The Relative Importance of Critical Technical and Regulatory Issues that Define Injection Well Feasibility: Pressure Matters

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Objectives

• Introduction

• Technology Overview
  (how wells and pressures work)

• Critical Technical Feasibility Concerns
  (and relationship to pressure)

• Critical Regulatory Feasibility Concerns
  (and relationship to pressure)

• Summary and Questions
Deepwells/Injection Wells
Why Should Operators Be Interested?

• Deepwell disposal can:
  – be a cost-effective contributor to wastewater management plans
  – provide support for - or an alternative to evaporation ponds and other approaches
  – help minimize project environmental footprints
  – be protective of human health and the environment

Pressure influences injection in many ways
How Does Injection Work?

- Porosity – the material property of having void space within a solid (only useful if connected)
- Permeability – the material property that allows liquid or gas to move through the porosity of a rock due to differential pressure
- Fluid and Rock Compressibility
  - large reservoir volumes
  - thickness and lateral extent
- Geologic Confinement
How Does Injection Work?

• Fluid is injected into saturated pores
  – native fluid is displaced, and
  – native fluid and injectate are compressed
    and rock pore space expands

• Injection reservoirs should be large,
  and if possible nearly infinite-acting
  systems – boundaries & interference
What is Critical for Capacity?

• Permeability-Thickness
• Porosity-Thickness
• Formation Pressures
• Efficient Wellbore Communicating to Reservoir
• System (Rock & Fluid) Compressibility
  – large reservoir volumes
  – thickness and lateral extent
Water Compressibility

- Water has a compressibility of approximately $3 \times 10^{-6}$ gal/gal/psi
- A sealed tank of 1,000,000 gallons would see a 1 psi pressure increase if 3 gallons of water were added
- For a reservoir with a radius of 5 miles, thickness of 100 feet, and porosity of 10%, injecting 500,000 gallons raises pressure by 1 psi in the entire reservoir. Operating <1 week at 50 gpm
- Rock matrix in a disposal zone can have a compressibility similar to brine, effectively doubling the volume required for equal pressure increase
System Compressibility

- Reservoir extent is important; larger is better than compartmented systems
- 640 acre spacing can be large for O&G production, but small for disposal purposes
- $5,280' \times 5,280' \times 100' \times 12\% = 2.5$ billion gallon pore volume
- 6 months @ 25 gpm = 6.5 million gallons
- $c = \frac{-1 \Delta v}{v \Delta p}$
- $\Delta p = \frac{6.5 \text{ million}}{(2.5 \text{ billion} \times 6e-06)} = 433 \text{ psi}$
Delta p ($\Delta p$)

- Pressure increase is greatest at the wellbore, and varies dramatically (log) with distance and time based on two parameter groups:

$$\Delta p = 162.6 \frac{g \mu B}{k h} \left[ \log \frac{k t}{\Phi \mu cr^2} \right] - 3.23$$

Matthews and Russell (1967)
## Injection Capacity Examples

<table>
<thead>
<tr>
<th>Formation</th>
<th>Permeability (k, md.)</th>
<th>Thickness (h, ft.)</th>
<th>Porosity (Φ, %)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Teckla, Teapot, Parkman (Mesa Verde) – Wyoming</td>
<td>1</td>
<td>200</td>
<td>12</td>
</tr>
<tr>
<td>Lance – Wyoming</td>
<td>10</td>
<td>300</td>
<td>17</td>
</tr>
<tr>
<td>Cedar Hills – Nebraska</td>
<td>3,000</td>
<td>60</td>
<td>30</td>
</tr>
<tr>
<td>Mt. Simon – Michigan</td>
<td>100</td>
<td>750</td>
<td>13</td>
</tr>
<tr>
<td>Arbuckle - Kansas</td>
<td>1,500</td>
<td>500</td>
<td>8</td>
</tr>
</tbody>
</table>

* generalized permeability-thickness estimates to allow relative comparisons
Well Performance/750,000 mdft - 25 gpm
(Arbuckle Example)
Well Performance/180,000 mdft – 25 gpm
(Cedar Hills Example)

Max Inj. dP

Pressure Rise (psi)

Time (Years)
Well Performance/3,000 mdft – 25 gpm
(Lance Example)
Well Performance/200 mdft – 25 gpm
(Teckla, Teapot, Parkman Example)
Summary of Injection Well Performance
25 gpm, S=0, Infinite Acting

![Graph showing pressure rise over time for different permeability levels.](image)

- **200 md-ft**
- **3,000 md-ft**
- **75,000 to 750,000 md-ft**

*Typical Max Inj. dP*
## Injection Capacity Examples

(25 gpm for 20 years)

<table>
<thead>
<tr>
<th>Formation</th>
<th>Permeability-Thickness (kh, mdft.)</th>
<th>Pressure Rise (psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Teckla, Teapot, Parkman (Mesa Verde) – Wyoming</td>
<td>1*200 = 200</td>
<td>4,800</td>
</tr>
<tr>
<td>Lance – Wyoming</td>
<td>10*300 = 3,000</td>
<td>354</td>
</tr>
<tr>
<td>Mt. Simon - Michigan</td>
<td>100*750 = 75,000</td>
<td>20</td>
</tr>
<tr>
<td>Cedar Hills - Nebraska</td>
<td>3,000*60 = 180,000</td>
<td>8</td>
</tr>
<tr>
<td>Arbuckle - Kansas</td>
<td>15,00*500 = 750,000</td>
<td>2</td>
</tr>
</tbody>
</table>

*generalized permeability-thickness estimates to allow relative comparisons*
Industry Well Type Differences

- Other Well Operational Types Are Often Poor Analogs For Brine Disposal Performance

- Oil and gas production rates have very different economics (in the oilfield 1 gpm (34 BOPD) production could equate to +/- $0.5 million per year, but feasible disposal typically requires 10 to >100 gpm capacity)

- Smaller hydrocarbon reservoir extent can be economic (10s to 100s vs. >10,000 acres per disposal well)

- Hydrocarbon reservoir compressibility typically much larger (water x10^{-6}, gas x10^{-1} to x10^{-4}, oil x10^{-3} to x10^{-5})

- Shorter hydrocarbon production life may still be economic (years vs. >decades)
Industry Well Type Differences

• Disposed industrial and ISR uranium brines can have a higher viscosity than produced oilfield fluids (relatively lower injection temperature will increase viscosity and increase required injection pressure; water 0.3-1.5 cp, gas 0.005 – 0.05 cp)

• ISR uranium mining and oilfield water flooding or pressure maintenance may not be a good analog since there are both sources and sinks (disposal formations typically only have injectors, no offset production to reduce pressure)
Industry Well Type Differences

- Injection pressures will increase due to decreased well efficiency (skin factor grows >0) if chemical and physical fluid quality and compatibility cause wellbore and/or formation plugging (filtration and scale inhibition).

- Technologies are available to enhance well communication to injection zones (possible permitting complication and significant cost), but ultimately capacity can be dominated long-term by reservoir permeability-thickness.

- Oilfield operations may also not be a good analog due to the different regulations that apply to Class I and Class II wells:
  - It may be legal to operate some Class II wells at above injection formation fracture propagation pressure, but federal regulations prohibit the initiation or propagation of fractures during Class I well operation.
Pressure Front vs. Waste Front

• During injection, the pressure front typically leads the waste front
• After shut-in, during static conditions the waste front can lead the pressure front
• Both can be reliably projected using a variety of methods depending on the complexity of the well system being modeled
• Multiple wells in a reservoir can spread the effects, but the effects are additive (theory of superposition) – might be critical to feasibility
Technical Issues

• Availability of suitable injection horizons (permeability & thickness)
• Injection reservoir capacity
• Economics (capital and operating costs)
• Containment issues (neighboring wells, geologic features, caprock, fracturing)
• Potential for Induced Seismicity

Each concern is related to pressure
Regulatory Issues

• Cone of influence (pressure rise)
  – Defines the area that requires the most rigorous geologic characterization
  – drives evaluation of containment issues (neighboring wells, geologic features, caprock)

• Maximum operating conditions defined by capacity and pressure rise (fracture pressure)

• Induced seismicity concerns related to geology, rate and pressure but are localized

• Induced seismicity rare but critical
Regulatory Issues

• Due to renewed public scrutiny, efforts are needed to educate the public about the technology, and explaining how well pressures work can be a challenge

• Competing water disposal and pore space uses (oilfield disposal, O&G production, CCS - geologic CO2 sequestration) which can involve additive pressures from nearby activity

Many concerns relate back to pressure
Summary

• Well capacity will primarily be defined by geologic conditions and fluid quality
• Available pressure rise will limit capacity due to maximum WHP and reservoir extent
• Advanced planning and “proof of concept” often advisable to quantify site specific reservoir/capacity and permitting issues
• Most technical and regulatory issues are related to pressure rise, so understanding pressure is critical to evaluating disposal well feasibility
Discussion and/or Questions?

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