SPE 168271
Tubing Retrievable Surface Controlled Subsurface Safety Valve Floating Flapper Remediation

B. Gary, Halliburton; C. Hosli, Shell; A. Luviano, Welltec; J. Langley, Expro
Presentation Agenda

• Introduction
• TRSCSSV Flapper Obstruction and Failed Operation
• Toolstring Development and Testing
• Operational Deployment
• Conclusions and Observations
Introduction

- Conventional offshore completions require a “subsurface safety device.”
  - Surface-controlled subsurface safety valve (SCSSV)
  - Subsurface-controlled subsurface safety valve (SSSSV)
  - Injection valve
  - Tubing plug
  - Tubing/annular subsurface safety device
- During through-tubing operations (wireline, CT etc.), the SV can be damaged due to
  - Improper equalization before opening
  - Toolstring running speed – if valve is not properly locked open
- Damage specific to flapper-type valve – shearing of the hinge pin
Introduction

- Traditional intervention – Slickline rotating wedge with hold open sleeve
  - Rotate wedge to bypass flapper
  - Set open sleeve in SV profile
  - Set device (retrievable packer, stop) to secure sleeve
- Method would allow for:
  - Toolstring deployment past the obstruction
  - Future up-hole recompletion operations
- Case History consists of:
  - Initial attempt to bypass broken flapper
  - Five full-scale tests on four different BHA’s – one SL and three EL
  - Successful operation to insert isolation sleeve across flapper obstruction
• Introduction
• TRSCSSV Flapper Obstruction and Failed Operation
• Toolstring Development and Testing
• Operational Deployment
• Conclusions and Observations
Vertical Access Well in Deepwater Gulf of Mexico – Sequence of events

- 2006 – SL ran 2” LIB – Tagged up on SV flapper @ 6,008-ft. MD
- 2010 – ran memory camera
- 2012 – decision made to re-complete well
- Problem – needed to by-pass broken flapper to make three runs:
  - 2.20 inverted gauge
  - 2.125 inch OD inflatable bridge plug
  - 2.188-in mechanical tubing cutter
- 2013 – successfully developed, tested and deployed bypass device across obstruction
Initial Well Diagnostics (2006)

- Ran 2-in. SL LIB
- 4.5-in. TRCSSV flapper @ 6,008-ft. MD broken off hinge
- Impression of flapper in “top up” position
- Root cause *unidentified*
- Installed Wireline Retrievable SV in 3.562-in. RPT profile of TRCSSV
Camera Deployment (2010)

- Flapper in “top up” position
- Minimal paraffin deposition
- Flapper “floating” in cavity below hinge tabs
- Lower Seal Bore (and rest of completion) Blocked
**Pre-Rig Intervention Objectives**

1. Bypass flapper for 2.200-in. Inverted Gauge, 43.5-ft x 2.125-in. IBP, and run a 2.188-in. mechanical cutter,
2. Secure bypass device for continued production / well intervention – A Stop
3. Reinstall 3.660-in. ML BP x 2.5-in. PB-WRSCSSV
**Conventional Intervention/1st Attempt**

- SL, paraffin cleaning required, flag NO-GO run
- 90° Ratcheting Flapper Manipulation Tool
- 3.560-in. Hold Open Sleeve (HOS)
  - 12.3-ft. HOS Barrel Length
- Pinned Shear Sub

**Results**

- Friction Locked in RPT profile
  - **Flapper Top Up** vs **Flapper Bottom Up**
- Multiple LIB deployments & flow periods
- HOS end damaged from impact
**Learnings**

1. Flowing well at **10–15% choke/impacting the flapper** with the FMT wedge could flip the flapper
2. “Flapper Bottom Up” position *might* be a more convenient isolation orientation
3. **Flagged depth accuracy** from the original 3.650-in. no-go was critical for both wedge interaction vs HOS insertion and to verify RPT location
4. **FMT impact location** had a significant effect on whether the toolstring would be caught by the hinge tabs or if the flapper would recess flush

**Target**

- Closing Pre Rig Window – *But No Plan Otherwise*
- Pass 3 toolstrings to access 3.5-in., 9.2 ppf 13CR cut joints at 15,995–ft MD

<table>
<thead>
<tr>
<th>Depth</th>
<th>ID</th>
<th>Qty</th>
<th>Description</th>
<th>OD</th>
<th>ID</th>
<th>Length</th>
</tr>
</thead>
<tbody>
<tr>
<td>15,954.00</td>
<td>41.62</td>
<td>1</td>
<td>Adpt Assy Joint - 3 1/2&quot; 9.2# 13Cr 95my Varst-1</td>
<td>3.50</td>
<td>2.992</td>
<td>15,858.02</td>
</tr>
<tr>
<td>15,995.62</td>
<td>41.64</td>
<td>1</td>
<td>Tubing - 3 1/2&quot; 9.2# 13Cr 95my Varst-1 (2 Joints)</td>
<td>3.50</td>
<td>2.992</td>
<td>15,899.64</td>
</tr>
</tbody>
</table>

1. 2.200-in Inverted Gauge
2. 43.5-ft x 2.125-in IBP
3. 2.188-in. mechanical cutter
Presentation Agenda

• Introduction
• Case History Background
• TRSCSSV Flapper Obstruction and Failed Operation
  • Toolstring Development and Testing
• Operational Deployment
• Conclusions and Observations
1st (of 5) Toolstrings “Developed” and “Tested”

- January 2013
- EL “cannon”
- Inconel 718 Flappers – material currently in well
- Shrapnel Remnants – too large
- Not a viable option
## Toolstring Development and Testing

### Test Fixture Procurement and Construction

- Operator inventory
- Concentric confinement, full BHA containment, 0 deg inclination, 2 test wells secured

<table>
<thead>
<tr>
<th>Component</th>
<th>Description</th>
<th>ID</th>
<th>Length**</th>
</tr>
</thead>
<tbody>
<tr>
<td>Slips</td>
<td>Slips for 4.5” 15.10# (Can use elevator to lift into place)</td>
<td>(in)</td>
<td></td>
</tr>
<tr>
<td>Pup Joint</td>
<td>4.5” 15.10# (Grade not critical, ID critical)</td>
<td>3.826</td>
<td>10.00</td>
</tr>
<tr>
<td>Coupling</td>
<td>Coupling to mate pup joint to 4.5” joint tubing (Grade not critical, ID critical)</td>
<td>3.826 (sized to mate to tubing and pup joint)</td>
<td>1.00</td>
</tr>
<tr>
<td>Pup Joint</td>
<td>4.5” 15.10# 13cr95y pup joints x 10’ long (Grade not critical, ID critical)</td>
<td>3.826</td>
<td>10.00</td>
</tr>
<tr>
<td>Upper Restriction</td>
<td>Upper SCSSV Assembly Restriction</td>
<td>3.562</td>
<td>1.17</td>
</tr>
<tr>
<td>SCSSV Upper Sub</td>
<td>Top Seal Bore SCSSV</td>
<td>3.625</td>
<td>7.02</td>
</tr>
<tr>
<td>SCSSV Cavity</td>
<td>Cavity of appropriate length and ID as specified to mimic cavity flapper is currently sitting.</td>
<td>5.945</td>
<td>0.40</td>
</tr>
<tr>
<td>SCSSV Lower Sub</td>
<td>Bottom Seal Bore SCSSV</td>
<td>3.567</td>
<td>1.17</td>
</tr>
<tr>
<td>Pup Joint</td>
<td>4.5” 15.10# 13cr95y pup joints x 10’ long (Grade not critical, ID critical)</td>
<td>3.826</td>
<td>10.00</td>
</tr>
<tr>
<td>Bottom Cap</td>
<td>Cap to keep millings and parts from falling for subsequent analysis</td>
<td>N/A</td>
<td>0.50</td>
</tr>
</tbody>
</table>

* Lengths in Schematic are not to scale

**Lengths for coupling, flange, and joint tubing are estimated
Toolstring Development and Testing

2nd Toolstring **Developed and Tested** - 4/16/2013

- **3.15-in Mill Shoe EL BHA with a 3.5 in Spring Loaded Skirt**
- Run #1 Designed to mill core

- Run #2 Designed to insert assurance sleeve (3.62-in. OD/2.79-in. ID)

**Three Runs**
1. Flapper Top Up, 3 tags, 20 min, 2.95-in. OD x 1.195-in. core
2. Assurance Sleeve Insertion
3. Flapper Bottom Up, multiple tags, 2 hrs, flapper rotation
2nd Toolstring Testing Results

• Flapper Top Up Preferred
• Skirt Friction + WOB + Tractor Stabilization + Flapper Orientation = Milled Core
• 925 Stainless Flappers vs. 718 Inconel Flappers
• 2.95-in. Core vs. Anchor nut of 2.75-in. ID.

Possible Solution:
• 1st run – pilot hole of 1.53-in. with a different core bit
• Core: 1.25-in OD x 1.195-in
• 2nd run – 3.15-in. core bit (the same bit used during the test), modified with a pilot hole, core catching device
• 3rd run – sleeve assurance insertion
• Testing with this solution was never completed
Toolstring Development and Testing

3rd Toolstring Developed and Tested - 5/3/2013

- 2.75-in. Sleeve EL BHA with 1.69-in. Camera Wedge Shrouded Assembly, Upper 2.75-in. Hammer Assembly, and 26 ksi 0.125-in. Brass Two-Pin Shear Sub

1. Visually indentify orientation
2. Rotate and/or flip flapper for preferred orientation
3. Force flapper up and into position within cavity
4. Lower lockout sleeve into position through cavity
5. Land out top of sleeve assembly onto no-go.
6. Shear off sleeve from carrier sub

Camera / Wedge Assembly
Lockout Sleeve with carrier Sub
EL rope socket and Hammer Assembly
3rd Toolstring **Testing Results**

- **1st run** – Flapper Bottom Up Position
  - Multiple Impacts
  - Rectangular bottom up position limited pass through to 2.640-in. max (modeling provided post testing) vs 2.75-in sleeve

- **2nd run** – Flapper Top Up Position
  - Multiple Impacts
  - Offset Hinges limited Pass through to 2.425-in. max
  - Flapper Bottom Up Preferred
  - Positive Profile ID
  - Flapper Top Up not allow for req’d ID
4th Toolstring **Modified and Tested** - 5/9/2013

- **Reduced Dimension 2.625-in. SL HOS/FMT Assembly (2.225-in. ID)**

1. Flagged 3.650-in. no-go
2. 2.625-in. SL HOS/FMT with the **flapper bottom up**. Jarred 2–3 times and set the HOS.
3. 2.625-in. SL HOS/FMT with the **flapper bottom up**. Immediately made it through flapper
4. 2.625-in. SL HOS/FMT with the **flapper top up**. Not able to set HOS.

4th Toolstring **Testing Results**

- Flapper Bottom Up
- 2.625-in. OD HOS Sufficiently sized
- Can be very easy to insert
- Impact at positions (1) or (2)
- 2.225-in. bore
5th Toolstring Developed and Tested - 5/15/2013

- Reduced 2.5-in. Sleeve EL BHA with 1.69-in. Camera Wedge Shrouded Assembly, Upper 2.75-in. Hammer Assembly, and 26ksi 0.125-in. Brass Two-Pin Shear Sub (2.25-in ID) Sleeve Reduction
Toolstring Development and Testing

5th Toolstring Testing Results

• 1st run – Flapper Bottom Up Position
  • Able to bypass
  • Rotation off flapper possible

• 2nd run – Flapper Top Up Position
  • Impact Positions 5 - 8 resulted in repositioning into concave position

• Flapper Bottom Up Preferred

• 2.250-in. Bore
  • Flapper Top Up would not move
• Introduction
• Case History Background
• TRSCSSV Flapper Obstruction and Failed Operation
• Toolstring Development and Testing
• Operational Deployment
• Conclusions and Observations
Operational Deployment – 6/21/2013 to 6/27/2013

- 0.125-in. IPS SL Unit
  - Reduced Dimension 2.625-in. SL HOS/FMT Assembly (2.225-in. ID)
- 5/16-in. EL unit already on location
  - Reduced 2.5-in. Sleeve EL BHA with 1.69-in. Camera Wedge Shrouded Assembly
- Auxiliary supporting equipment for the EL package at dock
**Operational Deployment**

**Deployment Highlights**

**SETUP**
- (23) SL runs
- (5) paraffin cleanup
- (7) 3-in. LIB runs
- (5) 1-hr flow periods – (3) @ 13% choke, (1) @ 27% surge for 5 min, (1) @ 1300 psi spring loaded with 60% choke preset → Flapper not tagged

**ISOLATE FLAPPER**
- 2.625-in. **FMT/HOS** and wedge and set in 3.562-in. RPT profile
- 3.650-in. **fluted no-go w/o flapper checker** and set in HOS profile of SCSSV
- 3.680-in. **A Slip Stop** – TIC Special, set on top of HOS profile
- 2.200-in. **inverted tubing gauge w/ GR/CCL** to target depth
- 3.660-in. **bridge plug setting BHA with 2.50-in. PB valve**
Introduction

Case History Background

TRSCSSV Flapper Obstruction and Failed Operation

Toolstring Development and Testing

Operational Deployment

Conclusions and Observations
Conclusions and Observations

• Original toolstring was all that was required for modification and redeployment
• Three possible rigless operations
• Modeling and testing before deployment continues to shape the best view

I. The *problem of a floating flapper in this particular TRSCSSV* is especially difficult to isolate
II. Critical to match the *preferred flapper orientation to the BHA*
   a) SL FMT/HOS BHA – Flapper Bottom Up
   b) EL Camera/Wedge/HOS/Shear Sub BHA – Flapper Bottom Up
   c) EL Milling/Skirt BHA - Flapper Top Up
III. Depending on production characteristics, a *“hard” short surge* might be required to flip a flapper if not in the required orientation
IV. Ensuring *accurate flag depth* and toolstring location to these flagged depths
V. *Test fixture of the exact same dimensions* – if available, provides a means to test the BHA’s before operational deployment
Acknowledgements / Thank You / Questions

Shell Exploration and Production Company
Halliburton Energy Services
Expro Well Intervention Services
Welltec Well Intervention Services