use a guide rope line for long assemblies

■ Always use handling subs

Making Up Tools

■ All tools to be measured and drifted prior to running in well

■ Tool operator to direct the make up of the tools and advise driller on proper torque requirements

■ Use safety clamp or dog collar anytime the elevators are released from the tool

■ Always use a hole cover

■ Do not use iron rough neck on tools

Running in Well

■ Ensure the hole is filled before running in

■ Ensure the hole is stable before running in

■ Monitor well fluid while running in

・Slow down at liner laps

■ Avoid sudden stops while running in

■ Tool operator must be on rig floor at all times

Beginning Test

■ Set packer

■ lest packer seal by pressuring up on annulus

■ Ensure surface equipment is lined up correctly for inflow and light burners

■ With annulus pressure applied and tester valve open, pressure up on tubing and fire TCP guns

■ Observe surface pressure and monitor for leaks

■ Open surface choke manifold on flow well

- Check production for presence of H2S—abort test if surface equipment is not rated for H2S or H2S is over the low level ppm requirement
- Observe annulus pressure and maintain it at a predetermined pressure
- If annulus pressure suddenly increases or decreases, shut in downhole

Note: It is normal to see gradual pressure changes caused by temperature effects.

- If surface leak occurs, shut in downhole
- 1b shut in well for a "build up," release annulus pressure
- Observe annulus pressure for changes during the "buildup" period
- Observe tubing pressure for changes during the "buildup" period

Note: It is normal to see an increase in tubing pressure immediately after shut in when flowing gas. If tubing pressure is bled down during the "build up," enough pressure must be maintained to prevent collapse of the tubulars.

- Follow same procedure for additional flow and build up Periods

Terminating Test

- Reverse out all recovery with one of the following tools:
  - Annulus pressure operated
  - Tubing pressure operated
  - Bar drop operated
  - Mechanical operated
- If producing gas, fill the tubing prior to opening the reversing valve to help prevent U-tubing
- Reverse circulate until returns are free of hydrocarbons
- Unseat packer
- Observe annulus fluid for stability

Pulling Out of Hole

- Observe annulus fluid for stability
- Pull out of hole
- Stop periodically for flow check of well stability
- - Fill hole if necessary
- Use caution when breaking out tools for any pressure trapped between connections
- Use safety clamps or dog collars on tools
- Do not use iron rough neck on tools

Metallurgy

Service Environment

Immerse in various well fluids including hydrocarbons, dilute HC1, sour gas, salt water; and CO2 for the normal exposure time for drillstem testing.

Design Basis

This design meets or exceeds material requirements for sour gas service above 175°F set forth in NACE publication MR0175. Design calculations and safety factors are per Halliburton Specification 615.41861.

Specification

- Heat Treat, Fabrication, Material Test Requirements, AISI4140 Components for Sour Gas Service at temperatures of 175°F or greater

Heat Treatment - AISI 4140 - 271-301 Hb (Rc 28-32)

- Sour Gas Service at temperatures of 175°F or greater.

Short-Term Seal Selection Guide: O-rings

	ASTM D1418 Designation	NBR-Peroxide Cure	FKM	FKM	FEPM
	Trade Name	Nitrile	Viton	Fluorel	Aflas
	Specification	599.33001	600.33001	600.33001	601.30000
	Min. Temp °F (°C)	-40 (-40)	-10 (-23)	-10 (-23)	40 (4)[3]
	Max. Temp °F (°C) Exposure ≤ 24 hours	400 (204)	500 (260)	500 (260)	500 (260)
	Max. Temp °F (°C) Exposure ≤ 5 days	350 (177)[4]	400 (204)[5]	400 (204)[5]	400 (204)
	Max. Temp °F (°C) Exposure ≤ 5 days	275 (135)	325 (163)	325 (163)	400 (204)
	Max. Pressure at 500°F		10,000 psi (68,940 kPa)[6]	10,000 psi (68,940 kPa)[6]	10,000 psi (68,940 kPa)[6]
	Max. Pressure at 350°F	10,000 psi (68,940 kPa)	10,000 psi (68,940 kPa)	10,000 psi (68,940 kPa)	10,000 psi (68,940 kPa)
	Max. Pressure at 275°F	15,000 (103,410 kPa)	10,000 psi (68,940 kPa)	10,000 psi (68,940 kPa)	8,000 psi (55,152 kPa)
	Max. Pressure at 150°F	20,000 psi (137,880 kPa)	15,000 (103,410 kPa)	15,000 (103,410 kPa)	8,000 psi (55,152 kPa)
Gases	H_2S		8	8	8
	CO_2	8	8	8	8
	CH_4 (Methane)	8	8	8	8
	N_2	8	8	8	8
Oil-Based Fluids	Sweet Crude				
	Diesel				
	Aromatic Hydrocarbons and Solvents (Xylene and Toluene)	7			7
	Oil-Based Muds/Fluids	9	9	9	9
	Ester-Based Drilling Mud				
	Amine/Oil Inhibitors	7			
Water-Based Fluids	Water-Based Inhibitors				
	Steam				
	Salt Water				
	Zn Bromide				
	Ca Bromide (<14.2 ppg)				
	Na Bromide (<12.4 ppg)				
	Formates				
	High pH Fluids (>9)				
Other Fluids	Alcohols				
	Methanol				
	HCl and HCF Acid Mixture				
	Weak Acid (HCL<15%)				
	Strong Acid (HCL>15%)	7			
	Acetic and Formic Acids				

Excellent - Recommended

Good - Slightly affected, but no significant chemical change

Conditional - Time and/or temperature limitations Conditional - Operational considerations for running

Not recommended

No information available

Notes

1 Use Virgin PEEK backup rings above 400° F (204° C) and 10,000 psi (68 940 kPa).

2 Use Virgin PEEK backup rings above 350° F (177° C) and 5,000 psi (34 470 kPa).

3 Minimum temperature is 100F(38° C) if backup rings are used. The minimum temperature is 40F(4° C) if backup rings are not being used.

4 Field reports have shown successful results of working at 350° F (190° C) for 15 days.

5 Field reports have shown successful results of working at 410° F (210° C) for 8 days.

6 Virgin PEEK backup rings (beige) are rated to 10,000 psi (68 940 kPa) at 550F(288° C), Pink 25% glass Teflon backups are rated to 10,000 psi (68 940 kPa) at 400F(204° C).

7 Physical degradation could occur.

8 Explosive decompression is compound dependent and could damage seals or elements. Consult Elastomer Best Practices for ED resistant compounds.

9 Testing is recommended due to variability of proprietary ingredients of oil-based muds.

PEEK is a trademark of ICI Americas, Inc. Poly-Ether-Ether-Ketone.

Teflon is a registered trademark of DuPont—PTFE Polytetrafluoroethylene.

Viton is a registered trademark of DuPont Dow Elastomers, LLC - Fluorocarbon.

Fluorel is a registered trademark of 3 M.

Aflas is a registered trademark of Asahi Glass Co.—Propylene - Tetrafluoroethylene Copolymer.

Short-Term Guidelines: Packer Elements

	ASTM D1418 Designation	NBR - Sulfur Cure
	Trade Name	Nitrile
	Temperature Range °F (°C)	5
	Element Package Max. Pressure psi (MPa)	5
Gases	H_2S	3
Gases	CO_2	4
Gases	CH_4 (Methane)	4
Gases	N_2	4
Oil-Based Fluids	Sweet Crude	
Oil-Based Fluids	Diesel	
Oil-Based Fluids	Aromatic Hydrocarbons And Solvents (Xylene and Toluene)	1
Oil-Based Fluids	Oil-Based Muds/Fluids	6
Oil-Based Fluids	Ester-Based Drilling Mud	
Oil-Based Fluids	Amine/Oil Inhibitors	1
Water-Based Fluids	Water-Based Inhibitors	
Water-Based Fluids	Steam	
Water-Based Fluids	Salt Water	
Water-Based Fluids	Zn Bromide	2
Water-Based Fluids	Ca Bromide (<14.2 ppg)	2
Water-Based Fluids	Na Bromide (<12.4)	2
Water-Based Fluids	Formates	
Water-Based Fluids	High pH Fluids (>9)	
Other Fluids	Alcohols	
Other Fluids	Methanol	
Other Fluids	HCl and HF Acid Mixture	
Other Fluids	Weak Acid (HCL <15%)	
Other Fluids	Strong Acid (HCL <15%)	3
Other Fluids	Acetic and Formic Acid	

- Excellent - Recommended
- Good - Slightly affected, but no significant chemical change
- Conditional - Time and/or temperature limitations
- Conditional - Operational considerations for running
- Not recommended
- No information available

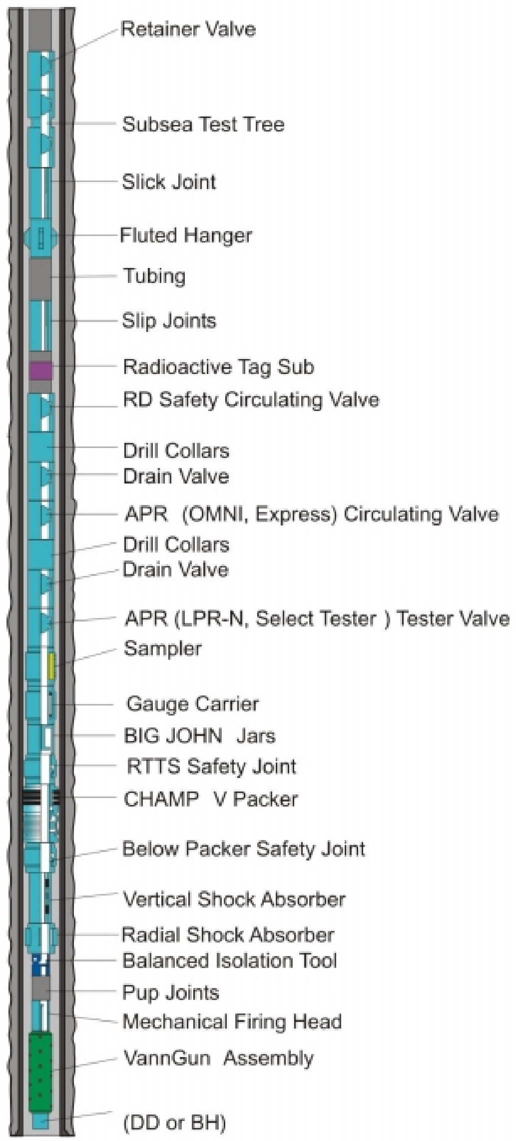
Notes:
1 Some chemicals and environments cause certain rubber types to lose elasticity, which can affect setting or resetting packer elements. Usually, no other physical degradation of the rubber is apparent. Service tools can be run in these environments if the packer or bridge plug is set within 8 hours of starting in the hole. The packer or plug cannot be reset after initial operations have begun.
2 Some chemicals can cause physical degradation of certain rubber types. To keep these chemicals from prolonged contact with the rubber, pump them into the work-string and the wellbore. Do not allow them in the drilling or completion fluids. If fluids are spotted, do not spot these chemicals across the packer seat (over displacement). Run a pup joint below a retrievable packer to provide a fluid barrier for packer elements. Place sand above a retrievable bridge plug to provide a physical barrier to pumped chemicals.
3 Incompatibilities that previously existed with chemicals that are produced from an oil or gas well may not exist in certain service operations if the well has been properly killed, and those chemicals do not exist in the wellbore. Further, pumping operations will keep produced chemicals from entering the wellbore during the service operation.
4 Chemical incompatibilities may not be severe enough to cause concern, but explosive decompression can damage seals or packer elements. Explosive decompression occurs when a sudden pressure loss occurs after prolonged exposure to this chemical. Explosive decompression is compound dependent and could damage seals or elements. Consult Elastomer Best Practices for ED resistant compounds.
5 Temperature and pressure ratings are dependent on tool design and application. For details see Retrievable Tools Manual 696.99999 and Drillable Tools Manual 802.20000 or contact the Service Tools Global Advisor.
6 Testing is recommended due to variability of proprietary ingredients in "Oil-Based Mud"

Cased Hole

String Examples

This section provides a brief discussion on some of the various tools used in cased hole testing including:

- Packers
- Circulating valves
- Tester valves
- Accessory tools



CHAMP V Packer

The CHAMP V packer is a hook wall-retrievable packer with a concentric bypass. 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.

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 hold down mechanism prevent the tool from being pumped up the hole. The bypass allows fluids to pass around the bottom of the tool when it is removed from the hole. This design eliminates accidentally opening a conventional bypass during circulation around the bottom of the packer

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

The CHAMP V packer is well suited to tubing conveyed perforating applications where the firing head assembly is easily incorporated into the CHAMP V packer. The CHAMP V packer is ideally suited for horizontal applications due to its limited rotational requirements and integrated circulating valve. Just a quarter-turn is required, at the tool, to set the packer and close the circulating valve. A straight upward pull opens the circulating valve and unseats the packer.

Features and Benefits

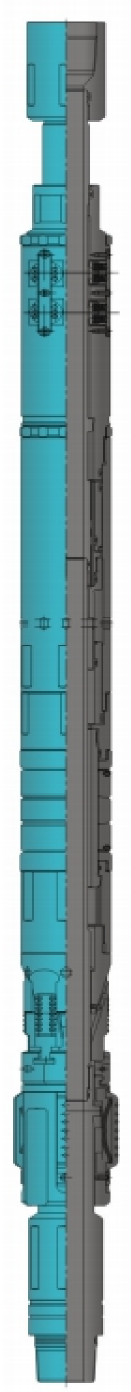
- The packer is used in highly deviated wells or where pipe manipulation is difficult.
- Picking the packer straight up (no torque required) opens the bypass.
- The tool is easily relocated in multiple zones during a single trip for treating, testing or squeezing.
- The concentric bypass valve allows a larger bypass flow area.
- The CHAMP V packer is used with a retrievable bridge plug for straddling zones during various operations.
- A CHAMP V packer would be the tool of choice where positive circulation below the packer is required such as in drill stem testing, TCP applications, using tailpipe, for shallow service, and as liner tools.

Operation

The tool is run slightly below the necessary setting position. If the packer is to be set, it must be picked up, and right-hand rotation must be applied so that a half-turn can be obtained at the tool. In deep or deviated holes, several turns with the rotary may be necessary. For the position to be maintained, the right-hand torque must be held until the mechanical slips on the tool are set and can begin taking weight.

Pressure applied below the packer forces the hydraulic hold down slips against the casing to prevent the packer from being pumped up the hole.

The concentric bypass valve is balanced to the tubing surface pressure, which prevents the bypass from being pumped open with tubing pressure. Straight, upward pull on the tubing string opens the bypass and unsets the packer.



CHAMP V Packer

Casing Size in.	Packer OD in. (cm)	Packer ID in. (cm)	End Connections	Nominal Casing Weight Ib/ft	Minimum Casing Drift ID in. (cm)	Maximum Casing ID in. (cm)	Length in. (cm)	Tensile Rating lb(kg)	Working Pressure psi(kPa)
5″	4.18 (10.62) 4.25 (10.795) 4.31 (10.954)	1.65 (4.20)	2 7/8 CAS	11.5-15	4.70 (11.948)	4.78 (12.141)	113.9 (289.3)	139,926 (63 469)	Burst 17,951 (123 800) Collapse 16,835 (116 100)
	3.98 (10.11) 4.15 (10.54)	1.65 (4.20)	2 7/8 CAS	18-21.4	4.56 (11.59)	4.64 (11.78)	113.6 (288.55)		
7″	6.35 (16.129) 6.25 (15.875) 6.15 (15.621) 6.05 (15.367)	2.24 (5.70)	3 7/8 CAS 31/2 IF	17-26	6.64 (16.861)	6.77 (17.193)	131.44 (333.86) 130.9 (332.57)	230,361 (104 490)	Burst 23,403 (161 400) Collapse 21,663 (149 400)
	5.93 (15.062) 5.77 (14.659) 5.75 (14.605)	2.24 (5.70)	3 7/8 CAS 31/2 IF	29-35	6.50 (16.515)	6.59 (16.744)	131.44 (333.86) 130.9 (332.57)	230,361 (104 490)	Burst 23,403 (161 400) Collapse 21,663 (149 400)
	5.65 (14.35)	2.24 (5.70)	3 7/8 CAS 31/2 IF	38	6.46 (16.408)	6.46 (16.408)	131.44 (333.86) 130.9 (332.57)	230,361 (104 490)	Burst 21,533 (148 500) Collapse 19,938 (137 500)
9-5/8″	8.70 (22.098) 8.65 (21.971) 8.55 (21.717) 8.45 (21.463)	2.874 (7.30)	3 7/8 CAS 31/2 IF 4 1/2 IF	29.3-40	9.23 (23.445)	9.31 (23.656)	144.88 (368.0) 145.04 (368.4) 145.67 (370.0)	431,589 (195 765)	Burst 21,982 (151 600) Collapse 20,880 (144 000)
	8.35 (21.209) 8.25 (20.955) 8.10 (20.574) 8.00 (20.32)	2.874 (7.30)	3 7/8 CAS 31/2 IF 4 1/2 IF	43.5-58.4	9.03 (22.937)	9.19 (23.343)	144.88 (368.0) 145.04 (368.4) 145.67 (370.0)	431,589 (195 765)	Burst 21,982 (151 600) Collapse 20,880 (144 000)
	8.00 (20.32) 7.95 (20.193) 7.80 (19.812)	2.874 (7.30)	3 7/8 CAS 31/2 IF 4 1/2 IF	59.4-71.8	8.89 (22.584)	9.01 (22.891)	144.88 (368.0) 145.04 (368.4) 145.67 (370.0)	431,589 (195 765)	Burst 18,604 (128 300) Collapse 17,328 (119500)

Although other sizes may be available, these sizes are the most common.

**The tensile strength value is calculated with new tool conditions. Stress area calculations are used so that tensile strength can be calculated.

***Pressure rating is the differential pressure at the tool. (Differential pressure is the difference in pressure between the casing annulus and the tool ID.)

These ratings are guidelines only.

RTTS Packer

The RTTS packer is a full-opening, hook wall packer used for testing, treating, and squeeze cementing 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 hold down mechanism help prevent the tool from being pumped up the hole. Drag springs operate the J-slot mechanism on 3 1/2-in. (88.9-mm) packer bodies, while larger packer sizes Z 4-in. (101.6 mm) use drag blocks. Automatic J-slot sleeves are standard equipment on all packer bodies.

The circulating valve, if used, is a locked-open/locked- closed type that serves as both a circulating valve and bypass. The valve automatically locks in the closed position when the packer sets. During testing or squeezing operations, the lock prevents the valve from being pumped open. A straight J-slot in the locked-open position matches with a straight J-slot (optional) in the packer body. This combination eliminates the need to turn the tubing to close the circulating valve or reset the packer after the tubing has been displaced with cement

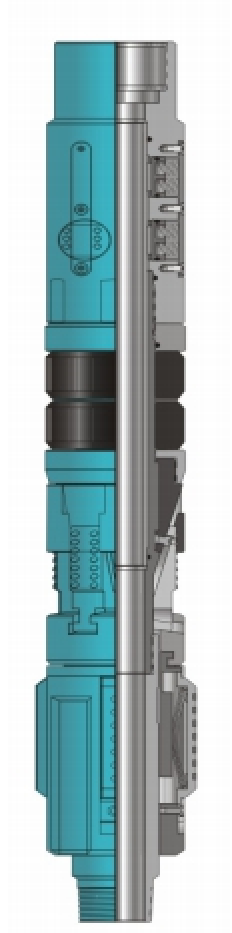
Features and Benefits

- The 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.
- The packer can be set and relocated as many times as necessary with simple tubing manipulation.
- Tungsten carbide slips provide greater holding ability and improved wear resistance in high-strength casing. Pressure through the tubing activates the slips in the hydraulic holddown mechanism.
- An optional integral circulating valve locks into open or closed position during squeezing or treating operations, and opens easily to allow circulation above the packer

Operation

The tool is run slightly below the desired setting position to set the packer and is then picked up and rotated several turns. If the tool is on the bottom, only a halfturn is actually required. However; in deep or deviated holes, several turns with the rotary may be necessary, lb maintain position, the right-hand torque must be held until the mechanical slips on the tool are set and can start taking weight

The pressure must be equalized across the packer to unset it. As the tubing is picked up, the circulating valve remains closed, establishing reverse circulation around the lower end of the packer The circulating valve is opened for coming out of the hole when the tubing is lowered, rotated to the right, and picked up.



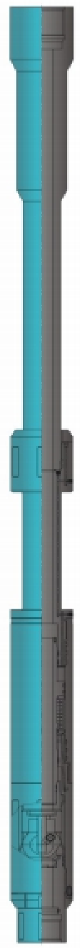
RTTS Packer

Casing Size In. (cm)	Casing Weight Range lb/ft	Nominal Tool OD in. (cm)	Minimum ID in. (cm)	Top Thread Connection (female)	Lower Thread Connection (male)
5″	15-18	3. 90 (9. 91)	1. 77 (4. 50)	3 3/32-10UN. B 2 7/8 EUE. B 2 7/8 CAS. B	2 7/8 EUE. P 2 7/8 EUE. P 2 7/8 CAS. P
	21.4-23	3. 86 (9. 80) 3. 78 (9. 60)	1. 77 (4. 50)	3 3/32-10UN. B 2 7/8 UP TBG. B	2 7/8 UP TBG. P 2 7/8 UP TBG. P
5. 5″	13-20	4. 55 (11. 557)	1.77 (4. 50)	2 3/8 IF. B 3 1/2-8 UN. B 2 7/8 UP TBG. B 2 7/8 CAS. B	2 3/8 IF. P 2 7/8 UP TBG. P 2 7/8 UP TBG. P 2 7/8 CAS. P
6 5/8″	24-32	5. 43 (13. 79)	1. 89 (4. 80)	3 1/2-8 UN. B 2 7/8 EUE. B 2 7/8 CAS. B	2 7/8 EUE. P 2 7/8 EUE. P 2 7/8 CAS. P
7″	17-26	6. 00 (15. 24)	2. 40 (6. 10)	4 5/32-8 UN. B 3 7/8 CAS. B 3 1/2 IF. B	2 7/8 UP TBG. P 3 7/8 CAS. P 3 1/2 IF. P
	23-29	5. 75 (14. 61)			
	32-38	5. 65 (14. 35)			
7 5/8″	20-26. 4	6. 75 (17. 14)	2. 44 (6. 20)	3 7/8 CAS. B	2 7/8 UP TBG. P
	26. 4-29. 7	6. 59 (16. 74)			
	29. 7-39	6. 35 (16. 14)			
9 5/8″	29. 3-53. 5	8. 25 (20. 95)	3. 98 (10. 10)	4 1/2 IF. B 3 1/2 IF. B	4 1/2 IF. P 3 1/2 IF. P
	40-71.8	7. 80 (19. 81)	3. 00 (7. 62)	4 1/2 IF. B	4 1/2 IF. P
13 3/8″	48-72	11.94 (30. 33)	3. 75 (9. 53)	4 1/2 IF. B	4 1/2 IF. P

These ratings are guidelines only.

Super Safety Valve

The Super Safety valve (SSV) is a master valve used for testing operations from jack-up or land rigs. The SSV is installed in the test string so that a BOP ram can be closed on the ramlock sub located in the top section of the valve. The annulus is then protected by the BOP rams, and the test string is protected by the safety valve. The Super Safety valve is capable of cutting wireline and 1.5-in. coiled tubing. If equipped with a cutter ball, it is capable of cutting 2-in. OD, .125-in. wall coiled tubing using a nitrogen dome charge or by applying balance line pressure.



Features and Benefits

The Super Safety valve is controlled by two hydraulic lines and contains a chemical injection port for injecting chemicals at the valve body further downhole to an injection sub or to actuate a subsurface safety valve. The valve is held open by maintaining hydraulic pressure on the control line.

The valve is designed to close by spring force but incorporates a nitrogen dome charge chamber to provide increased closing force and to lessen the time required for closing. This feature gives the valve the ability to cut wireline and coiled tubing without adding balance line pressure.

・ Normally dosed/fail-safe

- Maintains pump-through capabilities at all times

・ Nitrogen dome charge for fast response

・ Capable of cutting 1.5-in. coiled tubing, or if equipped with a cutter ball 2-in. OD, ,125 in. wall thickness coiled tubing

・ Small 8-in. OD fits inside 9 5/8-in.casing

Super Safety Valve

OD in. (cm)	ID in. (cm)	End Connections	Total Length in, (cm)	Tensile Rating** lb (kg)	Working Pressure三 lb (kg)	Temperature Range ° F(° C)
8.00	3,01	5 3/4 4SA.B	142.93	1417,032	15,000	-20 to 350
(20,32)	(7.65)	X5-4ACME.B	(363.05)	(642 755)	(6804)	(-29 to 177)

Meets requirements of NACE MR-01-75

**The tensile strength value is calculated with new tool conditions. Stress area calculations are used to calculate tensile strength.

**Pressure rating is defined as differential pressure at the tool. (Differential pressure is the difference in pressure between the casing annulus and the tool ID.)

These ratings are guidelines only.

FUL-FLO Hydraulic Circulating Valve

The FUL-FLO hydraulic circulating valve serves as a bypass around the packer or as a circulating valve to circulate a well after testing.

When run below a closed valve, the tool serves as a bypass around the packer and helps relieve pressure buildup below the closed valve when it is stung into a production packer

When run above a closed valve, the tool can be used as a circulating valve when the workstring is picked up.

Features and Benefits

■ Permits passage of wireline tools through its full-opening bore

■ Requires no pipe rotation to operate

Operation

Bypass ports close when weight is set down and reopen when weight is lifted.

A hydraulic metering system provides a 2 to 3-minute delay in closing after weight is applied. This delay allows either the RTTS packer to be set or the test string to be stung into a permanent packer before the bypass ports close. The ports reopen without a time delay.

During stimulation work, the latching piston adds a downward force on the circulating sleeve to help keep the valve closed.

Operation of the valve is the same whether it is used as a circulating valve or as a bypass. No torque is required. Weight is applied to close the tool, and the workstring is picked up to reopen it

FUL-FLO Hydraulic Circulating Valve

Nominal Tool Size in.	OD in. (cm)	ID in. (cm)	Thread Connections	Service Temperature* ° F(° C)	Length in. (cm)	Stroke length in. (cm)	Tensile Rating** lb(kg)	Working Pressure*** psi (bar)	Flow Area In.^{2} (cm^2)	Number of ports
3 7/8″	3. 90 (9. 91)	1. 77 (4. 50)	27/8 EUE 27/8 CAS	400 (204)	94. 78 (240. 75)	3. 98 (10. 10)	230, 361 (104 490)	15, 000 (1034)	1. 17 (7. 55)	4
			27/8 REG		93. 41 (237. 25)					
5″	5. 02	2. 24	3 7/8 CAS	400	91. 02 (231. 2)	3. 15	328, 219	15, 000	1. 67	4
	(12. 75)	(5. 70)	3 1/2 IF	(204)	90. 55 (230. 0)	(8. 00)	(148 878)	(1034)	(10. 76)	

Meets requirements of NACE-0175 (>175° F)

[1]Add 3.00 in. (7.52 cm)

*Service temperature up to 450° F (dressed with 600 series o-rings and PEEK backup seals)

**The values of tensile, burst, and collapse strength are calculated with new tool conditions, Lame's formulas with Von-Mise's Distortion Energy Theory for burst and collapse strength, and stress area calculations for tensile strength.

***Pressure rating is defined as the differential pressure at the tool. (Differential pressure is the difference in pressure between the casing annulus and the tool ID.)

These ratings are guidelines only.

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RTTS Safety Joint

The RTTS safety joint is an optional emergency back off device. The safety joint releases the workstring and tools above the packer if the packer becomes stuck during operations.

The design of the RTTS safety joint makes unintentional operation difficult.

Features and Benefits

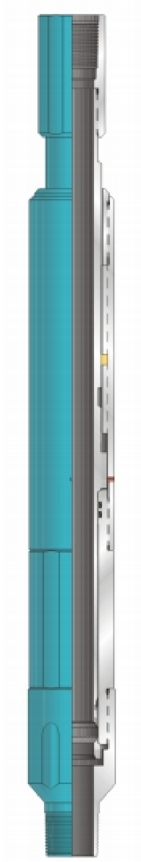
- Positive sequence of operation helps prevent premature release.
- Tools above it can be retrieved when string is stuck.

Operation

The RTTS safety joint is run immediately above the RTTS packer so that the greatest number of tools above the packer can be removed.

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.

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



RTTS Circulating Valve

The RTTS circulating valve is a locked-open/locked-closed valve that serves as both a circulating valve and bypass. The clearance between the RTTS packer (or any hook wall 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 generally used.

Features and Benefits

- The valve can be locked closed when the packer is unset to reverse fluid around the bottom of the packer
- The tool's full opening allows tubing-type guns and other wireline equipment to pass.

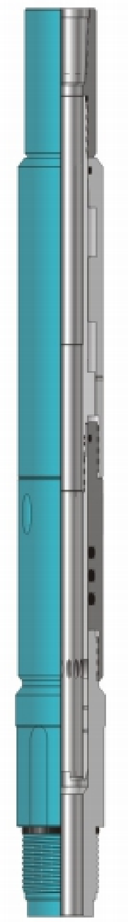
Operation

The RTTS circulating valve is automatically locked in the closed position when the packer is set. During testing and squeezing operations, the lock helps prevent the valve 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 eliminates the need to turn the tubing to close the circulating valve or reset the packer after the tubing has been displaced with cement

The RTTS circulating valve can be run directly above the packer body or further up the workstring.

When placed in the hole, the valve must be in the locked-open position. The J-slot in the packer-body drag block (or drag sleeve) must also be placed in the unset position.

When the circulating valve is opened to come out of the hole, the tubing is lowered, turned to the right, and picked up.



RTTS Safety Joint

Size in.	OD in. (cm)	ID in. (cm)	End Connections	Length in. (cm)	Tensile Rating** lb(kg)	Burst Rating** psi (kPa)	Collapse Rating** psi (kPa)
4 1/2″ to 5″	3. 68 (9. 35)	1.90 (4. 83)	2 3/8 EUE	48. 09 (122. 15)	214, 096 (97 112)	22, 693 (156 500)	20, 880 (144 000)
			2 7/8 EUE	44. 79 (113. 76)			
			2 7/8 CAS	44. 39 (112. 74)			
5 1/2″ to 6 5/8″	4. 06 (10. 31)	2. 00 (5. 08)	2 3/8 EUE	40. 70 (103. 37)	202, 915 (92 041)	13, 717 (94 600)	20, 329 (140 200)
			2 7/8 CAS	45. 6 (115. 84)			
7″ to 7 5/8″	5. 00 (12. 70)	2. 44 (6. 20)	2 7/8 UP TBG	41. 34 (105. 0)	238, 234 (108 061)	16, 675 (115 000)	15, 805 (109 000)
			3 7/8 CAS	46. 46 (118. 0)			
			3 1/2 IF	45. 67 (116. 0)			
8 5/8” to 13 3/8″	6. 12 (15. 55)	3. 11 (7. 90)	4 1/2 IF	47. 07 (119. 55)	449, 923 (204 081)	18. 212 (125 600)	14, 863 (102 500)
			3 1/2 IF	47. 46 (120. 55)			

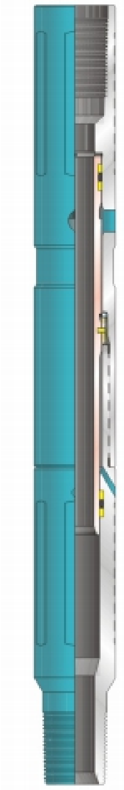
These are the most common sizes. Other sizes may be available.
**The values of tensile, burst, and collapse strength are calculated using new tool conditions, Lame's formula with Von Mise's Distortion Energy theory for burst and collapse strength, and stress area calculations for tensile strength.
These ratings are guidelines only.

RTTS Circulating Valve

Size in.	OD in, (cm)	ID in. (cm)	End Connections	Length in. (cm)	Tensile Rating** lb (kg)	Burst Rating** psi (kPa)	Collapse Rating** psi (kPa)
4 1/2″ to 5″	3,56	1.77	2 3/8 EUE. Bx3 3/32-10 UN. P	35.69 (90.64)	179, 294	23,853	21,866
	(9.05)	(4.50)	2 7/8 CAS	39.94 (101.45)	(81 327)	(164 500)	(150 800)
5 1/2″ to 6 5/8”	4.17	1,99	2 3/8 UP TBG.B x3 1/2-8 UN.P	35.51	191,667	14,384	13,775
	(10.6)	(5.05)	2 7/8 CAS	(90.2)	(86 939)	(99 200)	(95 000)
T	4.86 (12.35)	2,36	2 7/8 UP TBG.B x4 5/32 - 8 UN.P	36.50 (92.7)	226,536	20,300	19,140
	5,00 (12.7)	(6.00)	3 1/2 IF	39.17 (99.5)	(102 755)	(140 000)	(132 000)
8 5/8″ to 20″	6,12 (15.55)	3,00 (7.62)	4 1/2 IF	42.86 (108.87)	516,736 (234 388)	15,515 (107 000)	14,790 (102 000)

These are the most common sizes. Other sizes may be available.
**The values of tensile, burst, and collapse strength are calculated with new tool conditions, Lame's formulas with Von-Mise's Distortion Energy Theory for burst and collapse strength, and stress area calculations for tensile strength.
These ratings are guidelines only.

Internal Pressure-Operated (IPO) Circulating Valve



The internal pressure-operated (IPO) circulating valve is a single-shot circulating valve which allows circulation through the workstring before trip-out and serves as a drain valve during trip-out It can be run in cased holes or openholes and maintains a full bore through the tool. The IPO circulating valve is used in the following situations:

- When a full-opening string is needed
- When redundant backup to annulus pressure- operated circulating valves is needed
- When a limited amount of annulus pump pressure is available to operate annulus pressure tools

Features and Benefits

- Requires no string manipulation to operate tool
- Permits passage of wireline tools through full-opening bore

Operation

The IPO circulating valve is operated by internal pressure (500 to 10,000 psi above hydrostatic). Pressure required to operate the tool is determined by shear pins, which hold the sliding valve in the closed position, lb open the valve, tubing pressure is increased to a pressure above annulus hydrostatic equal to the shear value of the shear pins. Once operated, the IPO circulating valve is locked open.

Nominal Tool Size in.	OD in. (cm)	ID in. (cm)	Thread Connections	Service "Temperature* ° F(° C)	Length in. (cm)	Tensile Rating** lb (kg)	Working Pressure*** psi (bar)	Flow Area in.2 (cm2)	Number of Ports
3 7/8"	3.90 (9.91)	1.77 (4.50)	2 7/8 UP TBG 2 7/8 CAS	400 (204)	23,52 (59.74) 26,85 (68,20)	230,046 (104 347)	15,225 (1050)	1,23 (7.94)	4
5"	5.02 (12.75)	2.24 (5.70)	3 7/8 CAS 3 1/2 IF	400 (204)	26.77 (68.00) 26.28 (66.74)	462,746 (209 898)	15,225 (1050)	1,49 (9.61)	4

Internal Pressure Operated (IPO) Circulating Valve

Meets requirements of NACE-0175 (>175° F)
*Service temperature up to 450° F (dressed with 600 series O-rings and PEEK backup seals)
**The values of tensile, burst, and collapse strength are calculated with new tool conditions, Lame's formulas with Von-Mise's Distortion Energy Theory for burst and collapse strength, and stress area calculations for tensile strength.
***Pressure rating is defined as the differential pressure at the tool. (Differential pressure is the difference in pressure between the casing annulus and the tool ID.) These ratings are guidelines only.
PEEK is a trademark of ICI Americas, Inc. Poly-Ether-Ether-Ketone.

Rupture Disk (RD) Safety Circulating Valve

The rupture disk (RD) safety circulating valve functions as both a safety valve and circulating valve. The tool functions as a safety valve when the annulus pressure reaches a predetermined value. At that pressure, the valve isolates the workstring below the tool and establishes communication between the annulus and the workstring above the tool. This tool converts into a circulating valve when the ball valve section is removed.

Features and Benefits

The tool is composed of three major sections:

- The power section consists of a power mandrel case and rupture disk that is available for a wide range of pressure applications. The rupture disk bursts at a predetermined pressure, allowing annulus pressure to be applied to a differential area on the power mandrel. The power mandrel moves down, first pushing the ball valve closed, and then opening a set of circulating ports.
- The circulating section consists of a set of ports that are initially sealed by the power mandrel. When the rupture disk bursts, the power mandrel moves down, exposing the ports that allow communication between the annulus and workstring.
- The safety valve consists of a ball valve, operating pins, and collet fingers. As the power mandrel moves down, the operating arms close the ball valve. The collet fingers expand, allowing the power mandrel to continue traveling down to open the circulating ports.

Operation

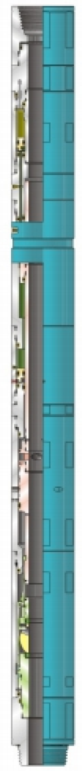
Before the RD safety circulating valve is used, the operating pressure is calculated for selecting the proper rupture disk pressure rating. Required information includes mud weight, testing depth, bottomhole temperature, and maximum annulus pressure. When the rupture disk safety circulating valve is run with an annulus pressure-operated valve, the safety valve operating pressure should be kept l,000 psi above the operating pressure of the tester valve.

Rupture Disk (RD) Safety Circulating Valve

Nominal Tool Size in.	OD in. (cm)	ID in. (cm)	Thread Connections	Service Temperature* ° F(° C)	Length in. (cm)	Tensile Rating** lb (kg)	Working Pressure*** psi (bar)	Flow area in.[2] (cm²)	Number of Ports
3 7/8"	3.90 (9.91)	1.77 (4.50)	2 7/8 CAS	400 (204)	75.4 (191.5)	264,330 (119 900)	15,225 (1050)	1.758 (11.34)	4
5"	5.02 (12.75)	2.24 (5.70)	NC38 3 7/8 CAS	400 (204)	72.56 (184.3)	478,493 (217 041)	15,000 (1034)	3.142 (20.268)	4

[1]Full sour gas service
fThe tool can be converted to a higher pressure rating by changing out to a 5 1/4 in. circulating case.
*Service temperature up to 450° F (dressed with 600 series O-rings and PEEK backup seals)
**The values of tensile, burst, and collapse strength are calculated with new tool conditions, Lame's formulas with Von-Mise's Distortion Energy Theory for burst and collapse strength, and stress area calculations for tensile strength.
***Pressure rating is defined as the differential pressure at the tool. (Differential pressure is the difference in pressure between the casing annulus and the tool ID.)
Meets NACE-0175 requirements (175° F)
These ratings are guidelines only.
PEEK is a trademark of ICI Americas, Inc. Poly-Ether-Ether-Ketone.

OMNI Circulating Valve



The OMNI circulating valve is an annulus pressure operated, recloseable circulating valve. Throughout the operation, the tool is repeatedly cycled up to a predetermined annulus pressure and then released.
The OMNI valve consists of a nitrogen section, an oil system, a circulating valve, and a ball valve. The nitrogen section contains the nitrogen gas that counterbalances the hydrostatic and annulus pressures. The amount of nitrogen in the tool depends on well hydrostatic (mud weight and depth) and downhole temperature. This information must be known to properly prepare the tool for running in.
Note: With certain completion fluids, the mud weight at the surface can be significantly different from the actua mud weight downhole.
The operating and control mechanisms are contained in a closed oil system activated by annulus pressure acting on the nitrogen chamber; allowing an unlimited number of pressure cycles.
The circulating valve and the ball valve work together to keep circulating pressure off the formation. The ball valve will close before the circulating valve opens. The ball valve closes off the workstring.

Features and Benefits

・Permits well testing, pressure testing, and fluid circulation

■ Allows unlimited number of pressure cycles

Operation

The well can be flow tested when the valve is in the well test position. When in this position, the circulating ports are closed and the ball valve is opened. During a downhole closure drill stem test, the OMNI valve is in the well test position during flow and shut-in periods. The workstring can be pressure- tested in the blank position because the ball valve closes before the circulating valve opens. Fluid can be pumped in either direction through the tool in the circulating position. In this position, the circulating ports are open and the ball valve is closed.
Note: Before the tool is run, the hydrostatic pressure at the specified tool depth must be known. This information is required to obtain the proper nitrogen charging pressure.

OMNI Circulating Valve

Nominal Tool Size in.	OD in. (cm)	ID in. (cm)	Thread Connections	Temperature* ° F(° C)	Length in. (cm)	Tensile Rating** lb (kg)	Working Pressure*** psi (bar)	Circulating Flow Area in.² (cm²)	Number of Ports
3 7/8″	3.90 (9.91)	1.77 (4.50)	2 7/8 CAS	400 (204)	283.3 (719.6)	220,822 (100 163)	15,000 (1034)	3. 598 (23.21)	6
5″	5. 02	2. 24	NC38(3 1/2 IF)	350	258.1	457, 572	15, 225	3, 534	6
	(12. 75)	(5. 70)	3 7/8 CAS	(177)	(655.5)	(207 551)	(1050)	(22.80)	

Meets NACE-0175 requirements (>175° F)
Maximum Differential Operating Pressure:
• From bottom of ball when opening—1,000 psi (69 bar)
• From top of the ball when opening—5,000 psi (345 bar)
• For operating the circulating ports— ,000 psi OD to ID (annulus to tubing) (413 bar)
—0 psi ID to OD (tubing to annulus)
*Service temperature up to 450° F (dressed with 600 series o-rings and PEEK backup seals)
**The values of tensile, burst, and collapse strength are calculated with new tool conditions, Lame's formulas with Von-Mise's Distortion Energy Theory for burst and collapse strength, and stress area calculations for tensile strength.
***Pressure rating is defined as the differential pressure at the tool. (Differential pressure is the difference in pressure between the casing annulus and the tool ID.)
These ratings are guidelines only.
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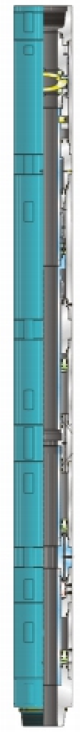
Select Tester Valve



The Select Tester valve is a full-opening, annulus pressure operated tool. With applied pressure, the tool can be locked open and then returned to the normal operating sequence at any time. The ball valve operates independently of pressure changes from operations such as acidizing and fracturing. This gives the Select Tester valve greater compatibility and flexibility with other tools in the string.

Features and Benefits

■ Incorporates advanced materials and processes providing a unique metal-to-metal seal for exceptional gas-holding capabilities
■ Has undergone extensive five-day qualification testing at 400°F and 15,000 psi including a 16,500 psi burst and collapse test
■ Allows operator to reverse out/circulate to the lowest point of circulation below the Select Tester valve. This facilitates well kill operations, saving both time and money.
■ Allows operator to run in or come out of a hole in the open position, enhancing safety and maximizing well control options.
■ Allows operator to spot cushion to the lowest point of circulation below the Select Tester valve. This improves control of drawdown pressure and reduces recovery of mud and other rathole fluids.
■ Simplifies string design by eliminating the need for a bypass when stinging into or out of a production packer
■ Maximizes flexibility during well kill operations since the Select Tester valve can be operated with the packer unset.
Note: When annulus pressure is applied or bled off to zero, it is recommended operating procedure to wait 10 minutes before operating the Select Tester valve again.

Operation

Once the packer is set, pressure is quickly applied to the annulus to operate the Select Tester valve. This creates the differential pressure that acts across the operating section to move the mandrel down, causing the ball to rotate to the open position. *To* close the ball, annulus pressure is released to zero. The nitrogen section acts to move the operating mandrel up. This upward travel of the mandrel rotates the ball valve back to the closed position, lb activate the lockout feature, the normal operating pressure is increased by 1,300 psi.

This higher level of pressure prevents the operating mandrel from moving up. In this position, the ball valve will remain open when the annulus pressure is released, lb reactivate the tool, annulus pressure is once again increased to 1,300 psi above normal operating pressure. This will reactivate the operating section and return the tool to normal operating mode. The lockout feature can be reactivated as many times as desired without having to remove the tool from the well.

Select Tester Valve

Nominal Tool Size in.	OD in. (cm)	ID in. (cm)	Thread Connections	Length in. (cm)	Tensile Rating** lb (kg)	Working Pressure*** psi (bar)
5″	5,02 (12.75)	2.24 (5.70)	NC38(3 1/2 IF)	290.7 (738.4)	438,000 (198 674)	15,255 (1050)

Service temperature up to 450° F (dressed with 600 series o-rings and PEEK backup seals)
Meets NACE-0175 requirements (>175° F)
**The values of tensile, burst, and collapse strength are calculated with new tool conditions, Lame's formulas with Von-Mise's Distortion Energy Theory for burst and collapse strength, and stress area calculations for tensile strength.
***Pressure rating is defined as the differential pressure at the tool. (Differential pressure is the difference in pressure between the casing annulus and the tool ID.)
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LPR-N Tester Valve

The LPR-N tester valve is a full-opening, annulus pressure-operated valve. It measures multiple closed-in pressures in cased holes where pipe manipulation is restricted and a full-opening string is required. The nitrogen chamber is charged at the surface to a selected pressure determined by surface temperature, bottomhole temperature, and bottomhole pressure. If the intended test requires a permanent packer that uses a stinger mandrel or seal nipple, a variety of bypass tools are available, depending on field application, to help ensure that the formations and downhole equipment are protected from excessive pressure buildup.

Features and Benefits

- The ball valve operates independently of internal pressure changes, such as with acidizing or fracturing operations.
- Advanced materials and processes provide a unique metal-to-metal seat for exceptional gas-holding capabilities.
- The LPR-N tester valve has been through an extensive five-day qualification testing at 400°F and 15,000 psi burst and collapse pressures.
- An open-in feature allows the operator to run the LPR-N tester in the hole with the ball valve opened or closed.
- Fluids can be spotted or circulated through the LPR-N tester with the packer unseated.

A double nitrogen chamber can be added to the LPR-N tester for use in deep, hot, high-pressure wells to reduce the operating pressure.

Operation

The LPR-N tester valve is composed of a ball valve section, a power section, and a metering section.

The ball valve section provides multiple downhole closures. It is turned by operating arms. The power section has a floating piston that is exposed to the hydrostatic pressure on one side and pressurized nitrogen on the other side. With the packer set, pump pressure applied to the annulus moves the piston downward, activates the operating arms, and opens the ball valve. When the annulus pressure is released, pressurized nitrogen returns the piston upward, closing the ball.

After the surface equipment is properly installed, the packer is set, and the rams are closed, pressure is applied to the annulus, using rig pumps to operate the LPR-N tester valve.

To begin testing, quickly apply pump pressure to the annulus to a predetermined pressure, and hold for 10 minutes to pressurize the nitrogen chamber After pressure has been metered through the metering cartridge, pressure in the nitrogen chamber will be slightly less than combined hydrostatic and pump pressure in the annulus. This helps ensure that the ball valve stays open during testing or treating operations.

The dosing force may be increased on wells with an extremely high flow rate and wells producing a large amount of sand. Before the tool is closed, the annulus pressure is increased to a predetermined safe pressure below the operating pressure of the circulating valve and held for 10 minutes. This procedure creates additional closing force when the annulus pressure is released.

Releasing the annulus pressure as quickly as possible closes the ball valve. A minimum of 10 minutes is needed to allow excess closing pressure in the nitrogen chamber to equalize before annulus pressure is reapplied. It is best to use the highest safe operating pressure to obtain maximum closing force.

LPR-N Tester Valve

Nominal Tool Size in.	OD in. (cm)	ID in. (cm)	Thread Connections	Service Temperature* ° F(° C)	Length in. (cm)	Tensile Rating** lb (kg)	Working Pressure*** psi (bar)
3 7/8″	3,90	1.77	2 7/8 CAS	400	213.9	328,894	15,000
	(9.91)	(4.50)	2 7/8 UP TBG	(204)	(543.4)	(149 184)	(1034)
5″	5.02	2,24	3 7/8 CAS	400	194.5	438,000	15,255
	(12.75)	(5.70)	NC38(3 1/2 IF)	(204)	(494.0)	(198 674)	(1050)

Meets NACE-0175 requirements (>175° F)

*Service temperature up to 450° F (dressed with 600 series o-rings and PEEK backup seals)

**The values of tensile, burst, and collapse strength are calculated with new tool conditions, Lame's formulas with Von-Mise's Distortion Energy Theory for burst and collapse strength, and stress area calculations for tensile strength.

***Pressure rating is defined as the differential pressure at the tool. (Differential pressure is the difference in pressure between the casing annulus and the tool ID.)

These ratings are guidelines only.

PEEK is a trademark of ICI Americas, Inc. Poly-Ether-Ether-Ketone.

Tubing String Testing (TST) Valve

The tubing string testing (TST) valve is a full-opening valve used to pressure-test the workstring while running in the hole. The valve is operated after it is stung into a permanent packer or after a retrievable packer is set. The TST valve requires a differential pressure between the annulus and the tubing to shear The TST valve can also be used for pipe flexing if it is run below an annulus pressure-responsive circulating valve.

The TST valve consists of:

- flapper valve and spring
- shear pin section
- locking dogs

Features and Benefits

- Flapper valve requires only 4 psi to open.
- Testing string can be pressure-tested as many times as required as it is run in the hole.
- Valve shear rating can be pre-determined at 500 psi increments.
- Valve can also be used for pipe flexing.

Operation

When the TST flapper valve opens, it allows the workstring to fill up. The shear pins hold the mandrel in place. The workstring can be pressure-tested as many times as required as it is run in the hole. While the workstring is stationary; a spring keeps the flapper valve closed. After the workstring pressure test is complete, the tool is sheared when annulus pressure is applied to the predetermined shear pin rating. (The shear rating can be adjusted in 500 psi increments to shear from 500 to 6,000 psi differential.) When the pins shear; the mandrel moves up and pushes the flapper open, allowing the locking dogs to engage. The tool is then fully open. The tool works on differential pressure between annulus and tubing. Failure to shear initially on application of annulus pressure is not critical. The process of drawing the well down also creates a pressure differential that helps the tool shear When used for pipe flexing, the TST valve is run below an annulus pressure-responsive circulating valve, such as the RD circulating valve. The string is pressured up against the flapper valve as many times as required. The circulating valve is sheared after flexing operations are complete, and the workstring is pulled out dry.

Tubing String Testing (TST) Valve

Nominal Tool Size in.	OD in. (cm)	ID in. (cm)	Thread Connections	Length in, (cm)	Tensile Rating** lb (kg)	Working Pressure*** psi (bar)
5″	5.02 (12.75)	2.24 (5.70)	3 7/8 CAS	52.48 (133.3)	481,193 (218 265)	15,255 (1050)

Service temperature up to 450° F (dressed with 600 series o-rings and PEEK backup seals)
Meets NACE-0175 requirements (>175° F)
**The values of tensile, burst, and collapse strength are calculated with new tool conditions, Lame's formulas with Von-Mise's Distortion Energy Theory for burst and collapse strength, and stress area calculations for tensile strength.
***Pressure rating is defined as the differential pressure at the tool. (Differential pressure is the difference in pressure between the casing annulus and the tool ID.)
These ratings are guidelines only.
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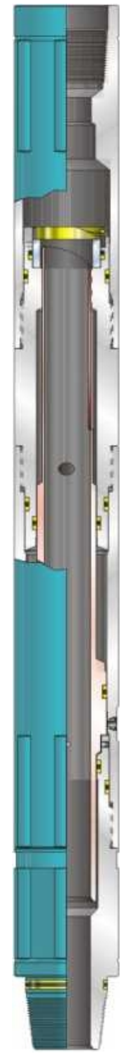
Rupture Disk (RD) Tubing String Testing (TST) Valve



The rupture disk (RD) tubing string testing (TST) valve is a full-opening valve used to pressure test the workstring while running in the hole. The valve is operated after it is stung into a permanent packer or after a retrievable packer is set. *To* operate the tool, annulus pressure is applied, rupturing the disk moving the mandrel up and pushing the flapper open.

The TST valve consists of:

- flapper valve and spring
- shear pin section
- locking dogs

Features and Benefits

-Flapper valve requires only 4 psi to open.

- Workstring can be pressure tested as many times as required as it is run in the hole.
- Valve shear rating can be predetermined by the rupture disk.
- Valve can also be used for pipe flexing.

Operation

The RD TST valve is normally set to operate at a pressure around 1000 psi (69 bar) above well hydrostatic at the tool. This allows the tool to be run in and operated when pressuring up on the first annulus cycle. When the TST flapper valve opens, it allows the workstring to fill up. The shear pins hold the mandrel in place. The workstring can be pressure tested as many times as required as it is run in the hole. While the workstring is stationary, a spring keeps the flapper valve closed. After the workstring pressure test is complete, the tool is sheared open when annulus pressure is applied to rupture the disk moving the mandrel up and pushing the flapper open, allowing the locking dogs to engage. The tool is then fully open.

Rupture Disk (RD) Tubing String Testing (TST) Valve

Nominal Tool Size in.	OD in. (cm)	ID in. (cm)	Thread Connections	Service Temperature*	Length in. (cm)	Tensile Rating** lb (kg)	Working Pressure*** psi (bar)
5″	5.02 (12.75)	2.24 (5.70)	3 7/8 CAS NC38(3 1/2 IF) 3 1/2 UP TBG	400 (204)	69.80 (117.3)	407,844 (213 571)	15,000 (1034)

*Service temperature up to 450° F (dressed with 600 series o-rings and PEEK backup seals)
Meets NACE-0175 requirements (>175° F)
**The values of tensile, burst, and collapse strength are calculated with new tool conditions, Lame's formulas with Von-Mise's Distortion Energy Theory for burst and collapse strength, and stress area calculations for tensile strength.
***Pressure rating is defined as the differential pressure at the tool. (Differential pressure is the difference in pressure between the casing annulus and the tool ID.)
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Rupture Disk (RD) Tubing String Testing (TST) Bypass Valve

The rupture disk (RD) tubing string testing (TST) bypass valve is a weight activated, normally open valve. It is run in the workstring to prevent pressure buildup below the tester valve while stinging into a production type packer or while setting a retrievable packer during a well test. It is a "one shot" type tool that must be removed from the well to re-open it.

Features and Benefits

The tool is composed of three major sections:

- The bypass port section consists of an upper adapter; ported mandrel, and ported nipple. The upper adapter contains two 1/4 NPT ports. Pressure applied to the lower port shifts the ported mandrel up. Pressure applied to the upper port shifts the ported mandrel down. This allows the tool to be pressure tested at the surface prior to going in the well.
- The metering section contains an air chamber and an oil chamber separated by a metering cartridge. Once the tool has been triggered, the operating mandrel in the section moves up, closing the bypass ports. This section provides a 10 to 20 minute delay, depending upon the hydrostatic pressure, in the closure of the ports.
- The trigger section is composed of a rupture disk nipple, splined housing, floating piston, splined mandrel, and lower adapter The splined mandrel, floating piston, and splined housing form a hydraulic ram whenever weight is applied. The resultant pressure is transmitted to a rupture disk in the rupture disk nipple. This prevents any upward movement of the splined mandrel until the correct weight is applied to shear the rupture disk.

Rupture Disk (RD) Tubing String Testing (TST) Bypass Valve

Nominal Tool Size in.	OD in. (cm)	ID in. (cm)	Thread Connections	Service Temperature* ° F(° C)	Length in. (cm)	Collapsed Length in. (cm)	Tensile Rating** lb (kg)	Working Pressure三 psi (bar)	Flow area in.² (cm²)	Number of Ports
5 “	5ˆ03 (12.78)	Z28 (5.79)	3 7/8 CAS	450 (232)	108.22 (274.88)	106.17 (269.67)	195,000 (88 452)	15,000 (1034)	2.14 (13.806)	4

Meets NACE-0175 (>175° F)
*Service temperature up to 450° F (dressed with 600 series o-rings and PEEK backup seals)
**The values of tensile, burst, and collapse strength are calculated with new tool conditions, Lame's formulas with Von-Mise's Distortion Energy Theory for burst and collapse strength, and stress area calculations for tensile strength.
**Pressure rating is defined as the differential pressure at the tool. (Differential pressure is the difference in pressure between the casing annulus and the tool ID.)
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PEEK is a trademark of ICI Americas, Inc. Poly-Ether-Ether-Ketone.

Rupture Disk (RD) Bypass Pressure Test Valve

The rupture disk (RD) bypass pressure test valve is a full-opening, single-shot annulus operated valve. The tool functions as a pressure testing and a bypass valve. The tool is commonly used at the start of a drill stem test to allow the tool string to be pressure tested against the closed ball valve. This tool also has a bypass below the ball that allows the tool string to be "stung in" to a production packer *To* operate the tool, annulus pressure is applied, rupturing the disk, closing the bypass ports, and opening the ball valve.

Features and Benefits

The tool is composed of three sections:

- The ball valve section is at the top of the tool and consists of a ball valve, operating pins, and collet fingers. The collet fingers expand, allowing the power mandrel to continue traveling up to open the ball valve and close the circulating ports.
- The power section consists of a power mandrel case and rupture disk available for a wide range of pressure applications. The rupture disk bursts at a predetermined pressure, allowing annulus pressure to be applied to a differential area on the power mandrel. The power mandrel moves up, first pushing the ball valve open, and then closing a set of circulating ports.
- The bypass section is at the bottom of the tool and consists of a set of ports and a power mandrel. When the rupture disk bursts, the power mandrel moves up, closing off the ports and communication between the annulus and the tool string.

Operation

The rupture disk bypass pressure test valve is normally set to operate at a pressure around 1000 psi (69 bar) above well hydrostatic at the tool. This allows the tool to be run in and then operated when pressuring up on the first annulus pressure cycle.

Another method of running the tool is to use it for pressure testing the tool string and then use well hydrostatic while running in to operate the tool automatically. When running the tool in this mode, it is acceptable to use shear pins to determine the operating pressure. If an accurate operating pressure is required, the rupture disk must be used.

Note: This tool should have the only closed ball valve while running in. If any other closed ball tools are run in the string, a bypass must be run to avoid an air chamber between the closed balls. The air chamber trapped between the balls could cause the tool to not operate, operate a very high pressure, or cause damage to the tool.

Rupture Disk (RD) Bypass Pressure Test Valve

Nominal Taol Size in.	OD in. (cm)	ID in. (cm)	Thread Connections	Service Temperature* ° F(° C)	Length in. (cm)	Tensile Rating** lb (kg)	Working Pressure*** psi (bar)	Flow Area in.² (cm²)	Number of Ports
5	5.03 (12.78)	2.28 (5.79)	3 7/8 CAS	450 (232)	72.44 (184.00)	313,813 (142 352)	15,000 (1034)		4

Meets NACE-0175 (>175° F) for H2S service
*Service temperature up to 450° F (dressed with 600 series o-rings and PEEK backup seals)
**The values of tensile, burst, and collapse strength are calculated with new tool conditions, Lame's formulas with Von-Mise's Distortion Energy Theory for burst and collapse strength, and stress area calculations for tensile strength.
***Pressure rating is defined as the differential pressure at the tool. (Differential pressure is the difference in pressure between the casing annulus and the tool ID.)
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Round Mandrel Slip Joint

The round mandrel slip joint, like other slip joints, accepts the movement associated with ocean heave or temperature change without allowing the movement to disturb the placement of downhole tools.

The round mandrel slip joint has the following characteristics:

- ■ Top of the mandrel slip joint has 4 3/4-in. (120.65-mm) drill collar profile for easy handling with the rig elevators and slips
- ・Maintains its full tensile rating when collapsed and locked
- ■ Can be locked in the closed position for handling, reducing the risk of damage to the lifting/sealing mandrel
- ■ Internally pressure and volume balanced
- ■ String can be picked up with the slip joint locked; the slip joint can then be unlocked before it is run into the hole
- ■ Provides free travel in the string to reciprocate tools without unseating the packer

A slip joint operates by balancing its volume. As the slip joint stretches and increases its internal volume, a differential piston within the slip joint allows the same volume of fluid into the pipe. The net result is no change in internal volume.

Each slip joint has 5 ft (1.52 m) of travel but can be combined with other slip joints to provide additional travel. When multiple slip joints are run, they are normally connected to one another rather than located throughout the pipe string. The number of slip joints required depends on ocean heave and the amount of expected contraction and expansion.

Features and Benefits

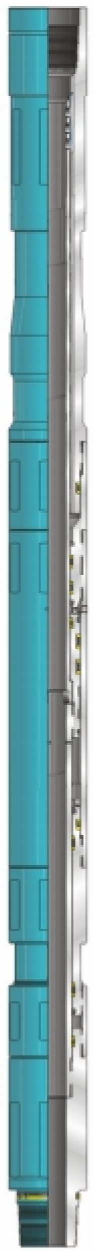
- ■ Provides a variable-length joint to allow the pipe to expand and contract during testing or stimulation
- ■ Keeps vertical movement of the drilling vessel from disturbing tool placement
- ■ Helps space out the testing string when the subsea tree is landed
- ■ Provides a constant weight on the packer during testing or stimulation

Operation

The weight of the tool string (excluding tools, anchor and traveling blocks) is used to determine the location of the slip joint Once the necessary packer-setting weight is shown on the weight indicator; the slip joint is placed into the string.

When multiple slip joints are used, the top joint makes its complete travel, then the next joint down makes its travel, and so on. The weight indicator may show a slight bump as each slip joint reaches the end of its travel.

A pressure test can be performed on the entire 5-ft (1.52-m) length of the sealing mandrel OD.



Round Mandrel Slip Joint

Nominal Tool Size in.	OD in. (cm)	ID in. (cm)	Thread Connections	Service Temperature* °F(°C)	Length in. (cm)	Stroke Length in. (cm)	Tensile Rating** lb (kg)	Working Pressure*** psi (bar)
3 7/8″	3.90 (9.91)	1.77 (4.50)	2 7/8 CAS	400 (204)	184.6 (468.8)	60.00 (152.4)	180.194 (81 735)	15,000 (1034)
5″	5.02 (12.75)	2.24 (5.70)	3 7/8 CAS 3 1/2 IF	400 (204)	184.5 (468.7) 184.0 (467.4)	60.00 (152.4)	296.949 (134 694)	15,000 (1034)

'Add 60.00 in, (1.52 cm) for extended length

Meets NACE-0175 requirements (>175° F)

*Service temperature up to 450° F (dressed with 600 series o-rings and PEEK backup seals)

**The values of tensile, burst, and collapse strength are calculated with new tool conditions, Lame's formulas with Von-Mise's Distortion Energy Theory for burst and collapse strength, and stress area calculations for tensile strength.

***Pressure rating is defined as the differential pressure at the tool. (Differential pressure is the difference in pressure between the casing annulus and the tool ID.)

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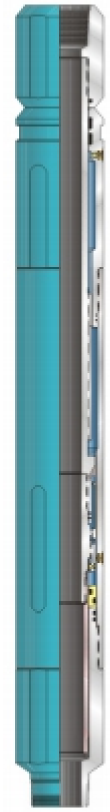
BIG JOHN Hydraulic Jar



The BIG JOHN hydraulic jar is included as part of a tool string to help remove stuck tools.
The jar helps free a stuck tool or toolstring by resisting a pull on the workstring. When the workstring is stretched by the pull, tension in the jar is released and an upward impact is delivered to the stuck tool.

Features and Benefits

- ・ Design of the hydraulic system ensures long life with little maintenance.
- ・ Rig time is reduced.
- ・ Jar can be recocked rapidly.
- ・ Jar time delay is adjustable.
- ・ Amount of pull to trip the jar can be varied within the limits of the time-delay system.

Operation

The temporary resistance that powers the jar is provided by a hydraulic time-delay system. Resistance is released when the metering sleeve inside the jar moves into a bypass section of the outer case. This action allows the special hydraulic oil to bypass rapidly.

The time delay required to release the temporary resistance varies in relation to the weight of the pull. For example, a light pull requires more time for release than a hard pull. When tools below the jar are stuck, a steady pull applied to the jar creates an upward impact blow to the string. The jar can be recocked when the string is set down.

BIG JOHN Hydraulic Jar

Nominal Tool Size in.	OD in. (cm)	ID in. (cm)	Thread Connections	Service Temperature* °F(°C)	Length in. (cm)	Stroke Length in. (cm)	Tensile Rating** lb(kg)	Working Pressure*** psi (bar)
3 7/8″	3.90 (9.91)	1.26 (3.20)	3 1/8 -8 UN	350 (177)	61.97 (157.4)	10.0 (25.4)	232.273 (105 357)	15,255 (1050)
			2 7/8 UP TBG		63.15 (160.4)			
			2 7/8 CAS		64.49 (163.8)			
5″	5.03 (12.75)	2.24 (5.70)	NC38	400 (204)	66.73 (169.5)	10.0 (25.4)	316,296 (143,469)	15,000 (1034)
			3 1/2 IF					
			3 1/2 FH					
			3 7/8 CAS					

[1]Add 10.00 in. (25.40 cm) for extended length for all jars except 3.00 in. For the 3.00 in. jar add 4.43 in. (11.25 cm).

[2]Maximum pull to trip is the pull placed on the jar to trip. Exceeding this pull might cause the metering case to burst or the impact mandrel to part.

[3]Maximum pull is the pull that can be placed on the jar immediately after the jar trips, which may be applied repeatedly without any damage. Any pull greater than this will fatigue the impact mandrel if done repeatedly.

Meets NACE-0175 requirements (>175° F)

*Service temperature up to 450° F (dressed with 600 series o-rings and PEEK backup seals)

**The values of tensile, burst, and collapse strength are calculated with new tool conditions, Lame's formulas with Von-Mise's Distortion Energy Theory for burst and collapse strength, and stress area calculations for tensile strength.

***Pressure rating is defined as the differential pressure at the tool. (Differential pressure is the difference in pressure between the casing annulus and the tool ID.)

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Drain Valve

The drain valve consists of a ported body, sliding sleeve, and rotating nut, which controls the position of the sliding sleeve. The sleeve either covers or exposes the ports in the body of the valve. The drain valve is suitable for sour service at all temperatures. A drain collar and associated components are required when relieving pressure.

Features and Benefits

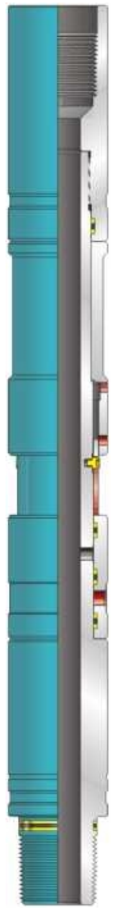
- ■ Allows pressure trapped between two closed valves to be relieved in a controlled manner
- ■ Used to recover large volume fluid samples

Operation

The drain valve is installed between any two valves that may come out of the hole with pressure or fluid trapped between them. Pressure is relieved by installing the drain collar and drain nipples on the drain valve. Valves, lines, or sample bottles may be attached to the drain nipples depending on the desired disposition of the fluid in the string. After the drain collar assembly is attached, the ports in the tool are exposed by using a chain wrench or pipe wrench to rotate the drain nut, which moves the sliding sleeve.

When the ports in the sleeve are aligned with the ports in the body of the tool, the fluid may be drained.

It is also possible to trap a large volume fluid sample between two valves if a sample chamber of some kind (tubing, drill collar; etc.) is placed between the valves. In most cases, the drain valve would be run at the bottom of the sample chamber to facilitate transfer This will not be a PVT sample.



Rupture Disk (RD) FUL-FLO Sampler

The rupture disk (RD) FUL-FLO sampler is a full-open, full bore sleeve sampler for use on drillstem tests. The sampler is controlled by a rupture disk that is operated by annulus pressure.

Features and Benefits

- ・Time-delay feature allows the sample to be trapped after a preset time. Different metering cartridges can be used to vary the closing time.
- ■ Full-open capabilities are retained after the tool has trapped its sample.
- \- Several samplers can be run on a test to allow sampling at different times.

Operation

The FUL-FLO sampler is controlled by a pressure- operated rupture disk and has a sample mandrel with a built-in differential area, lb catch a sample, annulus pressure is increased to a predetermined level, the rupture disk in the sampler breaks, and the mandrel traps the sample.

When the rupture disk breaks, the differential area of the sample mandrel is exposed to an air chamber on one side and hydrostatic pressure and applied annulus pressure on the other. This condition results in the sample mandrel moving up and trapping the sample. When the sample mandrel reaches the top of its stroke, it is locked in place by a set of locking dogs.

The 1,200-cc sample chamber allows a sufficient sample for two 500-cc non-monophasic (bulk) samples.

Drain Valve

Nominal Size in.	OD in. (cm)	ID in, (cm)	Thread Connections	Length in. (cm)	Tensile Rating** lb (kg)	Working Pressure*** psi (bar)
3 7/8″	3.90 (9.91)	1.77 (4.50)	2 7/8 CAS	34.65 (88.0)	357,126 (161 990)	15,000 (1034)
5″	5.02 (12.75)	2.24 (5.70)	3 7/8 CAS	45.63 (115.9)	400,207 (181 531)	15,225 (1050)

Meets NACE-0175 requirements (>175° F)
Service temperature up to 450° F (dressed with 600 series o-rings and PEEK backup seals)
**The values of tensile, burst, and collapse strength are calculated with new tool conditions, Lame's formulas with Von-Mise's Distortion Energy Theory for burst and collapse strength, and stress area calculations for tensile strength.
***Pressure rating is defined as the differential pressure at the tool. (Differential pressure is the difference in pressure between the casing annulus and the tool ID.)
These ratings are guidelines only.
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Rupture Disk (RD) FUL-FLO Sampler

Nominal Tool Size in.	OD in. (cm)	ID in. (cm)	Thread Connections	Length in. (cm)	Tensile Rating** lb (kg)	Working Pressure*** psi (bar)	Sample Volume cc
3 7/8″	3.90 (9.91)	1.77 (4.50)	2 7/8 CAS	125.5 (318.8)	301,450 (136 735)	15,225 (1050)	1,200
5″	5.02 (12.75)	2.24 (5.70)	3 7/8 CAS 3 1/2 IF	86.54 (219.8)	543, 732 (246 633)	15,000 (1034)	1,200

Service temperature up to 450° F (dressed with 600 series o-rings and PEEK backup seals)
Full sour gas service
**The values of tensile, burst, and collapse strength are calculated with new tool conditions, Lame's formulas with Von-Mise's Distortion Energy Theory for burst and collapse strength, and stress area calculations for tensile strength.
***Pressure rating is defined as the differential pressure at the tool. (Differential pressure is the difference in pressure between the casing annulus and the tool ID.)
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Shock Absorber

Halliburton offers two types of shock absorbers:

■ Vertical

Radial

Shock absorbers protect pressure-measuring equipment or other sensitive components in the workstring for shock loads transmitted through the workstring by firing of TCP guns.

Operation

The vertical shock absorber is designed to protect pressure measuring components from vertical shock loads and is normally run below the packer It is always run between the gauge carrier and perforating guns. It is recommended that the vertical shock absorber be run in conjunction with a drag block assembly for effective shock absorption.

A vertical shock absorber is available with a blank ID. When run in the workstring, this absorber is located below the TCP guns and above the gauges.

In radial shock absorbers, spring-loaded drag blocks absorb radial shock waves transmitted through the workstring. The drag block assembly is located below the packer and between the gauges and TCP guns.

Vertical Shock Absorber

Nominal Tool size in.	OD in. (cm)	ID in. (cm)	Thread Connections	Service Temperature* ° F(° C)	Length in. (cm)	Tensile Rating** lb (kg)	Working Pressure*** lb (bar)
3 7/8"	3,90 (9.91)	1.77 (4.50)	2 7/8 CAS	400 (204)	63,38 (161.0)	133,852 (60 714)	15,000 (1034)
			2 7/8 EUE		60,43 (153.5)		
5"	5,02 (12.75)	2.24 (5.70)	3 1/2 IF	400 (204)	62,80 (159.5)	258,931 (117 449)	15,000 (1034)
			3 7/8 CAS		63,38 (161.0)		

Radial Shock Absorber

Nominal Tool size in.	OD in. (cm)	ID in. (mm)	Thread Connections	Length in. (cm)	Tensile Rating** lb (kg)	Working Pressure*** psi (bar)	Casing Size Range in./lb
3 7/8"	5. 79 (14.70)	1.77 (4.50)	2 7/8 CAS	46.65 (118.5)	133,852 (60714)	Burst 19,575 (1350) Collapse 18125 (1250)	5 1/2" 6 5/8"
			2 7/8 EUE				13 to 23 28 to 32
7"	5. 34 (16.10)	2.24 (5.70)	3 1/2 IF	46.08 (117.05)	202,465 (91 837)	Burst 22,823 (1574) Collapse 20,982 (1447)	T 7 5/8"
			3 7/8 CAS				
			2 7/8 EUE				17 to 23 39 to 45.3

Meets NACE-0175 requirements [175° F (79° C)]

*Service temperature up to 450° F (dressed with 600 series o-rings and PEEK backup seals)

The tensile strength value is calculated with new tool conditions. Stress area calculations are used to calculate tensile strength,

**Pressure rating is defined as the differential pressure at the tool. (Differential pressure is the difference in pressure between the casing annulus and the tool ID.)

***The values of tensile, burst, and collapse are calculated using new tool conditions at ambient conditions, Lame's formula for burst and collapse, and stress area calculations for tensile.

These ratings are guidelines only.

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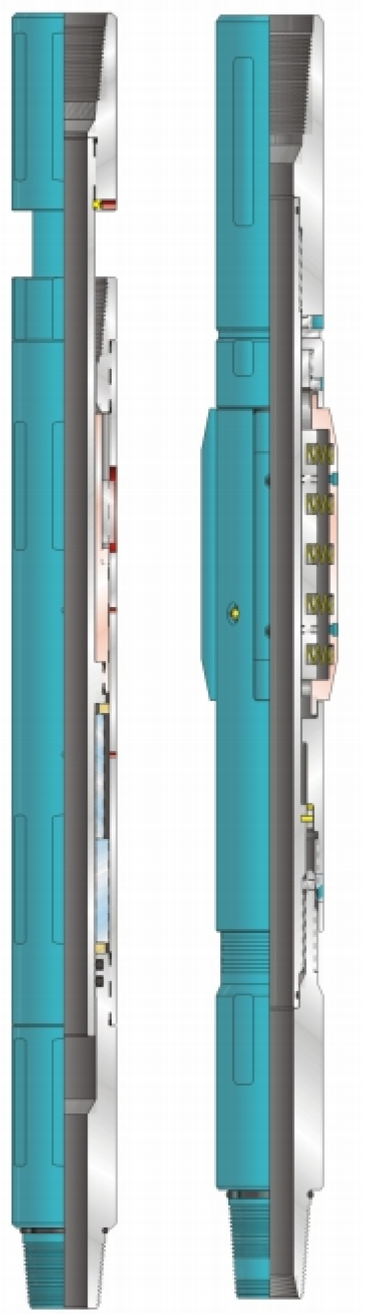
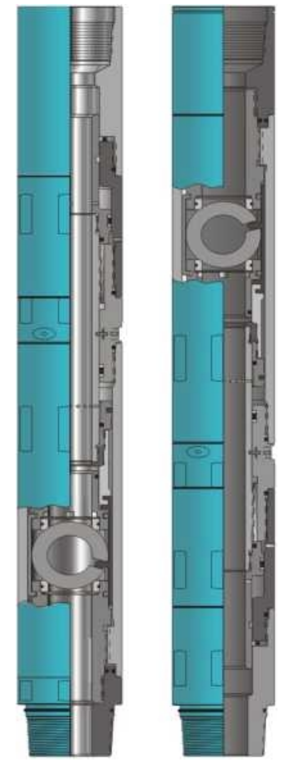


Pressure-Responsive (PR) Multi-Service Valve

The pressure-responsive (PR) multi-service valve is a full-opening, annulus pressure-operated valve for use in cased holes. This tool can be run as a surge valve or backpressure valve.

lop and bottom PR multi-service valves are run at the same time to form a surge chamber This surge helps clean debris from the perforations before a stimulation treatment, sand control treatment, or flow test.

Potential for sudden pressure surge is provided when two multi-service valves are spaced apart in the tubing string to form an atmospheric air chamber When the bottom ball valve is opened, solids forced into the perforations are swept into the air chamber by the fluid stage.



Features and Benefits

■ Requires no pipe manipulation to operate

■ Achieves more effective surge because of the instant ball opening

■ Creates the required air chamber volume by spacing valves

・Allows circulating or spotting of well fluid when surging is complete

■ Permits through-tubing operation through full-opening ID

Operation

As PR multi-service valves are run into a well, the ball valves are in a closed position, and atmospheric air is trapped between the valves. The bottom valve is opened by the operating piston, which has one side exposed to the annulus pressure above the packer and the other side exposed to pressure below the packer

After the packer has been set, pressure applied to the annulus moves the piston downward to pull the ball into the open position. The locking dogs drop into a groove, keeping the ball in the fully open position.

As long as the tubing pressure is equal to or greater than the annulus pressure, the top valve is kept closed when the lower valve is operated.

Before the top valve can be opened, tubing pressure must be relieved while the annulus pressure is maintained. The top PR multi-service valve also contains locking dogs that lock the ball in the fully open position. After the valves have been opened, circulation can occur with the packer unseated.

Opening pressure is controlled by the shear pins. The number and type of shear pins can be adjusted to raise or lower the operating pressure.

Pressure-Responsive (PR) Multi-Service Valve

Tool Size in.	OD in. (cm)	ID in. (cm)	End Connections	Length in. (cm)	Tensile Rating** lb(kg)	Burst Rating** psi (kPa)	Collapse Rating** psi (kPa)
3 7/8"	3.90 (9.91)	1.77 (4.50)	2 7/8 CAS	63,54 (161.4)	236,210 (107 143)	18,460 (127 300)	17,490 (120 600)

Meets NACE-0175 requirements (>175° F)

Service temperature up to 450° F (dressed with 600 series o-rings and PEEK backup seals)

**The values of tensile, burst, and collapse strength are calculated with new tool conditions, Lame's formulas with Von-Mise's Distortion Energy Theory for burst and collapse strength, and stress area calculations for tensile strength.

Pressure rating is defined as the differential pressure at the tool. (Differential pressure is the difference in pressure between the casing annulus and the tool ID.)

These ratings are guidelines only.

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