Abstract

The Ring Seal Floating Packer is a simple and low cost sealing device for use in steam injection wells and is proven to be an effective mechanical device for controlling and blocking the passage of fluids in an annular space between the tubing and casing. The Ring Seal Packer can be compared to a piston in a cylinder: Pressure forces acting upon a piston result in up and down motion while the piston maintains a seal against the cylinder (casing) wall. Compared to a conventional thermal packer, the Ring Seal Packer does not require an expansion joint allowing the injection tubing to thermally expand and contract while the Ring Seal Packer moves up and down the casing maintaining its sealing ability.

This paper covers the following areas:

- Mechanical Design
- Laboratory testing providing loading confirmation for deployment.
- Field results at PEMEX Samaria oil field, Mexico, Cyclic Steam Stimulation (CSS).
- California field results of CSS into vertical wells with multiple zones above and below the RSP.
- Field results at Mansarovar, Colombia.

Conclusion

References

Mechanical Design

The wellbore is the only means of communications between the surface and the underground, therefore maintaining wellbore integrity and reducing casing failures is a critical factor in well control and operational economics. The best well completion is the one having the lowest cost and that meets all the demands that will be placed on the well during its life time.

For steam injection wells the thermal packer provides a seal between the injection tubing and the inside of the casing, closing the annulus to steam leakage. In a steam injection it is important to keep the annulus above the packer dry, reducing casing thermal stress and resulting failures, reducing thermal loads on cement and resulting cement failures, and reducing wellbore heat losses.

The Ring Seal Floating Packer has a dual set of split rings machined from mild steel and heat treated to a specified spring rate allowing the rings to elastically collapse when inserted.

into the casing while maintaining a metal-to-metal sealing engagement with the inside walls of the casing. The seal is not perfect but the leaking is controlled and minimal having two leak paths: (1) along the mandrel OD inside the ring groove and under a pair of rings, (2) through the slotted groove of the ring sealing assembly. High temperature mesh can be added under the ring, between ring and mandrel, adding resistance and further restricting flow. Further leakage controlled can be obtained with a gas blanket in the annulus. The actual rate of leakage can be calculated using Lohms Law:  

$$\text{Lohms} = \frac{K \cdot f_T \cdot P_1}{Q}$$

K = Gas units constant  
fT = Temperature correction factor  
P1 = Upstream absolute pressure (psia)  
P2 = Downstream absolute pressure (psia)  
Q = Gas flow (std L/min)  
DeltaP = P1 - P2 (psid)

Flow restriction of the Ring Seal Floating Packer is controlled by the machining tolerances between the two rings and the mandrel. The mandrel is sized for minimum clearance with the well casing. To minimize this inherent leak paths each casing weight has a specially dimensioned sealing ring assembly thereby limiting the tolerance between ring and mandrel and the slot dimension of the ring. When installed, the gap in each ring assembly is oriented 180° apart. As the two sealing rings are compressed during installation the flow restriction is controlled and maximized.

Additional sealing can be accomplished by injecting Nitrogen (N\textsuperscript{2}) or other non-combustible gas down the annulus. This gaseous atmosphere has a second benefit of reducing wellbore heat flux by keeping wellbore dry and eliminating the potential for refluxing of wellbore fluids.

**Laboratory Testing**

Laboratory test have been performed to determine and confirm the running forces required to install the Ring Seal packer.

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\(^2\) A.B. Speirs, K.D. Webster, SPE 29632, Improving Production in Steamed Wells with a Ring Seal Packer, SPE Western Regional Meeting, March 1995.
The pressure to push the Ring Seal Floating Packer into the test casing is 50 psi or 1650 lbs of force required to move a single Ring Seal Floating Packer (with two sealing rings) into and through the casing. In the field the required weight will come from the tubing string above the Packer plus the elevator block, or a heavy drilling joint to get the packer started downhole. Once started the increasing weight of tubulars above the packer continue to move the packer to its desired wellbore position.

**Field Results, Samaria Oil Field, Tabasco, Mexico**

The Samaria field is located in the state of Tabasco, Mexico, in the geologic province of the Chiapas-Tabasco an area covering approximately 9,000 km². The field is located about 17 km to the northwest of the city of Villahermosa, Tabasco, Mexico.

Pemex commenced Cyclic Steam Stimulation (CSS) injection in 2009. Average well depth to top of the reservoir is 800 meters. Vertical, directional, and horizontally drilled wells are used. The oil is heavy with a density of 4° to 11° API. The typical CSS is 5,000 m³ of steam per steam cycle in vertical wells and 8,000 m³ in directional and horizontal wells. Steam temperatures is 315°C (600°F), and steam quality approximately 80% dry.

Wells are completed with Vacuum Insulated Tubing (VIT) that remains in wells for both steam injection and production. Once the soak period is completed wells will naturally flow for a short period and can be produced by gas lift. Once natural and gas assisted production declines, wells are produced using rod pumps until they are ready for their next steam cycle. Rods and pumps are pulled prior to each steam cycle then re-run after the soak, cool down, and natural/gas lift production period. Currently the Samaria pilot wells are on their 1st through 3rd steam cycle.

The project test results involve seven wells. Five wells are completed with conventional thermal packer with expansion joint and two wells with Ring Seal Floating Packers. The completions using the Ring Seal Floating Packers include a sliding seal assembly used to assist evacuation of the annulus prior to CSS. Aeschlimann (1985) showed the intensity of heat transfer is proportional to the amount of liquid trapped in the annulus above a packer. Based on his theory of refluxing, a reflux cell is established above the packer allowing the

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3 Steam pressure at wellhead is 1,600 psi (112.5 kg/m²)
liquid vaporization of fluids from hot surfaces to re-condense on the cool insulated tubing surfaces wherein the annulus fluids never evaporate and significantly adds conductive and convective heat losses to the system that would otherwise have extremely low heat loss because of the insulating characteristics of VIT.

Seven wells are analyzed in this paper:

<table>
<thead>
<tr>
<th>Well Number</th>
<th>Type of Completion</th>
<th>Type of Packer</th>
</tr>
</thead>
<tbody>
<tr>
<td>916</td>
<td>Vertical</td>
<td>Conventional Thermal</td>
</tr>
<tr>
<td>913H</td>
<td>Horizontal</td>
<td>Conventional Thermal</td>
</tr>
<tr>
<td>948</td>
<td>Vertical</td>
<td>Conventional Thermal</td>
</tr>
<tr>
<td>915H</td>
<td>Horizontal</td>
<td>Conventional Thermal</td>
</tr>
<tr>
<td>922</td>
<td>Vertical</td>
<td>Conventional Thermal</td>
</tr>
<tr>
<td>915</td>
<td>Vertical</td>
<td>Ring Seal Floating</td>
</tr>
<tr>
<td>901</td>
<td>Vertical</td>
<td>Ring Seal Floating</td>
</tr>
</tbody>
</table>

Conventional thermal packers with expansion joints are used in horizontal and vertical wells 916, 913H, 948, 915H, and 922. Ring Seal Floating Packers are installed in two (2) vertical wells 915 and 901. All wells have 7-inch 26-pound casing with thermal cement to the surface.

Based on observations of wells with the conventional thermal packers and expansion joints it was concluded all of the wells except on, well number 913H suffer from seal and/or mechanical failures resulting in packer leakage. Because of this leakage, all well are steamed with a Nitrogen blanket in the annulus.

Results for steaming operations:

<table>
<thead>
<tr>
<th>Well Number</th>
<th>N2 in Annulus</th>
<th>Observed Packer Seal Failure</th>
<th>Elongation of Wellhead (cm)</th>
</tr>
</thead>
<tbody>
<tr>
<td>916</td>
<td>No</td>
<td>Yes</td>
<td>25</td>
</tr>
<tr>
<td>913H</td>
<td>Yes</td>
<td>No</td>
<td>13</td>
</tr>
<tr>
<td>948</td>
<td>Yes</td>
<td>Yes</td>
<td>12</td>
</tr>
<tr>
<td>915H</td>
<td>Yes</td>
<td>Yes</td>
<td>8</td>
</tr>
<tr>
<td>922</td>
<td>Yes</td>
<td>Yes</td>
<td>4</td>
</tr>
<tr>
<td>915</td>
<td>Yes</td>
<td>No</td>
<td>3</td>
</tr>
<tr>
<td>901</td>
<td>Yes</td>
<td>No</td>
<td>2</td>
</tr>
</tbody>
</table>

Steam injection data for both horizontal and vertical wells has been collected. Figure 1 shows a typical horizontal well with conventional thermal packer and expansion joint, figure 2 is for the Ring Seal Floating Packer.
Blue = Steam Injection Pressure  
Red = N₂ Casing Pressure  
Green = Steam Temperature  
Purple = Casing Temperature

**Fig. 1: Injection Data Horizontal Well with conventional thermal packer and expansion joint using Nitrogen gas in annulus covering the annulus above the packer**

All wells are steamed having a Nitrogen blanket covering the annulus above the packer. Figures 1 and 2 show similar results, the flatness of the curves in Figure 2 confirm our belief the Ring Seal Floating Packer responds to Ohms Law and the pressure drop across the packer can be controlled and accurately calculated. Casing temperatures are consistent with calculated values for VIT and a dry annulus above a packer.

**Fig. 2: Injection Data Vertical Well with Ring Seal Floating Packer and Nitrogen gas blanket covering the annulus above the packer**

The elongation of the wellhead assembly for well 916 (green line) is consistent with a packer failure and has been steamed without the annulus Nitrogen blanket to confirm the advantage of this blanket. The reported casing elongation measured by wellhead growth of the other 6-wells confirms the operating efficiency of the Ring Seal Floating Packer and Nitrogen blanket.

The procedure to establish the Nitrogen blanket above the packer is as follows:

1. Attach high pressure N₂ to the casing vent valve, open valve and start pressurizing annulus.
2. Open the sliding sleeve above the Seal Ring Packer and continue to pressurize the annulus with N₂. Displace annular volume is (calculated area + 10%).
3. Close the sliding sleeve and pressurize annulus with N₂ to 1,300 psi in wells with a conventional thermal packer and 800-900 psi for wells with the Ring Seal Floating Packer.
4. Overlap N₂ injection with steam injection for approximately 1-hour until N₂ and steam pressure equalizes. After pressure equalization N₂ pressurization is discontinued, connection valves are closed and N₂ equipment is removed.
5. Continue with steam cycle. (If there is a steam shutdown, annulus N₂ is re-pressurized as above.)

**Field Results, North Midway-Sunset Oil Field (Diatomite), California**

Oil wells in the North Midway diatomite formation suffer from frequent well casing failures. Production of diatomite relies on
both temperature and pressure where steam pressure is used to both fracture the reservoir and assist oil recovery through thermal methods.

At North Midway steam is injected simultaneously into two oil bearing zones both above and below a double set of Ring Seal Floating Packers with and without high temperature packing under the sealing rings to increase resistance to leakage. Injection pressures range from 975 psi (542°F) to 1450 psi (590°F). Steam injection is down tubing string (delivered below packer) and down the casing annulus (delivered above packer). Higher pressure steam is injected into the lower zone at a pressure differential from 50-175 psi. Oil production is free flowing after each steam cycle.

The original well design incorporated high temperature rubber cut packers, repeated mechanical failures led to search for a different completion tool. The Ring Seal Floating Packer has been tried on 4-wells. All wells have 5 1/2" 17# casing with 2 7/8" 6.5# tubing from wellhead to the ring Seal Packer. Casing is perforated. The well and Ring Seal Packer (RSP) configurations are as follows:

<table>
<thead>
<tr>
<th>Well #</th>
<th>RSP Configuration</th>
</tr>
</thead>
<tbody>
<tr>
<td>43-43</td>
<td>Single RSP with high temperature packing under each sealing ring.</td>
</tr>
<tr>
<td>44-42</td>
<td>Dual RSP with no packing</td>
</tr>
<tr>
<td>45-43</td>
<td>Dual RSP with high temperature packing under each sealing ring.</td>
</tr>
<tr>
<td>48-48</td>
<td>Dual RSP with high temperature packing under each sealing ring.</td>
</tr>
</tbody>
</table>

All wells are completed with temperature and pressure monitoring allowing the operator to detect leakage around the Ring Seal Packer.

The results after multiple steam cycles on each of the four wells are very encouraging. Wells 45-43 and 48-48 using a double Ring Seal Packer and packing under the ring have no detectable leakage around the packer. After 6 steam cycles, well no. 45-43 has recorded zero leakage with a 60 psi steam differential across the packer. Well no. 48-48 has zero detectable leakage at 90 psi steam differential across the packer.

Field Results, Mansarover Energy, Jazmin and Moriche Fields, Colombia:

Jazmin and Moriche fields are operated by Mansarover Energy Colombia Ltd. and located

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4 Fracturing is without propet materials.
in the Middle Magdalena Valley basin containing 11° to 13°API gravities heavy oil. Development is with CSS thermal recovery methods in both vertical and deviated wells. Reservoir depths are 1,000 – 1,600 feet TVD.

7" Ring Seal Floating Packers are set at the top of the production liner and a Nitrogen blanket is used above the packer to control packer leakage.

Steam injection pressures are 1,000 to 1,400 psig. Steam injection rates are 120 bbl/hour (10,800 bbl per cycle). The volume of Nitrogen injected is 500-600 gallons at 100 to 200 psi lower than the steam injection pressure.

At the Moriche field, over a 6 month period of time, 5-wells using the Ring Seal Floating Packers have been monitored comparing oil production results to historical and forecasted data. The Ring Seal Floating Packer has shown positive results. Prior to use of the Ring Seal Floating Packer steaming at Moriche was without a packer because of their expense and history of failures. These 5-wells average of 86.3 barrels of oil per day (BPOD) of incremental oil compared to average historical oil production data from previous steam cycles.

<table>
<thead>
<tr>
<th>Well</th>
<th>Net (Forecast)</th>
<th>Actual</th>
<th>ΔNp</th>
<th>ΔNp BPOD</th>
</tr>
</thead>
<tbody>
<tr>
<td>S-02</td>
<td>14188</td>
<td>20008</td>
<td>5820</td>
<td>32.3</td>
</tr>
<tr>
<td>E-04</td>
<td>14501</td>
<td>19499</td>
<td>4998</td>
<td>27.7</td>
</tr>
<tr>
<td>E-03</td>
<td>19081</td>
<td>19819</td>
<td>738</td>
<td>4.1</td>
</tr>
<tr>
<td>AA-01</td>
<td>5301</td>
<td>7554</td>
<td>2253</td>
<td>12.5</td>
</tr>
<tr>
<td>AB-03</td>
<td>5527</td>
<td>7244</td>
<td>1717</td>
<td>9.5</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>15526</strong></td>
<td><strong>86.3</strong></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Other Completion Applications:**

Almost any area of the wellbore when a complete isolation (perfect seal) is not necessary the Ring Seal Floating Packer can be deployed. A Ring Seal Floating Packer placed within a production liner can help
selective injection of steam into reservoir areas where steam has not reached in prior steam cycles.

**Conclusion:**

The Ring Seal Floating Packer has proven success in several applications with potential for many others. The general characteristics and features of this tool are as follows:

1. It’s suitable for high temperature steam.
2. Allow for free movement and not become damaged from the thermal expansion and contraction of the tubing string.
3. Firmly engages the casing/liner and provide an adequate seal.
4. It is inexpensive and easy to install.

**References**

2. A.B. Speirs, K.D. Webster, SPE 29632, Improving Production in Steamed Wells with a Ring Seal Packer, SPE Western Regional Meeting, March 1995.