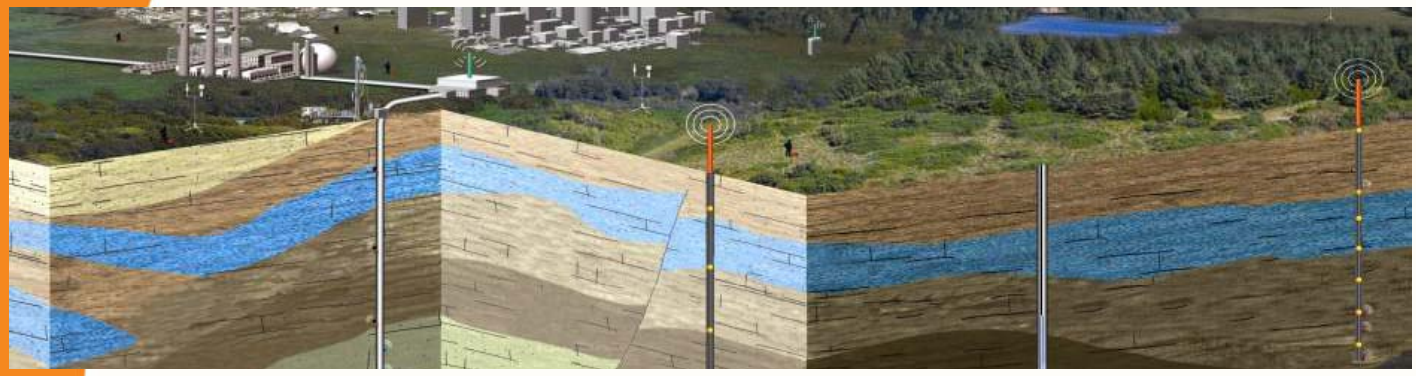
Schlumberger
Carbon Services

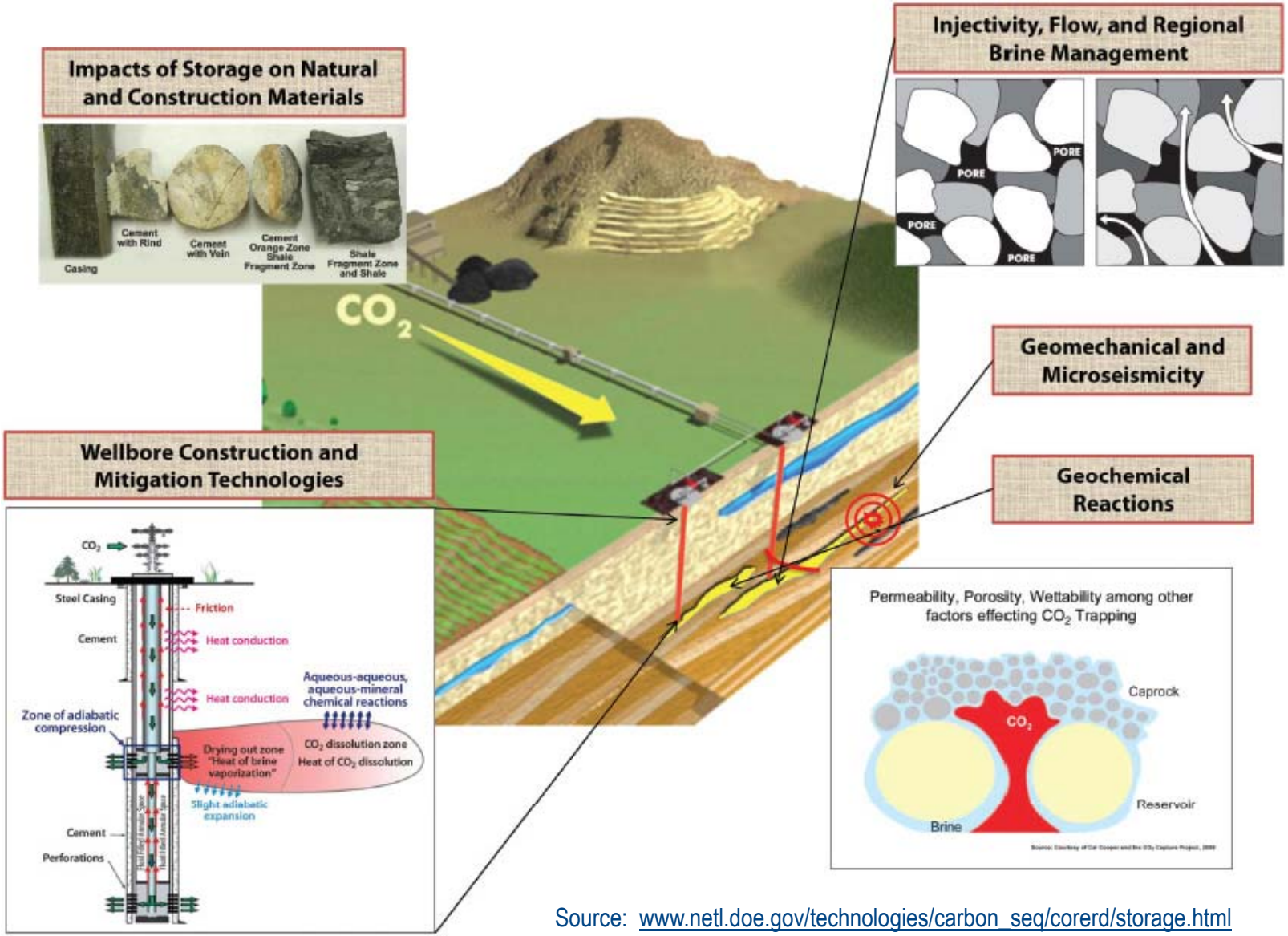


Wellbore Technologies

Dwight Peters
North America Business Manager

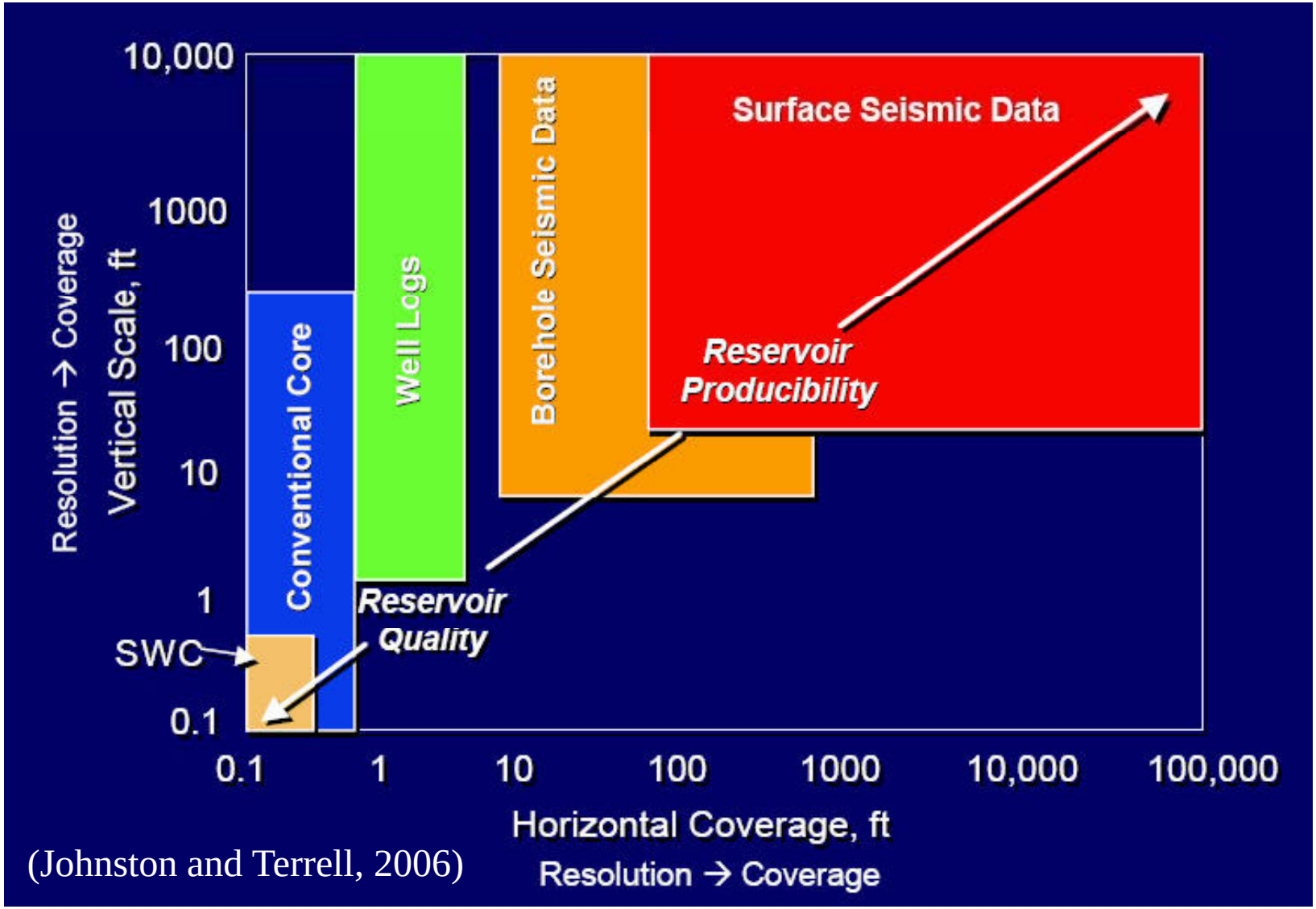
NETL R&D
Workshop
Oct 19, 2011

Geologic Storage



Source: www.netl.doe.gov/technologies/carbon_seq/corerd/storage.html

Data Scales



(Johnston and Terrell, 2006)

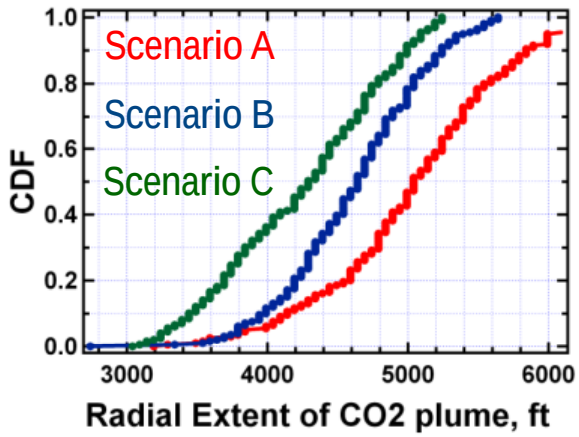
Reducing Uncertainty – Wellbore Limitations

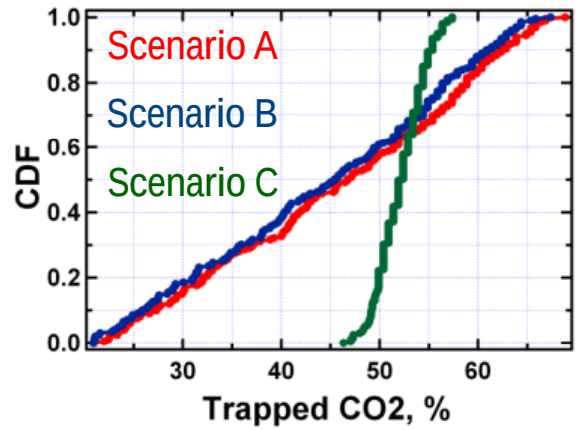
Injected CO_2:
400,000 tonnes
over 4 years

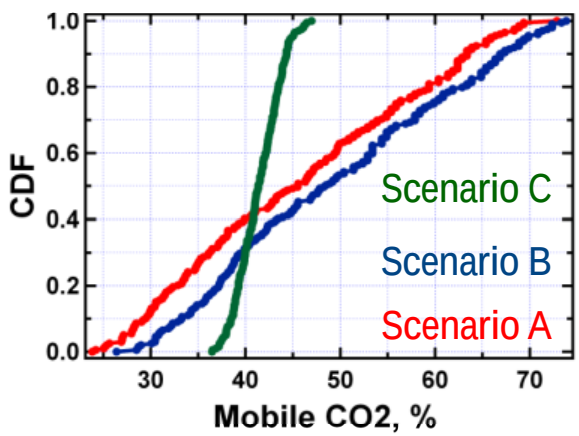
Monitoring:
46 years after injection
stops

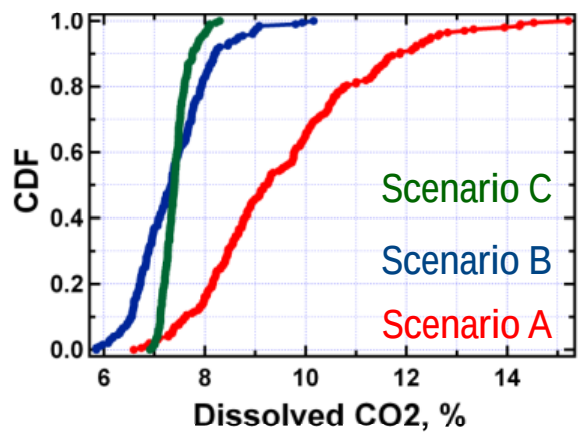
Injection zone:
bottom 20 feet of
formation

t = 50 years

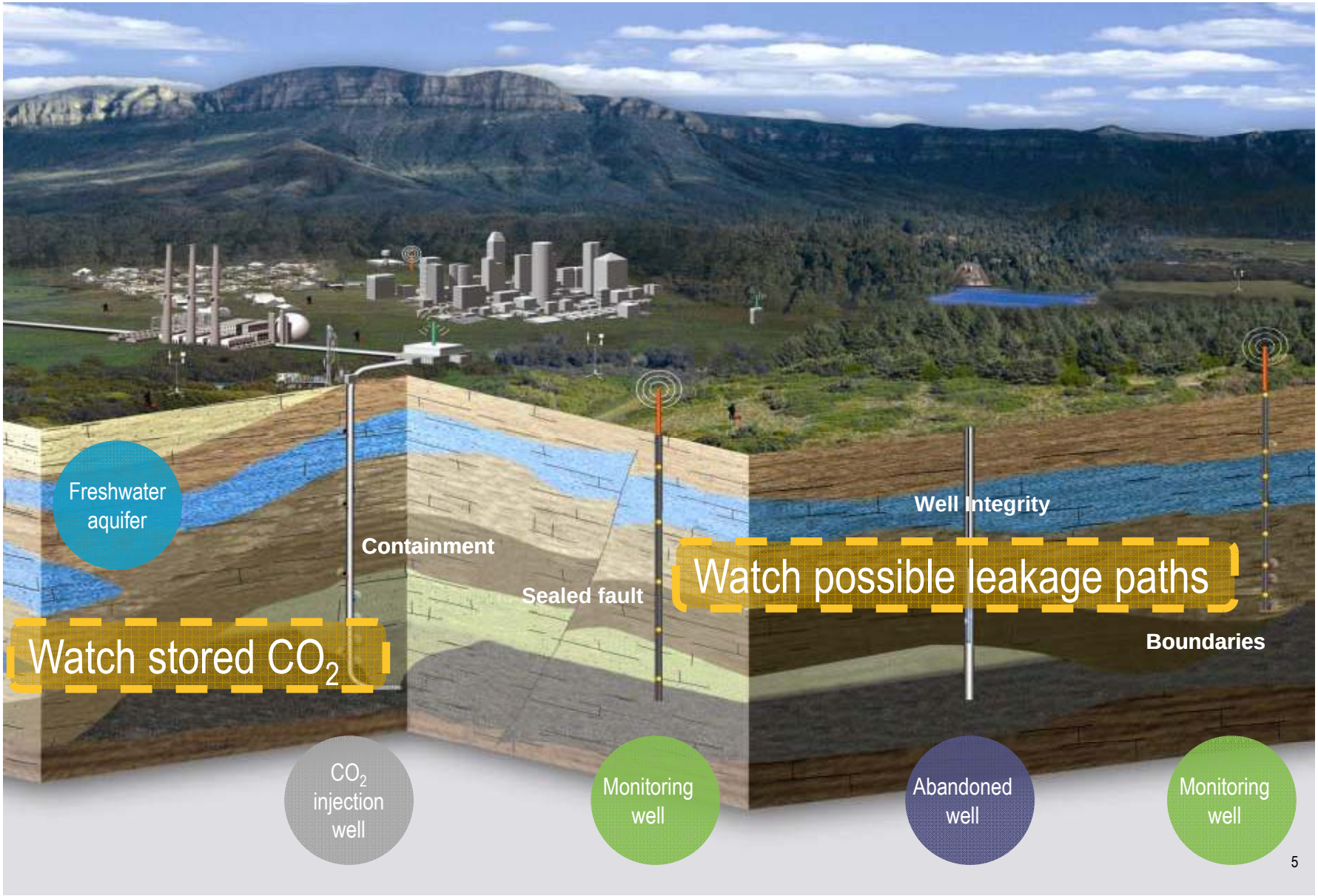






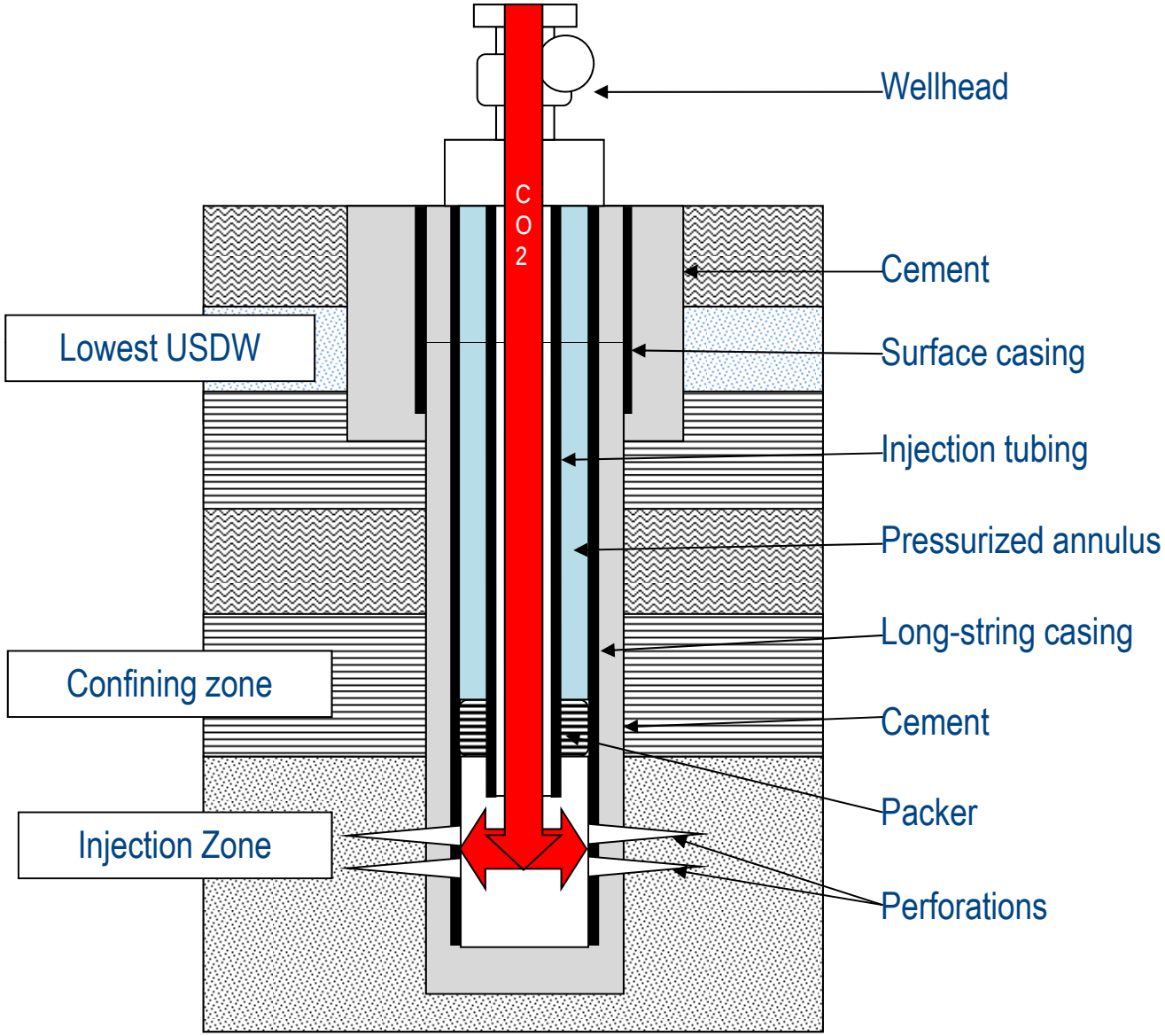


CO_2 Monitoring – Dependence on Wells



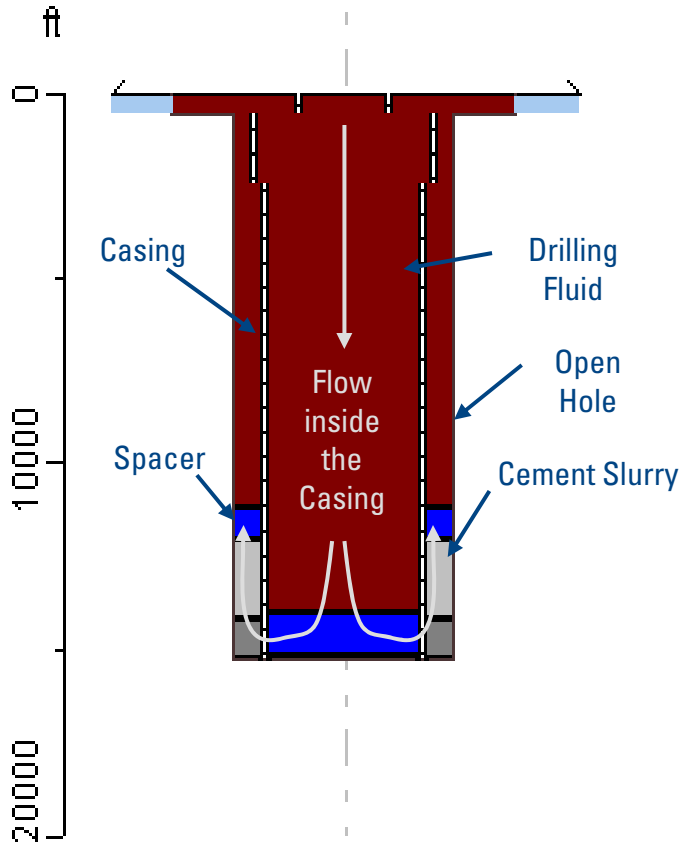
CO2 Injection Well

Schlumberger
Carbon Services



Executing a Cement Job

- Cement is pumped down inside the casing.
- Cement then passes in the gap (or annulus) between the casing and open hole.
- It is displaced into position with drilling fluid or water.
- Spacers are often pumped ahead and behind to clean the hole and protect the cement.



Fluid Sequence

Leading Causes of Cementing Failures

- Incomplete mud removal
- Irregular wellbore profile
- Breakdown of formation during cementing
- Well fluid flow during or after cement is placed
- Inappropriate cement slurry design
- Incorrect downhole hardware
- Surface execution problems
- Apparent failures that are not real

Well Integrity?

Schlumberger
Carbon Services

Injection Well Construction Requirements

- "Casing and cement or other materials used in the construction of each Class VI well must have sufficient structural strength and be designed for the life of the geologic sequestration project. All well materials must be compatible with fluids with which the materials may be expected to come into contact"
- "Cement and cement additives must be compatible with the carbon dioxide stream and formation fluids and of sufficient quality and quantity to maintain integrity over the design life of the geologic sequestration project."
- "At least one long string casing, using a sufficient number of centralizers, must extend to the injection zone and must be cemented by circulating cement to the surface in one or more stages"
- "Tubing and packer materials used in the construction of each Class VI well must be compatible with fluids with which the materials may be expected to come into contact"

➢ What about the mandatory in-zone monitor wells?

Injection Well Operating Requirements – Annular Pressure

"The owner or operator must maintain on the annulus a pressure that exceeds the operating injection pressure, unless the Director determines that such requirement <u>might harm the integrity of the well</u> or endanger USDWs."

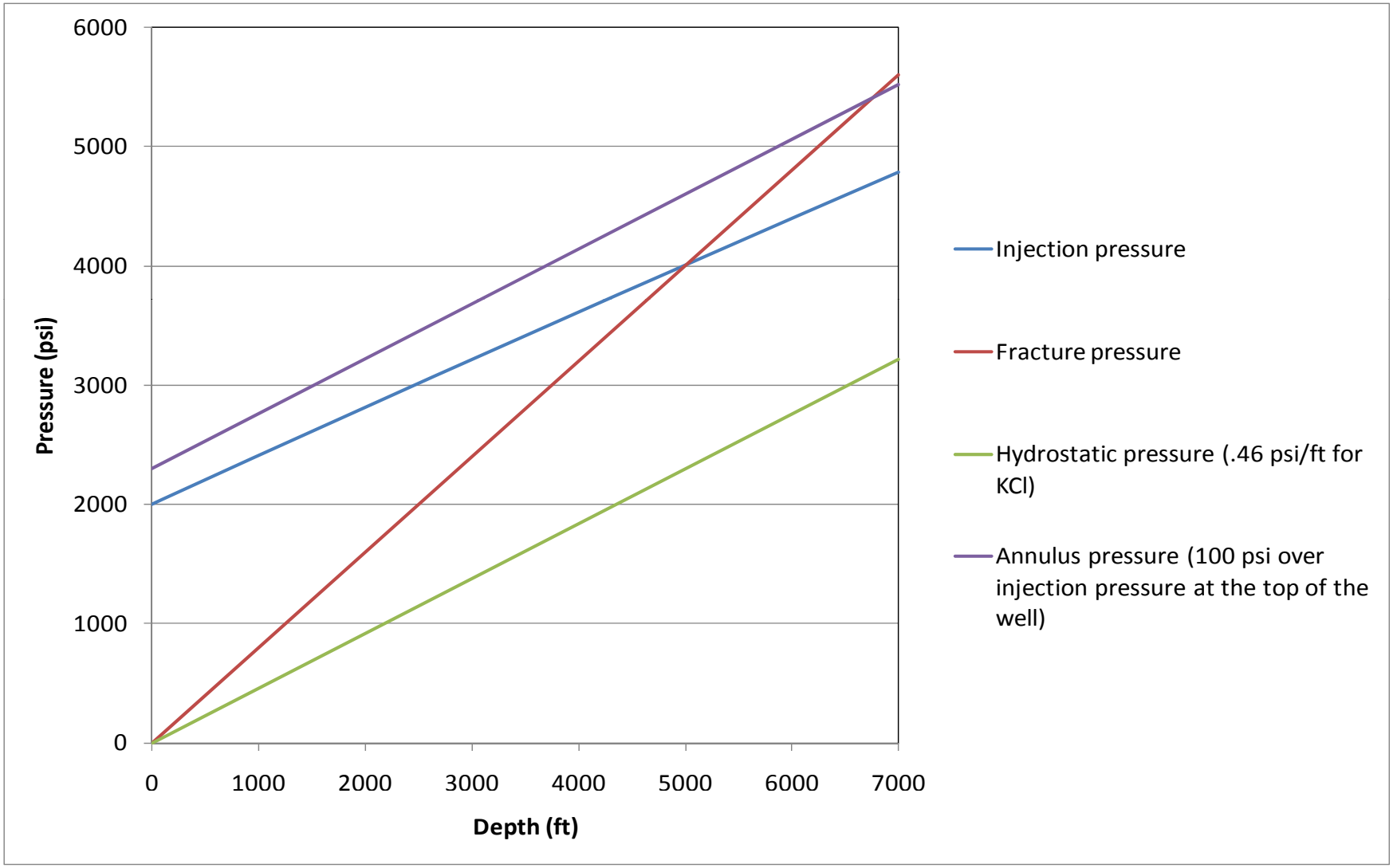
Concerns

- Exposes stage tools to high pressure
- May damage the cement isolation capacity
- May damage the surrounding formation

<u>EXAMPLE</u>

- Injection pressure at the top of the well of 2000 psi
- Surface temperature of 50°f and a gradient of 1°f per 100ft
- Annular fluid 10% KCl with a gradient of 0.46 psi/ft
- Annular pressure 100 psi above injection pressure at the top of the well
- A fracture pressure gradient of 0.8 psi/ft
- Injection depth 7000 ft
- Variable CO_2 density and gradient based on constant densities over 100-foot intervals calculated using REFPROP [Lemmon et al., 2007]

Annular Pressure



Summary

- NETL has a wealth of wellbore data at it's disposal
  - Covers the gamut of commercial technologies
  - Still a lot of work could be done with it
    - Not a trivial task
- High-quality wellbores are not a given
  - Even UIC Class VI has "issues"
  - We cannot allow bad events through complacency