Please Pass the Salt: Using Oil Fields for the Disposal of Concentrate

Robert E. Mace
Texas Water Development Board
Jean-Philippe Nicot
Bureau of Economic Geology
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Bureau of Reclamation
The problem:

- Communities interested in desalination need a cost-effective and safe solution for disposing of concentrate.
A possible solution:

- Inject concentrate into depleted oil fields.
Goal of the project:

To develop the scientific foundation upon which we can support recommended policy change to allow an easier approval path for permitting concentrate injection wells in oil fields.

- Show location of oil fields across state that may be potential injection sites.
- Show through physical and geochemical modeling that oil fields can accept concentrate.
- Make a recommendation on how to streamline permitting.
TECHNICAL APPROACH

- Identify depleted oil and gas fields
- Historical perspective on fluid injection in oil and gas fields in Texas
- Characteristics of analysis areas
- Characteristics of concentrates
- Formation damage
  - Scaling
  - Clay sensitivity
- Formation damage control
- Injection rates
IDENTIFY
DEPLETED OIL AND GAS FIELDS
Why Do We Care about Pressure Depletion?

- Create opportunity to inject fluid with little risk of exceeding maximum pressure that can be sustained by reservoir
- Simplify Area of Review Process
- Field production history guarantees surface infrastructure needed to move around fluids
Analysis Areas

1 Anadarko
2 Permian
3 East Texas
4 Fort Worth
5 Maverick
6 Southern Gulf Coast
Selected Stratigraphic Columns in Texas with Oil Production
Target Formations

- **Anadarko B.**: Granite Wash Fm.
- **Permian B.**: San Andres Fm.
- **East Texas B.**: Woodbine Fm.
- **Fort Worth B.**: Atoka Fm.
- **Maverick B.**: San Miguel/Olmos Fm.
- **Southern Gulf Coast B.**: Frio Fm.
Pressure-depleted Fields

Permian Basin
Bottom Hole Pressure (psig)

East Texas Basin
Bottom Hole Pressure (psig)

Southern Gulf Coast Basin
Bottom Hole Pressure (psig)

Anadarko Basin
Bottom hole pressure (psig)

Fort-Worth Basin
Bottom hole pressure (psig)

Maverick Basin
Bottom hole pressure (psig)
HISTORICAL PERSPECTIVE ON OIL AND GAS FIELDS IN TEXAS
Water Injection in Oil&Gas Fields

- Reservoir drive mechanisms in oil&gas fields:
  - Water drive
  - Gas cap drive
  - Solution gas drive

- Pressure maintenance and waterflooding with fresh, brackish, or produced waters

- Fresh water needs no treatment before injection

- Fresh water reduces or eliminates scaling in pipes but could generate downhole scaling and/or fine plugging

Source for figure: http://www.kgs.ukans.edu/Publications/Oil
Injection Historical Data

- Data compilation up to 1982

From RRC database (1982) – last year with data compilation
Conclusions

- Oil and Gas industry in Texas has an extensive experience with fluid injection.
- Fluids include fresh, brackish and saline waters.

Source: Hycal.com
SELECT ANALYSIS AREAS
Analysis Area Selection Criteria

- Counties with depleted oil/gas fields
- Counties with a predicted shortfall of water supply over the next 50 years
- Counties with brackish ground water resources
- Counties with injection wells not too deep
Water Quality of Shallow Groundwater

Blue = Fresh water < 1,000 mg/L TDS
Yellow = 1,000–3,000 mg/L TDS
Orange = 3,000–10,000 mg/L TDS

Target Brackish Water Sources

- Anadarko B.: Ogallala Aq. Dockum Aq.
- Permian B.: Ogallala Aq. Dockum Aq.
- East Texas B.: Carrizo-Wilcox Aq.
- Fort Worth B.: Trinity Aq.
- Maverick B.: Carrizo-Wilcox Aq.
- Southern Gulf Coast B.: Gulf Coast Aq.
CHARACTERISTICS OF ANALYSIS AREAS
Important Parameters

- Lithology/Mineralogy:
  - Rock type
  - Mineral in contact with flowing fluids
  - Clay content and nature

- Formation water composition

- Flow properties:
  - Porosity, permeability
  - Other fluid present (relative permeability)

- Field characteristics
  - Pay thickness
  - Geothermal gradient
  - Average pressure and depth
## Mineralogical Characteristics of Analysis Areas

<table>
<thead>
<tr>
<th>Basin</th>
<th>Rock Type</th>
<th>Important Minerals</th>
</tr>
</thead>
<tbody>
<tr>
<td>Anadarko</td>
<td>Silico-clastic</td>
<td>Feldspars, quartz, clays</td>
</tr>
<tr>
<td>Permian</td>
<td>Carbonate</td>
<td>Calcite, dolomite</td>
</tr>
<tr>
<td>East Texas</td>
<td>Silico-clastic</td>
<td>Feldspars, quartz, clays</td>
</tr>
<tr>
<td>Fort Worth</td>
<td>Silico-clastic</td>
<td>Quartz, feldspars</td>
</tr>
<tr>
<td>Maverick</td>
<td>Silico-clastic</td>
<td>Quartz, feldspars</td>
</tr>
<tr>
<td>S. Gulf Coast</td>
<td>Silico-clastic</td>
<td>Feldspars, quartz, clays</td>
</tr>
</tbody>
</table>
Porosity/Permeability of Analysis Areas

Permian Basin

East Texas Basin

Southern Gulf Coast Basin

Fort-Worth Basin
<table>
<thead>
<tr>
<th>Basin</th>
<th>Porosity (%)</th>
<th>Permeability (mD)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Anadarko</td>
<td>~12 (4 - 20)</td>
<td>~20 (6 – 65)</td>
</tr>
<tr>
<td>Permian</td>
<td>~9.3 (&lt;3 - &gt;20)</td>
<td>~5 (1 - &gt;100)</td>
</tr>
<tr>
<td>East Texas</td>
<td>~25 (20 - &gt;35)</td>
<td>~500 (15 - &gt;3,000)</td>
</tr>
<tr>
<td>Fort Worth</td>
<td>~14.5 (6 – 28)</td>
<td>~20 (1 - &gt;1,000)</td>
</tr>
<tr>
<td>Maverick</td>
<td>~25 (19 -32)</td>
<td>~30 (3 - &gt;2,000)</td>
</tr>
<tr>
<td>S. Gulf Coast</td>
<td>~25 (&lt;15 - &gt;35)</td>
<td>~305 (20 - &gt;1,000)</td>
</tr>
</tbody>
</table>
CHARACTERISTICS OF CONCENTRATES

From R.W. Beck
Concentrate

- Most feed water TDS between 1,000 and 3,000 mg/L
- Concentration factor of 4 (all ions have the same rejection rate)
- Closed system (no equilibration with CO$_2$)
- Two cases:
  - Addition of antiscalant
  - Addition of antiscalant and sulfuric acid to a pH=6
- Difficulty in obtaining minor element (Si, Fe, Ba, Sr) concentrations
FORMATION DAMAGE
Formation Damage Definitions

- A condition that occurs when barriers to flow develop in the near-wellbore region. Results in lower than expected production rate from (or injection rate into)

- Any process causing a reduction in the natural inherent productivity or injectivity of a producing or injection well
Mechanical Formation Damage

- Origin: injected suspended solids, formation fine migration plugging pore throats

Fines bridged at pore restrictions

Fluid flow

Mobile fines

Mod. From Michael Dixon, OMNI Laboratories, Inc.
Chemical Formation Damage

- Origin 1: deflocculation of clays, swelling of clays due to chemical changes (pH, ionic makeup)
- Origin 2: formation of scales due to mixing of incompatible water and change in environmental conditions

Mod. From Michael Dixon
OMNI Laboratories, Inc.
SCALING

UCLA, Cohen et al
What is scaling?

- Precipitation of minerals in the wellbore or in the formation.
- Calcite, gypsum, barite, silica (iron oxides, brucite, siderite, anhydrite, strontianite)
- Term also applies to corrosion products
- Fluid injection is typically less scale-prone than production
Approach

- Compute concentrate composition with the USGS geochemical code PHREEQC using standard industry pretreatment and a factor of 4
- Mix in different proportions concentrate with formation water with the USGS geochemical code SOLMINEQ (able to handle high salinity fluids)
- Choose randomly 2x5,000 samples to mix
- Analyze statistically (histograms) saturation index for relevant minerals of resulting combinations
- Determine the fraction of mixing combinations above the SI threshold beyond which antiscalants are not effective
Examples of SI Histograms

Permian Basin - Mixed Water - Calcite SI
Number of bins: 41; Bin size: 0.1; Number of data points: 28,305

East Texas Basin - Mixed Water - Calcite SI
Number of bins: 41; Bin size: 0.1; Number of data points: 19,568

South. Gulf Coast Basin - Mixed Water - Calcite SI
Number of bins: 41; Bin size: 0.1; Number of data points: 19,999

East Texas Basin - Mixed Water - Gypsum SI
Number of bins: 41; Bin size: 0.1; Number of data points: 19,349

South. Gulf Coast Basin - Mixed Water - Gypsum SI
Number of bins: 41; Bin size: 0.1; Number of data points: 19,999

Permian Basin - Mixed Water - Barite SI
Number of bins: 41; Bin size: 0.1; Number of data points: 2,300

East Texas Basin - Mixed Water - Barite SI
Number of bins: 51; Bin size: 0.1; Number of data points: 320

South. Gulf Coast Basin - Mixed Water - Barite SI
Number of bins: 61; Bin size: 0.1; Number of data points: 4,128

Permian Basin - Mixed Water - Silica SI
Number of bins: 41; Bin size: 0.1; Number of data points: 17,662

East Texas Basin - Mixed Water - Silica SI
Number of bins: 41; Bin size: 0.1; Number of data points: 14,232

South. Gulf Coast Basin - Mixed Water - Silica SI
Number of bins: 41; Bin size: 0.1; Number of data points: 18,043

With acidified concentrate
Summary of S/’s of Mixing Combinations

- Most S/ are <1 including amorphous (colloidal) silica
- Barite may be a problem locally (S/ is also higher because of $\text{H}_2\text{SO}_4$)

Median and 95th percentile
With acidified concentrate
Previous results assume thorough mixing between concentrate and formation water.

This is conservative because mixing is likely to be less than thorough owing to piston flow of concentrate displacing formation water.
CLAY SENSITIVITY

Source: hycal.com
What is Clay Sensitivity?

- Clay sensitivity is due to the ability of clays to exchange ions with surroundings and/or to absorb water (swelling).
- A change in environmental conditions (ionic makeup, salinity, pH) may also disperse clay particles (deflocculation).

Before injection, two questions need to be answered:
- Is there any clay?
- What type of clay?

![Diagram showing flocculation and deflocculation](image)
<table>
<thead>
<tr>
<th>Basin</th>
<th>Clay Abundance</th>
<th>Clay Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>Anadarko</td>
<td></td>
<td>Chlorite, illite, kaolinite</td>
</tr>
<tr>
<td>Permian</td>
<td>Rare</td>
<td>Kaolinite</td>
</tr>
<tr>
<td>East Texas</td>
<td>Common</td>
<td>Smectite, illite, chlorite, kaolinite</td>
</tr>
<tr>
<td>Fort Worth</td>
<td></td>
<td>Chlorite, illite, kaolinite</td>
</tr>
<tr>
<td>Maverick</td>
<td>Abundant</td>
<td>Mx-layer illite-smectite, chlorite, kaolinite</td>
</tr>
<tr>
<td>S. Gulf Coast</td>
<td>Abundant</td>
<td>Mx-layer illite-smectite, smectites, kaolinite</td>
</tr>
</tbody>
</table>
Clay Sensitivity Principles

Ka=kaolinite
Il=illite
Mx=mixed layers;
Sm=smectite
TCC=Total Cation Conc.

Any water inside the delineated domain will deflocculate the corresponding clay at equilibrium.

Possible cation stripping and deflocculation in the transient stage.

Plot mod. from Scheuerman and Bergersen, 1990, SPE Paper No. 18481
MAR Study: East TX B. Analysis A.

MAR Ratio = 
\[ \frac{[Na]^2/[Ca]}{[Na]^2/[Ca]}_{conc} / \frac{[Na]^2/[Ca]}{[Na]^2/[Ca]}_{form} \]

If MAR Ratio < 0.5, problems are expected for smectite clay.
FORMATION DAMAGE CONTROL
Chemical and Physical Solutions

- Matrix acidizing by HCl, H$_2$SO$_4$ (both for carbonates), HF (for silicates), organic acids
- Treatment with KOH and NaOH (for calcium sulfate)
- CaCl$_2$ brine treatment (to limit clay sensitivity). NaCl and KCl. Clay stabilizers that bind clays to the substrate
- Hydraulic fracturing
- Heat treatment (?)
Operational Solutions

- Surface treatment to remove suspended solids
- Lower flow rate, increase perforation density
- Gradual change in salinity to avoid salinity shock
- Injection of a buffer solution
- Oxygen scavengers, antiscalant
INJECTION RATES
Injection Rate Issues

- Maximum injection rate controls number of wells needed
- Injection rate is dependent on formation parameters: 

\[
\Delta P = \frac{Q \mu}{4\pi kb} \ln \left( \frac{2.25kt}{\phi c \mu r^2} \right)
\]

(Limited sampling of injection wells)
Computed Injection Rates

Anadarko Basin - Computed Maximum Injection Rate

West Texas Basin - Computed Maximum Injection Rate

East Texas Basin - Computed Maximum Injection Rate

Fort Worth Basin - Computed Maximum Injection Rate

Maverick Basin - Computed Maximum Injection Rate

Southern Gulf Coast Basin - Computed Maximum Injection Rate

median = 7.3 gpm; 95th = 23 gpm

median = 13.2 gpm; 95th = 153 gpm

median = 466 gpm; 95th = 3,347 gpm

median = 9.8 gpm; 95th = 376 gpm

median = 6.3 gpm; 95th = 270 gpm

median = 278 gpm; 95th = 9,038 gpm
Injection Rate Conclusions

1 MGD of concentrate:
- Is equivalent to 695 gpm
- Would require a couple of wells in the eastern half of the state in recent formations
- Would require one or several well clusters in the paleozoic formations

Injection rate can be augmented by screening the pay thickness and stimulating the well
Summary of Technical Conclusions

- A significant fraction of the wells would qualify for a variance of AOR.
- Scaling can be mitigated with standard approaches (acidification, antiscalant).
- Clay sensitivity may be a local issue for several fields. It could be dealt with but at a price.
- Multiple wells/well clusters are needed to accommodate concentrate output of a typical plant.
Policy procedures:

• Met with RRC and TCEQ
• Met with EPA Region 6 and headquarters
• Talked with other states about their solutions
• Researched permitting and permitting options
Current permitting process:

- History
- Class I
- Class II
- Class V
Possible permitting paths:

• Non-hazardous Class I
• Class II
• Class V
• Dual-permitted wells
• General permit, Class I
• Special Class I
• Change Federal regulations