A Pressure-Limited Model to Estimate CO$_2$ Injection and Storage Capacity of Saline Formations: Investigating the Effects of Formation Properties, Model Variables and Presence of Hydrocarbon Reservoirs

Hossein Jahediesfanjani, LynxNet - contracted to USGS, Reston, VA
Peter D. Warwick, U.S. Geological Survey, Reston, VA

International Energy Agency Greenhouse Gas R&D Programme
Modelling and Risk Management Network Meeting
Grand Forks, ND
2018
Estimated CO$_2$ storage capacity - Mount Simon Formation

- Zhou et al. (2010) model: 5 Gt
- Szulczewski et al. (2012) model: 111 Gt
- Eccles et al. (2012) model: 254 Gt
- NETL (2012) model: 42.2 Gt (medium)
- USGS (2013a) model: 91 Gt ($P_{50}$)

• Modeling Goals

- Estimating practical CO$_2$ injection and storage capacity of a given saline formation

- Designing a CO$_2$ injection plan (number of wells, well spacing, duration of injection, well injection rate, brine extraction rate) for a given saline formation
We used Tough2-ECO2N to model CO₂ injection and storage in saline formations.
Model development - Numerical simulation

- We modeled and history matched the Illinois Basin Decatur Project for CO$_2$ injection based on data from Senel and Chugunov (2013) as a starting point
  - This model covers an effective area of 10 km by 10 km
  - A CO$_2$ injection rate of 1 Mt over 3 years
Model development - Numerical simulation (Cont.)

- What if the Illinois Basin Decatur Project continued for longer time (50, 100 years)?
  - The effective CO$_2$ injection area would be larger (25 by 25 km for this case example)
- Eventually, we are modeling a series of CO$_2$ injection effective areas ($A_{eff}$)
Model development - Formation heterogeneity

- The Mount Simon Formation saline Storage Assessment Unit (SAU) contains a large number of heterogeneities
- Formation porosity, permeability, depth, net thickness…
Model Development - Statistical formulation

- \( V_{inj,t} = a\phi^b H^c A^d k^e D^f t^g \)
- \( V_{inj} = V_{inj,t} t \)

\( V_{inj,t} \): Annual cell injection rate, Mt/year  
\( V_{inj} \): Total cell injection, Mt  
\( A \): Effective injection (cell) area, km\(^2\)  
\( D \): Effective injection average depth, m  
\( H \): Effective injection thickness (m)  
\( k \): Effective injection permeability (mD)  
\( t \): Duration of injection (years)  
\( \phi \): Effective injection porosity (%)  

\[ y = 1.674E-09x \]
\[ R^2 = 0.96 \]

<table>
<thead>
<tr>
<th>Parameter</th>
<th>a</th>
<th>b</th>
<th>c</th>
<th>d</th>
<th>e</th>
<th>f</th>
<th>g</th>
</tr>
</thead>
<tbody>
<tr>
<td>Value</td>
<td>1.674E-09</td>
<td>0.66</td>
<td>0.85</td>
<td>0.64</td>
<td>0.18</td>
<td>1.25</td>
<td>-0.31</td>
</tr>
</tbody>
</table>
Model development - Advantages

• The 3D numerical simulation is conducted only for a representative $A_{\text{eff}}$

• Each $A_{\text{eff}}$ acts as a closed domain and hence can be operated independently

• Possible to model any fault and natural barrier by considering them as boundary conditions to a given $A_{\text{eff}}$

• The developed statistical method makes it possible to apply this approach to determine the annual CO$_2$ injection rate for similar saline formations
Model results

- This model is applied to estimate the CO\textsubscript{2} injection and storage capacity of 192 Storage Assessment Units (SAUs) in 33 U.S. basins defined and reported by the U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team (2013a,b)

- By applying the model to the Mount Simon Formation, injection rate density maps are produced
Model results - Mount Simon Formation

- Two cases are assumed:
  - Formation heterogeneity is not known: most likely values are used
  - Formation heterogeneity is known and used in capacity estimation
Model applications: Effect of hydrocarbon reservoirs

- Many of the important SAUs contain a large number of oil and gas reservoirs.

- In addition, there could be several undiscovered hydrocarbon reservoirs in the SAUs.

- Hydrocarbon production from these reservoirs depends largely on each reservoir’s prevailing conditions and operating pressure.

- Any CO₂ injection into or near these reservoirs will disturb their governing and driving mechanisms.

- Over 5,000 discovered oil and gas reservoirs are in U.S. Gulf Coast SAUs alone with an average decline time to their economic limit of over 40 years.
Model applications: Effect of hydrocarbon reservoirs

- Sligo-Hosston- Cotton Valley SAU is the largest defined SAU in Gulf of Mexico
- Determined CO₂ injection capacity is 840 Mt/year ignoring the hydrocarbon reservoirs
- Determined CO₂ injection capacity is 355 Mt/year taking into account the presence of hydrocarbon reservoirs
Comparison of estimated CO$_2$ storage capacity – Mount Simon Formation

- **Pressure limited models:**
  - Zhou et al. (2010) model: 5 Gt
  - Jahedieszfanjani et al. (2017) model: 3.5 Gt

- **Other Models:**
  - Szulczewski et al. (2012) model: 111 Gt
  - Eccles et al. (2012) model: 254 Gt
  - NETL (2012) model: 42.2 Gt (medium)
  - USGS (2013a) model: 91 Gt ($P_{50}$)

- **Pressure management techniques, such as brine extraction before or during CO$_2$ injection, will greatly increase a saline formation’s CO$_2$ storage capacity applying any pressure limited model.**
Pressure management - Brine extraction

- We modeled brine extraction scenarios utilizing a 5-spot pattern similar to waterflooding and/or CO₂ EOR operations in oil reservoirs.

![Graph showing brine extraction scenarios](image-url)
Summary

• Based on this model, the entire saline formation is divided into equal cells that:
  – Contain a single CO$_2$ injection well
  – Each cell functions independently as closed boundary cell
  – Each cell injection rate is a function of formation properties, cell size and duration of injection
  – A buffer zone is created around hydrocarbon reservoirs with no CO$_2$ injection

• Brine extraction is being modeled to estimate additional CO$_2$ injection capacity due to proper pressure management technique

• This model provides a practical roadmap to estimate each SAU’s CO$_2$ storage capacity, optimum number of wells, well spacing and injection/extraction rates
References


Utilization of Carbon and other Energy Gases – Research and Assessments Project

For more information contact:
Hossein Jahediesfanjani, hjahediesfanjani@contractor.usgs.gov
Peter D. Warwick, pwarwick@usgs.gov
Steve T. Anderson, sanderson@usgs.gov

Selected Publications
http://go.usa.gov/xZDpz