Materials Challenges for Deep-water Oil & Gas Production

A Presentation for the NACE Houston Chapter
August 13, 2013

Lillian Skogsberg
&
Jim Skogsberg
Deepwater Depth History

- Going deeper
- Complex
- Moored
- Floaters
- Subsea
Subsea production system - several subsystems for HC production from one or more subsea wells and transfer HC to a processing facility located offshore (fixed, floating or subsea) or onshore, or to inject water/gas through subsea wells.
E & P Challenges

- Targets in deep water, water depth > 8,000 feet
- Project Life ~ 30 years
- Mooring adjustments due to hurricanes affect fixed TLP’s & subsea structures
- Weight & Space limits on floaters
- EOR
- Maybe HPHT – up to 30,000 psi & 550°F
- Subsea processing

- Well costs on TLP’s or Floaters ~ $30MM (drill & complete)
- Well costs subsea ~ $80MM (drill & complete)
- Wells complex
- Commodity shortages
- Mills @ capacity
  - Increasing uncertainty in project estimates
- $H_2S$ – a few ppm to 1,000 psi
Complex Equipment

- 20” 5400’
- 16” 7100’
- 11 3/4” 11300 – 14000’
- 9 5/8” 15000 – 19000’
- 7” or 7 5/8”

- 36”
- 28”
- 20”
- 16”
- 11 3/4”
- 9 5/8”
- 7” or 7 5/8”
- 5400’
- 7100’
- 11300 – 14000’
- 15000 – 19000’
High Pressure High Temperature (HPHT)

- **Target Wells**
  - Bottom Hole Pressure > 20,000 psi – 30,000 psi
  - Temperature > 400°F – 550°F

- **Materials Needed for Completions**
  - NACE MR0175/ISO15156 with pH vs H₂S
  - Steel YS > 95 ksi min to 140 – 160 ksi
  - For sour service, KᵢSSC > 40 ksi√in
  - Long lead times
  - High Qualification Costs

- **Failures in North Sea & GOM:**
  - Tubing hangers, production valves etc.
Subsea Materials Selection

Issues:
- Well equipment
- Trees
- Manifold/ESP
- Jumpers
- Sleds
- Flow lines-high temp CI needed
- Umbilicals
- Subsea Control Module
- Seals
- Insulation
- CP
- HSE

Not to mention installation and Operation
Steps in Selecting CRAs

1. Define design life: 10 years, 20 years, zero tolerance for failure?
2. Establish economic risk: HPHT, high H2S, subsea or deep water?
3. Determine alloy strength requirements based upon design.
4. Choose most economic alloy to prevent general corrosion.
   • CO2 corrosion
   • H2S corrosion
   • Organic acids
5. Consider localized corrosion resistance (pitting & under-deposit corrosion)
   • Chlorides
   • Sulfur
6. Choose alloy to resist environmental cracking.
   • Sulfide stress-cracking and
   • Stress-corrosion cracking
7. As needed, compliment field experience and the literature with laboratory study.

8/15/2013
Selecting CRAs –
Defining Mechanical Properties

• Define required yield strength and tensile strength for design in burst, collapse and tensile load.
• Consider the effect of temperature on yield and tensile strengths.
  – 5% to 15% decrease depending upon the alloy and the manufacturing process
• Some CRAs have non-isotropic mechanical properties.
  – A factor for cold-worked alloys NOT for the 13 % Cr alloys or the age-hardenable alloys (alloy 825, 28% Cr etc.)
  – 5% to 15% decrease depending upon the alloy and the manufacturing process

XHPHT wells – limited design data.

No recognized industry data base for design.
Selecting CRAs: Define All Environments That May Cause Corrosion & Cracking

• Production Environment: short-term & long-term
  – Water cut, bubble point, velocity, pH, & chlorides.
  – Partial Pressures of $H_2S$ & $CO_2$
    o Reservoir souring?
  – BHT & surface or mud-line temperatures
  – BHP & FTP
  – Contaminants – organic acids
  – Desired project life: 5 yrs, 10 yrs, or 20 yrs?
• Annular Environment: short-term & long-term
  – Chlorides – types of clear brines – NaCl, NaBr$_2$, ZnBr$_2$
    o pH, oxygen scavenger, corrosion inhibitor, & biocide
  – Effect of acid gas leaks up the annulus
• Workover:
  – Acidizing, clear brines without inhibitor & oxygen scavenger, & mixing with sour gases during flow back.
  – Flow back through subsea equipment
  – Shut in conditions (weeks, months to years)

Both production and annular environments must be documented for changing conditions.
Challenges for Selection of Low Alloy Steels

• **Forgings:**
  – Thicker-walls
  – Higher strengths >80 ksi SMYS
  – Weldability: <250 HVN hardness in sour service & < 350 HVN hardness in sea water with CP

• **Casing and Tubing:**
  – Strength grades of 110 ksi to 140 ksi with good notch toughness
  – In sour service, grades >95 ksi with cracking resistance down to +40°F.
  – Reliable industry data base for effect of temperature on mechanical properties

• **For all equipment:** lead time for delivery
### Tubing and Casing Part 2 Table A.3 uses Designations in API Spec 5CT/ISO

<table>
<thead>
<tr>
<th>Tubing and Casing Grades</th>
<th>Operating Temperatures $^{(B)}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>All Temperatures $^{(A)}$</td>
<td>$&gt;66 ^\circ C$ ($150 ^\circ F$)</td>
</tr>
<tr>
<td>Tubing, Casing Grades</td>
<td>Tubing, Casing Grades</td>
</tr>
<tr>
<td>H-40, $^{(C)}$ J-55, K-55, M-65, L-80 (type 1), C-90 type 1, T-95 type 1</td>
<td>N-80 (Q &amp; T), C-95</td>
</tr>
<tr>
<td>Proprietary $^{(H)}$ grades as described in A.2.2.3.3</td>
<td>Proprietary Q&amp;T to 700 MPa (110 ksi) max. YS</td>
</tr>
<tr>
<td>Pipe now in Table A.2.</td>
<td></td>
</tr>
</tbody>
</table>

$^{(A)}$ All Temperatures >66$ ^\circ C$ (150$ ^\circ F$) >79$ ^\circ C$ (175$ ^\circ F$) $\geq 107 ^\circ C$ ($\geq 225 ^\circ F$)

$^{(B)}$ Tubing and Casing Grades

$^{(C)}$ J-55, K-55, M-65, L-80 (type 1), C-90 type 1, T-95 type 1

$^{(G)}$ Q-125

$^{(H)}$ Proprietary grades as described in A.2.2.3.3

Pipe now in Table A.2.

No major changes in 2003.
Challenges for Selection of CRAs

- Alloys must be evaluated for resistance to SCC at 450°F > T > 550°F.
  - Most wells in the world are at <350°F.
  - NACEMR0175 limits alloys to 450°F except for C-276 and C-22HS.
- Alloys must be evaluated with 160 ksi min SMYS
  - Except for alloy C-276, NACEMR0175 limits alloys to 150 KSI max YS.
- Evaluation of age-hardenable nickel-base alloys for hydrogen embrittlement service
  - Failures of tubing hangers and packers
  - Clear brine packer fluids, galvanic coupling, acidizing, & cathodic protection
  - Not covered in NACEMR0175.
- Need a reliable industry data base for effect of temperature on mechanical properties
  - Transverse vs. longitudinal
    - Lead time for delivery
      - Major issue for large diameter and range 3 pipe.
## Table A.14: Cold Worked Ni-Based Alloys

Ni-based alloys are grouped by composition.

**Type 4C:** Alloys 825, 28Cr, & 2535.

**Type 4D:** Alloys G-3, 2550 & G-50

**Type 4E:** Alloy C-276

### Alloy Type Compositions Defined in Table A.12

Wrought or cast solid-solution nickel-based products in these applications shall be in the annealed and cold-worked condition and shall meet all of the following:

- a) The maximum hardness value for alloys in these applications shall be 40 HRC.
- b) The maximum yield strength of the alloys achieved by cold work shall be:
  - Type 4c: 1 034 MPa (150 ksi)
  - Type 4d: 1 034 MPa (150 ksi)
  - Type 4e: 1 240 MPa (180 ksi)
- c) UNS N10275 (Type 4e) when used at a minimum temperature of 121°C (250°F) shall have a maximum hardness of 45 HRC.

**NOTE** The limits of application of the materials types 4c, 4d and 4e in this table overlap.

---

### Table A.14 — Environmental and materials limits for annealed and cold-worked, solid-solution nickel based alloys used as any equipment or component

<table>
<thead>
<tr>
<th>Materials type</th>
<th>Temperature max. °C (°F)</th>
<th>Partial pressure ( P_{\text{H}_2\text{S}} ) max. kPa (psi)</th>
<th>Chloride conc. max. ( c_{\text{Cl}} ) mg/L</th>
<th>( pH )</th>
<th>Sulfur resistant?</th>
<th>Remarks</th>
</tr>
</thead>
<tbody>
<tr>
<td>232 (450)</td>
<td>200 (30)</td>
<td>See &quot;Remarks&quot; column</td>
<td>See &quot;Remarks&quot; column</td>
<td>No</td>
<td>Any combination of chloride concentration and in situ pH occurring in production environments is acceptable.</td>
<td></td>
</tr>
<tr>
<td>218 (425)</td>
<td>700 (100)</td>
<td>See &quot;Remarks&quot; column</td>
<td>See &quot;Remarks&quot; column</td>
<td>No</td>
<td></td>
<td></td>
</tr>
<tr>
<td>204 (400)</td>
<td>1 000 (150)</td>
<td>See &quot;Remarks&quot; column</td>
<td>See &quot;Remarks&quot; column</td>
<td>No</td>
<td></td>
<td></td>
</tr>
<tr>
<td>177 (350)</td>
<td>1 400 (200)</td>
<td>See &quot;Remarks&quot; column</td>
<td>See &quot;Remarks&quot; column</td>
<td>No</td>
<td></td>
<td></td>
</tr>
<tr>
<td>132 (270)</td>
<td></td>
<td>See &quot;Remarks&quot; column</td>
<td>See &quot;Remarks&quot; column</td>
<td>Yes</td>
<td>Any combination of hydrogen sulfide, chloride concentration and in situ pH in production environments is acceptable.</td>
<td></td>
</tr>
<tr>
<td>218 (425)</td>
<td>2 300 (300)</td>
<td>See &quot;Remarks&quot; column</td>
<td>See &quot;Remarks&quot; column</td>
<td>No</td>
<td>Any combination of chloride concentration and in situ pH occurring in production environments is acceptable.</td>
<td></td>
</tr>
<tr>
<td>140 (300)</td>
<td></td>
<td>See &quot;Remarks&quot; column</td>
<td>See &quot;Remarks&quot; column</td>
<td>Yes</td>
<td>Any combination of hydrogen sulfide, chloride concentration and in situ pH in production environments are acceptable.</td>
<td></td>
</tr>
<tr>
<td>232 (450)</td>
<td>7 000 (1 000)</td>
<td>See &quot;Remarks&quot; column</td>
<td>See &quot;Remarks&quot; column</td>
<td>Yes</td>
<td>Any combination of hydrogen sulfide, chloride concentration and in situ pH occurring in production environments is acceptable.</td>
<td></td>
</tr>
<tr>
<td>204 (400)</td>
<td></td>
<td>See &quot;Remarks&quot; column</td>
<td>See &quot;Remarks&quot; column</td>
<td>Yes</td>
<td>Any combination of hydrogen sulfide, chloride concentration and in situ pH in production environments is acceptable.</td>
<td></td>
</tr>
</tbody>
</table>

Metallurgical properties.
Summary

- The production of oil and gas from deep water wells provides technical challenges in the development of materials to provide safe and reliable service at reasonable cost.
- Materials technology continues to evolve to meet this challenge.

Thank you for your attention and the opportunity to present this talk. Are there any questions?