Challenges Associated with Produced Water Re-Injection for Offshore Waterflood Projects

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Common Sources of Injection Water Offshore

1. Seawater
   - Treated seawater (deoxygenated, filtered)
   - Desulfated seawater
   - Raw seawater (may or may not be filtered)
   - Low salinity water

2. Produced Water
   - Formation/connate/aquifer water plus:
     - Injected water

3. Aquifer Water
   - From non-producing reservoirs
   - Any Combination of the Above
Primary Concerns When Selecting a Water for Injection

1. Availability
   - Enough volume to meet demand over the life of the field?

2. Compatibility
   - Compatibility with the Formation

3. Topsides Impacts
   - Weight, space and power
   - Operations workload

4. Solids
   - Topsides filtration requirements
   - Risk of injectivity impairment

5. Oil and Grease
   - Impact on filtration
   - Impact on injectivity
   - Reduction of discharges

6. Scaling
   - Injection system water incompatibilities
   - Production system scale management

7. Sourcing
   - H₂S production and control

8. Temperature
   - Cooling requirements
   - Material limitations
   - Injectivity considerations

9. Corrosion
   - Materials selection costs and operational risks
Drivers for Produced Water Re-Injection?

• Why do we look to inject produced water?
  • Water injection increasingly attractive in deepwater to maximize overall production and return on investment
  • Reduced environmental footprint
  • Removal of need to lift and deaerate seawater for injection
  • Reduced or eliminated scaling concerns
  • Decreased souring risks compared to mixed or seawater-only systems
  • Aquifer waters generally not available in sufficient location or quality to make extra wells and risers worthwhile
Water Injection in Deepwater

• So what’s different?
  • Rapid pressure depletion and high hydrostatic head can require immediate or early water injection (e.g. Gulf of Mexico)
  • May need to start injection with, or prior to, initial production to maintain bubble point (e.g. West Africa)
  • Limited injection well stock due to high cost - Increases consequences of losing a well
    • Well workover/stimulation cost
    • Deferred production costs due to reduced injection
  • Materials selection and flow assurance more challenging for subsea developments
    • Consequences of scale formation much more difficult to treat for subsea wells
    • High-pressure wells require high-strength materials that are often more susceptible to souring or require increased qualification testing
Water Injection in Deepwater

- **So what’s different?**
  - Limited weight and space for topsides for certain hull types (SPARs, TLPs, Semi’s)
    - High incremental cost of hull size increases
    - Particularly challenging for brown-field developments
  - Increased internal and external visibility of operations
    - Increased project sizes and production rates provide an increased impact on global Operator revenues
    - Increased scrutiny due to high profile of large projects and their placement in pristine environments
Produced Water Availability

- **Biggest hurdle in early life**
  - Can drive a move towards seawater injection
  - Also a problem for fields planning water diversion/water shut-off in late life

- **Typically requires make-up with seawater during field life**
  - Means that some infrastructure is required for seawater injection

- **Injection profile is important**
  - If early injection rate is the maximum required rate then low incentive to consider PWRI as seawater system capacity meets full-life requirements
  - If more injection is required in later life then a smaller seawater package for early life and later make-up by produced water becomes more attractive
**Topsides Impacts**

- **Seawater only**
  - Commonly use coarse strainers to fine filters to deaerator
    - Some operators place final filters downstream of deaerator
  - May need sulfate removal for scaling and souring control
    - Large and heavy equipment
    - Operator intensive
  - Deaerator placement can be a big issue
    - High CoG of vacuum and gas stripping towers
    - Operator intensive operation of compact systems
  - Higher-grade alloys or FRP needed for corrosion resistance
Basic Seawater Injection System Layout

Filtration determined by injection specification
- In North Sea only coarse filtration is often required
- In deepwater GoM only coarse and cartridge filters may be required
- West African facilities typically have coarse and m/m filters, often with cartridge filters
**Topsides Impacts**

- **Produced Water only**
  - Commonly use fine filters to surge drum
    - Variability in instantaneous produced water rates makes a surge drum a common requirement
    - Filter design can be difficult to determine, especially for new-build developments
  - Prior chemical application needs to be considered
    - Benefits of scale inhibitor and corrosion inhibitor carry-over
    - Minimal concerns regarding biocide discharges
    - Issues due to water clarifier floc and oil and grease may increase filter size
  - Materials selection based around carbon steel
    - Minimal oxygen in the system means that the use of carbon steel is the preferred materials selection option
Basic Produced Water Injection Layout

- Level of filtration determined by injection specification
- Surge tank needed to provide constant flow to injection pumps without need for overboard discharge
Topsides Impacts

- **Mixed Systems**
  - Combine the worst points of both systems
    - Deaerator, surge drum and multiple filtration packages
    - Materials selection and corrosion control issues
  - Increased concerns around bacterial control and scale formation downstream of the mixing point
    - Mixing with desulfated seawater is an option to support scale and souring control
Solids Control and Injectivity

- Often the biggest hurdle from a facilities design standpoint
  - Sand carry-over from high-rate production wells
  - Corrosion products from carbon steel piping
  - Wax, scale and asphaltenes
  - Floc from produced water treatment

- Erosion is usually a minor issue due to relatively low flow velocities in liquid-packed systems
  - Usually the limiting factor is the injection pumps, rather than valves or piping

- Solids can impair well injectivity above pre-determined levels
  - Limits based on completion design and formation properties
  - Matrix versus fracture injection has a profound influence on solids limits
Solids Control and Injectivity

- Solids tend to be higher in produced waters than in seawater and generally more difficult to remove
  - Problem with filter plugging as a result of oil-wet solids
    - Generally higher risk of injector plugging with produced water
    - 1/3 bridging rule for seawater often modified to 1/6 solids to pore throat size for PWRI
  - High solids loadings also impact oil and water separation, further increasing water quality concerns
    - Decreased chemical performance
    - Decreased vessel residence times
    - Decreased hydrocyclone performance
Monitoring for Solids Contents: Process Management

- **Direct Filtration (spot measurements)**
  - For TSS and stacked filters (for TSS and mass profile) downstream of filters and pumps
  - Good to have results from the extreme downstream end of the system, but do not routinely sample from high-pressure systems after injection pumps

- **Turbidity analyzers (on-line)**
  - Typically not reliable due to large number of small particles commonly present in produced water and the range of sizes and reflectivities
  - Useful for trending performance once correlated with other methods

- **Particle size analyzers (spot or on-line)**
  - Good at detecting trends and changes in the data
  - Generally reliable and robust
Monitoring for Solids Contents: After the Fact

Injectivity loss at 6MM bbls

Injectivity loss at 3MM bbls

Formation Over-Pressure and Fracturing

Continued Injectivity
Produced Water Filtration Options

- Anything that removes solids prior to the injection system is a good thing
  - Sand-control hydrocyclones
    - Primary solids-control option
    - Can operate at 5 psi DP, but 20 to 60 psi generally provides better performance
      - Erosion rates increase with increasing pressure drop
    - Usually good for solids down to 10 µm
      - May see operational problems with 2 to 5 µm units due to fouling of smaller-diameter elements
  - In-line separators
    - Attractive for retrofits as no pressure drop
    - Generally only provide efficient removal of solids down to around 50 µm
Produced Water Filtration Options

- Common performance limits for various filter types
  - Centrifuges have also been used offshore – typically with poor outcomes

<table>
<thead>
<tr>
<th>Filter Type</th>
<th>Maximum Effective Solids Removal (µm)</th>
<th>Inlet O&amp;G Limit (mg/l)</th>
<th>Inlet TSS Limit (mg/l)</th>
<th>Notes</th>
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<tr>
<td>Multimedia Filters</td>
<td>2 to 5</td>
<td>-</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>Nut Shell Filters</td>
<td>2 to 5</td>
<td>150</td>
<td>-</td>
<td>Reduces O&amp;G</td>
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<tr>
<td>Cartridge Filters</td>
<td>2 to 5</td>
<td>5</td>
<td>-</td>
<td>Plugging at Tighter Specs</td>
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<tr>
<td>Membrane Filters</td>
<td>&lt;1</td>
<td>50</td>
<td>15</td>
<td>Usually for SW</td>
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Oil and Grease

• Primary driver for PWRI in the late 90’s was the belief that re-injection would save on chemicals and treatment facilities
  • Injectivity impairment usually only a concern above ~ 100 mg/l
  • GoM discharge specs are 29 mg/l (avg) and 42 mg/l (max), leaving scope to reduce treatment requirements without impacting injectivity

• Reality is that we can’t generally inject above discharge limits
  • Impact on production when operating outside of discharge spec
    • Any injection system trip often drives a shut-in of production as cannot divert off-spec water overboard
    • Option on FPSO’s if large produced water tanks are available
  • Generally easier to maintain water at spec than have to bring the system down to spec from a higher point in a finite time
Reservoir Sourcing

- Decreased (but not zero) risk of souring with PW only
  - Offshore experience is limited, but plenty of onshore examples of souring following PWRI

- High risk of souring if mixed with seawater
  - Much greater risk of souring if produced water is commingled with seawater than if either water is injected
    - Due to high sulfate from seawater, coupled with high nutrient and carbon loading of produced water
    - Contributed to by poor seawater system or production system biological control
Comparisons of Mixed Injection Regimes
Controlling Souring

• Lower risk of souring for well-managed systems
  • Maintaining injection and production system cleanliness with bacterial monitoring and batch biociding is always a good start

• Nitrate injection
  • Now widely accepted as a souring mitigation tool
  • Works in most cases, especially when employed from the start of injection
  • There are serious concerns regarding corrosion in mixed seawater/produced water systems that have caused some applications to be halted
  • Treatment rate for SW/PWRI systems depends on water compositions, but are generally higher than for seawater treatment alone

• Sulfate removal
  • Accepted as a means of decreasing souring risk for seawater systems
  • At least one field mixing low-sulfate seawater and produced water has soured
Scaling and Water Incompatibility

- Produced water generally better than seawater injection
  - Possible issue when injection to various different zones with different formation water properties
    - Significant issue for deepwater developments covering large areas or multiple reservoirs (e.g. for many West African developments)
  - Mixing at the injector can be controlled with scale inhibitor treatment to the initial flood front
  - Scale management at the producers will depend on the degree of incompatibility and the type and location of the scale formed
- When injecting produced water to non-native reservoirs or intervals then coreflood testing is a necessity
  - Differences in salinity or water composition can drive clay swelling in susceptible reservoirs
Temperature Limitations

- Limited cooling capabilities on brownfield projects can impact produced water injection feasibility
  - Decreased thermal fracturing at higher arrival temperatures can impact well injectivity performance
    - One reason why North Sea water injection projects tend to have lower filtration requirements than their GoM and West African counterparts
  - Riser flex joints are typically limited to around 120°F for continuous operation
  - Flexible risers and flowlines often have similar operating limits, depending on the choice of polymer liner
    - HDPE is commonly used for water injection systems and is limited to around 140°F
Corrosion Mechanisms

- Produced water typically much more benign than seawater
  - Issues are carbon dioxide, possibly H$_2$S, and bacteria
  - Management typically as required for the water-leg of the separation system
    - Carry-through of corrosion inhibitor usually protects from CO$_2$ corrosion
    - Batch biociding used for bacterial control – no overboard discharge, so can be more aggressive than comparable seawater systems
    - Need to monitor for oxygen ingress through low-pressure water system and pump seals
  - Unlike seawater systems, carbon steel is generally suitable
    - Potential large savings on subsea flowlines and downhole tubing over seawater injection
Conclusions

- Produced water re-injection was adopted as a ‘default’ position by the majors in the late 1990’s
  - Response to the North Sea regulatory environment and growing public awareness of produced water discharges
- Translation of this into practice for deepwater developments has been challenging
  - Increased awareness of the facilities and operational impacts of PWRI
  - More recent move away from PWRI as the default design case for non-FPSO hull types and typically discounted completely for retrofit projects
    - Availability and topsides design impacts are the largest impediments to PWRI use, with souring and injectivity concerns following in importance
  - High well costs in deepwater, limited well numbers and limited topsides real estate have driven a trend towards seawater injection with overboard produced water discharge
The Future?

- Increasing public pressure to limit produced water discharges
  World-wide – potential for regulatory changes in the long-term
  - Early requirement for water will continue to see a need for seawater injection, with occasional aquifer water injection where available
  - Increased use of low salinity or smart water operations may limit produced water injection or the timing of this
  - Weight, space and power requirements for injection make disposal wells more costly in deepwater than for North Sea and Shelf operations
    - Likely to drive increased use of commingled SW/PW injection streams in the mid to late life of facilities
    - May enable the use of lower-capacity seawater systems for early life, with higher volumes from produced water make-up as the field matures
The Future?

- Emphasis on the produced water treatment industry to develop compact and reliable technologies to overcome current issues
- Need to develop integrated produced water treatment and water injection systems
  - Require less operator intervention than current systems
  - Accommodate produced water upsets
  - Account for the capture and removal of solids – recycling back to the production system isn’t an option
  - Reliably deliver high-spec water that promotes long injection well lives and high sustained injection rates
Questions and Discussion

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CHALLENGES ASSOCIATED WITH
PRODUCED WATER RE-INJECTION FOR
OFFSHORE WATERFLOOD PROJECTS