UNDERSTANDING CARBON STORAGE IN SHALES AFTER FLUID FRACTURING INJECTION, A POTENTIAL CARBON MANAGEMENT RESOURCE

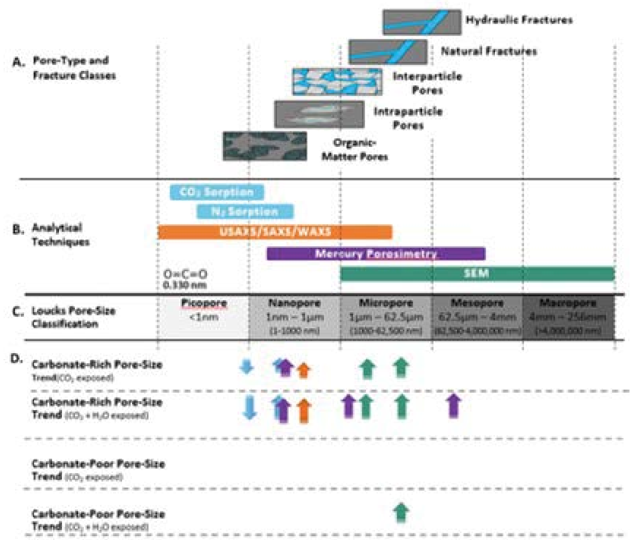
Carbon storage advanced research and development.

EXPLORING WAYS TO PERMANENTLY STORE CO_2 IN SHALE AFTER OIL RECOVERY

NETL Research and Innovation Center researchers have shown that shales reacted with hydraulic fracturing fluid, followed by CO_2, undergo carbonate dissolution and barite, gypsum, and carbonate precipitation under in-situ conditions.

These changes lead to etching and pitting of the shale that increases micro-porosity, potentially increasing the ability of the shale to store CO_2.

Understanding the impact on CO_2 transport into the matrix is critical to understanding the potential of CO_2 storage in depleted shale reservoirs.



ANALYSIS OF RESULTS SHOW SHALE COMPOSITION HAS A MAJOR EFFECT ON CO_2-SHALE INTERACTIONS AND IMPACTS THE ABILITY TO STORE CO_2

Synthetically aged (30 days in synthetic fracturing fluid) and non-aged shale:

Non-Aged

- Pores decrease with CO_2 exposure.
- Pores increase with CO_2 + H_2O exposure.

Aged

- Pores decrease with CO_2 exposure and CO_2 + H_2O exposure.

Carbonate content in shales:

Carbonate rich:

- Micro-scale porosity increases with CO_2 and CO_2/H_2O.
- Nano-scale porosity decreases with CO_2 and CO_2/H_2O.

Carbonate poor:

- Increase in micro fracture abundance and size for both conditions.

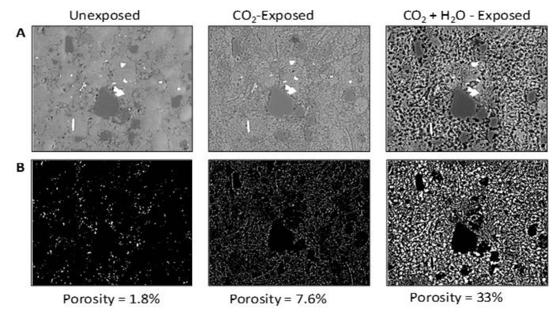
Reactivity of CO_2 and impact on permeability:

- CO_2 did not promote significant reactivity with the shale if water was not present.
- Porosity and permeability increased in core shale samples after exposure to CO_2-saturated-fluid due to dissolution of carbonate (no new or altered flow paths created; increased microporosity).
- Exposure to CO_2 and CO_2-saturated-fluid did not alter the mechanical properties of the shale samples.
- No trend that could tie CO_2 or fluid reactivity to physical or chemical properties of the shale formations at the basin scale was observed.

REACTIVITY OF CO_2 WITH UTICA, MARCELLUS, EAGLE FORD, AND BARNETT SHALES AND THE IMPACT ON PERMEABILITY

Researchers examined samples from three shale basins across the U.S. (Utica and Marcellus Shales in the Appalachian Basin, Barnett Shale in the Bend Arch-Ft. Worth Basin, and Eagle Ford in the Western Gulf Basin). Images below show conditions prior to exposure, after exposure to pressurized CO_2, and after exposure to pressurized CO_2 (14 days) and water (14 days).

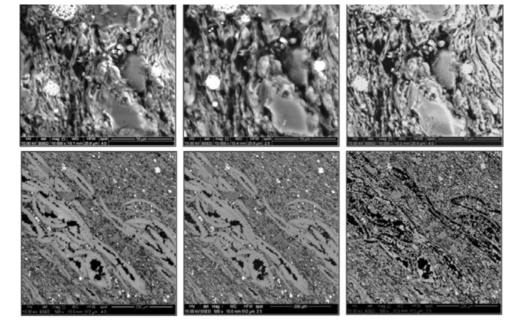
Utica Shale



- Etching and pitting from CO_2 exposure.
- Increase in dissolution and porosity with exposure to CO_2 and H_2O.

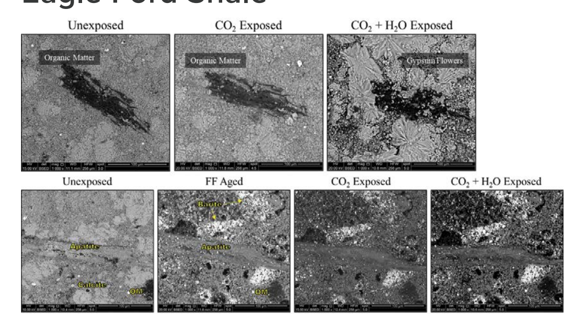
B: modified above image where porosity is white and solid space is black.

Marcellus Shale



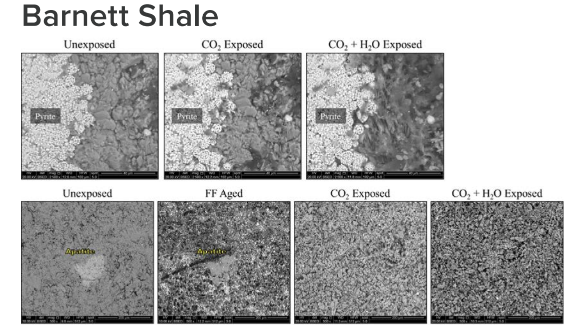
- Top: silicate rich shale, no etching and pitting.
- Bottom: gray carbonate veins are dissolved, causing etching and pitting.

Eagle Ford Shale



- Top: organic matter reacts in CO_2 and H_2O, precipitates gypsum/ dissolves carbonate.
- Bottom: hydraulic fracturing fluids etch and pit, precipitate barite.

Barnett Shale



- Carbonate dissolution observed.
- No formation of gypsum (organic matter did not contain sulphur).

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DOE $948,000

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DEMONSTRATE AND DEPLOY POINT-SOURCE CARBON CAPTURE

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