Technology Alliance with Packers Plus
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<td>StackFRAC (SF) Ball</td>
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</tr>
</tbody>
</table>
Packers Plus provides multistage completion systems and solutions for challenging applications in horizontal, vertical, multilateral, and HPHT wells. Innovation remains critical to the company’s success as it continues adapting to industry demand in Canada, the United States, and internationally. Having completed >240,000 stages in more than 16,000 wells, Packers Plus is a key player in this important market segment.

Schlumberger is the world’s leading provider of technology for reservoir characterization, drilling, production, and processing to the oil and gas industry. Working in more than 85 countries, Schlumberger supplies the industry’s most comprehensive range of products and services, from exploration through production and integrated pore-to-pipeline solutions for hydrocarbon recovery that optimize reservoir performance.

Packers Plus and Schlumberger have worked together outside North America since 2005 with a shared commitment to operational excellence, innovation, and customer service. In 2016 the two companies formalized this alliance, combining their multistage completion portfolios to address more effectively the wide range of challenges facing customers in this growing market. The alliance will operate in all international markets outside North America.
Multistage Stimulation
The Diamondback® composite drillable frac plug is designed to isolate zones in vertical, deviated, and horizontal wells during multistage stimulation. During millout, its antirotation features transmit torque and prevent spinning of components, increasing penetration rate and reducing debris size.

An optional pumpdown ring minimizes the fluid needed to transport the plug to depth, and rigid slips and an internal shear ring prevent presetting. A one-way internal check valve is closed with a ball dropped from the surface while the zone above the plug is being fractured. The check valve allows free flow of fluids from below the plug after stimulation.

The plug can be set using wireline, coiled tubing, or threaded pipe. It is designed to be drilled out quickly into small cuttings that can be easily circulated out of the well. A special mule shoe at the end of the plug prevents spinning during millout, reducing overall millout time.

Milling recommendations
This composite plug can be milled with most commonly available mills. A five-bladed, reverse-clutch junk mill dressed with starcut carbide provides the best results. The material enables the plug to be milled out into small cuttings that can be easily circulated out of the well. The plug’s design prevents spinning during the milling operation, reducing overall millout time.
<table>
<thead>
<tr>
<th>Casing Size, in [mm]</th>
<th>Casing Weight, lbm/ft [kg/m]</th>
<th>Plug OD, in [mm]</th>
<th>Min. ID, in [mm]</th>
<th>Ball Diameter, in [mm]</th>
<th>Length, in [mm]</th>
<th>Pressure Rating, psi [kPa]</th>
<th>Temp. Rating, degF [degC]</th>
<th>Pumpdown Ring</th>
</tr>
</thead>
</table>

†Available on request
Copperhead
Drillable bridge and frac plugs

APPLICATIONS
- Vertical, deviated, and horizontal wells
- Zone isolation applications during multistage stimulation

BENEFITS
- Eliminates presetting and withstands multiple pressure reversals to reduce rig time and costs

FEATURES
- Nondegradable aluminum material
- Unique activation system to allow for a superior seal even under multiple pressure and temperature cycles
- Proprietary slip design to keep wickers from chipping or cracking in hard steel casing and slipping in softer steel casing
- Element backup system to keep rubber element locked in place with no protrusion
- Rotational lock mechanism to prevent slipping or spinning during removal
- Positive engagement clutch to prevent spinning of bottom sub on top of the next plug in multiple-plug drillout
- Ratings to 15,000 psi [103,421 kPa] and 400 degF [204 degC]

The Copperhead* drillable bridge and frac plug is most commonly used to isolate zones during multistage stimulation. The Copperhead Extreme* drillable bridge and frac plug can be used in high-pressure and high-temperature reservoirs that are likely to have high fracturing pressures.

Both bridge plugs have a solid core that allows them to hold pressure from both directions. A one-way, internal check valve allows the free flow of fluids from below the plug after stimulation.

Copperhead drillable bridge and frac plugs are designed to withstand pressures up to 15,000 psi [103,421 kPa] and temperatures up to 400 degF [204 degC].

Plug components can be drilled out quickly by the Copperhead plug mill into small, consistently sized cuttings that can be easily circulated out of the well. These bridge plugs can be set using wireline, coiled tubing, or threaded tubing.
### Copperhead Plug Specifications

<table>
<thead>
<tr>
<th>Casing Size, in [mm]</th>
<th>Casing Weight, lbm/ft [kg/m]</th>
<th>Max. OD, in [mm]</th>
<th>Pressure Rating, psi [kPa]</th>
<th>Temperature Rating, degF [degC]</th>
</tr>
</thead>
<tbody>
<tr>
<td>3.5 [88.9]</td>
<td>12.95 [19.27]</td>
<td>2.562 [65.08]</td>
<td>10,000 [68,945]</td>
<td>350 [175]</td>
</tr>
<tr>
<td>7 [177.8]</td>
<td>20–26 [29.76–38.69]</td>
<td>6.0 [152.4]</td>
<td>10,000 [68,945]</td>
<td>350 [175]</td>
</tr>
<tr>
<td>7 [177.8]</td>
<td>26–35 [38.69–52.08]</td>
<td>5.75 [146.05]</td>
<td>10,000 [68,945]</td>
<td>350 [175]</td>
</tr>
</tbody>
</table>

### Copperhead Extreme Plug Specifications

<table>
<thead>
<tr>
<th>Casing Size, in [mm]</th>
<th>Casing Weight, lbm/ft [kg/m]</th>
<th>Max. OD, in [mm]</th>
<th>Pressure Rating, psi [kPa]</th>
<th>Temperature Rating, degF [degC]</th>
</tr>
</thead>
<tbody>
<tr>
<td>4.5 [114.3]</td>
<td>15.1 [22.47]</td>
<td>3.44 [87.34]</td>
<td>13,000 [89,630]</td>
<td>400 [205]</td>
</tr>
<tr>
<td>4.5 [114.3]</td>
<td>16.6–18.9 [24.7–27.1]</td>
<td>3.44 [87.34]</td>
<td>15,000 [103,420]</td>
<td>400 [205]</td>
</tr>
<tr>
<td>5 [127]</td>
<td>23.2–24.2 [34.52–36.01]</td>
<td>3.77 [95.76]</td>
<td>15,000 [103,420]</td>
<td>400 [205]</td>
</tr>
<tr>
<td>5.5 [139.7]</td>
<td>26 [38.69]</td>
<td>4.25 [108.00]</td>
<td>15,000 [103,420]</td>
<td>400 [205]</td>
</tr>
</tbody>
</table>
Copperhead Big Bore
Flow-through frac plug

APPLICATIONS
- Horizontal extended-reach and deep wells where the use of coiled tubing is not feasible
- Plug-and-perf operations
- Multistage fracturing operations

BENEFITS
- Minimizes risk and cost of intervention using frac balls made of ELEMENTAL* degradable technology
- Eliminates milling interventions in wellbore after fracturing job
- Reduces completion costs by eliminating the need for coiled tubing
- Facilitates tubing interventions later if wellbore cleanup becomes necessary
- Minimizes cost of completion and time at location
- Allows for deeper installation of plugs in all well types

FEATURES
- Large flow-through ID for interventionless flowback after fracturing and production
- Antipreset ring to prevent early setting of the plug during installation
- Ability to be set using wireline, coiled tubing, or jointed pipe
- High-strength frac balls made of ELEMENTAL technology for fracturing at higher pressures and longer intervals
- Compatibility with ELEMENTAL technology to provide fullbore production and remove the need for millout operations

The Copperhead Big Bore® flow-through frac plug is a cast-iron frac plug with a large flow-through ID that allows fluids to flow freely from below the plug after stimulation. It features a high-strength frac ball made of ELEMENTAL degradable technology, and it is most commonly used to isolate zones during multistage stimulation. Copperhead Big Bore frac plugs can be set using wireline, coiled tubing, or jointed pipe.

Antipreset ring
A proprietary antipreset ring prevents early setting of the plug during installation.

Higher-pressure fracturing
Once the degradable frac ball is dropped from the surface, the Copperhead Big Bore frac plug holds pressure up to 10,000 psi [68,947 kPa] for up to 8 hours. The aluminum alloy frac balls dissolve completely, even in wells with temperatures as low as 100 degF [37.78 degC].

No milling out
The design of the Copperhead Big Bore frac plug ensures the flow path remains open after the degradable frac ball has dissolved, eliminating the need for millout operations.

Copperhead Big Bore Frac Plug Specifications

<table>
<thead>
<tr>
<th>Casing Size, in [mm]</th>
<th>Casing Weight Range, lbm/ft [kg/m]</th>
<th>Max. OD, in [mm]</th>
<th>Min. ID, in [mm]</th>
<th>Length, in [mm]</th>
<th>Pressure Rating, psi [kPa]</th>
<th>Temperature Rating, degF [degC]</th>
</tr>
</thead>
<tbody>
<tr>
<td>5.5 [139.70]</td>
<td>20.0–23.0 [29.76–34.23]</td>
<td>4.44</td>
<td>3.00</td>
<td>18.8</td>
<td>10,000 [68,947]</td>
<td>350 [177]</td>
</tr>
</tbody>
</table>
Copperhead Mill
Single-trip plug-removal device

APPLICATIONS
- Removal of Copperhead® drillable bridge and frac plugs from vertical, deviated, and horizontal wells

BENEFITS
- Elimination of multiple millout trips saves time and reduces costs.
- Small, consistently sized cuttings minimize plug removal time.

FEATURES
- Reduced weight on bit and wear on mill
- Consistent millout times
- Serrated and flat blade combination for constant milling rate
- Large bypass and flow-through features to facilitate cuttings removal
- Tungsten carbide buttons on outer surface for gauge maintenance

The Copperhead mill can remove all Copperhead plugs in a single trip downhole. The tool is designed to simulate the action of a machine shop lathe. A serrated blade cuts grooves in the aluminum and a flat blade follows it, flattening the peaks. This process occurs three times per rotation. The mill cuts into the metal instead of crushing it, producing small, consistently sized, lightweight cuttings that can be circulated out of the well, keeping the mill face clean. The mill’s bypass and flow-through features also facilitate cuttings removal.

The design of the mill minimizes the required weight on bit (WOB), improving millout time in long, horizontal sections where friction limits the weight that can be transmitted to the bit. Tungsten carbide buttons on the outer surface keep the mill OD in gauge during the milling of multiple plugs, preventing coring of the plugs, and also protect the casing from damage.

Copperhead Mill Sizes

<table>
<thead>
<tr>
<th>Casing Size, in [mm]</th>
<th>Casing Weight, lbm/ft [kg/m]</th>
<th>Mill OD, in [mm]</th>
</tr>
</thead>
<tbody>
<tr>
<td>2.875 [73]</td>
<td>6.5 [9.67]</td>
<td>2.25 [57.15]</td>
</tr>
<tr>
<td></td>
<td>7.8–8.7 [11.76–12.95]</td>
<td>2.125 [53.98]</td>
</tr>
<tr>
<td>3.5 [88.9]</td>
<td>9.3–10.3 [13.84–15.33]</td>
<td>2.72 [69.09]</td>
</tr>
<tr>
<td></td>
<td>12.95 [19.27]</td>
<td>2.562 [65.08]</td>
</tr>
<tr>
<td>4.5 [114.3]</td>
<td>11.6–15.1 [17.26–22.47]</td>
<td>3.625 [92.08]</td>
</tr>
<tr>
<td></td>
<td>15.1–17 [22.47–25.33]</td>
<td>3.5 [88.90]</td>
</tr>
<tr>
<td></td>
<td>21.6 [32.14]</td>
<td>3.25 [82.55]</td>
</tr>
<tr>
<td>5.0 [127]</td>
<td>18–21.4 [26.78–31.84]</td>
<td>3.875 [98.43]</td>
</tr>
<tr>
<td></td>
<td>23.2–24.2 [34.52–36.01]</td>
<td>3.75 [95.25]</td>
</tr>
<tr>
<td>5.5 [139.7]</td>
<td>15.5–17 [23.07–25.30]</td>
<td>4.625 [117.48]</td>
</tr>
<tr>
<td></td>
<td>20–23 [29.76–34.23]</td>
<td>4.415 [112.14]</td>
</tr>
<tr>
<td>7.0 [177.8]</td>
<td>20–26 [29.76–38.69]</td>
<td>6 [152.4]</td>
</tr>
<tr>
<td></td>
<td>26–35 [38.69–52.08]</td>
<td>5.75 [146.05]</td>
</tr>
</tbody>
</table>
ELEMENTAL
Degradable technology frac balls

APPLICATION
- Temporary isolation of zones during multistage stimulation operations in cemented and uncemented wells

BENEFITS
- Unrestricted flow after stimulation, ensuring that production reaches its full potential
- Uninterrupted operations that accelerate time to production
- Degradable technology that minimizes risk of lost production due to stuck balls
- Elimination of interventions to remove frac balls, saving time and costs and minimizing QHSE risks

FEATURES
- Proprietary degradable alloy that is stronger than conventional alloys
- Compatibility with brine and other common water-based stimulation fluids, including slickwater, linear gel, cross-linked gel, and foams
- Ability to hold pressure under a broad range of bottomhole conditions
- Ability to withstand differential pressures up to 10,000 psi (69 MPa) and temperatures up to 300 degF (150 degC)
- Predictable degradability based on fluid and downhole conditions

ELEMENTAL* degradable technology frac balls are designed for multistage stimulation operations in cemented and uncemented wells. The balls degrade predictably and fully at bottomhole conditions—with the need for chemical additives, an acidic environment, retrieval operations, or milling after fracturing. No production is lost after stimulation as a result of stuck balls, which ensures that production always reaches its full potential.

Patented alloy dissolves within hours
Frac balls made with ELEMENTAL technology are composed of a proprietary aluminum-based material that is stronger than conventional alloys. It uses microgalvanic electrochemical cells that derive electrical energy from a spontaneous redox reaction taking place within the cells. This oxidation-reduction reaction accelerates the dissolution process, allowing the material to fully degrade within hours or days, depending on ball size and downhole conditions. The degradation by-product, a fine powder (micrometer scale), is environmentally safe and does not interfere with production.

Degradability is highly predictable
Extensive testing at a wide range of temperatures and pressures showed that the material made with ELEMENTAL technology degrades predictably in common water-based stimulation fluids such as brines, slick water, and cross-linked fluids. Water alone causes the balls to fully degrade in a matter of hours to a few days, even under very low temperatures, without the need for acid or other additives.

Predictive models aid planning
Mathematical models based on fluid and downhole conditions are used to predict degradation time and facilitate planning for a wide variety of downhole conditions.

![Rate of Ball Degradation by Temperature](chart)

ELEMENTAL technology balls degrade predictably in a wide variety of downhole conditions. In temperatures > 250 degF (121 degC), for example, disintegration takes place in 12 hours or less, depending on downhole conditions.
Degradable balls are compatible with existing systems

Degradable balls used with the Falcon* and nZone* multistage stimulation systems and Copperhead* drillable bridge and flow-through frac plugs enable high-stage-count jobs to be carried out in both cemented and uncemented wells by eliminating the need to mill out any balls that do not flow back during the cleanup stage.

**ELEMENTAL Degradable Technology Ball Specifications**

<table>
<thead>
<tr>
<th>Specification</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Working temperature range, degF [degC]†</td>
<td>75–300 [23.9–148.9]</td>
</tr>
<tr>
<td>Max. differential pressure, psi [MPa]</td>
<td>10,000 [68.948]</td>
</tr>
<tr>
<td>Fluid compatibilities</td>
<td>Water-based fluids, guar-based gel, 15% HCl (acid spearhead)</td>
</tr>
<tr>
<td>Ball material</td>
<td>Degradable aluminum-based alloy</td>
</tr>
<tr>
<td>Specific gravity</td>
<td>2.6</td>
</tr>
</tbody>
</table>

†Reservoir temperature may be higher, depending on application, once cool-down effect is considered.

Microgalvanic electrochemical cells in the alloy made with ELEMENTAL technology derive their electrical energy from a spontaneous chemical reaction taking place in the cells. This oxidation-reduction reaction accelerates the dissolution process, allowing the balls to fully degrade within hours or days, depending on variables such as ball size and downhole conditions.
The KickStart™ rupture disc valve is the first tool in a multistage stimulation string. It eliminates the need for coiled tubing—or tubing-conveyed perforating in the first stage, offering a more efficient and cost-effective method of starting the fracturing process.

The valve is run to the toe of the well as part of the casing string. Increasing the casing pressure to a predetermined value causes the valve’s rupture discs to burst, shifting a sliding sleeve and opening the valve, thereby exposing the formation to the fracturing fluid. The first stimulation treatment can begin and subsequent pumpdown operations can follow.

**Greater reliability through redundant rupture discs**
Each KickStart valve features two rupture discs, placed 180° apart. The system has full redundancy as only one of the two discs must rupture to activate the sliding sleeve. Rupture discs are available in 250- to 300-psi pressure increments and can be installed at the wellsite.

**Reduced fracture initiation pressure**
The valve’s helical exit ports have been specifically designed to reduce the fracture initiation pressure and to provide 360° coverage so that fractures are initiated in the preferred plane.

**Enhanced operational safety via dissolvable technology**
Usually, the casing is pressure tested and then the pressure increased still further to burst the rupture discs. Introduction of ELEMENTAL degradable technology has enabled the valve opening pressure to be set below the maximum casing test pressure. After the valve opens, a ball is dropped from the surface to land on a seat above the valve, sealing off the valve so that the casing above can be tested to the desired pressure. The ball is made using ELEMENTAL technology and soon dissolves completely, enabling the fracturing operation to resume.

### KickStart Valve Specifications

<table>
<thead>
<tr>
<th>Size, in [mm]</th>
<th>Min. Openhole Size, in [mm]</th>
<th>Min. ID, in [mm]</th>
<th>Max. OD, in [mm]</th>
<th>Area Open to Flow, in² [cm²]</th>
<th>Ball Size OD, in [mm]</th>
</tr>
</thead>
<tbody>
<tr>
<td>4.5 [114.3]</td>
<td>5.875 (149.225)</td>
<td>3.25 (82.55)</td>
<td>5.625 (142.875)</td>
<td>10.5 [67.7]</td>
<td>3.657 [92.887]</td>
</tr>
<tr>
<td>5 [127]</td>
<td>5.875 (149.225)</td>
<td>3.25 (82.55)</td>
<td>5.625 (142.875)</td>
<td>10.5 [67.7]</td>
<td>3.657 [92.887]</td>
</tr>
<tr>
<td>5.5 [139.7]</td>
<td>7.875 (200.025)</td>
<td>4.61 (117.09)</td>
<td>7.61 [193.29]</td>
<td>15.6 [100.6]</td>
<td>4.533 [115,138]</td>
</tr>
</tbody>
</table>

† Max. OD for 5.5-in valve is not measured around the valve circumference but only at two points: 3 in long and 4.25 in wide; nominal OD is 7 in.

### KickStart Valve Operating Ratings

<table>
<thead>
<tr>
<th></th>
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</tr>
</thead>
<tbody>
<tr>
<td>4.5 [114.3]</td>
<td>350 [177]</td>
<td>10,000 [69]</td>
<td>20,000 [138]</td>
<td>15,000 [103]</td>
<td>10,000 [13,558]</td>
</tr>
<tr>
<td>5.5 [139.7]</td>
<td>325 [163]</td>
<td>10,000 [69]</td>
<td>20,000 [138]</td>
<td>12,000 [83]</td>
<td>15,000 [20,337]</td>
</tr>
<tr>
<td>5.5 [139.7]</td>
<td>350 [177]</td>
<td>10,000 [69]</td>
<td>15,000 [103]</td>
<td>12,500 [86]</td>
<td>15,000 [20,337]</td>
</tr>
</tbody>
</table>
Applications
- Openhole and cased hole wells
- Multistage fracturing
- Reservoir compartmentalization
- Flowing wells with inflow control devices
- Straddle assemblies
- Cement replacement
- Annular barrier for sand screens

Benefits
- Single-trip installation minimizes rig time, installation risks, and costs.
- Delayed swelling feature reduces risk of premature setting.
- Bonding and shorter element enhance well integrity.

Features
- Elastomer bonded directly onto basepipe
- Increased pressure rating per foot
- No moving parts
- Durable, self-healing and self-sealing construction
- Time-delayed reactive filler for improved mechanical stiffening properties
- Tuned curing process for balanced swell kinetics
- Maximized swelling capability due to pipe bonding
- Shorter element lengths, which are better able to traverse tight openhole sections and lateral transitions
- Associated predictor software for product selection and job planning

The ResPack® swellable bonded-to-pipe packer is designed to swell on contact with fluid and expand to seal the annulus around the pipe. The elastomer is bonded directly onto the basepipe. The packer has no moving parts and is installed in a single trip; no special personnel or equipment is required. Applications range from well construction to completion in both openhole and cased hole wells.

Swelling mechanism
The packer element, which is shorter than typical packer elements, is engineered from a complex polymer that has properties similar to those of rubber before swelling. After swelling, the polymer and shorter element allow the packer to achieve the higher differential pressure and temperature ratings required in high-pressure applications such as multistage fracturing and sealing in flowing wells; the packer remains pliant enough to accommodate washouts and irregular wellbores.

The packer is available with elements that swell in either oil or water.

Oil-swellable packer
An integral delay mechanism engineered into the polymer of the oil-swellable packer minimizes the risk of premature swelling and setting without the need for any additional exterior coating. Hydrocarbon molecules diffuse into the elastomer matrix to generate volumetric expansion.

Water-swellable packer
In the water swellable packer, reactive fillers integrated into the elastomer prevent the loss of strength and the deswelling effects seen in conventional water-swellable packers, which rely solely on osmosis for swelling. Osmosis can reverse over time, causing other packers to deswell and leak. The proprietary reactive technology, however, is based on an irreversible chemical reaction that mechanically reinforces the elastomer and enables higher differential pressures to be withstood by shorter lengths. This unique-to-Schlumberger technology enables higher pressure ratings per foot than for conventional water swellable packers.
Sizes and ratings
ResPack packers are provided in sizes ranging from 2 3/8 in to 13 3/8 in. They have a wide temperature range, from 100 to 365 degF [37 to 185 degC] and a differential pressure rating of up to 15,000 psi [103 MPa], the highest psi/ft rating in the industry.

Swelling to first seal
Swelling starts immediately after contact with the fluid (oil for the oil-swellable packer and water for the water-swellable packer) and progresses in small increments, enabling the packer to reach the target setting depth, where it continues to swell and seal.

Stringent qualifications
Our packers undergo full-scale highly accelerated life cycle testing and are qualified to rigorous standards. Elastomers are tested in high concentrations of hydrogen sulfide (H₂S), hydrochloric acid (HCl), and carbon dioxide (CO₂) at simulated downhole temperatures and pressures.

Swell-prediction software
Proprietary Schlumberger software is used to evaluate packer performance in various well environments. The software predicts the estimated swell time and pressure ratings for a certain hole ID. The results are used to select the appropriate packer and minimize risks during deployment.
The ResPack Slip® swellable slip-on packer is designed to swell on contact with oil and expand to seal the annulus around the pipe in both openhole and cased hole wells. It is designed to be slipped onto the completion tubular and anchored with locking gauge rings. The packer has no moving parts and is installed in a single trip; no special personnel or equipment is required. Applications range from well construction to completion.

**Modular assembly**
The modular ResPack Slip packer assembly enables operators to stock only one product for each completion size. It is available with a single element for applications requiring inflow control devices and with spaced elements for increased wellbore contact.

**Swelling mechanism**
The packer element is engineered from a complex polymer with properties similar to those of rubber; after swelling, however, the polymer’s mechanical properties make it better suited for coping with high-pressure applications and sealing in flowing wells, though it remains pliant enough to control washouts and to seal in irregular wellbores.

An integral delay mechanism engineered into the polymer of the oil-swellable packer minimizes the risk of premature swelling and setting without the need for any additional exterior coating. Hydrocarbon molecules diffuse into the elastomer matrix to generate volumetric expansion.

The ResPack Slip packer’s modular design, which includes options for (top to bottom) single, stacked, and spaced elements, enables operators to stock only one product for each completion size.
ResPack Slip packers are provided in sizes ranging from 3½ to 7 in (88.9 to 177.8 mm). They have a wide temperature range, from 100 to 365 degF [37 to 185 degC] and a differential pressure rating of up to 3,000 psi [20.7 MPa].

**Swelling to first seal**
Swelling starts immediately after contact with oil and progresses in small increments, enabling the packer to reach the target setting depth, where it continues to swell and seal.

**Stringent qualifications**
Our packers undergo full-scale highly accelerated life cycle testing and are qualified to rigorous standards. Elastomers are tested in high concentrations of hydrogen sulfide (H₂S), hydrochloric acid (HCl), and carbon dioxide (CO₂) at simulated downhole temperatures and pressures.

**Swell-prediction software**
Proprietary Schlumberger software is used to evaluate packer performance in various well environments. The software predicts the estimated swell time and pressure ratings for a certain hole ID. The results are used to select the appropriate packer and minimize risks during deployment.
ResFlow SP and ResFlow MP
Single-position sleeve ICD and multiposition sleeve ICD

APPLICATIONS FOR RESFLOW SP
- Wells with direct vertical access
- Multizone openhole completions with hydraulic-set packers

BENEFITS OF RESFLOW SP
- Cost-effective solution to optimize recovery during well life cycle
- Enhanced reservoir management
- Decreased produced water handling costs
- Optimized production facility capabilities
- Ability to deploy in open or closed position
- Preservation of washdown capability without washpipe
- Ability to shut off unwanted water/gas breakthrough
- Field-replaceable ICDs
- Actuated with commercially available third-party shifting tools
- Intervention available with:
  - ACTive* family of live downhole coiled tubing services with real-time depth correlation
  - ResSOLVE* instrumented wireline intervention service with universal shifting tool for real-time depth correlation
- Ability to include commercially available water tracer to identify water influx interval

APPLICATIONS FOR RESFLOW MP
- Stimulation
- Steam distribution

ADVANTAGES OF RESFLOW MP
- Two or three ports used as as openings or configured for injection or inflow control
- Short sleeve and shorter valve travel for easy activation
- No risk of false positives
- Patented volume diversion seals
- Improved resistance to sticking

Single-position ICD
ResFlow SP* single-position sliding sleeve ICD is used with the ResFlow ICD for openhole completions to shut off unwanted water/gas breakthrough. It can also be run in closed position to provide the completion string with the hydraulic integrity required for various operational procedures, eliminating the need for washpipe. These procedures include circulation to the toe of the well and operations requiring application of pressure to wellbore fluids.

The ResFlow SP ICD houses an integrated isolation assembly, which consists of a sliding sleeve that closes the ports in the basepipe, entirely shutting off flow through the screen joint. This sliding sleeve is actuated by deploying a shifting tool designed to match profile and size of the isolation sleeve, which in turn is dependent on the basepipe size.

The recommended shifting tools for the ResFlow SP ICD’s isolation sleeves are flow-activated shifting tools for coiled tubing intervention or universal shifting tools for wireline intervention. These tools can be run in completions with multiple sleeves to selectively open some sleeves without disturbing the others.

Multiposition ICD
ResFlow MP* multiposition sliding sleeve ICD allows operators to dynamically manage the pressure profile along horizontal wells and drive optimum well performance from complex reservoir intervals. The unique valve and port system can be actuated for a variety of production and injection operations over the life of the well.

The ResFlow MP ICD consists of a multiposition valve integrated with either two or three ports, which can be left as simple openings or configured with nozzles suitable for either injection or inflow control. A Harrier shifting tool, run on coiled tubing, is used to shift the position of the valve to expose different port configurations.
### ResFlow SP ICD Specifications

<table>
<thead>
<tr>
<th>Max. temperature, degF [degC]</th>
<th>300 [149]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sliding sleeve pressure rating, psi [kPa]</td>
<td>5,000 [34,473]</td>
</tr>
<tr>
<td>Sliding sleeve material</td>
<td>413% Cu L80, 13 Cr L80</td>
</tr>
<tr>
<td>Seals material</td>
<td>Viton® or customer request</td>
</tr>
<tr>
<td>Screen size, in (mm)</td>
<td>4.5 [114.3] 4.5 [114.3] 4.5 [114.3] 5.5 [139.7] 5.5 [139.7] 6.625 [168.3]</td>
</tr>
</tbody>
</table>

#### Upper completion

| Min. tubing OD, in [mm] | 3.5 [88.9] 4 [101.6] 4 [101.6] 4.5 [114.3] 4.5 [114.3] 5.5 [139.7] |
| Tubing weight, lbm/ft [kg/m] | 9.2 [23.7] 11.6 [29.5] 11.6 [29.5] 13.5 [34.9] 13.5 [34.9] 17.0 [43.2] |

#### Intervention

| ResOLVE service max. OD, in [mm] | 3.2 [81.3] 3.2 [81.3] 3.2 [81.3] 3.2 [81.3] 3.2 [81.3] 3.2 [81.3] 4.3 [109.2] |
| Max. CT OD, in [mm] | 2.72 [69.1] 3.06 [77.7] 3.25 [82.6] 3.75 [95.3] 3.75 [95.3] 4.52 [114.8] |
| Option | CT only CT only CT/WL CT/WL CT/WL CT/WL |

### ResFlow MP ICD Specifications

<table>
<thead>
<tr>
<th></th>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
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<tbody>
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<td>2.867 [72.9]</td>
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<td>10,000 [68.95]</td>
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<td>L-80</td>
<td>3.5 NUE</td>
<td>3.5 NUE</td>
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<tr>
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<td>3.90 [99.1]</td>
<td>11.6 [17.3]</td>
<td>3.680 [98.5]</td>
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<td>8,000 [55.16]</td>
<td>3.75 [95.25]</td>
<td>L-80</td>
<td>4.5 LTC</td>
<td>4.5 LTC</td>
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<tr>
<td>5 [127.0]</td>
<td>6.00 [152.4]</td>
<td>4.30 [109.2]</td>
<td>15.0 [22.3]</td>
<td>4.280 [108.7]</td>
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<td>8,000 [55.16]</td>
<td>2.1 [1,354.8]</td>
<td>L-80</td>
<td>5.0 LTC</td>
<td>5.0 LTC</td>
</tr>
<tr>
<td>5.5 [139.7]</td>
<td>6.63 [168.4]</td>
<td>4.82 [122.4]</td>
<td>17.0 [25.3]</td>
<td>4.800 [121.9]</td>
<td>337,000 [1,499,050]</td>
<td>8,000 [55.16]</td>
<td>8,000 [55.16]</td>
<td>2.6 [1,677.4]</td>
<td>L-80</td>
<td>5.5 LTC</td>
<td>5.5 LTC</td>
</tr>
<tr>
<td>5.625 [168.3]</td>
<td>7.80 [198.1]</td>
<td>5.82 [147.8]</td>
<td>24.0 [35.7]</td>
<td>5.800 [147.32]</td>
<td>337,000 [1,499,050]</td>
<td>8,000 [55.16]</td>
<td>8,000 [55.16]</td>
<td>2.6 [1,677.4]</td>
<td>L-80</td>
<td>6.625 LTC</td>
<td>6.625 LTC</td>
</tr>
</tbody>
</table>

†Tensile strengths states are designed to match or exceed standard liner tensile strengths.
Reclosable CT Fracturing Sleeve
Enhances wellbore coverage

Applications
- Cemented multistage stimulation with single-entry fracture placement
- Openhole multistage stimulation, deployed with openhole packers

Benefits
- Simplifies rig operations
- Enables reliable zonal shutoff

Features
- Reclosable sleeve for cemented and openhole completions uses CT tension to open sleeves
- Rated to 10,000 psi [69 MPa] and 15,000 psi [103 MPa]
- Premium coatings and scraping mechanisms are proven in the harshest thermal environments
- Large flow port area ensures access to fracture planes
- Fullbore has no effect on cementing or reentry for subsequent stimulation
- Reliable shifting tool technology provides positive sleeve actuation
- Shifting tool is fail-safe opening and closing; only releases if the operator stops pumping or if the sleeve shifts
- Short length of sleeve facilitates handling and installation

Selective sleeve activation
The reclosable CT fracturing sleeve is part of a robust cemented or openhole fracturing system designed to allow operators to perform selective single-point multistage fractures.

The sleeve is a two-position, fullbore, reclosable fracturing sleeve designed for the most common high-pressure and high-rate fractures. The inner sleeve is run in a pinned configuration and sheared when desired, providing positive indication that the specified port has opened before fracturing.

The sleeve can be opened, closed, or reopened, allowing operators to tailor production over the life of the well using the CT fracturing sleeve shifting tool. This has been accomplished through premium manufactured sealing technology, incorporating coatings and associated inner bore scraping mechanisms that have been proven in the harshest thermal environments. In addition, the sleeve utilizes an adjustable detent locking system that locks the sheared sleeve to prevent accidental manipulation and provides operators with reliable weight indicators to mark when the sleeve has shifted.

Positive sleeve actuation
The Harrier shifting tool that actuates the sleeve is compact (2.5 ft [0.8 m]), featuring a self-centralizing design with a 10,000-psi [69-MPa] pressure rating, and individual hydraulically controlled keys to ensure maximum performance during actuation up to 35,000 lbf [155,687 N] of overpull without releasing the sleeve unless desired.

The shifting tool has been engineered as a fracture-in-place solution with no requirements for isolation or related service tools, even after hundreds of stages are fractured. The fully compartmentalized and hydraulically balanced design with multiple layers of solids control ensures that no solids will interfere with the tool’s operation.

Fail-safe operation
The shifting tool, in combination with the reclosable cemented fracturing sleeves’ adjustable detent lock mechanism, provides operators with reliable surface indication of when a sleeve has shifted, determined by positive indication on the weight indicator combined with the release of the shifting tool. The shifting tool is designed to release the sleeve even when actuated only once the sleeve has shifted or once the operators have stopped pumping.
**Reclosable CT Fracturing Sleeve**

### 4.5-in. Reclosable CT Fracturing Sleeve

**Sleeve Specifications**
- Max. OD: 5.5 in [139.7 mm]
- Min. ID: Drift
- Sleeve weight: 85 lbm [28.6 kg]
- Total length: 34.6 in [878.8 mm]
- Up position/lower position: Stimulation/closed
- Fracture port area: 10.70 in² [69.03 cm²]

**Casing Specifications**
- Size: 4.5 in [114.3 mm]
- Weight: 11.6–15.1 lbm/ft [17.3–22.5 kg/m]

**Sleeve Operating Data**
- Tensile: 380,000 lbf [1,690,323 N]
- Max. pressure: 15,000 psi [103 MPa]
- Temperature rating: 350 degF [177 degC]
- Up shifting weight: 5,000 lbf [22,241 N]
- Down shifting weight: 2,100 lbf [9,341 N]
- Torque: 6,700 ft.lbf [9,083 N.m]

### 5.5-in. Reclosable CT Fracturing Sleeve

**Sleeve Specifications**
- Max. OD: 7.0 in [177.8 mm]
- Min. ID: Drift
- Sleeve weight: 155 lbm [70.3 kg]
- Total length: 36.20 in [919.48 mm]
- Up position/lower position: Stimulation/closed
- Fracture port area: 11.94 in² [77.03 cm²]

**Casing Specifications**
- Size: 5.5 in [139.7 mm]
- Weight: 17.0–23.0 lbm/ft [25.3–34.2 kg/m]

**Sleeve Operating Data**
- Tensile: 660,000 lbf [2,935,825 N]
- Max. pressure: 10,000 psi [69 MPa]
- Temperature rating: 350 degF [177 degC]
- Up shifting weight: 6,000 lbf [26,689 N]
- Down shifting weight: 3,000 lbf [13,344 N]
- Torque: 18,000 ft.lbf [24,404 N.m]

---

### 4.5-in Harrier Shifting Tool Specifications

**Tool Specifications**
- Casing drift ID: 3.875 in [98.43 mm]
- Gauge ring max. OD: 3.75 in [95.25 mm]
- Min. ID: 1 in [25.4 mm]
- Length: 23.8 in [604.5 mm]

**Top connection (PAC)**
- 2.375 in [63 mm]

**Bottom connection (PAC)**
- 2.375 in [63 mm]

**Tool Operating Data**
- Tensile (on keys): 38,000 lbf [169,032 N]
- Working pressure: 3,000 psi [20.65 MPa]

---

### 5.5-in Harrier Shifting Tool Specifications

**Tool Specifications**
- Casing drift ID: 4.545 in [115.44 mm]
- Gauge ring max. OD: 4.63 in [117.60 mm]
- Min. ID: 1 in [25.4 mm]
- Length: 25.5 in [647.7 mm]

**Top connection (PAC)**
- 2.375 in [63 mm]

**Bottom connection (PAC)**
- 2.375 in [63 mm]

**Tool Operating Data**
- Tensile (on keys): 45,000 lbf [200,170 N]
- Working pressure: 3,000 psi [20.65 MPa]

---

**Step 1.** A hydraulic differential extends the keys of the Harrier shifting tool. Even up to a 10,000-psi [69-MPa] differential, the keys deflect the same amount and engage the sleeve.

**Step 2.** The leading key deflects overcome the sleeve. The grappling face of the rear key grabs the sleeve. Tension is created by the CT, and is enough to either shear the inner sleeve (first opening) or over the sleeve’s detent locking mechanism (future opening and closing). Shifting indication is seen at surface.

**Step 3.** The kickoff profile of the lead key hits the kickoff profile in the sleeve and both keys deflect the same amount to release the sleeve.

**Step 4.** If the Harrier shifting tool releases while pumping when going through the sleeve, then the sleeve has shifted. The system was engineered to eliminate false positives.

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Schlumberger and Packers Plus Technology Alliance
Liner Hangers
COLOSSUS M2M Metal-to-Metal Expandable Liner Hanger Systems
LH Max
Metal-to-metal, high-pressure expandable liner hanger system

Rated to 10,000 psi [69 MPa]
Rated to 176 degC [349 degF]

APPLICATIONS
- Land and offshore completions
- Gas and oil wells
- Long-liner deployment
- Vertical and horizontal wellbores
- HPHT environments
- Drill-in applications

BENEFITS
- Improves cement integrity and enhances well stability, enabling long, heavy liners to be rotated and reciprocated during cementing
- Ensures liner top integrity with metal-to-metal bonded elastomeric seal
- Eliminates presetting because there are no external components
- Reduces formation surging and decreases trip time with large fluid bypass

FEATURES
- Integral tieback receptacle available in 10- to 20-ft lengths
- Nonexpanding body yields high burst, collapse, and tensile strengths
- High-torque capability to enable rotation in challenging wellbore configurations
- Integral retrievable cementing bushing profile
- Machine-hardened wickers on the expansion sleeve support heavy liner loads
- No external-facing parts

As part of the COLOSSUS M2M* metal-to-metal expandable liner hanger systems portfolio, the LH Max* metal-to-metal, high-pressure expandable hanger system is a premium system designed for deployment in all types of wells. The hybrid design has all the features and benefits of an expandable liner hanger as well as the strength and quality materials of a conventional liner hanger.

The nonexpanding hanger body (mandrel) enables the user to select from a vast array of material options, including high-strength alloy, high-chrome, and stainless steel. In addition, the static mandrel offers the high burst, collapse, and tensile capacities typically found only in conventional hanger systems.

The unique design of the LH Max system uses the liner weight to aid in the final expansion of the hanger. The interlock between the integral polished bore receptacle (swage) transfers the liner load to the expansion sleeve after initial contact with the host casing.

Bonded elastomeric seals located on the outside of the hanger’s expansion sleeve provide a fluid-tight seal when set in the host casing. Redundant metal-to-metal seals on the sleeves and mandrel ensure liner top integrity after expansion.

When used with the running tool and premium high-torque connections, the LH Max system is an ideal drill-in liner system.

### LH Max System Specifications

<table>
<thead>
<tr>
<th>Liner × Casing Size, in [mm]</th>
<th>Pressure, psi [MPa]</th>
<th>Temperature, degC [degF]</th>
</tr>
</thead>
<tbody>
<tr>
<td>3.5 × 7.0 [88.9 × 177.8]</td>
<td>10,000 [69]</td>
<td>176 [325]</td>
</tr>
<tr>
<td>4.5 × 7.0 [114.3 × 177.8]</td>
<td>10,000 [69]</td>
<td>176 [325]</td>
</tr>
<tr>
<td>5.0 × 7.0 [127 × 177.8]</td>
<td>10,000 [69]</td>
<td>176 [325]</td>
</tr>
<tr>
<td>5.0 × 7.625 [127 × 193.6]</td>
<td>10,000 [69]</td>
<td>176 [325]</td>
</tr>
<tr>
<td>5.5 × 7.625 [139.7 × 193.6]</td>
<td>10,000 [69]</td>
<td>176 [325]</td>
</tr>
<tr>
<td>7.0 × 9.625 [177.8 × 244.5]</td>
<td>10,000 [69]</td>
<td>176 [325]</td>
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<tr>
<td>7.625 × 9.625 [193.6 × 244.5]</td>
<td>10,000 [69]</td>
<td>176 [325]</td>
</tr>
</tbody>
</table>
Hydraulic Setting Tool and Hydraulic Running Tool

APPLICATIONS
- Extreme wellbore conditions and long laterals
- Liners requiring reaming or drilldown capabilities
- Rotation and reciprocation ability during cementing operations
- Long- and heavy-liner deployment
- Long lateral installations

BENEFITS
- Maintains equal pressure across cylinders using balanced pistons with debris barriers
- Prevents premature hanger expansion or fouling due to lost circulation material
- Improves cement integrity by rotating or reciprocating the liner during cementing operations
- Permits higher circulating rates
- Minimizes completion time through ability to rotate liner to achieve target depth
- Reduces risk of pulling liner out of the well with secondary release feature

FEATURES
- Modular design allows for the addition or subtraction of cylinders based on desired setting pressure
- Setting force is provided by multiple hydraulic pistons during the expansion process
- Torque bushing prevents connection backoff and transfers drilling or reaming torque to the liner
- Secondary mechanical release ensures liner release
- Adjustable stainless steel wire to configure pressure rating setup of the secondary release
- Designed to carry heavy liner loads
- Robust clutch design transfers high torque to liner

Hydraulic setting tool
The hydraulic setting tool for the LH Max system uses differential hydraulic pressure to generate the required expansion forces needed to set the LH Max system’s expandable liner hanger. The modular design enables the addition or subtraction of cylinders to customize each hookup to the user’s requirements or wellbore conditions.

Torque bushings eliminate the applied rotational or drilling torque from all threaded connections while preventing the possibility of backing them off.

Debris barriers in the setting tool and in the balance pistons (found in all exposed cylinders) prevent debris and cuttings from filling up cylinders, prevent strokes during setting, and maintain balanced pressure across the cylinders.

Hydraulic Setting Tool Specifications
Sizes, in [mm]

<table>
<thead>
<tr>
<th>Size</th>
<th>Diameter [mm]</th>
</tr>
</thead>
<tbody>
<tr>
<td>3.5 × 7.0</td>
<td>88.9 × 177.8</td>
</tr>
<tr>
<td>4.5 × 7.0</td>
<td>114.3 × 177.8</td>
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<td>5.0 × 7.0</td>
<td>127.0 × 177.8</td>
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<tr>
<td>7.0 × 9.625</td>
<td>177.8 × 244.5</td>
</tr>
<tr>
<td>7.625 × 9.625</td>
<td>193.6 × 244.5</td>
</tr>
</tbody>
</table>

Hydraulic running tool
The hydraulic running tool for the LH Max system is a high-torque hydraulic release running tool that incorporates a secondary mechanical release.

Hydraulic pressure achieved during the setting of the LH Max hanger system trips the hydraulic lock on the running tool and enables it to be released after an applied compressive load locks the collet in the upward position.

Torque bushings eliminate the applied rotational or drilling torque from all threaded connections while preventing the possibility of backing them off. The clutch and the torque bushing permit high-torque and drilldown capabilities throughout the expandable liner hanger system. Rotation and reciprocation of the system is possible during cementing operations.

Running Tool Specifications
Sizes, in [mm]

<table>
<thead>
<tr>
<th>Size</th>
<th>Diameter [mm]</th>
</tr>
</thead>
<tbody>
<tr>
<td>3.5 × 7.0</td>
<td>88.9 × 177.8</td>
</tr>
<tr>
<td>4.5 × 7.0</td>
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</tr>
<tr>
<td>7.625 × 9.625</td>
<td>193.6 × 244.5</td>
</tr>
</tbody>
</table>
Liner Tieback

Metal-to-metal, gas-tight liner tieback system

Rated to 11,700 psi [103 MPa]
Rated to 160 degC [320 degF]

APPLICATIONS
- Structural integrity
- Extended-reach drilling
- Slot recovery
- Long-term intervention operations

BENEFITS
- Enables connection of liners to a tieback string of casing using a durable, permanent metal-to-metal seal
- Provides flexibility in landing casing and liner space-out
- Enables greater equivalent circulating density (ECD)
- Eliminates need for polished bore receptacle elastomeric sealing
- Enables planning for well integrity over the field’s lifetime
- Eliminates weak points in the completion or casing string
- Rapidly reinstates well integrity during production in adverse situations

FEATURES
- ISO 14310 V0-rated
- Installation depth not limited by liner tieback technology
- Full axial load-bearing capability of 2,500,000 lbf
- Burst pressure ratings close to base casing
- Effective for the life of the well
- NACE compatible

As a part of the COLOSSUS M2M* metal-to-metal expandable liner hanger system portfolio, the liner tieback metal-to-metal, gas-tight liner tieback system is a V0 ISO 14310 certified, full axial-load-bearing connection system that connects liners to a tieback string of casing with a permanent, durable seal. The unique Metalmorphology* metal-to-metal sealing technology shapes metal downhole to create metal-to-metal solutions that conform perfectly to the shape of the casing string.

Applications
To be able to reach setting depths of 30,000 ft [9,144 m] or more, operators are increasing the number of casing strings in well designs. Tighter annular clearances require the use of more flush joint connections. Conventional liner hanger equipment is unable to match the ratings of the casing in these well designs, especially when the liner needs to be tied back to surface. With the liner tieback system, operators are able to run a conventional hanger system and tie the liner string back to the wellhead without loss of casing integrity or rating. The liner tieback system can also be installed higher up the wellbore, enabling the operator to drill a new wellbore for an existing well without losing a slot in the subsea permanent guide structure.

As casing strings become longer, there is an advantage to running the string in two stages. Installing a liner string in the lower openhole section and then tying the liner back to the wellhead greatly reduces the equivalent circulating density of the cement as well as the installation time compared with running a long string. It also enables the operator to space out the tieback into the wellhead in a controlled environment. Running the liner tieback system in the liner hanger assembly provides the operator with full V0-rated downhole casing connection integrity.

Liner Tieback Specifications

<table>
<thead>
<tr>
<th>Feature</th>
<th>Size, in [cm]</th>
<th>High-Pressure Systems</th>
</tr>
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<td>Casing weight, lbm [kg]</td>
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<td></td>
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<td>[24.3]</td>
</tr>
<tr>
<td>OD, in [cm]</td>
<td>8.350</td>
<td>12.097</td>
</tr>
<tr>
<td></td>
<td>[21.209]</td>
<td>[30.726]</td>
</tr>
<tr>
<td></td>
<td>[15.707]</td>
<td>[21.679]</td>
</tr>
<tr>
<td>Burst rating, psi [MPa]</td>
<td>11,220</td>
<td>10,900</td>
</tr>
<tr>
<td></td>
<td>[77.2]</td>
<td>[75.2]</td>
</tr>
<tr>
<td>Collapse rating, psi [MPa]</td>
<td>8,500</td>
<td>7,930</td>
</tr>
<tr>
<td></td>
<td>[58.6]</td>
<td>[54.7]</td>
</tr>
</tbody>
</table>

Linermorphing tool.
Rated to 13,400 psi [94 MPa]
Rated to 150 degC [302 degF]

APPLICATIONS
- HPHT applications
- Anchor tiebacks and hangers to enable higher load capability
- Anchor hangers in polished bore receptacles (PBR)

BENEFITS
- Reduce thermal expansion while anchoring extended-reach drilling completion strings
- Enables use of conventional liner hanger equipment that would otherwise be unable to support heavy axial loads
- Anchors completion strings immediately while waiting for swellables to react
- Prevents movement of tieback casing during thermal expansion
- Removes the load transfer onto the liner hanger and tieback system

FEATURES
- Cost-effective, nonsealing, robust metal-to-metal load anchor system
- Full axial-load-bearing capability of 1,300,000 lbf
- Bidirectional, extreme high-load capabilities
- Externally rated to 12,550 psi [86 MPa]
- Internally rated to 13,400 psi [92 MPa]
- NACE compliant
- Effective for the life of the well

As a part of the COLOSSUS M2M™ metal-to-metal expandable liner hanger systems portfolio, the load anchor system provides full metal-to-metal anchoring of tieback casing, effectively removing the transferred compression load to the liner tieback and liner hanger.

The unique Metalmorphology™ metal-to-metal sealing technology shapes metal downhole to create metal-to-metal solutions that conform perfectly to the shape of the upper casing string. Expansion ratios can be up to 60% with 100% conformance to the casing or open hole.

The result is a gas-tight, axial-load-bearing, metal-to-metal sealing solution which meets well integrity legislation and retains its effectiveness for the life of the well.

Applications
The load anchor is set against the outer casing above the hanger to remove excessive compression loading from the hanger and tieback seal. Additionally, the load anchor can be used to prevent movement of the tieback casing to help maintain the integrity of traditional seal stacks and PBR systems.

In some casing designs, high thermally-generated axial loads can occur in tieback casings. This may cause problems for the liner hanger system, the casing, or even the casing threads, particularly when the casing design requires semiflush connection profiles, which have reduced axial load capabilities. The load anchor system is run as part of the tieback casing and will anchor the tieback to the outer casing to remove any axial load transfer onto the liner hanger system.

<table>
<thead>
<tr>
<th>Load Anchor Specifications</th>
</tr>
</thead>
<tbody>
<tr>
<td>Size, in [cm]</td>
</tr>
<tr>
<td>7.875 × 11.875 [20.003 × 30.163]</td>
</tr>
<tr>
<td>OD, in [cm]</td>
</tr>
<tr>
<td>5.750 [14.605]</td>
</tr>
<tr>
<td>14.500 [36.83]</td>
</tr>
<tr>
<td>Standard ID, in [cm]</td>
</tr>
<tr>
<td>6.375 [16.193]</td>
</tr>
<tr>
<td>12.360 [31.394]</td>
</tr>
<tr>
<td>14.688 [37.308]</td>
</tr>
<tr>
<td>Internal pressure, psi [MPa]</td>
</tr>
<tr>
<td>11,000 [75.8]</td>
</tr>
<tr>
<td>10,000 [68.9]</td>
</tr>
<tr>
<td>5,000 [34.4]</td>
</tr>
<tr>
<td>External pressure, psi [MPa]</td>
</tr>
<tr>
<td>13,400 [92.4]</td>
</tr>
<tr>
<td>9,000 [62.1]</td>
</tr>
<tr>
<td>5,000 [34.4]</td>
</tr>
<tr>
<td>Axial rating, lbf [N]</td>
</tr>
<tr>
<td>1,300,000 [5,782,688]</td>
</tr>
<tr>
<td>2,500,000 [11,120,554]</td>
</tr>
</tbody>
</table>

Load anchor.
As a part of the COLOSSUS M2M™ metal-to-metal expandable liner hanger systems portfolio, the Casing Reconnect™ metal-to-metal, gas-tight casing repair system is a VO ISO 14310 and ISO 13679 certified, full axial-load-bearing metal-to-metal reconnection solution that seamlessly replaces stuck or damaged casing. It keeps drilling programs on schedule without the need for lengthy fishing operations or costly sidetracks, secures well integrity for P&A operations, and minimizes costs.

The Casing Reconnect system is a robust, cost-effective remediation solution for the life of the well operations. With no reduction in ID, the reliable system can be used to back out casing, realign space-out, and offer an economical alternative to costly sidetrack operations.

Applications
When subsea wellhead or mudline suspension systems require a workover, a subsea tieback between the wellhead and the rig may be installed to assist with landing out the tieback string in the surface wellhead and the tieback point. The Casing Reconnect system allows space-out flexibility with a high-integrity seal to enable safer workover activities.

During drilling operations, the casing may become stuck at a point close enough to the intended depth to still be viable. However, the casing will likely not have been landed out in the hanger, limiting the options for some applications such as subsea wellheads. Using the Casing Reconnect system enables cutting and pulling the casing anywhere between the wellhead and the stuck point. Replacement casing is then run with a Casing Reconnect system receptacle on the bottom. The casing stump is morphed into the Casing Reconnect system receptacle to rejoin the two strings with a high-axial-load-bearing, metal-to-metal seal. The system accommodates excess swallow at the connection, greatly simplifying space-out for correctly landing the hanger.

### Casing Reconnect System Specifications

<table>
<thead>
<tr>
<th>Feature</th>
<th>Specification</th>
</tr>
</thead>
<tbody>
<tr>
<td>Size, in [cm]</td>
<td>7 [17.780], 9.625 [24.426], 9.875 [25.083], 13.375 [34.057], 13.625 [34.608]</td>
</tr>
<tr>
<td>OD, in [cm]</td>
<td>8.350 [21.209], 12.097 [30.726], 12.035 [30.569], 16.750 [42.545], 17.000 [43.18]</td>
</tr>
<tr>
<td>Length, ft [m]</td>
<td>29.3 [8.9], 27.7 [8.4], 28.4 [8.7], 31.0 [9.4], 31.0 [9.4]</td>
</tr>
<tr>
<td>Collapse rating, psi [MPa]</td>
<td>8,500 [58.6], 7,930 [54.7], 7,930 [54.7], 2,880 [19.9], 4,590 [31.6]</td>
</tr>
</tbody>
</table>

Note: Grapple to place casing in tension available on request. Ratings are based on ISO 10400 calculation methods using P110 base pipe. Application-specific ratings available on request.
COLOSSUS CMT Cemented Liner Hanger
System: Premium System

Compatible Accessories
CMIB Internal Bypass Cement Manifold
CMIB Light Internal Bypass Cement Manifold
CRT Collet Running Tool
PDPC and LWPC Pumpdown Plug and Liner Wiper Plug
PSCD Pressure Surge Control Device
RCB Retrievable Cement Bushing
RBS Rotational Ball Seat
The premium high-capacity hydraulic rotating liner hanger (HCHR) is a hydraulic-set, hydraulic-release hanger designed for deepwater, high-temperature, and high-pressure applications. Its slip-cone design distributes axial and radial loading through the hanger body and provides increased hanging capacity over cone-type hangers.

The HCHR liner hanger features high-torque capacity and pocketed slips to facilitate drilldown operations under challenging wellbore conditions. An antipreset mechanism prevents the hanger from being set prematurely until the hydraulic setting mechanism is activated. When enough pressure has been applied to the system and the slips have been set, a high-performance bearing allows long, heavy liners to be rotated during cementing to improve cement integrity.

The HCHR, part of the COLOSSUS CMT* cemented liner hanger system, is run in combination with the PV-3 liner top packer or setting adapter. The CRT hydraulic-release collet running tool or the RRT-HM right-hand release hydromechanical running tool provides rotational drilldown capabilities.

The HCHR uses standard 80,000-psi [552-MPa] through 125,000-psi [862-MPa] yield materials. Other yield strengths and materials are available on request.
<table>
<thead>
<tr>
<th>Liner × Casing Size, in [mm]</th>
<th>Size, in [mm]</th>
<th>Weight Range, lbm/ft [kg/m]</th>
<th>Casing</th>
<th>Size, in [mm]</th>
<th>Weight, lbm/ft [kg/m]</th>
<th>Liner</th>
<th>Max. OD, in [mm]</th>
</tr>
</thead>
<tbody>
<tr>
<td>5.000 × 7.000 [127.0 × 177.8]</td>
<td>7.000 [177.8]</td>
<td>26–32 [38.7–47.7]</td>
<td>5.000 [127.0]</td>
<td>15 [22.4]</td>
<td>5.921 [150.4]</td>
<td></td>
<td></td>
</tr>
<tr>
<td>7.000 × 9.625 [177.8 × 244.5]</td>
<td>9.625 [244.5]</td>
<td>43.5–53.5 [64.8–79.7]</td>
<td>7.000 [177.8]</td>
<td>29 [43.2]</td>
<td>8.325 [211.5]</td>
<td></td>
<td></td>
</tr>
<tr>
<td>9.625 × 11.750 [177.8 x 298.5]</td>
<td>11.750 [298.5]</td>
<td>60.0–66.7 [89.3–99.3]</td>
<td>9.625 [298.5]</td>
<td>47.0 [69.9]</td>
<td>10.472 [266.0]</td>
<td></td>
<td></td>
</tr>
<tr>
<td>11.75 × 13.375 [298.5 x 339.8]</td>
<td>13.375 [339.8]</td>
<td>68.0–72.0 [101.2–107.1]</td>
<td>11.75 [339.8]</td>
<td>60.0 [89.3]</td>
<td>12.144 [308.5]</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

1. Other sizes available on request.
2. Nonrotating.
### LTP Max Specifications

<table>
<thead>
<tr>
<th>Liner × Casing Size,(^\d)</th>
<th>Casing Weight Range, lbf/ft [kg/m]</th>
<th>Pressure, psi [MPa]</th>
<th>Temperature, degF [degC]</th>
</tr>
</thead>
<tbody>
<tr>
<td>(5.0 \times 7.0 ) ([127 \times 177.8])</td>
<td>26.0–32.0 ([38.7–47.6])</td>
<td>10,000 ([68.9])</td>
<td>325 ([162.7])</td>
</tr>
<tr>
<td>(7.0 \times 9.625 ) ([177.8 \times 244.5])</td>
<td>43.5–53.5 ([64.7–79.7])</td>
<td>10,000 ([68.9])</td>
<td>325 ([162.7])</td>
</tr>
<tr>
<td>(7.0 \times 9.625 ) ([177.8 \times 244.5])</td>
<td>47.0–53.5 ([64.8–79.7])</td>
<td>10,000 ([68.9])</td>
<td>400 ([204.4])</td>
</tr>
<tr>
<td>(7.0 \times 9.625 ) ([177.8 \times 244.5])</td>
<td>53.5–58.4 ([79.7–86.9])</td>
<td>10,000 ([68.9])</td>
<td>325 ([162.7])</td>
</tr>
<tr>
<td>(9.625 \times 11.750 ) ([177.8 \times 298.5])</td>
<td>60.0–66.7 ([89.3–99.3])</td>
<td>10,000 ([68.9])</td>
<td>325 ([162.7])</td>
</tr>
<tr>
<td>(9.625 \times 11.750 ) ([177.8 \times 298.5])</td>
<td>68.0–72.0 ([101.2–107.1])</td>
<td>10,000 ([68.9])</td>
<td>325 ([162.7])</td>
</tr>
<tr>
<td>(11.75 \times 13.375 ) ([298.5 \times 339.8])</td>
<td>68.0–72.0 ([101.2–107.1])</td>
<td>7,500 ([51.8])</td>
<td>325 ([162.7])</td>
</tr>
</tbody>
</table>

\(^\d\) Other sizes available on request.

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**APPLICATIONS**
- Gas applications and hostile gas environments
- Vertical and horizontal wells
- Offshore, deepwater, and deep onshore wells
- ISO-14310 V0 liner top packoff requirements
- Liner hanger applications requiring drilldown capabilities
- HPHT environments

**BENEFITS**
- Has large fluid bypass area that aids hole cleaning, reduces circulation time, and decreases trip time
- Optimizes well integrity and enhances well stability and safety with ISO-14310 V0–qualified equipment
- Minimizes completion time with drilldown liner
- Has hold-down slips that prevent upward movement of the liner, resulting in more secure liner installation

**FEATURES**
- Antiswab element design
- Compatibility with mechanical- or hydraulic-release setting tools
- ISO-14310 V0 tested and qualified
- High torque capacity to rotate long liners
- Integral mandrel and setting adapter design
- Standard tieback receptacle
- Standard hold-down slips
- Integral retrievable cementing bushing profile

The LTP Max\(^*\) high-pressure liner top packer, part of the COLOSSUS CMT\(^*\) cemented liner hanger system, is ISO-14310 V0 qualified and rated up to a differential pressure of 10,000 psi \([68.9 \text{ MPa}]\). The LTP Max packer is run above a liner hanger with either a mechanical right-hand release running tool or hydraulic collet-running tool in HPHT environments. After the liner hanger has been set and cemented, the packer is set by picking up the running string, placing rotating dog assembly above the liner top, and slacking off weight. Excess cement above the liner top can then be circulated out after the packer is set.

The integral setting adaptor and mandrel design permits the transmission of high torque from the running string to the liner. This feature is used to drill down the liner during running in hole. When a rotational hanger is deployed, the liner can be rotated after the liner hanger is set to improve cement integrity. Optimized design and materials maximize mandrel performance criteria such as burst, collapse, torque, and tensile ratings.

During running and cementing operations, a cementing packoff maintains a seal between the workstring and the liner. The LTP Max packer includes an integral retrievable cementing bushing profile, which is designed to eliminate extra connections in the liner hanger assembly.

The LTP Max packer uses standard 80,000- to 125,000-psi \([552- to 862-\text{MPa}]\) yield materials. Other yield strengths and materials are available on request.

---

*LTP Max* high-pressure liner top packer.
COLOSSUS CMT Cemented Liner Hanger System: Intermediate System

Compatible Accessories
CMIB Internal Bypass Cement Manifold
CMIB Light Internal Bypass Cement Manifold
CRT Collet Running Tool
PDPC and LWPC Pumpdown Plug and Liner Wiper Plug
PSCD Pressure Surge Control Device
RCB Retrievable Cement Bushing
RRT Right-Hand-Release Running Tool
The hydraulically set pocket-slip (HPS) hanger, part of the COLOSSUS CMT* cemented liner hanger system, has heavy-duty rotating capabilities. The tongue-and-groove slip design minimizes running interference and reduces the potential of casing deformation after the hanger is set. The slips also feature an effective cone angle two times larger than those found on conventional hangers, thus reducing the burst pressure exerted on the casing and allowing longer and heavier liners to be run on multistring or uncemented casing.

The HPS liner hanger can be configured with a spacer sleeve in place of the bearing assembly with the same hanging capacities and minimal casing load characteristics for nonrotating applications. The hydraulically set liner hanger is standard; a mechanically set version is also available—the rotating pocket-slip mechanical (RPSM) liner hanger.

The HPS liner hanger is run with a setting adapter or packer and the corresponding running tool. The STHR hydraulic-release setting tool or CRT collet running tool or the STS double-spline mechanical setting tool or RRT right-hand release running tool provides rotational capability.

The HPS liner hanger uses standard 80,000-psi through 125,000-psi yield materials. Other yield strengths and materials are available by special order.
<table>
<thead>
<tr>
<th>Liner × Casing Size,† in [mm]</th>
<th>Casing</th>
<th>Liner</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Size, in [mm]</td>
<td>Weight, lbm/ft</td>
</tr>
<tr>
<td>5.000 × 7.000 [127.0 × 177.8]</td>
<td>7.000 [177.8]</td>
<td>23.00–26.00</td>
</tr>
<tr>
<td>5.000 × 7.000 [127.0 × 177.8]</td>
<td>7.000 [177.8]</td>
<td>26.00–29.00</td>
</tr>
<tr>
<td>5.000 × 7.000 [127.0 × 177.8]</td>
<td>7.000 [177.8]</td>
<td>29.00–32.00</td>
</tr>
<tr>
<td>5.000 × 7.000 [127.0 × 177.8]</td>
<td>7.000 [177.8]</td>
<td>32.00–35.00</td>
</tr>
<tr>
<td>5.000 × 7.625 [127.0 × 193.7]</td>
<td>7.625 [193.7]</td>
<td>33.7–39.00</td>
</tr>
<tr>
<td>7.000 × 9.625 [177.8 × 244.5]</td>
<td>9.625 [244.5]</td>
<td>36.00–43.50</td>
</tr>
<tr>
<td>7.000 × 9.625 [177.8 × 244.5]</td>
<td>9.625 [244.5]</td>
<td>47.00–53.50</td>
</tr>
<tr>
<td>7.000 × 10.750 [177.8 × 273.0]</td>
<td>10.750 [273.0]</td>
<td>55.50–65.70</td>
</tr>
<tr>
<td>7.000 × 10.750 [177.8 × 273.0]</td>
<td>10.750 [273.0]</td>
<td>71.10–85.30</td>
</tr>
<tr>
<td>7.625 × 9.625 [193.7 × 244.5]</td>
<td>9.625 [244.5]</td>
<td>43.50–47.00</td>
</tr>
<tr>
<td>7.625 × 9.625 [193.7 × 244.5]</td>
<td>9.625 [244.5]</td>
<td>53.5</td>
</tr>
<tr>
<td>4.500 × 7.000 [114.3 × 177.8]</td>
<td>7.000 [177.8]</td>
<td>23.0–26.0</td>
</tr>
<tr>
<td>4.500 × 7.000 [114.3 × 177.8]</td>
<td>7.000 [177.8]</td>
<td>29.0–32.0</td>
</tr>
<tr>
<td>4.500 × 7.000 [114.3 × 177.8]</td>
<td>7.000 [177.8]</td>
<td>35.0–38.0</td>
</tr>
<tr>
<td>4.500 × 7.000 [114.3 × 177.8]</td>
<td>7.000 [177.8]</td>
<td>35.0–38.0</td>
</tr>
<tr>
<td>11.75 × 13.375 [298.5 × 339.8]</td>
<td>13.375 [339.8]</td>
<td>68.0–72.0</td>
</tr>
</tbody>
</table>

†Other sizes available on request
The LTP Max® high-pressure liner top packer is a part of the COLOSSUS CMT® cemented liner hanger system, ISO-14310 V0 qualified, and rated up to a differential pressure of 10,000 psi [68.9 MPa]. It is run above a liner hanger with either a mechanical right-hand release running tool or hydraulic collet-running tool in HPHT environments. After setting the liner hanger, setting the packer involves picking up the running string, placing the rotating dog assembly above the liner top, and slacking off weight. Excess cement above the liner top can then be circulated out after the packer is set.

The integral setting adaptor and mandrel design permits the transmission of high torque from the running string to the liner. This feature is used to drill down the liner during running in hole. When a rotational hanger is deployed, the liner can be rotated after the liner hanger is set to improve cement integrity. Optimized design and materials maximize mandrel performance criteria such as burst, collapse, torque, and tensile ratings.

During running and cementing operations, a cementing packoff maintains a seal between the workstring and the liner. The LTP Max packer includes an integral retrievable cementing bushing profile, which is designed to eliminate extra connections in the liner hanger assembly.

The LTP Max packer uses standard 80,000- to 125,000-psi [552- to 862-MPa] yield materials. Other yield strengths and materials are available on request.

### LTP Max Packer Specifications

<table>
<thead>
<tr>
<th>Liner × Casing Size,† in [mm]</th>
<th>Casing Weight Range, lbm/ft [kg/m]</th>
<th>Pressure, psi [MPa]</th>
<th>Temperature, degF [degC]</th>
</tr>
</thead>
<tbody>
<tr>
<td>5.0 × 7.0 [127 × 177.8]</td>
<td>26.0–32.0 [38.7–47.6]</td>
<td>10,000 [68.9]</td>
<td>325 [162.7]</td>
</tr>
<tr>
<td>7.0 × 9.625 [177.8 × 244.5]</td>
<td>43.5–53.5 [64.7–79.7]</td>
<td>10,000 [68.9]</td>
<td>325 [162.7]</td>
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<tr>
<td>7.0 × 9.625 [177.8 × 244.5]</td>
<td>47.0–53.5 [64.8–79.7]</td>
<td>10,000 [68.9]</td>
<td>400 [204.4]</td>
</tr>
<tr>
<td>7.0 × 9.625 [177.8 × 244.5]</td>
<td>53.5–58.4 [79.7–86.9]</td>
<td>10,000 [68.9]</td>
<td>325 [162.7]</td>
</tr>
<tr>
<td>9.625 × 11.750 [177.8 × 298.5]</td>
<td>60.0–66.7 [89.3–99.3]</td>
<td>10,000 [68.9]</td>
<td>325 [162.7]</td>
</tr>
<tr>
<td>9.625 × 11.750 [177.8 × 298.5]</td>
<td>68.0–72.0 [101.2–107.1]</td>
<td>10,000 [68.9]</td>
<td>325 [162.7]</td>
</tr>
<tr>
<td>11.75 × 13.375 [298.5 × 339.8]</td>
<td>68.0–72.0 [101.2–107.1]</td>
<td>7,500 [51.8]</td>
<td>325 [162.7]</td>
</tr>
</tbody>
</table>

† Other sizes available on request.
MPS
Mechanically set pocket-slip hanger

APPLICATIONS
- Vertical wells
- Onshore wells

BENEFITS
- Reduces costs for nonrotational liner hanger applications
- Maximizes reliability, and minimizes lifetime well costs with solid-body construction

FEATURES
- Solid-body construction for increased performance ratings
- Compatibility with premium connections
- Standard right-hand mechanical setting and release
- Multiple cone designs, to minimize stress in supporting casing
- Hangs light- to medium-weight liners

The mechanically set pocket-slip (MPS) hanger, part of the COLOSSUS CMT* cemented liner hanger system, is designed for use in wells where the workstring can be manipulated to set the hanger. The MPS hanger is composed of the hanger body or mandrel, one or more sets of cone pads, slips, and a cage assembly to carry the slips. The cage contains a J slot and drag springs. When the liner reaches the target depth, mechanical manipulation of the hanger body moves the cage J slot from the running position to the setting position, bringing the slips into contact with the cones. A gauge ring protects the slips while the hanger is being run into the wellbore.

The MPS hanger is manufactured from mechanical tubing. The J lug, gauge ring, and cone pads are machined, integral features. This construction enhances the performance of the hanger. The slips are manufactured to 55-60 Rockwell “C” hardness and thus are compatible with high-grade casing. MPS dimensions are compatible with premium thread connections.

The MPS hanger is run in combination with a setting adapter or packer and the corresponding setting tool. The STL mechanical release setting tool and RRT right-hand running tool are commonly used for MPS applications.

The MPS hanger uses standard 80,000-psi [552-MPa] through 125,000-psi [862-MPa] yield materials. Other yield strengths and materials are available on request.
<table>
<thead>
<tr>
<th>Liner Hanger Size†</th>
<th>Casing Size, in [mm]</th>
<th>Weight, lbm/ft [kg/m]</th>
<th>Liner Size, in [mm]</th>
<th>Weight Range, lbm/ft [kg/m]</th>
<th>Max. OD, in [mm]</th>
</tr>
</thead>
<tbody>
<tr>
<td>5.000 × 7.000 [127.0 × 177.8]</td>
<td>7.000 [177.8]</td>
<td>23.00–26.00 [34.27–38.74]</td>
<td>5.000 [127.0]</td>
<td>11.50–24.10 [17.14–35.91]</td>
<td>6.050 [153.7]</td>
</tr>
<tr>
<td>7.000 × 9.625 [177.8 × 244.5]</td>
<td>9.625 [244.5]</td>
<td>36.00–43.50 [53.64–64.82]</td>
<td>7.000 [177.8]</td>
<td>17.00–35.00 [25.33–52.15]</td>
<td>8.430 [214.1]</td>
</tr>
<tr>
<td>7.625 × 9.625 [193.7 × 244.5]</td>
<td>9.625 [244.5]</td>
<td>36.00–43.50 [53.64–64.82]</td>
<td>7.625 [193.7]</td>
<td>24.00–47.10 [35.76–70.18]</td>
<td>8.500 [216.9]</td>
</tr>
</tbody>
</table>

† Other sizes available on request.
Pocket-Slip Liner Hanger System

Compatible Accessories
CMIB Internal Bypass Cement Manifold
CMIB Light Internal Bypass Cement Manifold
PDPC and LWPC Pumpdown Plug and Liner Wiper Plug
RCB Retrievable Cement Bushing
STP Pocket-Slip Setting Tool and STPR Pocket-Slip Rotational Setting Tool
**APPLICATIONS**
- Deepwater and deep onshore wells
- Well applications for which maintaining pressure integrity at the liner top is critical
- High-pressure, high-temperature environments
- Well applications requiring a pocket-slip liner hanger system

**BENEFITS**
- Large fluid by-pass area aids hole cleaning and reduces circulation time.
- Large fluid by-pass area decreases trip time.
- Maximizes pressure integrity and safety

**FEATURES**
- Packer and tieback receptacle are below liner hanger, maximizing system pressure integrity.
- System incorporates an antiswab element.
- Integral tieback receptacle is standard.
- Packer is available with integral retrievable cementing bushing (RCB) profile.
- System has large bypass area.
- Packer contains self-energizing nonextruding element.

The Frontier liner top packer (FSP), part of the COLOSSUS CMT* cemented liner hanger system, is designed for high-pressure, high-temperature applications. The element is rated to 10,000 psi [101.6 MPa] and 350 degF [177 degC] in some sizes. The FSP and pocket-slip tieback receptacle (TP) maximize system pressure integrity by allowing the tieback to be placed below the liner hanger.

The FSP with tieback sleeve has a large bypass area, eliminating close tieback sleeve tolerances. Combined with an antiswab element, the FSP facilitates high-circulation rates to condition holes, reduce circulation time, and improve cement integrity.

The FSP is a weight-set packer that is set with the packer setting tool made up to the pocket-slip liner running string. After the liner hanger has been set and cemented, the FSP is set by picking up the running string, placing the tamping dogs of the setting tool above the internal packer setting ring, and then slacking off weight. Excess cement above the liner top can then be circulated out after the FSP is set.

The FSP uses standard 80,000-psi [552-MPa] through 125,000-psi [862-MPa] yield materials. Other yield strengths and materials are available by special request.

<table>
<thead>
<tr>
<th>FSP Specifications</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Casing</strong></td>
</tr>
<tr>
<td>Size, in [mm]</td>
</tr>
<tr>
<td>8.625 [219.1]</td>
</tr>
<tr>
<td>9.625 [244.5]</td>
</tr>
</tbody>
</table>

†Other sizes available on request.
APPLICATIONS
- High-pressure environments
- Well applications requiring hanging heavy liners
- Well applications for which maintaining pressure integrity at the liner top is critical
- Offshore and onshore wells

BENEFITS
- Large fluid bypass area aids hole cleaning, reduces circulation time, and decreases trip time.
- System maximizes pressure integrity and safety.

FEATURES
- Slip design minimizes stress in supporting casing and eliminates cone collapse.
- System is designed to hang heavy liners.
- Slip design and hardness are compatible with high-grade casing.
- Liner hanger can be run with or without a packer.
- Optional packer and tieback receptacle below the hanger maximize pressure integrity of system.
- Close tieback sleeve tolerance is eliminated.
- Hanger has internal and external running bypass.
- Integral liner running threads eliminate setting adapter.

The pocket-slip liner hanger (PSH), part of the COLOSSUS CMT* cemented liner hanger system, delivers high hanging capacities and optimizes the pressure integrity of the liner system. The tongue-and-groove slip design minimizes running interference and reduces the potential of casing deformation after the hanger is set. The slips also feature an effective cone angle two times greater than those found on conventional hangers, thereby reducing burst pressure exerted on casing and allowing for longer and heavier liners to be hung in multistring or uncemented casing.

Different from conventional liner hanger systems, the pocket-slip liner hanger system features the PSH hanger positioned above the Frontier liner top packer (FSP) or the pocket-slip tieback receptacle (TP). This configuration eliminates differential pressure at the liner hanger. Thus, it improves pressure integrity below the liner top packer, reduces equivalent circulating density (ECD) and running interference, and increases hanging capacity. The PSH is run with the pocket-slip setting tool (STP), which incorporates a hanger setting mechanism that can be activated hydraulically or mechanically during the deployment of the liner.

The PSH uses standard 80,000-psi [552-MPa] through 125,000-psi [862-MPa] yield materials. Other yield strengths and materials are available on request.
### PSH Specifications

<table>
<thead>
<tr>
<th>Liner × Casing,† in [mm]</th>
<th>Casing lbm/ft [kg/m]</th>
</tr>
</thead>
<tbody>
<tr>
<td>3½ × 5 [88.90 × 127.00]</td>
<td>11.50 [17.30]</td>
</tr>
<tr>
<td>3½ × 5½ [88.90 × 139.70]</td>
<td>14.00 [20.80]</td>
</tr>
<tr>
<td>3½ × 6 [101.60 × 127.00]</td>
<td>11.50 [17.10]</td>
</tr>
<tr>
<td>4 × 5½ [101.60 × 139.70]</td>
<td>14.00 [20.80]</td>
</tr>
<tr>
<td>4½ × 5½ [114.30 × 139.70]</td>
<td>14 [20.80]</td>
</tr>
<tr>
<td>4½ × 6 [114.30 × 177.80]</td>
<td>17.00–20.00 [25.30–29.80]</td>
</tr>
<tr>
<td>5 × 7 [127.00 × 177.80]</td>
<td>17.00–20.00 [25.30–29.80]</td>
</tr>
<tr>
<td>5 × 7½ [139.70 × 177.80]</td>
<td>24.00–29.70 [35.70–44.20]</td>
</tr>
<tr>
<td>5½ × 7 [139.70 × 177.80]</td>
<td>24.00–29.70 [35.70–44.20]</td>
</tr>
<tr>
<td>5½ × 7½ [139.70 × 193.70]</td>
<td>33.70–39.00 [50.10–56.70]</td>
</tr>
</tbody>
</table>

### PSH Specifications, continued

<table>
<thead>
<tr>
<th>Liner × Casing,† in [mm]</th>
<th>Casing lbm/ft [kg/m]</th>
</tr>
</thead>
<tbody>
<tr>
<td>7 × 9½ [177.80 × 244.50]</td>
<td>32.30–40.00 [48.10–59.50]</td>
</tr>
<tr>
<td>7 × 10¼ [177.80 × 273.00]</td>
<td>40.50–45.50 [60.50–69.50]</td>
</tr>
<tr>
<td>7½ × 9½ [173.70 × 244.50] and 7¼ × 9½ [196.85 × 244.50]</td>
<td>40.00–47.00 [59.60–69.90]</td>
</tr>
<tr>
<td>7½ × 10½ [193.70 × 273.00]</td>
<td>51.50–55.50 [76.60–82.60]</td>
</tr>
<tr>
<td>9½ × 11½ [244.50 × 298.50]</td>
<td>66.00–65.00 [99.30–96.70]</td>
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<tr>
<td>9½ × 13¼ [244.50 × 339.70]</td>
<td>48.00 [71.40]</td>
</tr>
<tr>
<td>10½ × 13¼ [244.50 × 339.70]</td>
<td>48.00 [71.40]</td>
</tr>
<tr>
<td>11¼ × 13¼ [298.50 × 339.70]</td>
<td>54.50 [81.10]</td>
</tr>
<tr>
<td>13 × 16 [339.70 × 406.40]</td>
<td>55.00–70.00 [81.80–104.20]</td>
</tr>
<tr>
<td>16 × 20 [406.40 × 508.00]</td>
<td>94.00–106.50 [139.90–158.50]</td>
</tr>
</tbody>
</table>

†Other sizes available on request.
The pocket-slip rotational liner hanger (PSHR), part of the COLOSSUS CMT™ cemented liner hanger system, delivers high hanging capacities and optimizes the pressure integrity of the liner system. The tongue-and-groove slip design minimizes running interference and reduces the potential of casing deformation after the hanger is set. The slips also feature an effective cone angle two times greater than those found on conventional hangers, thereby reducing burst pressure exerted on the casing and allowing for longer and heavier liners to be hung in multistring or uncemented casing. Drive slots in the liner top permit rotation when running in the hole to navigate around obstructions.

Different from conventional liner hanger systems, the pocket-slip liner hanger system features the PSHR hanger positioned above the Frontier liner top packer (FSP) or the pocket-slip tieback receptacle (TP). This configuration eliminates differential pressure at the liner hanger. Thus, it improves pressure integrity below the liner top packer, reduces equivalent circulating density (ECD) and running interference, and increases hanging capacity. The PSHR is run with the pocket-slip rotating setting tool (STPR), which incorporates a hanger setting mechanism that can be activated hydraulically or mechanically during the deployment of the liner.

The PSHR uses standard 80,000-psi [552-MPa] through 125,000-psi [862-MPa] yield materials. Other yield strengths and materials are available by special request.
### PSHR Specifications

<table>
<thead>
<tr>
<th>Liner × Casing Size,† in [mm]</th>
<th>Casing, lbm/ft [kg/m]</th>
</tr>
</thead>
<tbody>
<tr>
<td>4½ × 7 [114.30 × 177.80]</td>
<td>17.00–20.00 [25.30–29.80]</td>
</tr>
<tr>
<td></td>
<td>23.00–26.00 [34.20–36.70]</td>
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<td>29.00 [43.20]</td>
</tr>
<tr>
<td></td>
<td>32.00–35.00 [47.60–52.10]</td>
</tr>
<tr>
<td></td>
<td>38.00 [56.50]</td>
</tr>
<tr>
<td>5 × 7 [127.00 × 177.80]</td>
<td>17.00–20.00 [25.30–29.80]</td>
</tr>
<tr>
<td></td>
<td>23.00–26.00 [34.20–36.70]</td>
</tr>
<tr>
<td></td>
<td>29.00 [43.20]</td>
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<td>32.00–35.00 [47.60–52.10]</td>
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<td>38.00 [56.50]</td>
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<td>5 × 7¼ [127.00 × 193.80]</td>
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<td>33.70–39.00 [50.10–58.00]</td>
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<td>42.80–45.30 [63.70–67.40]</td>
</tr>
<tr>
<td>5½ × 7 [139.70 × 177.80]</td>
<td>17.00–20.00 [25.30–29.80]</td>
</tr>
<tr>
<td></td>
<td>23.00–26.00 [34.20–36.70]</td>
</tr>
<tr>
<td></td>
<td>29.00 [43.20]</td>
</tr>
<tr>
<td></td>
<td>32.00–35.00 [47.60–52.10]</td>
</tr>
<tr>
<td></td>
<td>38.00 [56.50]</td>
</tr>
<tr>
<td>7 × 9¼ [177.80 × 244.50]</td>
<td>32.30–40.00 [48.10–59.50]</td>
</tr>
<tr>
<td></td>
<td>40.00–47.00 [59.50–69.90]</td>
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<td>47.00–53.50 [69.90–79.60]</td>
</tr>
<tr>
<td></td>
<td>58.40 [86.90]</td>
</tr>
<tr>
<td>7½ × 9½ [193.70 × 244.50]</td>
<td>32.30–40.00 [48.10–59.50]</td>
</tr>
<tr>
<td>and</td>
<td>40.00–47.00 [59.50–69.90]</td>
</tr>
<tr>
<td>7¾ × 9½ [196.85 × 244.50]</td>
<td>47.00–53.50 [69.90–79.60]</td>
</tr>
<tr>
<td></td>
<td>58.40 [86.90]</td>
</tr>
<tr>
<td>9½ × 11¼ [244.50 × 298.50]</td>
<td>60.00–65.00 [89.30–96.70]</td>
</tr>
<tr>
<td></td>
<td>48.00 [71.40]</td>
</tr>
<tr>
<td>9¼ × 13¼ [244.50 × 339.70]</td>
<td>54.50 [81.10]</td>
</tr>
<tr>
<td></td>
<td>61.00 [90.80]</td>
</tr>
<tr>
<td></td>
<td>68.00–72.00 [101.20–107.10]</td>
</tr>
<tr>
<td>10¼ × 13¼ [244.50 × 339.70]</td>
<td>48.00 [71.40]</td>
</tr>
<tr>
<td></td>
<td>54.50 [81.10]</td>
</tr>
<tr>
<td></td>
<td>61.00 [90.80]</td>
</tr>
<tr>
<td></td>
<td>68.00–72.00 [101.20–107.10]</td>
</tr>
<tr>
<td>11¼ × 13¼ [298.50 × 339.70]</td>
<td>48.00 [71.40]</td>
</tr>
<tr>
<td></td>
<td>54.50 [81.10]</td>
</tr>
<tr>
<td></td>
<td>61.00 [90.80]</td>
</tr>
<tr>
<td></td>
<td>68.00–72.00 [101.20–107.10]</td>
</tr>
</tbody>
</table>

†Other sizes available on request.
**APPLICATIONS**
- Wells that require tight annular clearance
- Wells that require hanging extremely heavy liners in heavy wall casing
- Wells that require rotation while running in hole to navigate around obstructions
- Hanging liners in low-strength, non-cemented, or multistring casing where thorough load distribution is critical
- Offshore and deepwater wells

**BENEFITS**
- Reach target depth and minimize the risk of setting hanger prematurely by rotating hanger when running in hole

**FEATURES**
- Large fluid bypass area aids hole clearing, reduces ECD, and decreases trip time
- Slip design that minimizes stress in supporting casing and eliminates cone collapse
- Compatibility of slip design and hardness with high-grade casing
- Drive slots in liner top to permit orientation around obstructions while running in hole
- Internal and external bypass fluid
- Integral design eliminates potential leaks and thread upset
- Optional or dual hydraulic and/or mechanical setting
- Heavy wall tubular alloy steel construction designed specifically to hang heavy liners
- Optional drillable or rotational cement bushing

The pocket-slip rotatable liner hanger (PST-D/R) is part of the COLOSSUS CMT* cemented liner hanger system. It is designed to be run in well applications that require tight annular clearance and it meets the requirements to hang extremely heavy liners in heavy-wall casing. It features an integral tieback receptacle (TBR) and either a drillable or rotational cement bushing (DCB or RCB).

The PST-D/R features a bypass that reduces the equivalent circulating density (ECD) to a low level. The hanger’s tongue-and-groove slip design minimizes running interference and reduces the potential of casing deformation after it is set. Drive slots in the liner top permit rotation when running in the hole to navigate around obstructions.

The PST-D/R is run with the pocket-slip rotating setting tool (STPR), which incorporates a hanger setting mechanism that can be activated hydraulically or mechanically during the deployment of the liner. In cases in which it is necessary to maintain pressure integrity at the liner top, the PST-D/R can be run with a second trip packer to provide for extra sealing capability.

The PST-D/R uses standard 80,000-psi [552-MPa] through 125,000-psi [862-MPa] yield materials. Other yield strengths and materials are available by special request.

**PST-D/R Specifications**

<table>
<thead>
<tr>
<th>Liner × Casing, in [mm]</th>
<th>Casing, lbm/ft</th>
</tr>
</thead>
<tbody>
<tr>
<td>4 × 5½ [101.60 × 139.70]</td>
<td>20 [29.72]</td>
</tr>
<tr>
<td>7 × 8½ [177.80 × 219.08]</td>
<td>24 [35.66]</td>
</tr>
<tr>
<td>7 × 9½ [177.80 × 244.48]</td>
<td>40 [59.44]</td>
</tr>
<tr>
<td>8½ × 10¼ [219.08 × 273.05]</td>
<td>70 [104.04]</td>
</tr>
<tr>
<td>9½ × 11¼ [238.13 × 298.45]</td>
<td>45.5 [67.62]</td>
</tr>
<tr>
<td>9½ × 11¼ [238.13 × 298.45]</td>
<td>51.00–55.00 [75.80–81.74]</td>
</tr>
<tr>
<td>9½ × 11¼ [238.13 × 298.45]</td>
<td>79.00–80.50 [117.41–119.64]</td>
</tr>
<tr>
<td>9½ × 11¼ [238.13 × 298.45]</td>
<td>85 [121.92]</td>
</tr>
<tr>
<td>10 × 11¾ [254.00 × 297.85]</td>
<td>87.20–94.00 [129.59–139.70]</td>
</tr>
<tr>
<td>11¼ × 13½ [289.45 × 339.72]</td>
<td>68.00–72.00 [101.06–107.01]</td>
</tr>
<tr>
<td>11¼ × 13½ [289.45 × 346.08]</td>
<td>82.00 [117.41]</td>
</tr>
</tbody>
</table>

PST-R pocket-slip rotatable liner hanger with integral TBR and RCB profile.
COLOSSUS CMT Cemented Liner Hanger
System: Conventional System

Compatible Accessories
CMIB Internal Bypass Cement Manifold
CMIB Light Internal Bypass Cement Manifold
CMSB Solid Body Cementing Manifold
CRT Collet Running Tool
PDPC and LWPC Pumpdown Plug and Liner Wiper Plug
RCB Retrievable Cement Bushing
RRT Right-Hand-Release Running Tool
The hydraulic dual-cone liner hanger (HDC) is designed for use in wells where the work string can be manipulated to set the hanger. The HDC is composed of the hanger body or mandrel, one or more sets of cone pads, slips, and a cage assembly to carry the slips. The cage contains a J slot and drag springs. When the liner reaches the target depth, mechanical manipulation of the hanger body moves the cage J slot from the running position to the setting position, bringing the slips into contact with the cones. A gauge ring protects the slips while the hanger is being run into the wellbore.

The HDC is manufactured from mechanical tubing. The J lug, gauge ring, and cone pads are machined, integral features. This construction enhances the performance of the hanger. The slips are manufactured to 55-60 Rockwell “C” hardness and thus are compatible with high-grade casing. HDC dimensions are compatible with premium thread connections.

The HDC is run in combination with a setting adapter or packer and the corresponding setting tool. The STL mechanical release setting tool and RRT right-hand running tool are commonly used for HDC applications.

The HDC uses standard 80,000-psi [552-MPa] through 125,000-psi [862-MPa] yield materials. Other yield strengths and materials are available on request.
<table>
<thead>
<tr>
<th>Liner Hanger Size¹</th>
<th>Casing Size, in [mm]</th>
<th>Casing Weight, lbm/ft [kg/m]</th>
<th>Liner Size, in [mm]</th>
<th>Liner Weight Range lbm/ft [kg/m]</th>
<th>Max. OD, in [mm]</th>
</tr>
</thead>
<tbody>
<tr>
<td>5.000 × 7.000 [127.0 × 177.8]</td>
<td>7.000 [177.8]</td>
<td>23.00–26.00 [34.27–38.74]</td>
<td>5.000 [127.0]</td>
<td>11.50–24.10 [17.14–35.91]</td>
<td>6.050 [153.7]</td>
</tr>
<tr>
<td>7.000 × 9.625 [177.8 × 244.5]</td>
<td>9.625 [244.5]</td>
<td>36.00–43.50 [53.64–64.82]</td>
<td>7.000 [177.8]</td>
<td>17.00–35.00 [25.33–52.15]</td>
<td>8.430 [214.1]</td>
</tr>
<tr>
<td>7.625 × 9.625 [193.7 × 244.5]</td>
<td>9.625 [244.5]</td>
<td>36.00–43.50 [53.64–64.82]</td>
<td>7.625 [193.7]</td>
<td>24.00–47.10 [35.76–70.18]</td>
<td>9.500 [241.9]</td>
</tr>
</tbody>
</table>

¹Other sizes available on request.
APPLICATIONS
- Vertical and horizontal wells
- Deepwater and deep onshore wells
- ISO-14310 V3 liner top packoff requirements
- Liner hanger applications requiring drilldown capabilities
- High-pressure, high-temperature environments

BENEFITS
- Has large fluid bypass area that aids hole cleaning, reduces circulation time, and decreases trip time
- Optimizes well integrity and enhances well stability and safety with ISO-14310 V3–qualified equipment
- Minimizes completion time with drilldown liner
- Has holddown slips that prevent upward movement of the liner, resulting in more secure liner installation

FEATURES
- Antiswab element design
- Compatibility with mechanical- or hydraulic-release setting tools
- ISO-14310 V3 tested and qualified
- High torque capacity to rotate long liners
- Integral mandrel and setting adapter design
- Standard tieback receptacle (TBR)
- Standard holddown slips
- Integral retrievable cementing bushing (RCB) profile

The LTP V3 liner top packer with hold-down slips, part of the COLOSSUS CMT™ cemented liner hanger system, is ISO-14310 V3 qualified and rated to a differential pressure of 10,000 psi [68.9 MPa] in most sizes. The LTP packer is run above a liner hanger with either a mechanical right-hand release running tool (RRT) or a hydraulic collet-running tool (CRT) in high-pressure and high-temperature environments. After the liner hanger has been set and cemented, the packer is set by picking up the running string, placing the tamping dogs of the setting tool above the liner top, and slacking off weight. Excess cement above the liner top can then be circulated out after the packer is set.

The integral setting adaptor and mandrel design permits the transmission of high torque from the running string to the liner. This feature is used to drill down the liner while it is being run inhole. When a rotational hanger is deployed, the liner can be rotated after the liner hanger is set to improve cement integrity. Optimized design and materials maximize mandrel performance criteria such as burst, collapse, torque, and tensile ratings.

During running and cementing operations, a cementing packoff maintains a seal between the workstring and the liner. The LTP weight-set liner top packer includes an integral retrievable cementing bushing (RCB) profile, which is designed to eliminate extra connections in the liner hanger assembly.

The LTP packer uses standard 80,000-psi [552-MPa] through 125,000-psi [862-MPa] yield materials. Other yield strengths and materials are available on request.
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>5.0 × 7.0 [127.0 × 177.8]</td>
<td>26.0–32.0 [38.7–47.7]</td>
<td>10,000 [68.9]</td>
<td>325 [162.7]</td>
</tr>
<tr>
<td>5.0 × 7.0 [127.0 × 177.8]</td>
<td>35.0–38.0 [52.1–56.5]</td>
<td>10,000 [68.9]</td>
<td>325 [162.7]</td>
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<tr>
<td>5.5 × 7.625 [139.7 × 193.7]</td>
<td>26.4–29.7 [39.3–44.2]</td>
<td>10,000 [68.9]</td>
<td>325 [162.7]</td>
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<tr>
<td>5.5 × 7.625 [139.7 × 193.7]</td>
<td>33.7–39.0 [50.2–56.1]</td>
<td>10,000 [68.9]</td>
<td>325 [162.7]</td>
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<tr>
<td>7.0 × 9.625 [177.8 × 244.5]</td>
<td>36.0–43.5 [53.6–64.7]</td>
<td>7,500 [51.8]</td>
<td>325 [162.7]</td>
</tr>
<tr>
<td>7.0 × 9.625 [177.8 × 244.5]</td>
<td>43.5–53.5 [64.8–79.7]</td>
<td>10,000 [68.9]</td>
<td>325 [162.7]</td>
</tr>
<tr>
<td>7.0 × 9.625 [177.8 × 244.5]</td>
<td>53.5–58.4 [79.7–86.9]</td>
<td>10,000 [68.9]</td>
<td>325 [162.7]</td>
</tr>
<tr>
<td>7.0 × 9.625 [177.8 × 244.5]</td>
<td>47.0–53.5 [70.0–79.7]</td>
<td>10,000 [68.9]</td>
<td>325 [162.7]</td>
</tr>
<tr>
<td>9.625 × 11.750 [177.8 × 298.5]</td>
<td>60.0–66.7 [89.3–99.3]</td>
<td>10,000 [68.9]</td>
<td>325 [162.7]</td>
</tr>
<tr>
<td>9.625 × 13.375 [177.8 × 339.8]</td>
<td>61.0–72.0 [90.8–107.1]</td>
<td>10,000 [68.9]</td>
<td>325 [162.7]</td>
</tr>
<tr>
<td>11.75 × 13.375 [298.5 × 339.8]</td>
<td>68.0–72.0 [101.2–107.1]</td>
<td>7,500 [51.8]</td>
<td>325 [162.7]</td>
</tr>
</tbody>
</table>

†Other sizes available on request
COLOSSUS UNC Uncemented Liner Hanger System: Conventional System

Compatible Accessory
LRST Long Reach Setting Tool
The Long Reach® liner packer (LRP), part of the COLOSSUS UNC® uncemented liner hanger system, is an integral liner hanger packer that facilitates successful liner deployment in vertical and long-reach horizontal wellbores in high-temperature environments. Hydraulic-setting capability, combined with push, pull, and rotation capabilities, allows controlled liner deployment without excessive workstring manipulation. The LRP features an optional internal circulating string for wellbore fluid displacement.

The LRP is deployed using the Long Reach setting tool (LRST). The LRP includes an internal bypass feature that reduces the piston effect during running-in-hole operations.

Long Reach packer elements are available with standard or thermal elastomers for use in steam-injection applications. The LRP is available in standard 80,000-psi [552-MPa] through 125,000-psi [862-MPa] yield materials. Other yield strengths and materials are available on request.
<table>
<thead>
<tr>
<th>Liner × Casing Size, † in [mm]</th>
<th>Casing</th>
<th>Liner</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Size, in [mm]</td>
<td>Weight Range, lbm/ft [kg/m]</td>
</tr>
<tr>
<td>5.000 × 7.000 [127.0 × 177.8]</td>
<td>7.000 [177.8]</td>
<td>20.00–26.00 [29.80–38.74]</td>
</tr>
<tr>
<td>5.500 × 8.625 [139.7 × 219.1]</td>
<td>8.625 [219.1]</td>
<td>28.00–32.00 [41.72–47.68]</td>
</tr>
<tr>
<td>7.000 × 9.625 [177.8 × 244.5]</td>
<td>9.625 [244.5]</td>
<td>40.00–47.00 [59.60–70.03]</td>
</tr>
<tr>
<td>7.000 × 9.625 [177.8 × 244.5]</td>
<td>9.625 [244.5]</td>
<td>43.50–53.50 [64.82–79.72]</td>
</tr>
</tbody>
</table>

† Other sizes available on request.
Accessories
The internal bypass cement manifold (CMIB) can be used for cementing liners with a top-drive system on the rig, eliminating cement contamination of the top-drive components. The CMIB creates a flow path for cement and displacement fluids without allowing them to pass through the rig’s top-drive assembly.

The CMIB consists of a swivel and an internal bypass manifold with modular ball-drop and plug-drop assemblies. The one-piece swivel housing eliminates threads, flanges, and welds while increasing strength and reducing the bending loads imposed on the inlets. Drop mechanisms are self-contained for low maintenance.

The CMIB can be configured for single-plug, dual-plug, or single-ball drop operations. It is also suitable for running and cementing all types of liner hangers, including rotating liner-hanger systems.

Rotating and/or reciprocating the liner while cementing improves cement integrity, enhancing well stability and safety.
### CMIB Specifications

<table>
<thead>
<tr>
<th>Size, in [mm]</th>
<th>Upper Connection, in</th>
<th>Lower Connection, in</th>
<th>Nominal OD, in [mm]</th>
<th>Minimum ID, in [mm]</th>
</tr>
</thead>
<tbody>
<tr>
<td>6.625 [168.3]</td>
<td>6.625 full hole</td>
<td>6.625 full hole</td>
<td>13.000 [330.2]</td>
<td>4.000 [101.3]</td>
</tr>
</tbody>
</table>

*Overall length depends on tool configuration.*

### CMIB Swivel Specifications

<table>
<thead>
<tr>
<th>Size, in [mm]</th>
<th>Pipe Connection, in</th>
<th>Inlet Connection</th>
<th>Apparent Diameter, in [mm]</th>
<th>Nominal ID, in [mm]</th>
<th>Overall Length, in [mm]</th>
</tr>
</thead>
<tbody>
<tr>
<td>6.625 [168.3]</td>
<td>6.625 full hole</td>
<td>WECO 2-in 1502</td>
<td>22,000 [558.8]</td>
<td>4.000 [101.3]</td>
<td>81,120 [2060.4]</td>
</tr>
</tbody>
</table>

*Overall length depends on tool configuration.*
CMIB Light

Internal bypass cement manifold

APPLICATIONS
- Cementing operations with a top-drive system on land rigs
- Ideally suited for smaller rigs on land where weight and handling are constraints
- Shallow to intermediate-depth well applications
- Well applications requiring reciprocating and rotating of the liner while cementing
- Compatibility with single- or dual-wiper plug cementing systems
- Well applications requiring ball drop operations

BENEFITS
- Increases rig safety and handling on rig floor because of light weight
- Eliminates cement contamination of top drive, preventing associated maintenance costs
- Improves cement integrity and enhances well stability and safety because of rotation and/or reciprocation of the liner during cementing
- Maximizes rig safety during handling and rotation because of flush OD profile
- Increases rig safety because remote control unit enables personnel to control cement manifold from outside the rig floor

FEATURES
- Ratings to 750,000-lbm [340,194-kg] hook load and 30,000-ft.lbf [68,000 N.m] torque
- 10,000-psi [68,948-kPa] pressure rating
- 3.235-in [82-mm] through-bore for high displacement rates
- Modular system for different ball-drop and wiper-plug operations
- Optional remote-control unit
- Single-piece swivel housing that eliminates threads, flanges, and welds
- Optional Kelly valve for use in upper or lower end of swivel
- Design that prevents plugs or balls from floating into drop mechanisms
- Integral antirotation tie-off located on swivel housing

The internal bypass cement manifold (CMIB) Light is well suited for smaller rigs on land where weight and handling are constraints. The CMIB Light can be used for cementing liners with a top-drive system on the rig, eliminating cement contamination of the top-drive components. The CMIB Light creates a flow path for cement and displacement fluids without allowing them to pass through the rig’s top-drive assembly.

The CMIB Light consists of an internal bypass manifold with modular ball-drop and plug-drop assemblies. The one-piece swivel housing eliminates threads, flanges, and welds while increasing strength and reducing the bending loads imposed on the inlets. Drop mechanisms are self-contained for low maintenance.

The CMIB Light can be configured for single-plug, dual-plug, or single-ball drop operations. It is also suitable for running and cementing all types of liner hangers, including rotating liner-hanger systems.

Rotating and/or reciprocating the liner while cementing improves cement integrity, enhancing well stability and safety.
### CMIB Light Specifications

<table>
<thead>
<tr>
<th>Nominal OD, in [mm]</th>
<th>Minimum ID, in [mm]</th>
<th>Upper/Lower Connection, in</th>
<th>Hook Load, Ibm [kg]</th>
<th>Torque, ft.lbf [N.m]</th>
<th>Pressure, psi kPa</th>
</tr>
</thead>
<tbody>
<tr>
<td>11 [279]</td>
<td>3.235 [82]</td>
<td>4.50 IF/4.50 IF</td>
<td>750,000 [340,194]</td>
<td>30,000 [68,000]</td>
<td>10,000 [68,948]</td>
</tr>
</tbody>
</table>

### CMIB Light Swivel Specifications

<table>
<thead>
<tr>
<th>Pipe Connection, in</th>
<th>Inlet Connection</th>
<th>Apparent Diameter, in [mm]</th>
<th>Nominal ID, in [mm]</th>
</tr>
</thead>
<tbody>
<tr>
<td>4.50 IF</td>
<td>WECO 2-in 1502</td>
<td>22 [558.8]</td>
<td>3.235 [82]</td>
</tr>
</tbody>
</table>
The collet running tool (CRT) is a hydraulic-release running tool that requires no rotation to be released from the liner, making it suitable for applications in high-inclination wells. The clutch and premium tool joint connections permit high-torque rotating and drilldown capabilities throughout the liner system. When a rotational liner hanger is deployed, the CRT also enables the liner to be rotated after the liner hanger is set.

The CRT has a backup mechanical-release mechanism to ensure its release from the liner. The mechanical release is achieved by a one-quarter left-hand turn and placement of the tool in compression.

The CRT is used to run liner hanger systems that use the PV-3 liner top packer or the PV-3 setting adapter (PV3-SA). The setting string assembly consists of a CRT running tool, a slick joint, a cementing packoff bushing, a liner wiper plug adapter, and an extension to connect to the running string. A packer dog assembly can be included if a PV-3 packer is being run.

### CRT Specifications

<table>
<thead>
<tr>
<th>Liner × Casing Size, in [mm]</th>
<th>Liner Specifications</th>
</tr>
</thead>
<tbody>
<tr>
<td>5.000 × 7.000 [127.0 × 177.8]</td>
<td></td>
</tr>
<tr>
<td>5.500 × 7.625 [139.7 × 193.7]</td>
<td></td>
</tr>
<tr>
<td>7.000 × 9.625 [177.8 × 244.5]</td>
<td></td>
</tr>
<tr>
<td>7.625 × 9.625 [193.7 × 244.5]</td>
<td></td>
</tr>
<tr>
<td>9.625 × 11.750 [244.5 × 298.5]</td>
<td></td>
</tr>
<tr>
<td>9.625 × 13.375 [244.5 × 339.8]</td>
<td></td>
</tr>
<tr>
<td>11.75 × 13.375 [298.5 × 339.8]</td>
<td></td>
</tr>
</tbody>
</table>

*Other sizes are available on request.*
PDPC and LWPC
Pumpdown plug and liner wiper plug

APPLICATIONS
- Cementing operations during liner applications
- Wiping of the running string behind the cement with pumpdown plug
- Wiping of the liner behind the cement with liner wiper plug
- Separation of cement from the displacement fluid during cementing operations with pumpdown plug and liner plug

BENEFITS
- Improves cement integrity at the liner toe by separating displacement fluids in the running string and liner
- Reduces drillout times and operating costs with antirotation feature, which allows plugs to be drilled quickly

FEATURES
- Pumpdown plug that locks into upper section of liner wiper plug
- Liner wiper plug locking mechanism that provides protection against back pressure when locked and sealed to landing collar
- Compatibility of tool body elastomers with complex drilling fluids
- PDC drillable pumpdown plug and liner wiper plug

The pumpdown plug (PDPC) and liner wiper plug (LWPC) separate cement from the displacement fluid during liner cementing operations. Both plugs are required because of the large ID difference between the workstring and the liner.

The PDPC, released from the cementing manifold at the surface between the cement and the displacement fluid, wipes cement from the drillpipe and lands in the LWPC. When this happens, the pressure increases and shears the LWPC, allowing both plugs to be displaced as a unit to the landing collar.

The LWPC plug, commonly shear pinned to the liner setting tool, has a hollow internal diameter that allows fluids and cement to pass through the plug until the PDPC latches into the upper part of the LWPC. The PDPC is then mechanically and hydraulically sealed to the LWPC, and the two plugs are sheared from the liner setting tool. After wiping the liner, the LWPC is latched and sealed to the landing collar, preventing the backflow of cement.

LWPCs and PDPCs are manufactured from high-grade aluminum, allowing for easier drillout with a PDC bit.
### PDPC Specifications

<table>
<thead>
<tr>
<th>Drillpipe Size, in [mm]</th>
<th>Mixed-String Drillpipe Size, in [mm]</th>
</tr>
</thead>
<tbody>
<tr>
<td>2.375 [60.3]</td>
<td>2.375 × 2.875 [60.3 × 73.0]</td>
</tr>
<tr>
<td>2.875 [73.0]</td>
<td>2.875 × 3.500 [73.0 × 88.9]</td>
</tr>
<tr>
<td>3.500 [88.9]</td>
<td>3.500 × 4.500 [88.9 × 114.3]</td>
</tr>
<tr>
<td>4.000 [101.6]</td>
<td>4.000 × 5.000 [101.6 × 114.3]</td>
</tr>
<tr>
<td>4.500 [114.3]</td>
<td>4.500 × 5.500 [114.3 × 139.7]</td>
</tr>
<tr>
<td>5.000 [127.0]</td>
<td>5.000 × 5.500 [127.0 × 139.7]</td>
</tr>
<tr>
<td>5.500 [139.7]</td>
<td>5.000 × 6.625 [139.7 × 168.3]</td>
</tr>
<tr>
<td>6.625 [168.3]</td>
<td></td>
</tr>
<tr>
<td>7.000 [177.8]</td>
<td></td>
</tr>
</tbody>
</table>

### LWPC Specifications

<table>
<thead>
<tr>
<th>Liner Size,† in [mm]</th>
<th>Weight, lbf/ft [kg/m]</th>
</tr>
</thead>
<tbody>
<tr>
<td>2.875 [73.0]</td>
<td>6.50–10.40 [9.69–15.50]</td>
</tr>
<tr>
<td>4.000 [101.6]</td>
<td>9.50 [14.16]</td>
</tr>
<tr>
<td>4.000 [101.6]</td>
<td>11.00–11.60 [16.39–17.26]</td>
</tr>
<tr>
<td>4.000 [101.6]</td>
<td>14.00 [20.86]</td>
</tr>
<tr>
<td>4.500 [114.3]</td>
<td>15.10 [22.50]</td>
</tr>
<tr>
<td>5.000 [127.0]</td>
<td>11.50–15.00 [17.14–22.35]</td>
</tr>
<tr>
<td>5.000 [127.0]</td>
<td>18.00–24.20 [28.01–36.06]</td>
</tr>
<tr>
<td>5.000 [127.0]</td>
<td>26.70 [39.78]</td>
</tr>
<tr>
<td>5.500 [139.7]</td>
<td>14.00–17.00 [20.86–25.33]</td>
</tr>
<tr>
<td>5.500 [139.7]</td>
<td>20.00–28.40 [29.80–42.32]</td>
</tr>
<tr>
<td>6.625 [168.3]</td>
<td>20.00–32.00 [29.80–47.68]</td>
</tr>
<tr>
<td>7.000 [177.8]</td>
<td>17.00–26.00 [25.33–36.74]</td>
</tr>
<tr>
<td>7.000 [177.8]</td>
<td>29.00–38.00 [43.21–56.62]</td>
</tr>
<tr>
<td>7.000 [177.8]</td>
<td>41.00–44.00 [61.09–65.56]</td>
</tr>
<tr>
<td>7.000 [177.8]</td>
<td>49.50 [73.76]</td>
</tr>
<tr>
<td>7.625 [193.7]</td>
<td>29.70–39.00 [44.25–58.11]</td>
</tr>
<tr>
<td>7.625 [193.7]</td>
<td>42.80–53.06 [63.77–79.06]</td>
</tr>
<tr>
<td>7.750 [196.9]</td>
<td>46.10 [68.69]</td>
</tr>
<tr>
<td>8.625 [219.1]</td>
<td>24.00–40.00 [35.76–59.60]</td>
</tr>
<tr>
<td>8.625 [219.1]</td>
<td>44.00–52.00 [65.56–77.48]</td>
</tr>
<tr>
<td>9.625 [244.5]</td>
<td>32.30–40.00 [48.13–59.60]</td>
</tr>
<tr>
<td>9.625 [244.5]</td>
<td>43.50–53.50 [64.82–79.72]</td>
</tr>
<tr>
<td>9.625 [244.5]</td>
<td>58.40–61.00 [87.02–90.89]</td>
</tr>
<tr>
<td>9.625 [244.5]</td>
<td>71.80 [106.98]</td>
</tr>
<tr>
<td>9.875 [250.8]</td>
<td>62.80 [92.94]</td>
</tr>
<tr>
<td>10.750 [273.1]</td>
<td>51.00–55.00 [75.99–81.95]</td>
</tr>
<tr>
<td>10.750 [273.1]</td>
<td>60.70–71.10 [90.44–105.94]</td>
</tr>
<tr>
<td>10.750 [273.1]</td>
<td>73.20–85.30 [109.07–127.10]</td>
</tr>
<tr>
<td>11.750 [298.5]</td>
<td>54.00–65.00 [80.46–96.85]</td>
</tr>
<tr>
<td>11.625 [301.6]</td>
<td>17.80 [26.52]</td>
</tr>
<tr>
<td>13.375 [338.7]</td>
<td>54.00–72.00 [80.46–107.28]</td>
</tr>
<tr>
<td>16.000 [406.4]</td>
<td>65.00–84.00 [96.85–125.16]</td>
</tr>
<tr>
<td>16.000 [406.4]</td>
<td>94.00 [140.06]</td>
</tr>
</tbody>
</table>

---

†Other sizes available on request
‡Used for multistage stimulation liner string with a rupture disc valve restriction of 3.25 in
### Applications
- Actuating hydraulic tools in pressure-sensitive formations
- High-inclination wells
- Openhole applications where the liner string consists of additional pressure-actuated tools, such as external casing packers and cementing stage collars

### Benefits
- Minimizes risk of fracturing formation by pressure to 500 psi [3.4 MPa] when releasing the setting ball
- Simplifies seating of setting ball in horizontal applications than with liner toe landing collar
- Reduces operation time in long liners because ball does not have to reach a landing collar at the liner toe

### Features
- Reduced surge of less than 500 psi during tool function
- Design that ensures the ball is dislodged as the ball seat shears
- Fullbore clearance after ball seat shears
- Variable shear pressure and settings
- Can be configured as single-action or multiaction shearing mechanism
- Rupture disc incorporated as contingency device

### PSCD Specifications

<table>
<thead>
<tr>
<th>Liner Size, in [mm]</th>
<th>Max. OD, in [mm]</th>
<th>Min. ID, in [mm]</th>
<th>Drop Ball Size, in [mm]</th>
<th>Min. ID After Shear, in [mm]</th>
<th>Connection,†</th>
<th>Connection,‡</th>
</tr>
</thead>
<tbody>
<tr>
<td>7.000 [168.3] and up</td>
<td>5.490 [139.4]</td>
<td>2.750 [69.8]</td>
<td>2.750 [69.9]</td>
<td>3.500 [88.9]</td>
<td>Stub Acme</td>
<td></td>
</tr>
</tbody>
</table>

†Other connections available on request.

Design to minimize the surge effect to the formation, the pressure surge control device (PSCD) is a ball seat that temporarily plugs the drillstring to allow hydraulic tools to be actuated. When pressure is required to set hydraulic liner systems, a ball is released from surface and lands on the ball seat within the PSCD. Pressure can then be applied to actuate tools. The PSCD is available as a single- or multicycle tool that can be configured for a variety of applications with the COLOSSUS CMT* cemented liner system and COLOSSUS UNC* uncemented liner hanger system.

**Available modes**

- **Single-cycle mode**
  - Increasing pressure above the predetermined shear value initiates the PSCD shear mechanism.
  - Pressure is then bled off at surface to 500 psi.
  - At this point, the tool rotates, releasing the setting ball from the PSCD and allowing circulation to recommence.
  - The tool can also be configured with multicycle mode, which enables multiple pressure cycles to take place prior to shearing and allows additional hydraulic actuations to be performed.

**Reduced formation pressure surge**

- Since the PSCD is positioned in the running string, and the pressure at which the setting ball is released from the PSCD is only 500 psi, it virtually eliminates the formation surge pressures experienced when conventional landing collar ball seats shear. Once the liner hanger has been set and the ball seat sheared, fullbore ID facilitates normal cementing operations, including the passage of drillpipe wiper plugs.
The retrievable cement bushing (RCB) is composed of a body with locking lugs and interior and exterior seals. The RCB sits in a machined profile in the liner setting adapter, liner top packer, or profile sub. The recess on the polished OD setting tool slick joint allows retrieval of the RCB with the setting tool.

The RCB can be run with most liner systems and provides pressure integrity from the workstring to the liner. It remains in position throughout the running and cementing operation and allows liner top packers to be pressure tested after they are set.

### Standard RCB Specifications

<table>
<thead>
<tr>
<th>Liner Size, in [mm]</th>
<th>Slick Joint Size, in [mm]</th>
</tr>
</thead>
<tbody>
<tr>
<td>4.500 (114.3)</td>
<td>2.625 × 2.000 (66.7 × 50.8)</td>
</tr>
<tr>
<td>5.000 (127.0)</td>
<td>2.625 × 2.000 (66.7 × 50.8)</td>
</tr>
<tr>
<td>5.500 (139.7)</td>
<td>3.250 × 2.500 (82.6 × 63.5)</td>
</tr>
<tr>
<td>6.625 (168.3)</td>
<td>2.625 × 2.000 (66.7 × 50.8)</td>
</tr>
<tr>
<td>7.000 (177.8)</td>
<td>3.750 × 3.000 (95.3 × 76.2)</td>
</tr>
<tr>
<td>7.625 (193.7)</td>
<td>3.750 × 3.000 (95.3 × 76.2)</td>
</tr>
<tr>
<td>8.625 (219.1)</td>
<td>3.750 × 3.000 (95.3 × 76.2)</td>
</tr>
<tr>
<td>9.625 (244.5)</td>
<td>4.000 × 3.000 (101.6 × 76.2)</td>
</tr>
<tr>
<td>10.750 (273.1)</td>
<td>4.000 × 3.000 (101.6 × 76.2)</td>
</tr>
<tr>
<td>11.750 (298.5)</td>
<td>4.000 × 3.000 (101.6 × 76.2)</td>
</tr>
</tbody>
</table>

*Other sizes available on request*

### COLOSSUS® Liner Hanger System RCB Specifications

<table>
<thead>
<tr>
<th>Liner Size, in [mm]</th>
<th>Casing, in [mm]</th>
<th>Slick Joint Size, in [mm]</th>
</tr>
</thead>
<tbody>
<tr>
<td>5.00 (127.0)</td>
<td>7.00 (177.8)</td>
<td>2.625 × 2.000 (66.7 × 50.8)</td>
</tr>
<tr>
<td>5.50 (139.7)</td>
<td>7.625 (193.7)</td>
<td>2.625 × 2.000 (66.7 × 50.8)</td>
</tr>
<tr>
<td>7.00 (177.8)</td>
<td>9.625 (244.5)</td>
<td>3.750 × 2.750 (95.3 × 69.9)</td>
</tr>
<tr>
<td>7.625 (193.7)</td>
<td>9.625 (244.5)</td>
<td>3.750 × 2.750 (95.3 × 69.9)</td>
</tr>
<tr>
<td>9.625 (244.5)</td>
<td>11.750 (298.5)</td>
<td>5.500 × 4.000 (139.7 × 101.6)</td>
</tr>
<tr>
<td>9.625 (244.5)</td>
<td>13.375 (339.8)</td>
<td>5.500 × 4.000 (139.7 × 101.6)</td>
</tr>
<tr>
<td>11.75 (298.5)</td>
<td>13.375 (339.8)</td>
<td>5.500 × 4.000 (139.7 × 101.6)</td>
</tr>
</tbody>
</table>

*Other sizes available on request*
RBS
Rotational ball seat

APPLICATIONS
- High-inclination wells
- Low-fracture pressure formations
- Well applications where liner string consists of additional pressure-actuated tools, such as external casing packers (ECPs)

BENEFITS
- Minimizes risk of ball-seating failure in horizontal sections
- Saves operation time in long liners because ball does not have to reach liner toe
- Reduces risk of fracturing formation because of sharp rise in equivalent circulating density (ECDs) when conventional liner toe ball seats shear

FEATURES
- Design that ensures that the ball is dislodged as the ball seat shears
- Full-bore clearance after ball seat shears
- Design that ensures that the ball seat is completely tripped and retained in full-bore open position
- Variable shear-pressure settings for liner systems consisting of numerous hydraulic actuating parts

The rotational ball seat (RBS) is a ball-type tubing-blockage device that is run in the liner setting string. When pressure is required to set hydraulic liner systems, a drop-ball is released from the surface and lands on the ball seat contained within the RBS. Increasing the pressure above the predetermined shear value causes the ball seat to shear and rotate down. The drop-ball is released, and a smooth and full ID is present through the tool.

Since the RBS is run in the setting string, it reduces formation pressure surges that are experienced when conventional liner toe ball seats shear. Once the liner hanger has been set and the RBS sheared, a full-bore ID allows normal cementing operations, including the passage of drillpipe wiper plugs.

RBS Specifications

<table>
<thead>
<tr>
<th>Liner Size, in (mm)</th>
<th>Max. OD, in [mm]</th>
<th>Min. ID, in [mm]</th>
<th>Drop Ball Size, in [mm]</th>
<th>Connection,† in [mm]</th>
</tr>
</thead>
<tbody>
<tr>
<td>6.625 [168.3] and up</td>
<td>5.5 [139.7]</td>
<td>3 [76.2]</td>
<td>1.25 [31.8]</td>
<td>3.5 [88.9] NU</td>
</tr>
<tr>
<td>4.5 [114.3] to 6.0 [152.4]</td>
<td>3.625 [92.1]</td>
<td>1.93 [49]</td>
<td>1.5 [38.1]</td>
<td>2.375 [60.3] NU</td>
</tr>
</tbody>
</table>

†Other connections available on request.
The right-hand-release running tool (RRT) is designed to mechanically or hydraulically set liner hanger systems that require high torque to enable drilling the liner during the operation. In cases where a rotational liner hanger is deployed, the RRT also enables the liner to be rotated after the liner hanger is set. The tensile and torque ratings make the RRT suitable for challenging liner hanger applications.

The RRT can be configured into a mechanical or hydro-mechanical release tool. The RRT-HM hydraulic model has an anti-prerelease feature that ensures the setting tool does not release prematurely in drill-down applications. After the hydraulic lock has been released by applying the required pressure, the RRT is mechanically released by rotating to the right in compression. In situations where a hydraulic anti-prerelease feature is not required, the RRT can be reconfigured for mechanical release only (RRT-M).

The RRT is also used to run mechanically or hydraulically set liner systems that employ the PV-3 liner top packer or the PV-3 setting adapter. The setting string assembly typically consists of an RRT, a slick joint, a cementing pack-off bushing, a liner wiper-plug adapter, and an extension to connect to the running string. A packer-dog assembly can be included if a liner top packer is being run.

### RRT Specifications

<table>
<thead>
<tr>
<th>Liner × Casing Size, † in [mm]</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>5.000 × 7.000 (127.0 × 177.8)</td>
<td></td>
</tr>
<tr>
<td>5.500 × 7.625 (139.7 × 193.7)</td>
<td></td>
</tr>
<tr>
<td>7.000 × 9.625 (177.8 × 244.5)</td>
<td></td>
</tr>
<tr>
<td>7.625 × 9.625 (193.7 × 244.5)</td>
<td></td>
</tr>
</tbody>
</table>

† Other sizes available on request.

Left: RRT-HM hydro-mechanical release running tool.

Right: RRT-M mechanical release running tool.
APPLICATIONS

- Offshore and onshore wells
- Well applications requiring mechanical or hydraulic liner hanger setting
- Well applications where rotation while running in the hole is required to navigate around obstructions

BENEFITS

- Minimizes completion time because of ability to pass liner around obstructions when running in hole

FEATURES

- Clutch feature allows orientation of liner system when running in the hole.
- Hydraulic or mechanical setting option is available during deployment.
- Centralizing system ensures easy release of running nut.
- Bearing eliminates need to find neutral to release.
- Slip-activating dogs provide uniform and controlled slip activation.
- Systems are designed to provide internal flow path.
- Systems can be run with or without packer setting tool.

The pocket-slip setting tool is available in a nonrotational (STP) and rotational (STPR) configuration. These tools are used to set the pocket-slip liner hanger (PSH) and rotational pocket-slip liner hanger (PSHR), respectively.

The STP and STPR tools incorporate a hanger setting mechanism that can be activated hydraulically or mechanically during liner deployment. When the hanger setting dogs are activated, the setting tool positively actuates the liner hanger slips, resulting in uniform loading when the liner is being hung. A right-hand liner running thread then facilitates the setting tool’s release from the liner. With the STPR, axial shear pins are used to release the drive clutch.

The setting tool assembly typically consists of an STP or an STPR, a slick joint, a cementing pack-off bushing, a liner wiper plug adapter, and an extension to connect to the running string. A packer setting tool can be included if a liner packer is being run.

### STP Specifications

<table>
<thead>
<tr>
<th>Tool Size</th>
<th>Sets Liner Hangers Inside Casing Size, in [mm]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Small</td>
<td>5.500 [139.7] and smaller</td>
</tr>
<tr>
<td>Medium</td>
<td>7.000 [177.8] and 7.625 [193.7]</td>
</tr>
<tr>
<td>Large</td>
<td>9.625 [244.5] and larger</td>
</tr>
</tbody>
</table>

†Some components are changed to accommodate different casing sizes and weights.

### STPR Specifications

<table>
<thead>
<tr>
<th>Tool Size</th>
<th>Sets Liner Hangers Inside Casing Size, in [mm]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Medium</td>
<td>7.000 [177.8] and 7.625 [193.7]</td>
</tr>
<tr>
<td>Large</td>
<td>9.625 [244.5] and larger</td>
</tr>
</tbody>
</table>

†Some components are changed to accommodate different casing sizes and weights.
The solid body cementing manifold (CMSB) suspends drillpipe from the rig elevators and retains the wiper plug so that it can be released after the cement has been pumped. The CMSB also connects the cementing lines to the running string during liner operations. It includes a heavy-duty swivel for easy string manipulation with the cementing lines in place. The swivel mechanism and drillpipe plug retainer are below the elevators for unobstructed operation.

The CMSB is available with single or dual plugdrop capabilities; an optional ball-drop assembly is available for use with hydraulic-set liner hanger systems.

**CMSB Specifications**

<table>
<thead>
<tr>
<th>Size (IF pin × lift sub), in [mm]</th>
</tr>
</thead>
<tbody>
<tr>
<td>2.875 [73.0] × 2.875 [73.0]</td>
</tr>
<tr>
<td>3.500 [88.9] × 3.500 [88.9]</td>
</tr>
<tr>
<td>4.500 [114.3] × 4.500 [114.3]</td>
</tr>
<tr>
<td>4.500 [114.3] × 5.000 [127.0]</td>
</tr>
</tbody>
</table>

**APPLICATIONS**
- Liner cementing operations
- Rotary rig cementing operations
- Liner systems requiring a ball drop

**BENEFITS**
- Rotating and reciprocating the liner while cementing improves cement integrity.
- Manifold enhances well stability and safety.

**FEATURES**
- Swivel that permits manipulation of the workstring without breaking cementing lines
- Optional flag sub feature that indicates drillpipe wiper plug release
- Strong steel construction
- Single plug configuration
LRST
Long Reach setting tool

APPLICATIONS
- Horizontal wells
- Well applications requiring rotation when running in hole
- Operations requiring pushing and pulling the liner to reach target depth
- Well applications requiring a hydraulic-setting and release mechanism

BENEFITS
- Minimize completion time by rotating the liner when running in hole
- Reduces risk of pulling liner out of well and saves associated time and costs with secondary-release option

FEATURES
- Clutch design to transmit torque to the liner
- Hydraulic pusher sleeve to hang and pack off tool
- Setting tool that accepts inner circulation string
- Internal bypass feature to reduce formation surge pressures
- Backup mechanical release (one-quarter left-hand turn) to ensure liner release

The Long Reach* setting tool (LRST) is used exclusively to run liner systems that use the Long Reach liner packer (LRP). The setting tool includes a collet-type hydraulic-release liner deployment and release mechanism, as well as a pusher sleeve to pack off the LRP. No rotation is required to release the LRST from the liner, making it suitable for horizontal and high-inclination wells.

The LRST allows the Long Reach liner system to be pushed, pulled, and rotated to achieve target depth. An internal bypass feature reduces formation surge pressures and allows faster running speeds. The LRST also features a backup mechanical-release mechanism that reduces the risk of not being able to release the LRST from the liner. The mechanical release is achieved by a one-quarter turn to the left.

<table>
<thead>
<tr>
<th>LRST Specifications</th>
</tr>
</thead>
<tbody>
<tr>
<td>Liner × Casing,† in [mm]</td>
</tr>
<tr>
<td>4.500 × 7.000 [114.3 × 177.8]</td>
</tr>
<tr>
<td>5.000 × 7.000 [127.0 × 177.8]</td>
</tr>
<tr>
<td>7.000 × 9.625 [177.8 × 244.5]</td>
</tr>
<tr>
<td>9.625 × 11.750 [244.5 × 298.5]</td>
</tr>
</tbody>
</table>

†Other sizes available on request.
Packers Plus Products
Overview
Packers Plus has a fully integrated quality assurance and quality control process that begins at the design stage and follows each tool through manufacturing, assembly, testing, shipping, and installation.

Automation and robotics are incorporated into this proven process to ensure consistency and repeatability of key criteria in each step of the design, development, and manufacture of these patented tools and systems.

Minimized risk
Efficient systems reduce time, costs, and risk and eliminate the cost of interventions.
- A fully integrated ISO 9001 and API Spec Q1 quality management and quality control process ensures every part meets high quality standards.
- Automation enables consistent and accurate tolerances and dimensions on every tool.
- All specification and testing information is stored in a unique 2D bar code for each tool, which is electronically stored in a data management system.
- Manual inspections are completed before shipping, at arrival and departure from service centers, and at arrival on site.

Improved performance
High-quality, reliable tools have been proven to improve field performance and subsequent production. A 97% success rate on Packers Plus FracPORT™ sleeve shifts was correlated to higher production in a study in a major US formation.

![Cumulative BOE by Sleeve Efficiency](image)

Highest sleeve efficiency (84–100% success) correlated to the highest BOE after 550 days.
Quality and Reliability

Robotics and automation

Automated storage and robotic assembly
Over 6,000 crates, with the capacity to hold 20,000 t, automatically deliver components to assembly robots. Robotic assembly is efficient, accurate, and less prone to human error.

Coordinated measuring machines
To achieve consistent precision and ensure the reliability of Packers Plus systems, all tools can be measured to within 0.0001 in [0.00025 cm].

Automated torque and pressure tests
This system can automatically load, test up to 15,000 psi [103 MPa], and unload multiple tools at a time.

Ball scan
A 3D laser scans all ball sizes, checking for defects from 18 positions. The scanner checks for ovality and verifies dimensions within a 0.003-in tolerance.

Full traceability capabilities
Each tool is imprinted with a 2D bar code to capture every stage of quality assurance:
- raw material certificate
- automated storage
- automated or manual assembly
- pressure, torque, drift, and other test results
- manual check before and after arrival at service centers
- shipping
- onsite installation
- position downhole.
Systems
StackFRAC HD
Multistage ball-activated completion system

OVERVIEW

StackFRAC® HD ball-activated completion systems are designed for openhole and cased hole stimulation in unconventional tight oil and gas formations. This innovative, field-proven system enables exact placement of stimulation treatments in one continuous pumping operation. Once the stimulation operation is complete, the well can be immediately flowed back and put on production. StackFRAC HD systems provide operators with an efficient and cost-effective method to complete their wells.

The system is modular with regard to tool placement and it can be combined with other Packers Plus tools and systems, enabling customized stimulation programs.

APPLICATIONS

- Multistage stimulation in openhole and cased hole horizontal and vertical wells
- Production testing before and after stimulation
- Tight oil and gas formations
- Critical sour environments
- Extended-reach horizontal wells
- Multilaterals

BENEFITS

- Reduce costs with continuous rigless pumping operation and immediate poststimulation flowback.
- Stimulate more of the wellbore with improved isolation using field-proven mechanical RockSEAL® H2 packers.
- Increase production by accessing natural fractures in openhole applications.
- Implement custom stimulation programs by combining a range of Packers Plus tools to complete the entire lateral.
**StackFRAC HD**

**FracPORT™ H2 sleeve**
- Ball-actuated, hydraulically activated injection/production port
- Unrestricted flow through ports for stimulation
- Drillable closeable (DC) version available for water or gas shutoff, flow control, refracturing, and production testing

**RockSEAL H2 packer**
- Dual-element, hydraulically set mechanical packer with premium seal technology
- Reliable high-pressure zonal isolation during stimulation and throughout the life of the well
- Short length, minimum OD, and antipreset features for ease of installation

**RockSEAL IIS packer**
- Single-element, double-grip anchor packer that is hydraulically set and retrievable
- Features slips that anchor the StackFRAC HD system at the toe of the well, wellbore junctions, or other areas for extra stability

**FracPORT™ H2 sleeve**
- Ball-actuated, hydraulically activated injection/production port
- Unrestricted flow through ports for stimulation
- Drillable closeable (DC) version available for water or gas shutoff, flow control, refracturing, and production testing

**RockSEAL IIS packer**
- Single-element, double-grip anchor packer that is hydraulically set and retrievable
- Features slips that anchor the StackFRAC HD system at the toe of the well, wellbore junctions, or other areas for extra stability
OVERVIEW

The StackFRAC® slimhole system is specially designed with a smaller OD, enabling reentry into vertical or horizontal wells. It provides a cost-effective solution for restimulation and well recovery applications.

The StackFRAC slimhole system was developed with the same features and efficiencies as the Packers Plus StackFRAC multistage completion system. This innovative system enables exact placement of stimulation treatments in one continuous pumping operation, saving operators time and money.

SLIMHOLE SYSTEM STAGE CAPABILITY

| Casing OD, in | 4½ | 5½ |
| Liner OD, in  | 2¾ | 3½ |
| Stage count capability with ⅛-in ball seat increments | 8 | 16 |
| Stage count capability with ¹⁄₁₆-in ball seat increments | 19 | 32 |

BENEFITS

- Increase production from previously produced reservoirs.
- Reduce completion time and cost with a continuous rigless pumping operation.
- Implement custom stimulation for each stage of a previously completed wellbore.
- Reduce dependency on integrity of existing casing.
APPLICATONS

1. Restimulation
Restimulation of existing vertical or horizontal wells completed with cemented liner or openhole multistage systems to improve recovery from damaged or depleted zones
- FracPORT™ sleeves can be aligned with existing ports to establish communication with the reservoir

2. Recovery
Recovery of wells where a loss of integrity has hindered the ability to stimulate
- Field-proven RockSEAL™ packers isolate liner breaches, enabling stimulation of the well
- FracPORT sleeves can be aligned with new or existing perforations to establish communication with the reservoir

3. Stimulation of openhole laterals
Stimulation of openhole laterals drilled off existing verticals to exploit new or depleted zones and increase productivity
- Eliminates the need to drill additional wells to exploit a reservoir
- Saves on well construction costs associated with drilling and casing a new wellbore
- Easily installed through high-angle build sections
QuickFRAC
Limited-entry ball-activated completion system

OVERVIEW

The QuickFRAC® system is an openhole multistage completion system that uses limited entry to selectively stimulate multiple stages with one treatment from surface.

The system is modular with regard to tool placement and it can be combined with other Packers Plus tools and systems, enabling a fully customizable system.

A configuration of RockSEAL® H2 packers and a number of QuickPORT™ V sleeves allows multiple, individually isolated stages to be grouped together in a single treatment zone. Using a designed pump rate to maintain the desired pressure differential, the system evenly distributes batch fractures in a select zone. After stimulation, the well can be immediately flowed back and put on production.

APPLICATIONS

- Openhole horizontal and vertical wells
- Batch stimulation of multiple stages
- Tight oil and gas formations
- Critical sour environments

BENEFITS

- Complete wells faster by stimulating multiple entry points in one treatment.
- Stimulate more of the wellbore with improved isolation using field-proven mechanical RockSEAL H2 packers.
- Customize stimulation programs by combining a variety of Packers Plus tools to complete the entire lateral.

Schlumberger and Packers Plus Technology Alliance
QuickFRAC

RockSEAL H2 packer
- Dual-element, hydraulically set mechanical packer with premium seal technology
- Reliable high-pressure zonal isolation during stimulation and throughout the life of the well
- Short length, minimum OD, and anti preset features for ease of installation

QuickPORT V sleeve
- Ball-actuated, hydraulically activated injection/production port
- Enables activation of multiple stages with the same size actuation ball
- Flow ports available in a variety of sizes to optimize limited-entry treatment

RockSEAL IIS packer
- Single-element, double-grip, hydraulically set, retrievable
- Features slips that anchor the QuickFRAC system at the toe of the well, wellbore junctions, or other areas for extra stability

Hydraulic toe sleeve
- Hydraulically activated injection/production port used for the first stage of stimulation
- Designed to ensure full opening for effective stimulation of the first stage
- Customizable activation shear
- Improved well longevity with corrosion-resistant option
TREX Single-Point Entry System
With cemented, ball-activated Diffusor sleeves

OVERVIEW

The TREX™ single-point entry system uses Diffusor™ sleeves to bring the operational efficiency of ball-activated completion technology to cemented liner completions. Once the system is cemented in place, a Diffusor landing dart and wiper ball are pumped from surface to clear the system of cement. For each successive stage, a ball is pumped from surface to open a Diffusor sleeve; high-pressure fluid can flow through the sleeve ports to stimulate the formation. Lower zones are isolated by increasing ball and seat sizes.

This multistage completion system enables exact placement of stimulation treatments in one continuous pumping operation, providing operators with an efficient and cost-effective method for completing cemented liner wells.

APPLICATIONS

- Horizontal and vertical wells with cemented liner
- Selective stimulation of multiple stages
- Tight oil and gas formations

BENEFITS

Reduce costs with a continuous rigless pumping operation and immediate post-stimulation flowback.

Design a customized stimulation program.

Combine a range of Packers Plus tools to complete the entire lateral.
TREX Single-Point Entry

**Diffusor sleeve**
- Ball-actuated, hydraulically activated injection/production port
- Ports provide unrestricted flow for stimulation
- Specially designed coating helps prevent cement from adhering to the tool

**Hydraulic toe sleeve**
- Hydraulically activated injection/production port used for the first stage of Packers Plus cemented stimulation system applications
- Premium seal package ensures reliability
- Specially designed coating helps prevent cement from adhering to the tool

**Diffusor landing dart and wiper ball with landing sub**
- Cleans the inside of the liner after cementing operations are complete
- Diffusor landing dart latches and seals into the Diffusor landing sub at the toe of the liner to close off flow between the liner and the annulus, allowing pressure to build
- Diffusor wiper ball compresses down to travel through various ball seat sizes
OVERVIEW

The TREX™ limited-entry system is a multistage completion system for cemented liners that uses QuickPORT™ IV sleeves to selectively stimulate multiple stages with one treatment from surface.

A number of QuickPORT IV sleeves of the same ball seat size enable multiple, individually isolated stages to be grouped together in a single treatment zone. Using a designed pump rate to maintain a desired pressure differential, the system evenly distributes batch fractures in a select zone of the wellbore. After stimulation, the well can be immediately flowed back and put on production.

The TREX limited-entry system is modular with regard to tool placement and it can be combined with other Packers Plus tools and systems, enabling customized stimulation programs.

APPLICATIONS

- Cemented liner and openhole wells
- Limited-entry batch stimulation of multiple stages
- Tight oil and gas formations
- Critical sour environments

BENEFITS

- Complete wells faster by stimulating multiple entry points in one treatment.
- Eliminate entry-point erosion by using reinforced flow ports.
- Reduce operational risks associated with wireline or coiled tubing runs.
**Diffusor™ landing dart and wiper ball with landing sub**

- Cleans the inside of the liner after cementing operations are complete
- Diffusor landing dart latches and seals into the Diffusor landing sub at the toe of the liner to close off flow between the liner and the annulus, allowing pressure to build
- Diffusor wiper ball compresses down to travel through various ball seat sizes

**QuickPORT IV sleeve**

- Simple design with few parts
- Ball-actuated, hydraulically activated injection/production port
- Enables activation of multiple stages with the same size actuation ball
- Flow ports available in a variety of sizes to optimize limited-entry treatment

**StackFRAC® (SF) ball**

- Used in multistage ball-activated stimulation systems to hydraulically activate downhole tools and divert fluid flow
- Mitigates the need for poststimulation intervention
- Multiple ball options to suit various completion designs
Packers
RockSEAL H2 Packer

APPLIcATIONS
- Open and cased holes
- Horizontal and vertical wells
- HPHT and sour service
- Isolation of individual zones for
  - stimulation
  - water and gas shutoff
- Production control
- Production testing

FEATURES AND BENEFITS
- Dual-element/piston design
- High expansion ratios
- Premium seal technology
- Ease of installation because of
  - short length
  - minimum running OD
  - antipreset features for running in hole
- Adjustable setting forces
- Application-specific elastomers
- Long-term, high-pressure zonal isolation
- Not affected by temperature cycling

Overview
The RockSEAL® H2 packer is a hydraulically set, mechanical packer. It features upgraded premium seal technology, which together with the dual-element design, ensures reliable, high-pressure zonal isolation during stimulation operations and throughout the life of the well.

The packer facilitates installation with its short length, minimum OD, and antipreset features. Hydraulic activation provides precise control over the setting operation, resulting in time and cost efficiencies.

Operation
The RockSEAL H2 packer is assembled in the completion toolstring according to well requirements and run into the wellbore to the planned depth. When the string is in place, the packer is hydraulically set by pressuring up the tubing string, causing the elements to extrude and secure the packer in the hole.
**RockSEAL IIS Packer**

**Applications**
- Open and cased holes
- Horizontal and vertical wells
- HPHT and sour service
- Isolation of individual zones for fracture stimulation
- Production control
- Production testing
- Essential anchoring for toe stimulation
- Retrievable bridge plug applications
- As a liner hanger packer in casing, together with a polished bore receptacle (PBR) seal assembly

**Features and Benefits**
- Single-element, double-grip anchor packer
- Minimum running OD
- High expansion ratios
- Antipreset features for running in hole
- Adjustable setting and releasing forces
- High-retention slip package
- Application-specific elastomers
- Feed-through capability

**Overview**
The RockSEAL® IIS packer is a single-element, double-grip, hydraulically set, retrievable openhole packer. It retains the proven mechanical and element systems of the RockSEAL II packer, together with an added anchoring capability. The anchoring slip design enables the packer to anchor the StackFRAC® system at the toe of the well, at wellbore junctions, or at sites along the system that require extra stability. The RockSEAL IIS packer is typically run with a RockSEAL II packer for added sealing capability, but it can be used on its own if required.

**Operation**
The RockSEAL IIS packer is assembled in the completion toolstring according to well requirements and run into the wellbore to the planned depth. When the string is in place, the packer is hydraulically set by pressuring up the tubing string, which causes the element to extrude and the slips to expand, securing the packer in the hole. If the packer needs to be retrieved, it can be released with straight pull on the tubing string or cut to release using an optional locator sub below the packer. Other methods of release are used depending on specific requirements.
Overview
The TuffSEAL™ packer is a hydraulically set, mechanical, single-element openhole packer. It can provide an economic zonal isolation option, depending on operator requirements, wellbore conditions, and formation characteristics.

The packer facilitates installation with its very short length and minimum OD.

Operation
The TuffSEAL packer is assembled in the completion toolstring according to well requirements and run into the wellbore to the planned depth. When the string is in place, the packer is hydraulically set by pressuring up the tubing string, which causes the element to extrude, securing the packer in the hole.

APPLICATIONS
- Open and cased holes
- Horizontal and vertical wells
- Isolation of individual zones for
  - stimulation
  - water and gas shutoff
- Production control and testing

FEATURES AND BENEFITS
- Economic zonal isolation
- Single-element/piston design
- Ease of installation because of
  - very short length
  - minimum running OD
- Adjustable setting forces
- Burst/collapse rating equal to or greater than casing
Titanium XV RockSEAL Packer

APPLICATIONS
- Specialized for HPHT conditions
- Open and cased holes
- Horizontal and vertical wells
- Sour service
- Isolation of individual zones for
  - stimulation
  - water and gas shutoff
- Production control
- Production testing

FEATURES AND BENEFITS
- Dual-element/piston design
- High expansion ratios
- Ease of installation because of
  - short length
  - minimum running OD
  - antipreset features for running in hole
- Adjustable setting forces
- Application-specific elastomers
- Long-term, high-pressure zonal isolation
- Not affected by temperature cycling

Overview
The Titanium® XV RockSEAL® packer is a dual-element, solid-body, hydraulically set openhole packer that combines the sealing strength of a mechanical element with the setting force of a dual-piston cylinder and mechanical body-lock system. It is used in the Packers Plus Titanium XV stimulation system and is designed to provide mechanical isolation for downhole pressures up to 15,000 psi and extreme bottomhole temperatures (BHTs).

The packer has a specially designed elastomer with the largest possible cross section to provide excellent expansion ratios for setting in oversized holes. Antipreset features enable the packer to be pushed through tight spots in the well without presetting or shearing the packer.

Operation
The Titanium XV RockSEAL packer is assembled in the completion toolstring according to well requirements and run into the wellbore to the planned depth. When the string is in place, the packer is hydraulically set by pressuring up the tubing string, which causes the elements to extrude by mechanical compression, securing the packer in the hole.
Overview
The StackFRAC® (SF) liner hanger packer is a production or injection packer that can be used for single- or multiple-zone completions. The packer seal bore is available in various lengths with a variety of seal assemblies to provide versatility with tubing movement requirements. Additionally, the seal assemblies can be latched or landed into the seal bore.

The packer is available with a complete line of tubing seal accessories and elastomers. Innovative antipreset features ensure reliability and performance.

The SF liner hanger packer has three versions:
- continuous bore
- ELB
- ELB torque lock.

Operation
The packer is assembled in the completion toolstring according to well requirements and run into the wellbore to the planned depth. Hydraulic tubing pressure is used to activate a setting tool, which strokes the SF liner hanger packer, causing the element to extrude and the slips to expand, securing the packer against the casing. To retrieve the packer, standard washer or pilot milling techniques can be employed, similar to retrieving a permanent packer.
Hydraulic-Set StackFRAC Liner Hanger Packer

Overview
The hydraulic-set StackFRAC® (SF) liner hanger packer is a production or injection packer that can be set without the need for a running tool. It can be used for single- or multiple-zone completions. The packer is available with a complete line of tubing seal accessories and elastomers. Innovative antipreset features are incorporated to ensure reliability and performance.

Operation
The hydraulic-set SF liner hanger packer is assembled in the completion toolstring according to well requirements and run into the wellbore to the planned depth. Hydraulic tubing pressure is used to set the packer, causing the slips to expand and the element to extrude, securing the packer in the casing. To retrieve the packer, standard washover or pilot milling techniques can be employed, similar to retrieving a permanent packer.

Applications
- Cased holes
- HPHT and sour service
- Anchoring liner in intermediate casing and sealing annulus
- Production control and testing
- Hydraulic fracturing

Features and Benefits
- No running tool required (option of using running tool available)
- Drillable
- Specialized slip design to maximize contact area
- Application-specific elastomers
- Antipreset features for running in hole
- Antiextrusion rings
- High-angle setting
Titanium XV Liner Hanger Packer

Overview
The Titanium® XV liner hanger packer is a production or injection packer that can be used for single- or multiple-zone completions. It is designed to provide mechanical isolation for downhole pressures up to 15,000 psi and extreme bottomhole temperatures (BHTs).

The packer sealbore is available in various lengths with a variety of seal assemblies to provide versatility with tubing movement requirements. Additionally, the seal assemblies can be latched or landed into the sealbore. The packer is available with a complete line of tubing seal accessories and elastomers. Innovative antipreset features ensure reliability and performance.

The Titanium XV liner hanger packer has three versions:
- continuous bore
- ELB
- ELB torque lock.

Operation
The packer is assembled in the completion toolstring according to well requirements and run into the wellbore to the planned depth. Hydraulic tubing pressure is used to activate a setting tool, which strokes the packer, causing the element to extrude and the slips to expand, thereby securing the packer against the casing. To retrieve the packer, standard washover or pilot milling techniques can be employed, similar to retrieving a permanent packer.
Specialty Packers
Overview
The SoftSEAL® high-expansion packer provides maximum expansion and is specifically designed for oversized and elliptical wellbores in soft rock formations. This packer provides the sealing strength of a hydraulically activated mechanical element that is locked into place immediately on setting. Built on the same principles as the field-proven RockSEAL® II openhole packer, the SoftSEAL high-expansion packer is designed to provide excellent long-term sealing.

The packer has a specially designed elastomer with the largest possible cross section to provide excellent expansion ratios for setting in oversized holes. The packer is designed with antipreset features that allow it to be pushed through tight spots in the well without presetting or shearing the packer.

Operation
The SoftSEAL high-expansion packer is assembled in the completion toolstring according to well requirements and run into the wellbore to the planned depth. When the string is in place, the packer is hydraulically set by pressuring up the tubing string, which causes the element to extrude, securing the packer in the hole.

Applications
- Specialized for oversized and elliptical wellbores in soft rock formations
- Open holes
- Horizontal and vertical wells
- HPHT and sour service
- Isolation of individual zones for stimulation, water and gas shutoff
- Production control
- Production testing

Features and Benefits
- Single packing element
- High expansion ratios
- Antipreset features for running in hole
- Adjustable setting forces
- Minimum running OD
- Antieextrusion rings
- Application-specific elastomers
- Not affected by changes in temperature or differential pressure
- Low forces exerted from the element into the formation
Overview
The SoftSEAL® II high-expansion packer provides maximum expansion and is specifically designed for oversized and elliptical wellbores in soft rock formations. This packer provides the sealing strength of a hydraulically activated mechanical element that is locked into place immediately on setting. Built on the same principles as the field-proven RockSEAL® II openhole packer, the SoftSEAL II high-expansion packer is designed to provide excellent long-term sealing.

The packer has a specially designed elastomer with the largest possible cross section to provide excellent expansion ratios for setting in oversized holes. The packer is designed with antipreset features that allow it to be pushed through tight spots in the well without presetting or shearing the packer.

Operation
The SoftSEAL II high-expansion packer is assembled in the completion toolstring according to well requirements and run into the wellbore to the planned depth. When the string is in place, the packer is hydraulically set by pressuring up the tubing string, which causes the elements to extrude, securing the packer in the hole.

APPLICATONS
- Specialized for oversized and elliptical wellbores in soft rock formations
- Open holes
- Horizontal and vertical wells
- HPHT and sour service
- Isolation of individual zones for stimulation, water and gas shutoff
- Production control
- Production testing

FEATURES AND BENEFITS
- Dual packing elements
- High expansion ratios
- Antipreset features for running in hole
- Adjustable setting forces
- Minimum running OD
- Antiextrusion rings
- Application-specific elastomers
- Not affected by changes in temperature or differential pressure
- Low forces exerted from the elements into the formation
SwellPLUS Packer

APPLICATIONS
- Open and cased holes
- Horizontal and vertical wells
- Slotted liners
- Isolation of individual zones for stimulation
- Production testing
- Production control

FEATURES AND BENEFITS
- Single element
- Element bonded to mandrel
- No moving parts
- Oil activated
- Ease of installation
- Designed to withstand
  - varying temperatures
  - temperature cycling during stimulation
- Able to accommodate a wide range of end connections
- Seals inside irregular wellbore geometries
- Mandrel material able to match material properties of completion toolstring
- Antiextrusion rings to hold the element in place
- Application-specific elastomers

Overview
The SwellPLUS™ packer has a specially designed and innovative elastomeric element to meet the most challenging wellbore conditions. The packer has no moving parts and the elastomeric element expands on contact with the activation fluid, sealing against the wellbore.

The time required for the packer to swell and hold the required pressure is determined by the downhole conditions, activation fluid composition, and element design. The SwellPLUS packer is capable of withstanding varying temperatures and ensures reliable zonal isolation during stimulation operations and throughout the life of the well.

Operation
The packer is assembled in the completion toolstring according to well requirements and run into the wellbore to the planned depth. During setting operations, activation fluid is absorbed into the packer over a period of time by diffusion, enabling the packer to swell and seal against the wellbore.
Sleeves
FracPORT H2 Sleeve

Overview
The FracPORT™ H2 sleeve is a ball-actuated, hydraulically activated injection/production port. It is run between two RockSEAL® H2 packers to enable specific zones of the wellbore to be isolated and selectively stimulated. Various ball seat sizes are available, allowing multiple FracPORT H2 sleeves to be run in sequence.

Operation
The sleeve is assembled in the completion string according to well requirements and run into the wellbore to the planned depth. The appropriate ball size is inserted into the string and pumped down onto the seat. The toolstring is then pressured up, causing the FracPORT H2 sleeve to open and allow injection of stimulation fluid into the annulus.

After stimulation the balls are flowed back and the well can be immediately put on production. If desired, the ball seats can be milled out based on the operator’s completion requirements.

Applications
- Open and cased holes
- Horizontal and vertical wells
- HPHT and sour service
- Selective stimulation

Features and Benefits
- Ball-actuated, hydraulically activated
- Can be run in multiples to stimulate several independent zones
- Lower zones isolated by increasing ball and seat sizes
- Adjustable activation shear
- Sleeve locked in place on opening
- Premium seal technology
- Ports that provide a flow area greater than the liner
- Ball seat quickly milled out in open or closed position
- Field-proven resistance to abrasion and erosion
- Corrosion-resistant design available
Overview
The hydraulic FracPORT™ sleeve is a hydraulically activated injection/production port used for the first stage of Packers Plus stimulation system applications. It opens at a specific pressure to enable communication between the toolstring and the annulus. The unique configuration of the sleeve ensures full opening for effective stimulation of the first stage.

Operation
The hydraulic FracPORT sleeve is assembled in the completion toolstring, typically between the last packer and the toe circulation sub, and run into the wellbore to the planned depth. The toolstring is pressured up, opening the sleeve and allowing stimulation fluid into the annulus.
Overview
The TuffPORT™ sleeve is a ball-actuated, hydraulically activated injection/production port. It is run between two packers to allow specific zones of the wellbore to be isolated and selectively stimulated. Various ball seat sizes are available, allowing multiple TuffPORT sleeves to be run in sequence.

Operation
The TuffPORT sleeve is assembled in the completion string according to well requirements and run into the wellbore to the planned depth. The appropriate ball size is inserted into the string and pumped down onto the seat. The toolstring is then pressured up, causing the TuffPORT sleeve to open and allow injection of stimulation fluid into the annulus.

After stimulation the balls are flowed back and the well can be immediately put on production. If desired, the ball seats can be milled out based on the operator’s completion requirements.

Applications
- Open and cased holes
- Horizontal and vertical wells
- HPHT and sour service
- Selective stimulation

Features and Benefits
- Economic stimulation
- Ball-actuated, hydraulically activated
- Lower zones isolated by increasing ball and seat sizes
- Adjustable activation shear
- Sleeve locked in place on opening
- Ports that provide a flow area greater than the liner
- Ball seat that can be quickly milled out in open or closed position
- Field-proven resistance to abrasion and erosion
- Corrosion-resistant design available
Titanium XV FracPORT Sleeve

Overview

The Titanium® XV FracPORT™ sleeve is a ball-actuated, hydraulically activated injection/production port used in the Packers Plus Titanium XV stimulation system. It is designed to provide stimulation for differential pressures up to 15,000 psi and extreme bottomhole temperatures (BHTs).

The sleeve is run between two Titanium XV RockSEAL® packers to enable specific zones of the wellbore to be isolated and selectively stimulated. Various ball seat sizes are available, allowing multiple Titanium XV FracPORT sleeves to be run in sequence.

Operation

The Titanium XV FracPORT sleeve is assembled in the completion string according to well requirements and run into the wellbore to the planned depth. The appropriate ball size is inserted into the string and pumped down onto the seat. The toolstring is then pressured up, causing the sleeve to open and allow injection of stimulation fluid into the annulus.

After stimulation the balls are flowed back and the well can be immediately put on production. If desired, the ball seats can be milled out based on the operator’s completion requirements.

APPLICATIONS

- Specialized for HPHT conditions
- Open and cased holes
- Horizontal and vertical wells
- Sour service
- Selective stimulation

FEATURES AND BENEFITS

- Ball-actuated, hydraulically activated
- Can be run in multiples to stimulate several independent zones
- Lower zones isolated by increasing ball and seat sizes
- Adjustable activation shear
- Sleeve locked in place on opening
- Ports that provide a flow area greater than the liner
- Ball seat quickly milled out in open or closed position
- Field-proven resistance to abrasion and erosion
- Corrosion-resistant design available
Overview
The Titanium® XV hydraulic FracPORT™ sleeve is a hydraulically activated injection/production port used for the first stage of Packers Plus Titanium XV stimulation system applications. It is designed to provide fracture stimulation for differential pressures up to 15,000 psi and extreme bottomhole temperatures (BHTs).

The sleeve opens at a specific pressure, enabling communication between the toolstring and the annulus. Its unique configuration ensures full opening for effective fracturing of the first stage.

Operation
The Titanium XV hydraulic FracPORT sleeve is assembled in the completion toolstring, typically between the last packer and the Titanium XV toe circulation sub, and run into the wellbore to the planned depth. The toolstring is then pressured up, causing the sleeve to open and allow injection of stimulation fluid into the annulus.

APPLICATIONS
- Specialized for HPHT conditions
- Open and cased holes
- Horizontal and vertical wells
- Sour service
- Selective fracturing and production

FEATURES AND BENEFITS
- Field-proven hydraulic activation
- Built-in redundancy and reliability:
  - unique design that ensures full opening
  - sleeve held in place on opening
- Adjustable activation shear
- Ports that provide a flow area greater than the liner
- Field-proven resistance to abrasion and erosion
- Corrosion-resistant design available
Drillable Closeable FracPORT Sleeve

APPLICATIONS
- Open and cased holes
- Horizontal and vertical wells
- HPHT and sour service
- Selective stimulation
- Selective production
- Production testing
- Future operations such as
  - water and gas shutoff
  - flow control
  - restimulation

FEATURES AND BENEFITS
- Ball-actuated, hydraulically activated
- Can be run in multiples to stimulate several independent zones
- Lower zones isolated by increasing ball and seat sizes
- Can be closed or reopened with or without the ball seat in place
- Adjustable activation shear
- Sleeve locked in place on opening
- Ports that provide a flow area greater than the liner
- Ball seat quickly milled out in open or closed position
- Field-proven resistance to abrasion and erosion
- Corrosion-resistant design available

Overview
The drillable closeable (DC) FracPORT™ sleeve is a ball-actuated, hydraulically activated injection/production port. It is run between two packers to enable specific zones of the wellbore to be isolated and selectively stimulated and produced.

Various ball seat sizes are available, allowing multiple DC FracPORT sleeves to be run in sequence. The sleeve can be milled out to remove the ball seat, and it can be closed or reopened with or without the ball seat in place for future operations.

Operation
The DC FracPORT sleeve is assembled in the completion toolstring according to well requirements and run into the wellbore to the planned depth. The appropriate ball size is inserted into the string and pumped down onto the seat. The toolstring is then pressured up, causing the sleeve to open and allow injection of stimulation fluid into the annulus. After stimulation the ball can be flowed back and if desired, the ball seat can be milled out.

To close or reopen the DC FracPORT sleeve, a specialized hydraulic shifting tool is run in hole to depth where it engages a shifting profile in the sleeve or top/bottom of the ball seat. Upward force (straight pull) or downward force is applied to close or reopen the sleeve, respectively. The shifting tool can be disengaged using hydraulic force.
Drillable Closeable Hydraulic FracPORT Sleeve

Overview

The drillable closeable (DC) hydraulic FracPORT™ sleeve is a hydraulically activated injection/production port that can be used for the first stage of Packers Plus stimulation system applications. It opens at a specific pressure, enabling communication between the toolstring and the annulus.

The unique configuration of the sleeve ensures full opening for effective fracturing of the first stage. If desired, the sleeve can be closed or reopened for future operations.

Operation

The DC hydraulic FracPORT sleeve is assembled in the completion toolstring—typically between the last packer and the toe circulation sub—and run into the wellbore to the planned depth. The toolstring is then pressured up, causing the sleeve to open and allow injection of stimulation fluid into the annulus.

To close or reopen the sleeve, a shifting tool is run in hole to depth where it engages a shifting profile. Upward force (straight pull) or downward force is applied to close or reopen the sleeve, respectively.

APPLICATIONS

- Open and cased holes
- Horizontal and vertical wells
- HPHT and sour service
- Selective fracturing and production
- Production testing
- Future operations such as
  - water and gas shutoff
  - flow control
  - refracturing

FEATURES AND BENEFITS

- Field-proven hydraulic activation
- Can be closed or reopened using a shifting tool
- Built-in redundancy and reliability:
  - unique design that ensures full opening
  - sleeve held in place on opening
- Adjustable activation shear
- Ports that provide a flow area greater than the liner
- Can be quickly milled out
- Field-proven resistance to abrasion and erosion
- Corrosion-resistant design available
QuickPORT IV Sleeve

**APPLICATIONS**
- Limited-entry stimulation of multiple stages
- Open holes
- Cemented liners
- Horizontal and vertical wells
- HPHT applications
- Selective stimulation

**FEATURES AND BENEFITS**
- Simple design with few parts
- Ball-actuated, hydraulically activated
- One ball size to activate multiple QuickPORT™ IV sleeves within a limited-entry treatment zone
- Various flow port sizes available
- Lower zones isolated by increasing ball and seat sizes
- Adjustable activation shear
- Ball seat quickly milled out in open or closed position, if desired
- Resistant to abrasion and erosion

**Overview**
The QuickPORT IV sleeve is a ball-actuated, hydraulically activated injection/production port. It is run with the Packers Plus QuickFRAC® system in an open hole or a cemented liner.

The sleeve allows more than one stage to be activated with the same size actuation ball for limited-entry stimulation. Using various ball sizes, multiple stimulation treatments can be run in sequence. Sleeve flow ports are available in a range of sizes to optimize the limited-entry stimulation treatment.

**Operation**
QuickPORT IV sleeves are assembled in the completion toolstring according to well requirements and run into the wellbore to the planned depth. The appropriate ball size is inserted into the string and pumped down to the uppermost sleeve in the limited-entry treatment zone. The toolstring is pressured up and the sleeve is shifted open. The ball then passes through the sleeve and continues down the liner to activate other QuickPORT IV sleeves within the treatment zone.

Once the sleeves are opened, the designed stimulation rate can be achieved. As with other Packers Plus completion systems, a continuous pumping operation is enabled by dropping incrementally larger balls to activate the QuickPORT IV sleeves in the subsequent treatment zones. The larger ball size also isolates lower zones from the uphole pumping operations. After stimulation the well can be immediately put on production and if desired, the ball seats can be milled out based on the operator’s completion requirements.
QuickPORT V Sleeve

APPLICATIONS
- Limited-entry batch stimulation of multiple stages
- Open holes
- Horizontal and vertical wells
- HPHT applications
- Selective stimulation

FEATURES AND BENEFITS
- Ball-actuated, hydraulically activated
- One ball size to activate multiple QuickPORT™ V sleeves within a limited-entry treatment zone
- Various flow port sizes available
- Lower zones isolated by increasing ball and seat sizes
- Adjustable activation shear
- Ball seat quickly milled out in open or closed position
- Resistant to abrasion and erosion
- Possible to flow back actuation balls

Overview
The QuickPORT V sleeve is a ball-actuated, hydraulically activated injection/production port. It is run between packers in the Packers Plus QuickFRAC® system to allow selective stimulation of multiple zones of the wellbore.

The sleeve allows more than one stage to be activated with the same size actuation ball for limited-entry batch stimulation. Using different ball sizes, multiple batch treatments can be run in sequence. Sleeve flow ports are available in various sizes to optimize limited-entry stimulation treatments.

Operation
QuickPORT V sleeves are assembled in the completion toolstring and run into the wellbore. A ball is pumped to the uppermost sleeve in the limited-entry treatment zone. The toolstring is pressurized up and the sleeve is activated as the ball passes through and continues down to activate other QuickPORT V sleeves within the treatment zone.

Once the sleeves are open, fluids can be pumped as per the completion program. As with other Packers Plus systems, incrementally larger balls are used to activate the QuickPORT V sleeves in subsequent treatment zones. Increasing ball sizes isolate lower zones from the uphole pumping operations. After stimulation the balls can be flowed back and if desired, the ball seats can be milled out; the well can be immediately put on production.
**Overview**

The Diffusor™ sleeve is a ball-actuated, hydraulically activated injection/production port that enables specific zones of a cemented wellbore to be selectively stimulated. Various ball seat sizes are available, enabling multiple Diffusor sleeves to be run in sequence.

**Operation**

The Diffusor sleeve is assembled in the completion string according to well requirements and run into the wellbore to the planned depth. During stimulation operations, the appropriate size ball is inserted into the string and pumped down onto the seat. The toolstring is then pressured up, causing the Diffusor sleeve to open and allow injection of stimulation fluid into the formation.

After stimulation the balls are flowed back and the well can be immediately put on production. If desired, the ball seats can be milled out based on the operator’s completion requirements.
Hydraulic Diffusor Sleeve

Overview
The hydraulic Diffusor™ sleeve is a hydraulically activated injection/production port used for the first stage of Packers Plus cemented stimulation system applications. It opens at a specific pressure, enabling communication between the toolstring and the formation. The unique configuration of the sleeve ensures full opening for effective stimulation of the first stage.

Operation
The hydraulic Diffusor sleeve is assembled in the completion toolstring at the desired toe position. The toolstring is then run into the wellbore to the planned depth and the liner is cemented in place. When stimulation operations are ready to commence, the toolstring is pressured up, causing the hydraulic Diffusor sleeve to open and allow injection of stimulation fluid into the formation.

APPLICATIONS
- Cemented liner completions
- Cased holes
- Plug and perf
- Horizontal and vertical wells
- Selective stimulation

FEATURES AND BENEFITS
- Specially designed coating to help prevent cement from sticking to the tool
- Tool function not affected by cement in the annulus
- Built-in redundancy and reliability:
  - unique design that ensures full opening
  - sleeve locked in place on opening
- Adjustable activation shear
- Ports that provide a flow area greater than the liner
- Field-proven resistance to abrasion and erosion
- Corrosion-resistant design available
Stage Tools
StackFRAC (SF) Cementor D Stage Collar

APPLICATIONS
- Open holes
- Horizontal and vertical wells
- Cementing back of vertical and build section

FEATURES AND BENEFITS
- Hydraulically opened; closed with actuation ball or specialized wiper plug
- Built-in secondary close mechanism with no inside diameter restriction
- Corrosion-resistant design available

Overview
The StackFRAC® (SF) Cementor™ D stage collar is a hydraulically opened stage cementing tool that is closed using an actuation ball or specialized wiper plug. It is used to cement the section above Packers Plus openhole multistage systems. The stage collar’s design allows it to be opened and closed without any mechanical movement at surface.

Operation
The SF Cementor D stage collar is assembled in the completion string according to well requirements and run into the wellbore to the planned depth. When the string is in place and the packers have been set, the toolstring is pressured up to open the stage collar. The cement is pumped and then displaced as per the program. When cementing is complete, a specialized wiper plug is injected and pumped down the system to the SF Cementor D stage collar, where it lands to close the tool.
StackFRAC (SF) Cementor Stage Collar

Overview
The StackFRAC® (SF) Cementor™ stage collar is a hydraulically opened, mechanically closed stage cementing tool. It is used to cement the vertical and build sections above openhole StackFRAC systems in monobore wells. The stage collar’s design allows it to be opened and closed without the use of a wiper plug or dart. This eliminates the need for a cement head and reduces postcementing cleanout operations, debris issues, and associated costs.

Operation
The SF Cementor stage collar is assembled in the completion string according to well requirements and run into the wellbore to the planned depth. When the string is in place and the packers have been set, the toolstring is pressured up to activate the stage collar. The cement is pumped and then displaced as per the program.

When cementing is complete, the SF Cementor stage collar is mechanically closed and locked by lowering the casing and applying compression. Well stimulation operations can then commence.

APPLICATIONS
- Open holes
- Horizontal wells
- Monobore well design
- Cementing back of vertical and build section

FEATURES AND BENEFITS
- Hydraulically opened, mechanically closed
- Positive lock when closed
- Can be reopened during cementing operations
- Built-in secondary close mechanism with no inside diameter restriction
- Reduced postcementing cleanout operations
- Reduced debris issues
- No cement head/manifold required
- Corrosion-resistant design available
Overview
The Packers Plus debris sub is used in conjunction with cementing stage tools such as the StackFRAC® (SF) Cementor™ stage collar. The main functions of the debris sub are to provide a barrier to cement stringers or debris and to act as a platform for cleanup operations. The debris sub accepts a standard Packers Plus actuation ball, and it can be fully milled out to regain communication with the toolstring.

Operation
The debris sub is assembled in the toolstring between the stage tool and the completion string. The system is run into the wellbore to the required depth. Before beginning cementing operations, a ball is dropped to the debris sub. Subsequently, cementing operations will proceed as per well requirements. The debris sub will help prevent any cement stringers from entering the toolstring during the cementing operations.

After cementing has been completed, if milling of the stage tool is required, any fragments will be pushed to the debris sub. A junk basket can be run to retrieve the debris left in the debris sub. Once that has been removed, the debris sub can be milled out. The unique design of the debris sub allows milling operations to result in little to no leftover cuttings.

When positioned below packers, the debris sub can also be used as a plugging tool to create a pressure differential for setting packers. In addition, should the hydraulic FracPORT™ sleeve prematurely open during cementing operations, the ball will seat on the debris sub, protecting the system downhole from cement or debris.
Additional Tools
# Diffusor Landing Dart and Wiper Ball with Landing Sub

## Applications
- Cemented liner completions
- Horizontal and vertical wells

## Features and Benefits
- Guided nose design enables Diffusor™ landing dart to travel through multiple Diffusor sleeves
- Diffusor landing dart latches into Diffusor landing sub to ensure liner integrity is maintained
- Diffusor wiper ball compresses down to travel through varying ball seat sizes

## Overview
The Diffusor landing dart and wiper ball are used to clean the inside of the liner after cementing operations are completed to minimize the amount of cement left behind, ensuring proper tool function.

## Operation
The landing dart and wiper ball are loaded into a cement head. After the specified volume of cement has been pumped, the landing dart is launched and pumped downhole, followed by the wiper ball and displacement fluid. The landing dart latches and seals into the Diffusor landing sub at the toe of the liner, shutting off flow between the liner and the annulus.
Landed Seal Assembly and PBR

APPLICATIONS
- HPHT and sour service
- Expansion joint for tubing movement

CAPABILITIES
- Suitable for single- or multiple-zone completions
- Built-in redundancy and reliability with multiple seals
- Combination of bonded- and vee-seal configurations
- Customizable lengths based on design requirements

Overview
The landed seal assembly (LSA) and polished bore receptacle (PBR) can be used for single- or multiple-zone completions. They are used in conjunction to create an expansion joint to provide stroke length when significant liner movement is expected during well treatment and production.

Multiple seal sets are used to create a reliable seal between the fracture string or production tubing and the liner top as the LSA floats inside the PBR. The LSA and PBR work together with the StackFRAC® (SF) liner hanger packer or Titanium® XV liner hanger packer to provide versatility with tubing movement requirements.

The LSA and PBR are available in multiple versions, depending on stimulation and production requirements. A pressure test can be performed to ensure that the expansion joint is sealing correctly.

Operation
When shear-pinned together, the LSA and PBR are run in hole before the toolstring has been set. After setting the system, an upward force is required to detach the LSA from the PBR, thereby creating an expansion joint. The LSA is removed from the PBR with straight pull.
Latch Seal Assembly

Overview
The latch seal assembly is a fixed seal that can be used for single- or multiple-zone completions. It provides a seal between the liner top and the fracture string or production tubing and holds the tubing in the liner top, preventing it from moving up or down. It works with the StackFRAC® (SF) liner hanger packer or Titanium® XV liner hanger packer to restrict tubing movement in a variety of applications.

The latch seal assembly is available in two versions. In both cases, a slight downward force is needed to secure the latch into the liner top.

- Anchor latch seal assembly: Rotation and straight pull are required to release the latch from the liner top.
- Snap latch seal assembly: Straight pull is needed to release the tool from the liner top.

Operation
The latch seal assembly is run in hole after the toolstring has been set. When it reaches the liner hanger packer, slight downward force is applied to latch the anchor mechanism into the packer.

The latch seal assembly is released with a slight upward pull and right-hand rotation or with a straight pull. The anchor mechanism makes it ideal for completions where tubing movement is not desirable.

APPLICATIONS
- Horizontal and vertical wells
- HPHT and sour service
- Prevention of tubing movement

FEATURES AND BENEFITS
- Suitable for single- or multiple-zone completions
- Positive indication of proper seal location in the sealbore
- Built-in redundancy and reliability
- Available in bonded-seal or a combination of bonded- and vee-seal configurations
DCH Shifting Tool

Overview
The drillable closeable hydraulic (DCH) shifting tool is a rugged, bidirectional shifting tool designed for use in Packers Plus stimulation systems to open and/or close DC FracPORT sleeves. The tool is fully selective, allowing specific ports to be opened or closed without affecting other ports. One or more ports can be opened or closed in the same run. The shifting tool is equipped with an emergency shear-out to prevent damage to itself or to the DC FracPORT sleeve.

Operation
The DCH shifting tool is run into existing systems equipped with DC FracPORT sleeves to selectively open or close them as per customer requests. It is run in on coiled tubing with an appropriate bottomhole assembly and hydraulically activated. The amount of flow needed to activate the shifting tool is determined by replaceable choke nozzles that may be set up and adjusted on location.

The tool is designed with a self-releasing profile. Once the DC FracPORT sleeve is shifted and locked, the DCH shifting tool will release automatically. It is not necessary to stop flow through the tool to release it.

APPLICATIOMS
- Open and cased holes
- Horizontal and vertical wells
- Selective opening and/or closing of drillable closeable (DC) FracPORT™ sleeves
- Enabling of operations such as
  - Water and gas shutoff
  - Flow control
  - Restimulation
- HPHT and sour service

FEATURES AND BENEFITS
- Hydraulically activated
- Bidirectional
- Self-releasing profile
- Emergency shear-out
- Rugged, slimline design
Flow Release Shifting Tool

Overview
The flow release shifting tool is used to shift tools with ball seats in place. It is available in different sizes to work with a variety of ball seats and equipped with an emergency shear-out via straight pull to prevent damage to the shifting tool or the ball seat.

Operation
The appropriate nozzle size must be selected before running in hole. The flow release shifting tool is run in hole on coiled tubing until it reaches the ball seat; the tool will collapse as it passes through the seat. When upward force is applied (straight pull), the ball seat will shift. Once the seat is shifted, the shifting tool is moved down off the seat and circulation is applied. This allows the tool to collapse, enabling it to be pulled up through the seat.

APPLICATIONS
- Open and cased holes
- Horizontal and vertical wells
- HPHT and sour service
- Shifting of tools with ball seats in place

FEATURES AND BENEFITS
- High-strength collet to pass through and engage the seat
- Flow release capabilities
- Adjustable nozzle sizes for various flow rates and mud weights
- Safety release that uses straight pull
Overview
The Titanium XV hydraulic anchor is used in Packers Plus Titanium XV stimulation systems. This hydraulically set anchor secures the system in the wellbore to prevent movement, which can cause tool damage. It can be used to provide extra anchoring for stimulation at the toe of the wellbore or anywhere along the system that requires extra stability.

The anchor features a slip arrangement with exceptional holding power to keep it from moving under the hydraulic and mechanical forces that may be exerted on the tool. It is designed to hold against differential pressures up to 15,000 psi and withstand extreme bottomhole temperatures (BHTs). Antipreset features enable it to be pushed through tight spots in the well without presetting.

Operation
The Titanium XV hydraulic anchor is assembled in the completion toolstring according to well requirements and run into the wellbore to the planned depth. When the string is in place, the anchor is hydraulically set by pressuring up the tubing string, which causes the slips to expand and secure the anchor against the casing or formation. A field-proven lock system ensures that the tool remains set in extreme conditions.

APPLICATIONS
- Specialized for HPHT conditions
- Open and cased holes
- Horizontal and vertical wells
- Sour service
- Securing the Titanium® XV stimulation system in the wellbore
- Anchoring for stimulation of the toe

FEATURES AND BENEFITS
- Ease of installation
- Short length
- Minimum running OD
- Antipreset features for running in hole
- Adjustable setting forces
Overview
The toe circulation sub (TCS) is used in all Packers Plus stimulation systems to control flow between the completion toolstring and the annulus. The TCS is kept open while running the completion liner in the well to allow circulation through the tubing string. After system installation the TCS is closed, enabling the toolstring to be pressured up for hydraulic activation of downhole tools, such as liner hanger packers, RockSEAL® packers, and hydraulic FracPORT™ sleeves.

Operation
The TCS is assembled in the completion string and run into the wellbore to the required depth. The appropriate ball size is inserted into the string and pumped down onto the seat. The toolstring is then pressured up, causing the TCS to close and shut off communication between the liner and the annulus. Once it has been shifted to the closed position, features of the tool prevent it from shifting open. The tubing string is then pressured up in various stages to set the hydraulic tools in the system.

The completion string tail assembly is strategically designed to provide excellent run-in reliability in any well conditions. Tools in the tail assembly include a bullet guide at the bottom of the liner, followed by a float collar and the TCS.

APPLICATIONS
- Open and cased holes
- Horizontal and vertical wells
- HPHT and sour service

FEATURES AND BENEFITS
- Positive-acting seal valve
- Closed by dropping appropriate activation ball
- Can also be closed by running coiled tubing to depth
- Ball seat can be quickly milled out
Overview
The Titanium® XV toe circulation sub (TCS) is used in the Packers Plus Titanium XV stimulation system and is designed for differential pressures up to 15,000 psi and extreme bottomhole temperatures (BHTs). It controls flow between the completion toolstring and the annulus. It is kept open while running the completion liner in the well to allow circulation through the tubing string. After system installation the TCS is closed, enabling the toolstring to be pressured up for hydraulic activation of downhole tools, such as liner hanger packers, Titanium XV RockSEAL® packers, and Titanium XV hydraulic FracPORT™ sleeves.

Operation
The Titanium XV TCS is assembled in the completion string and run into the wellbore to the required depth. The appropriate ball size is inserted into the string and pumped down onto the seat. The toolstring is then pressured up, causing the TCS to close and shut off communication between the liner and the annulus. Once it has been shifted to the closed position, features of the tool prevent it from shifting open. The tubing string is then pressured up in various stages to set the hydraulic tools in the system.

The completion string tail assembly is strategically designed to provide excellent run-in reliability in any well conditions. Tools in the tail assembly include a bullet guide at the bottom of the liner, followed by a float collar and the Titanium XV TCS.
StackFRAC (SF) Ball

APPLICATIONS
- Open and cased holes
- Horizontal and vertical wells
- HPHT and sour service
- Activation of downhole tools
- Diversion of fluid flow

FEATURES AND BENEFITS
- Available in a variety of sizes and materials
- Resistant to chemical attack
- Low-specific-gravity balls for optimal flowback capability
- Balls quickly milled out if required

Overview
StackFRAC® (SF) balls are used in all Packers Plus multistage ball-drop stimulation systems to enable hydraulic activation of downhole tools and divert flow of fluids. A range of ball sizes allows activation of multiple tools in sequence.

SF balls are available in different materials to suit various operational requirements.
- SF2: ceramic polymer, specific gravity 1.3
- SF7: epoxy composite, specific gravity 1.8
- SF10: metallic composite, specific gravity 2.8

Operation
After multistage stimulation system installation, an SF ball is inserted into the system and pumped down to a seat. This allows hydraulic pressure to build inside the system; the pressure is used to activate tools and/or divert fluid along the system. Multiple tools can be activated by dropping successively larger balls. After stimulation operations, the balls can be flowed back or milled out, if desired.