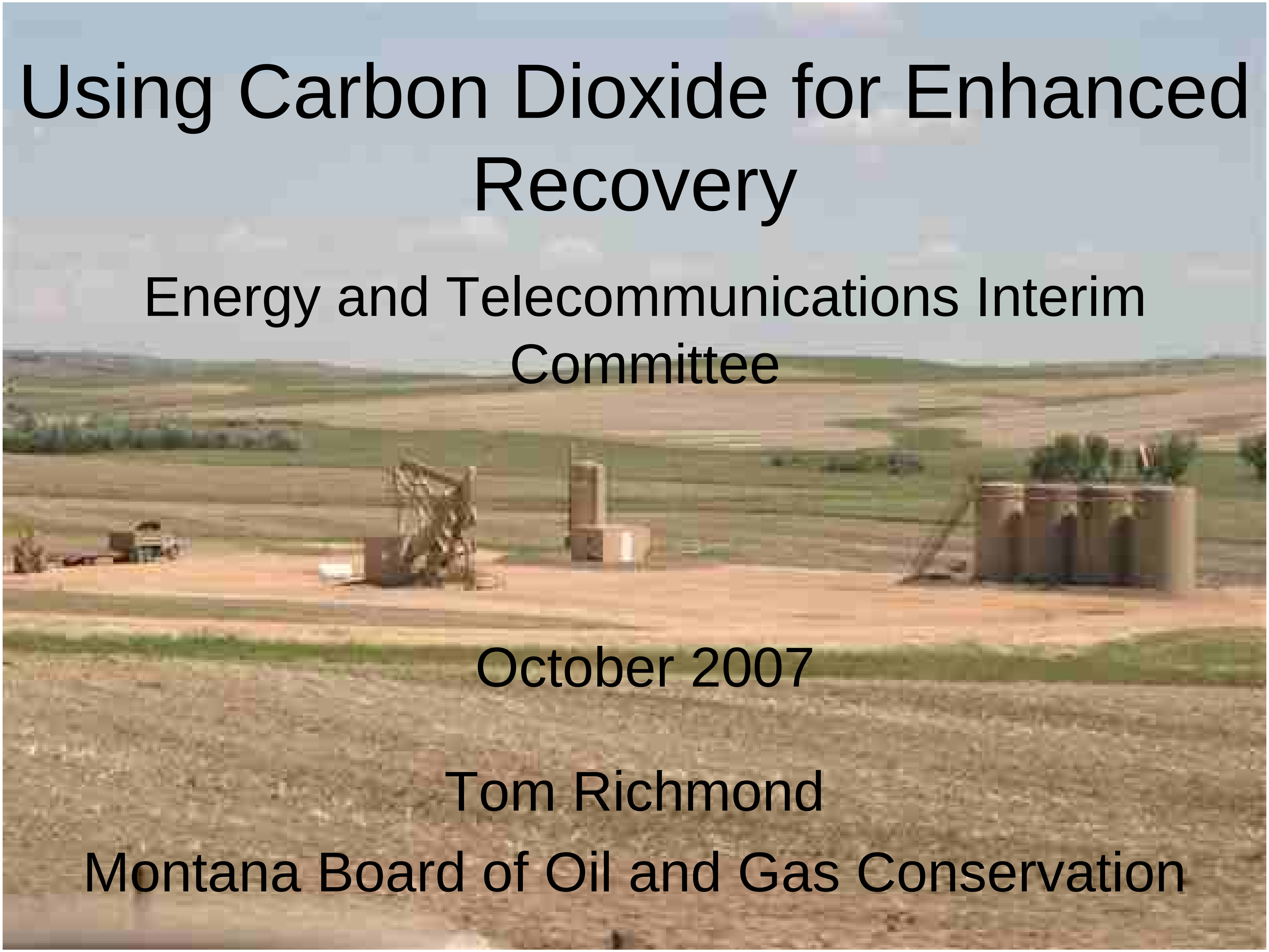


Using Carbon Dioxide for Enhanced Recovery

Energy and Telecommunications Interim Committee

October 2007

Tom Richmond

Montana Board of Oil and Gas Conservation

Before I came here I was confused about this subject. Having listened to your lecture I am still confused. But on a higher level.

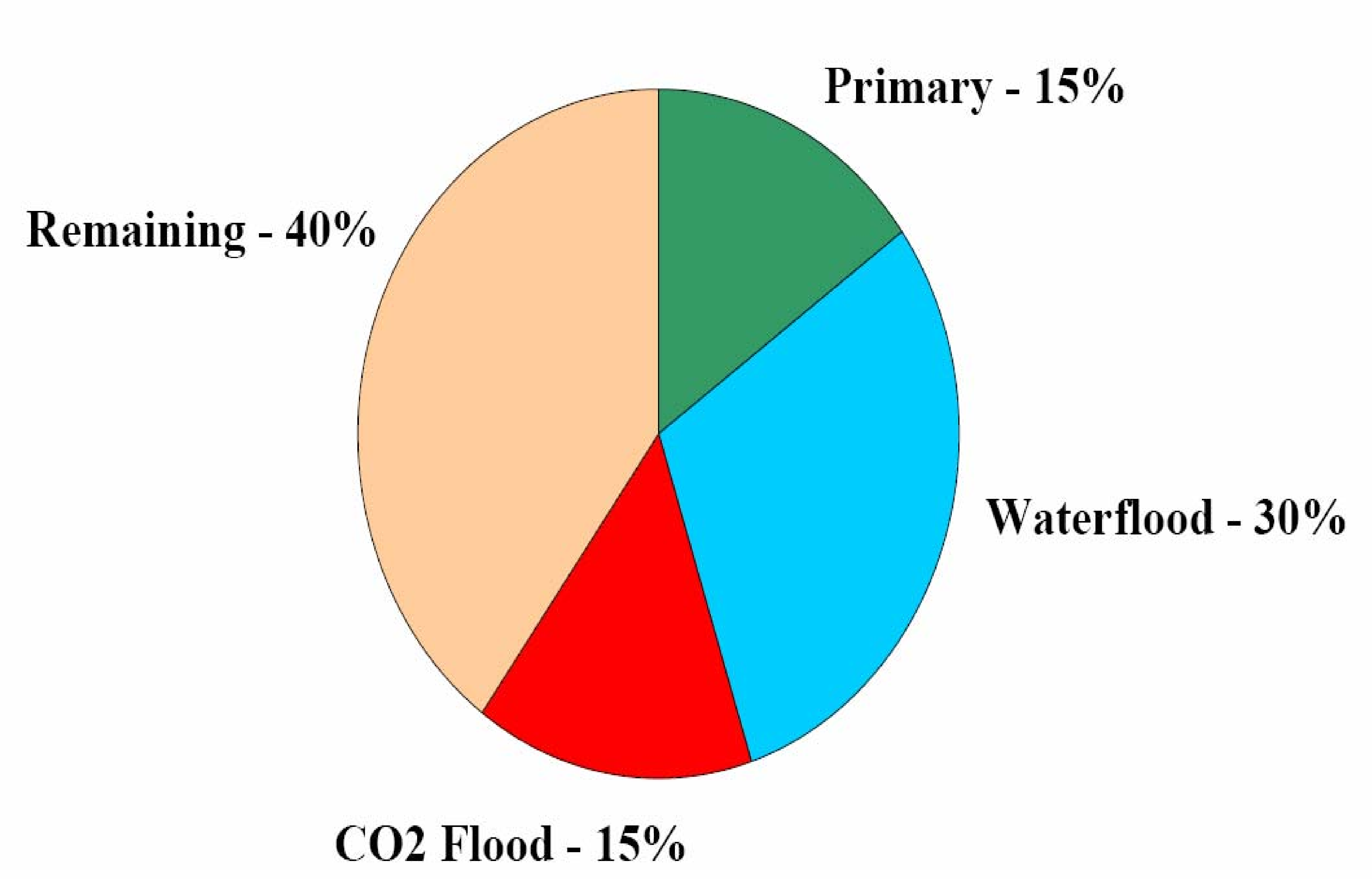
Enrico Fermi

What is Enhanced Recovery?

82-11-101 (6) "Enhanced recovery" means the increased recovery from a pool achieved by artificial means or by the application of energy extrinsic to the pool; such artificial means or application includes pressuring, cycling, pressure maintenance, or injection into the pool of any substance or form of energy as is contemplated in secondary recovery and tertiary programs but does not include the injection in a well of a substance or form of energy for the sole purpose of aiding in the lifting of fluids in the well or stimulating of the reservoir at or near the well by mechanical, chemical, thermal, or explosive means.

15-36-303 (3) "Enhanced recovery project" means the use of any process for the displacement of oil from the earth other than primary recovery and includes the use of an immiscible, miscible, chemical, thermal, or biological process.

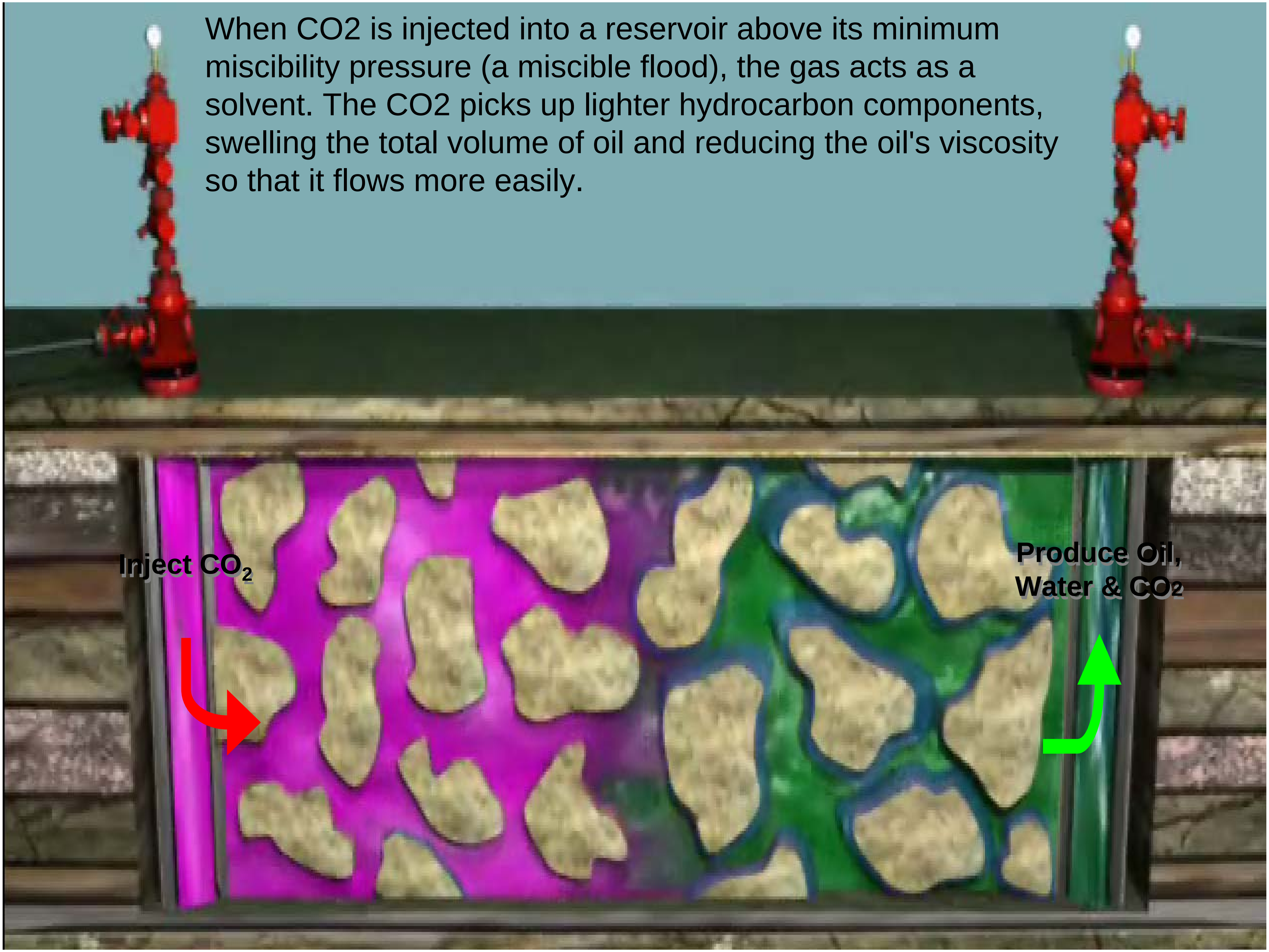
Recovery Efficiencies



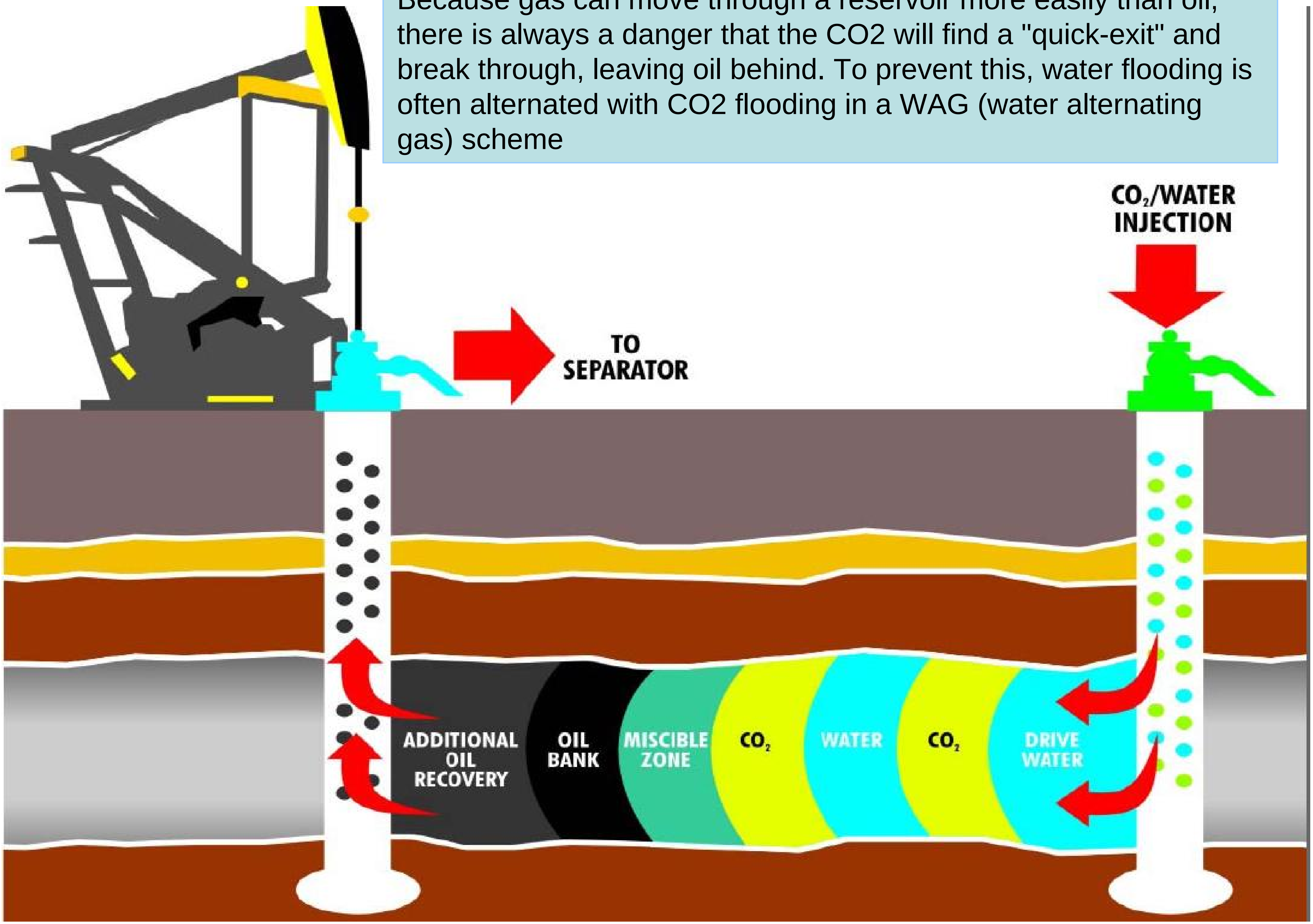
Where has CO_2 flooding been used?

- The first CO_2 flood took place in 1972 in Scurry County, Texas.
- CO_2 floods have been used successfully throughout the Permian Basin, as well as in Louisiana, Mississippi, Wyoming, Oklahoma, Colorado, and several other states.
- Outside the U.S., CO_2 floods have been implemented in Canada, Hungary, Turkey and Trinidad.
- Half of the CO_2 floods around the world are still located in the Permian Basin and use more than 1 BCF of CO_2 per day with oil production of about 140,000 barrels of oil each day.

When CO_2 is injected into a reservoir above its minimum miscibility pressure (a miscible flood), the gas acts as a solvent. The CO_2 picks up lighter hydrocarbon components, swelling the total volume of oil and reducing the oil's viscosity so that it flows more easily.



Because gas can move through a reservoir more easily than oil, there is always a danger that the CO2 will find a "quick-exit" and break through, leaving oil behind. To prevent this, water flooding is often alternated with CO2 flooding in a WAG (water alternating gas) scheme



Factors for Successful CO_2 Project

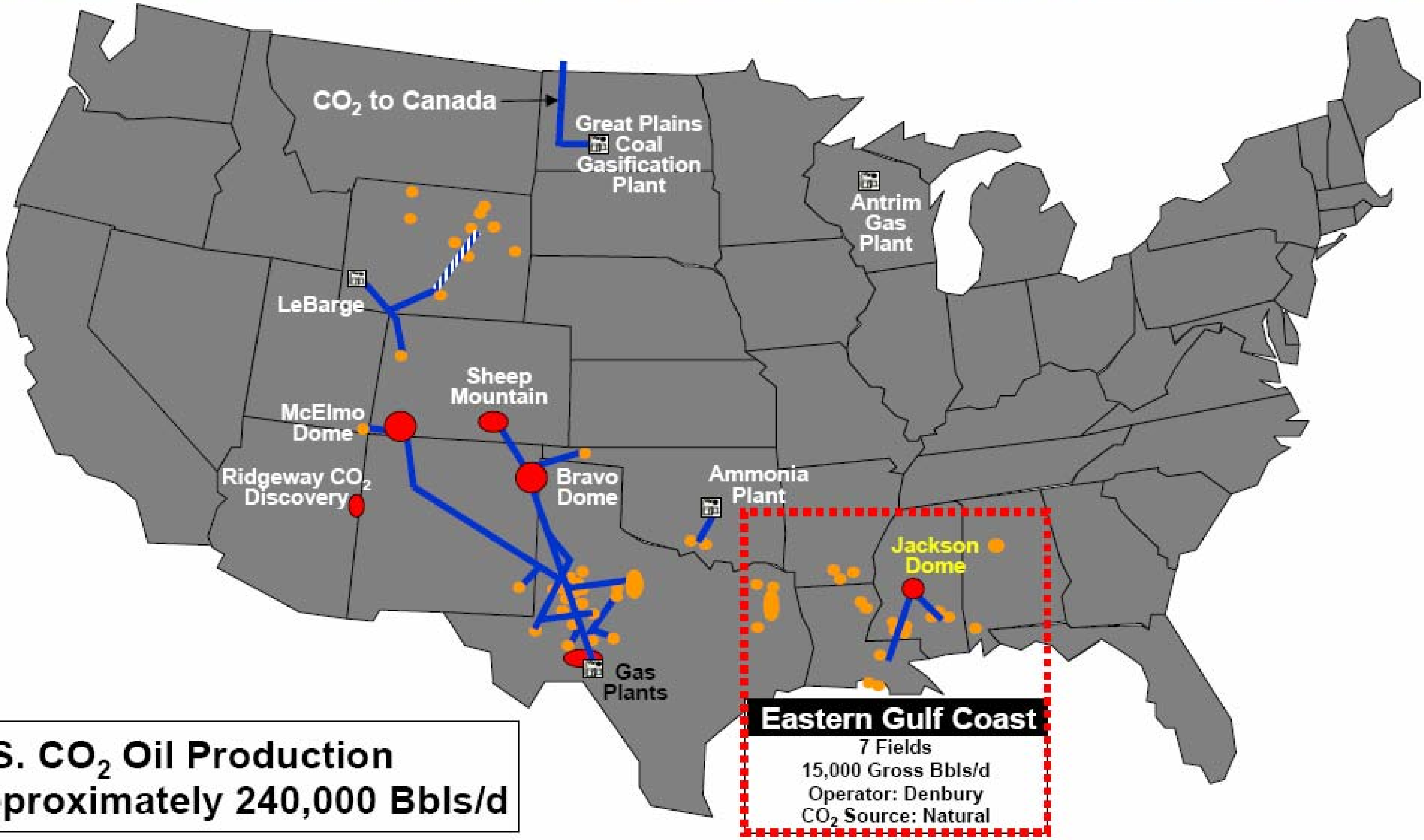
To be an effective solvent, CO_2 must flow through the reservoir above its minimum miscibility pressure (MMP). This means that the reservoir generally should be greater than 2,500 ft. deep.

CO_2 is most effective with light crudes, those with oil gravities greater than 25° API.

Because CO_2 flows through the reservoir more easily than oil, it also does best in reservoirs with homogeneous reservoir properties. If some layers of the reservoir are far more porous than others, CO_2 will flow there preferentially, rather than maintaining a uniform front and high sweep efficiency.

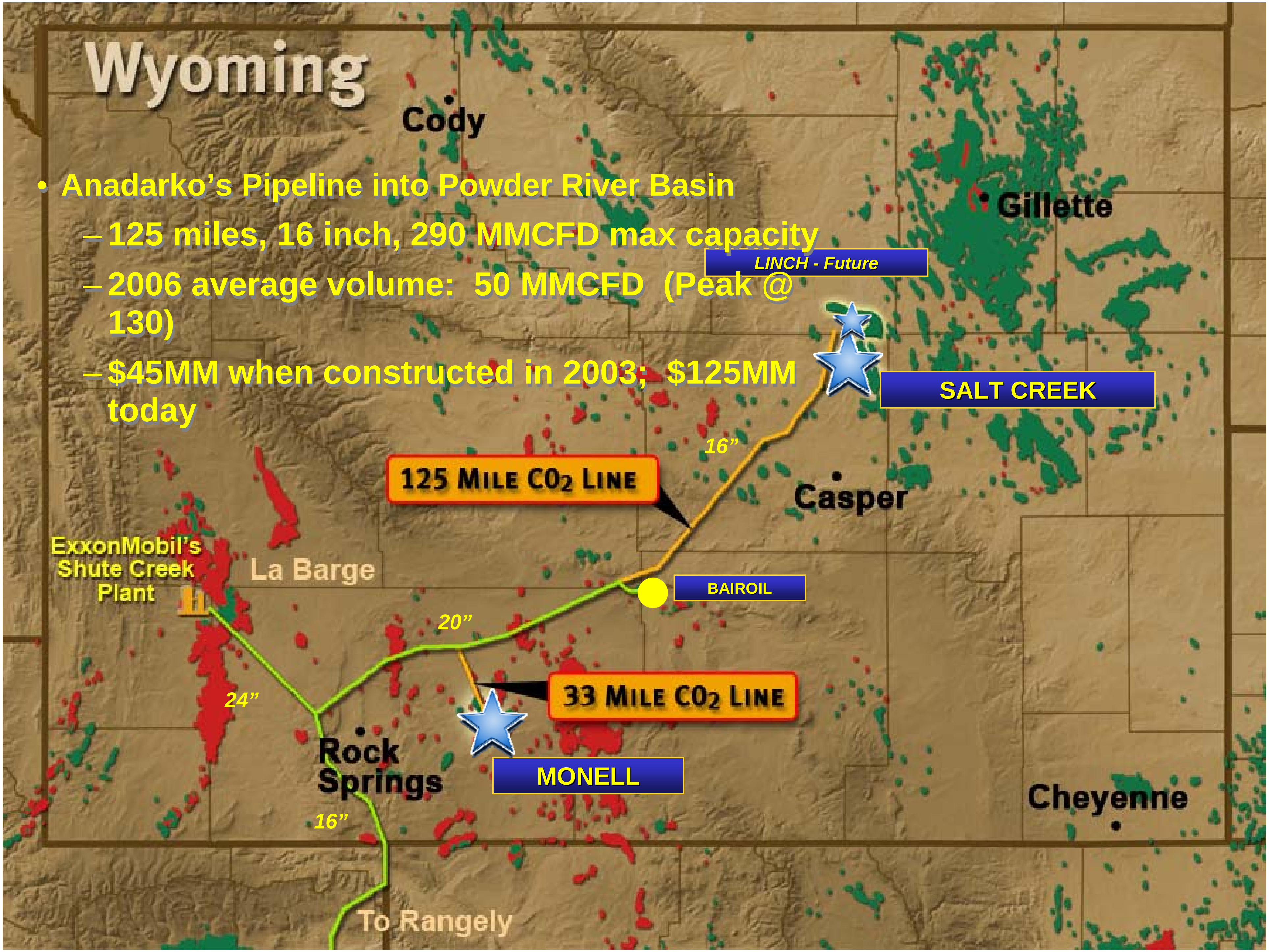
Stratification, fracturing and adjacent loss zones (adjacent gas caps) can cause loss of CO_2 and reduced oil recovery.

Current CO_2 Sources & Pipelines

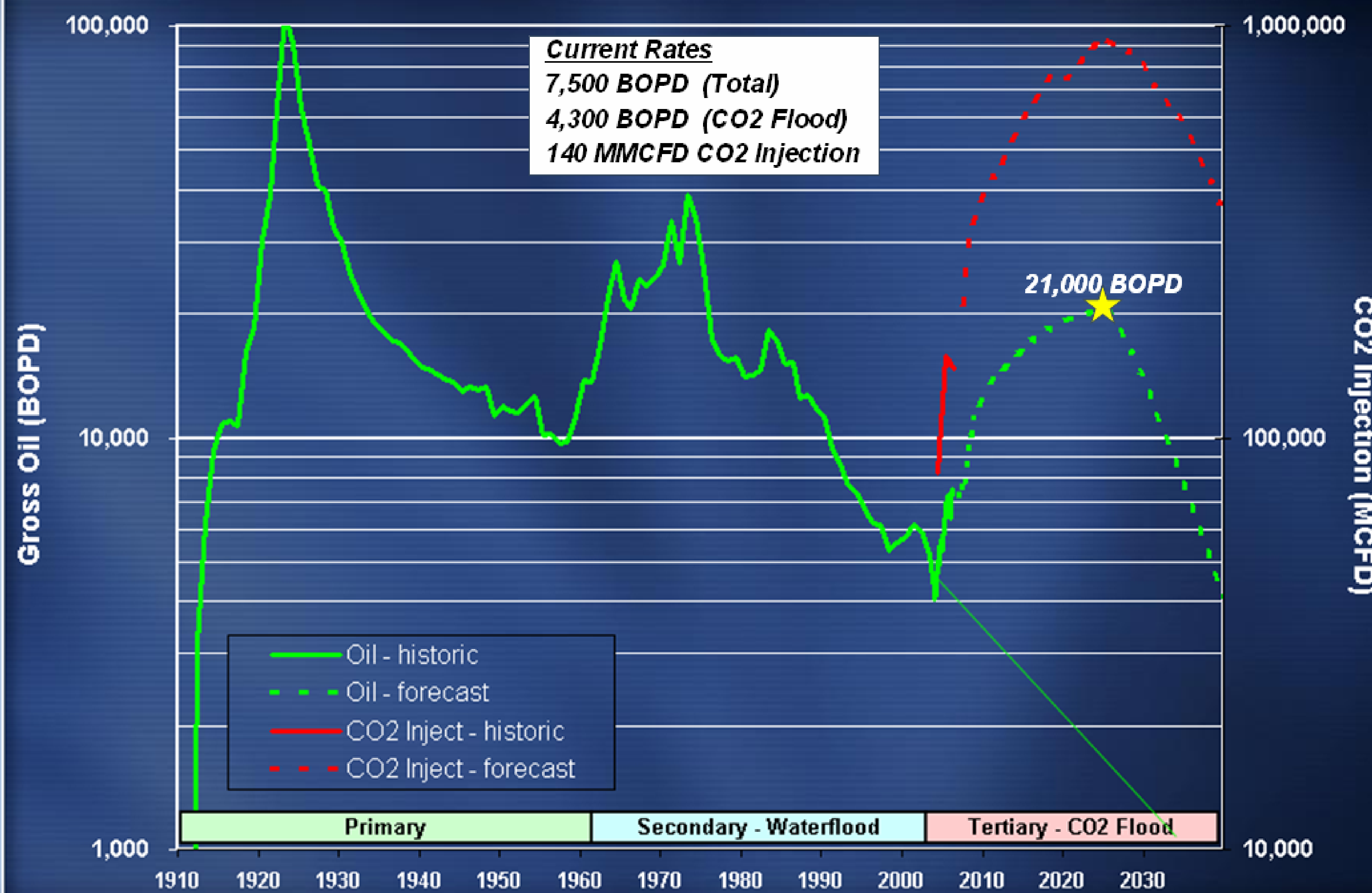


U.S. CO_2 Oil Production
Approximately 240,000 Bbls/d

- Anadarko's Pipeline into Powder River Basin
  - 125 miles, 16 inch, 290 MMCFD max capacity
  - 2006 average volume: 50 MMCFD (Peak @ 130)
  - $45MM when constructed in 2003; $125MM today

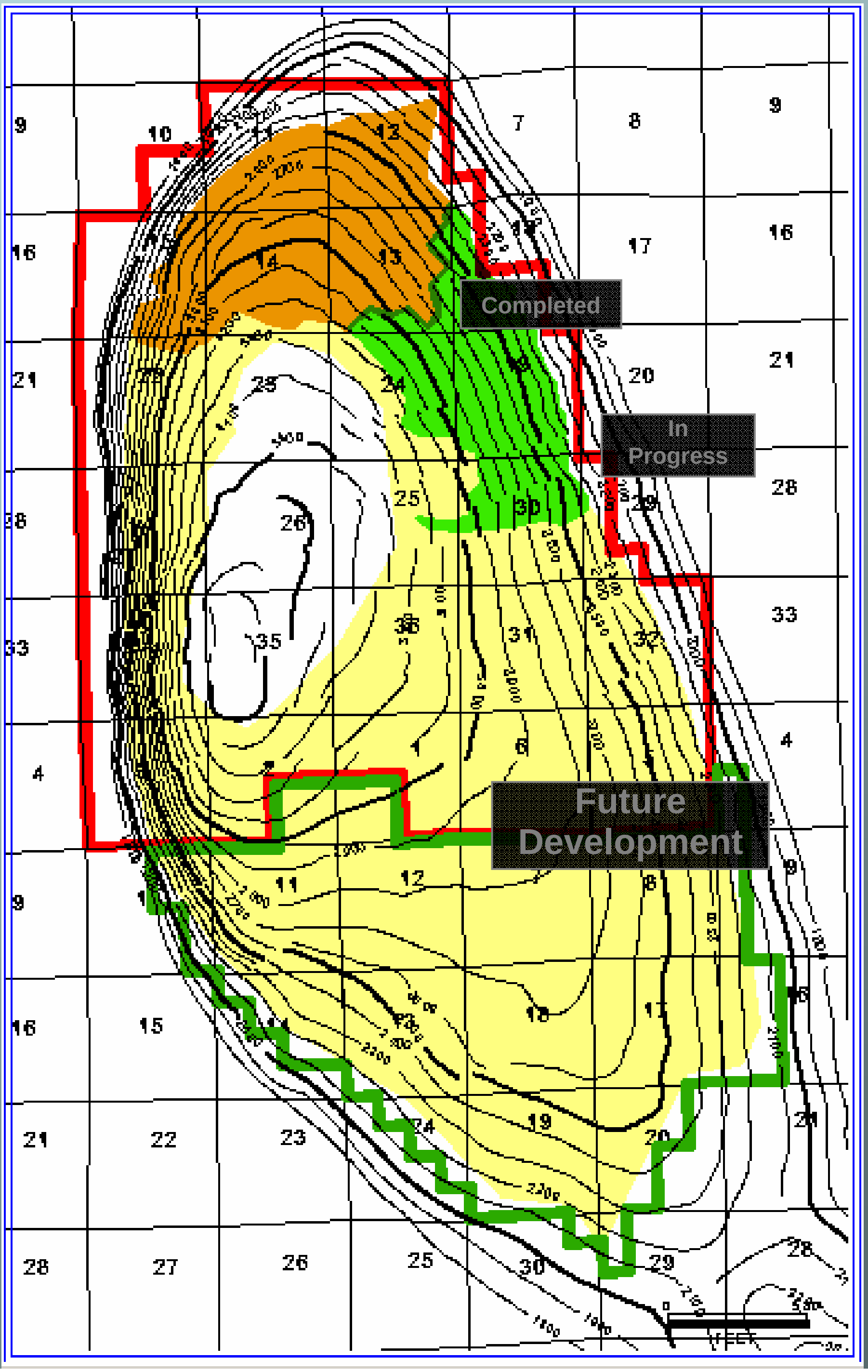


Salt Creek Field – Performance



Salt Creek Field

- Discovered late 1800's
- OOIP 1,680 MMBO
- Cumulative production 655 MMBO
- First CO_2 injection Jan 2004
- Expect to recover 10-15% OOIP
- Sequester 490 BCF CO_2



Salt Creek Field, Wyoming

Discovered in 1890's; nine separate producing formations

Current CO2 Project in 2nd Wall Creek Sand (Frontier Fm equivalent)

Second Wall Creek – MMP = 1250 psi

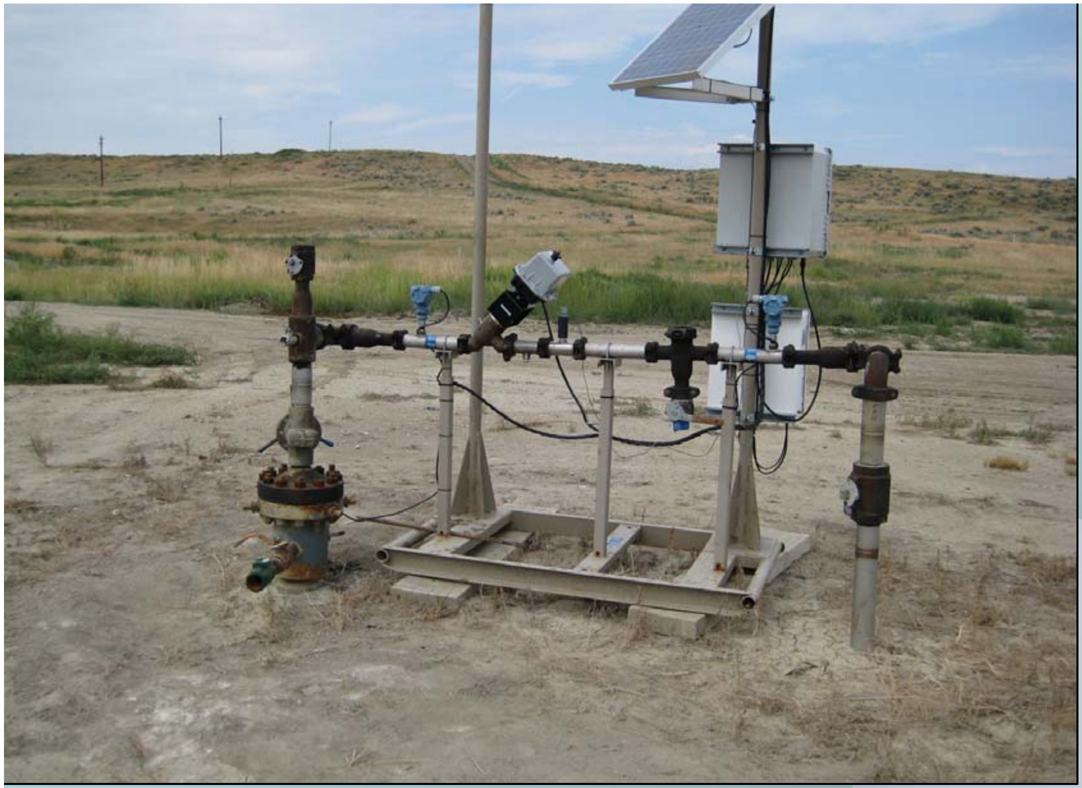
Pay Zone 100 - 130 feet thick

API Gravity = 39^o

Field CO2 Delivered in 12” carbon steel pipeline

Delivery Pressure – 2400 psi


Injection Manifold
BETTIS

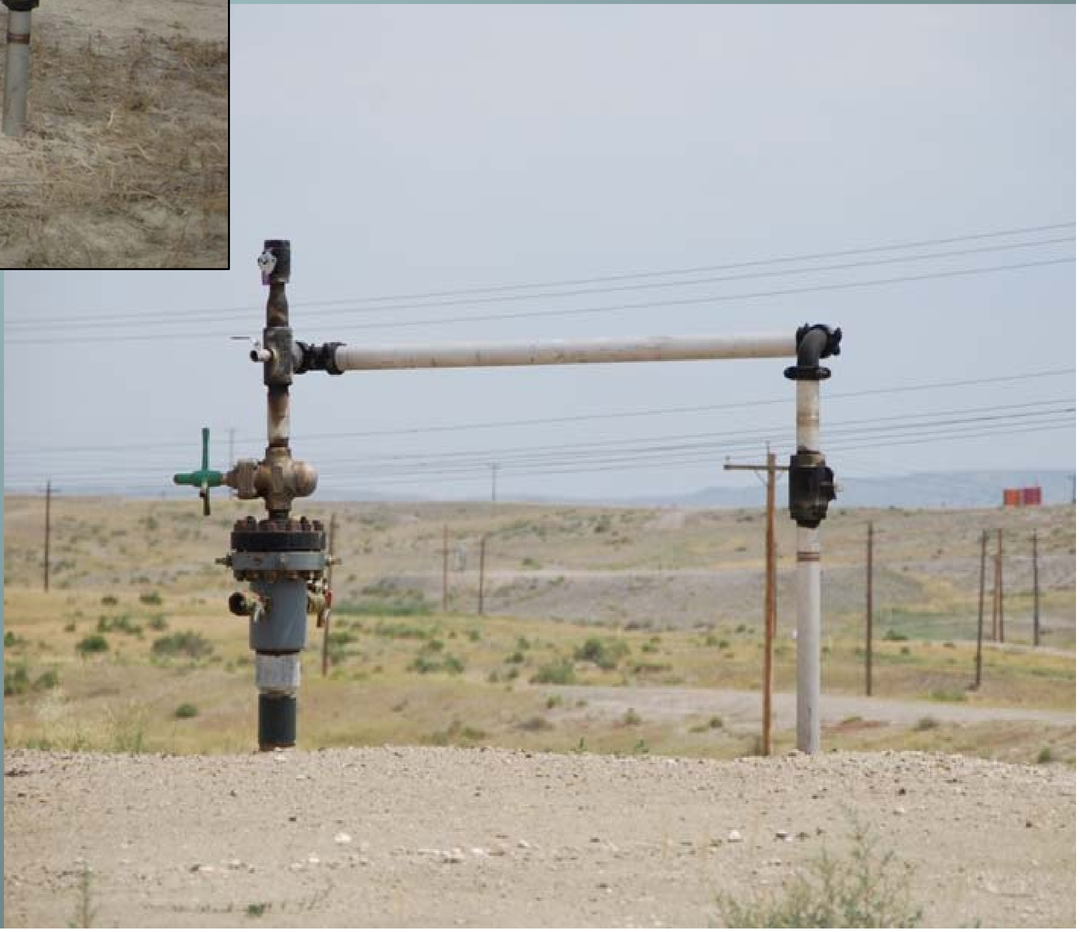


<< Injection Well

Injection Pressure = 1400 psi

Production Well >>

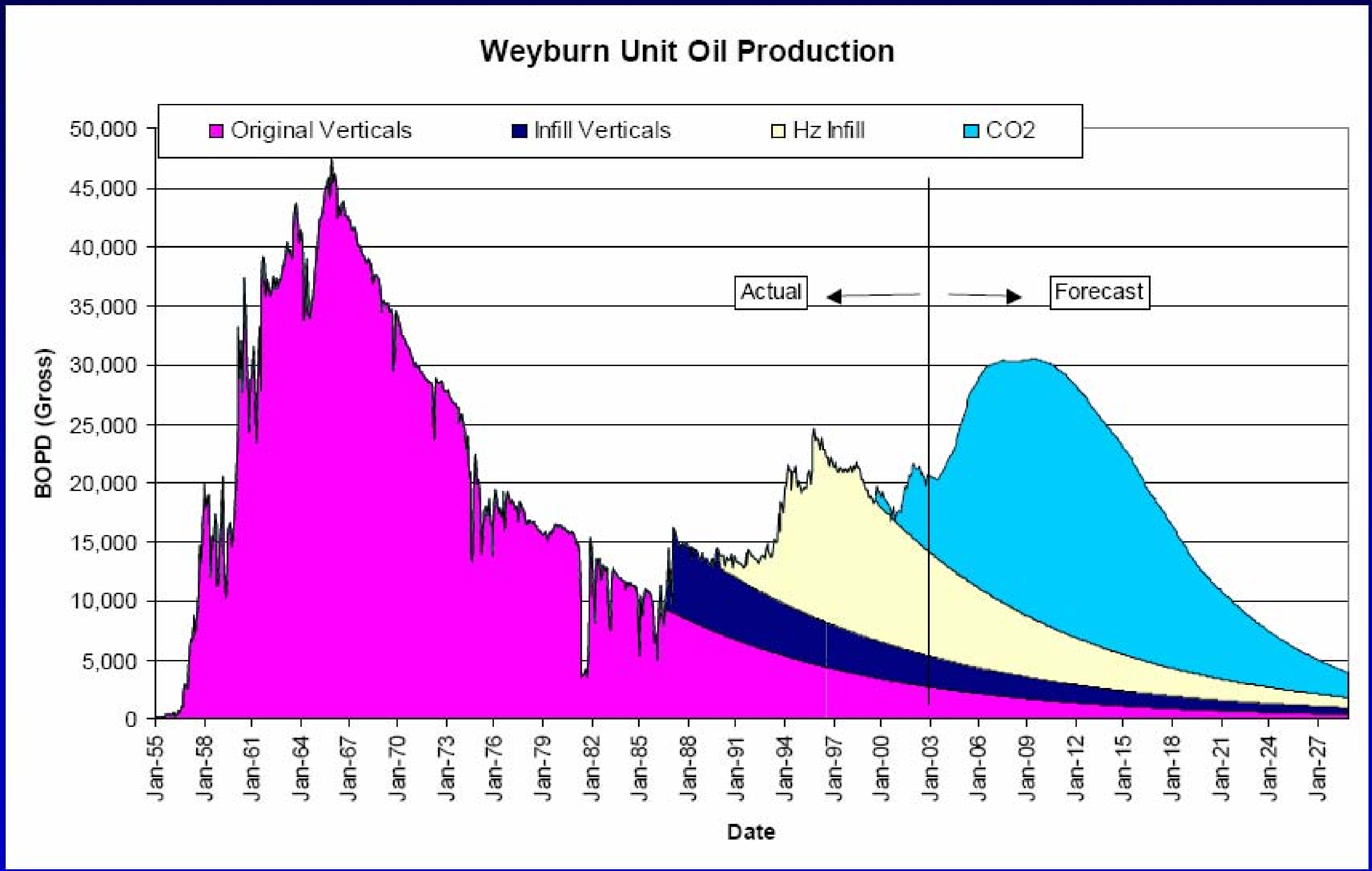
Back pressure held at 400 psi – wells flow without artificial lift



CO_2 Pipeline

- 205 miles
- 14” and 12” carbon steel pipe
- MAOP 2700 psig & 2964 psig
- Strategically routed through Williston Basin oil fields

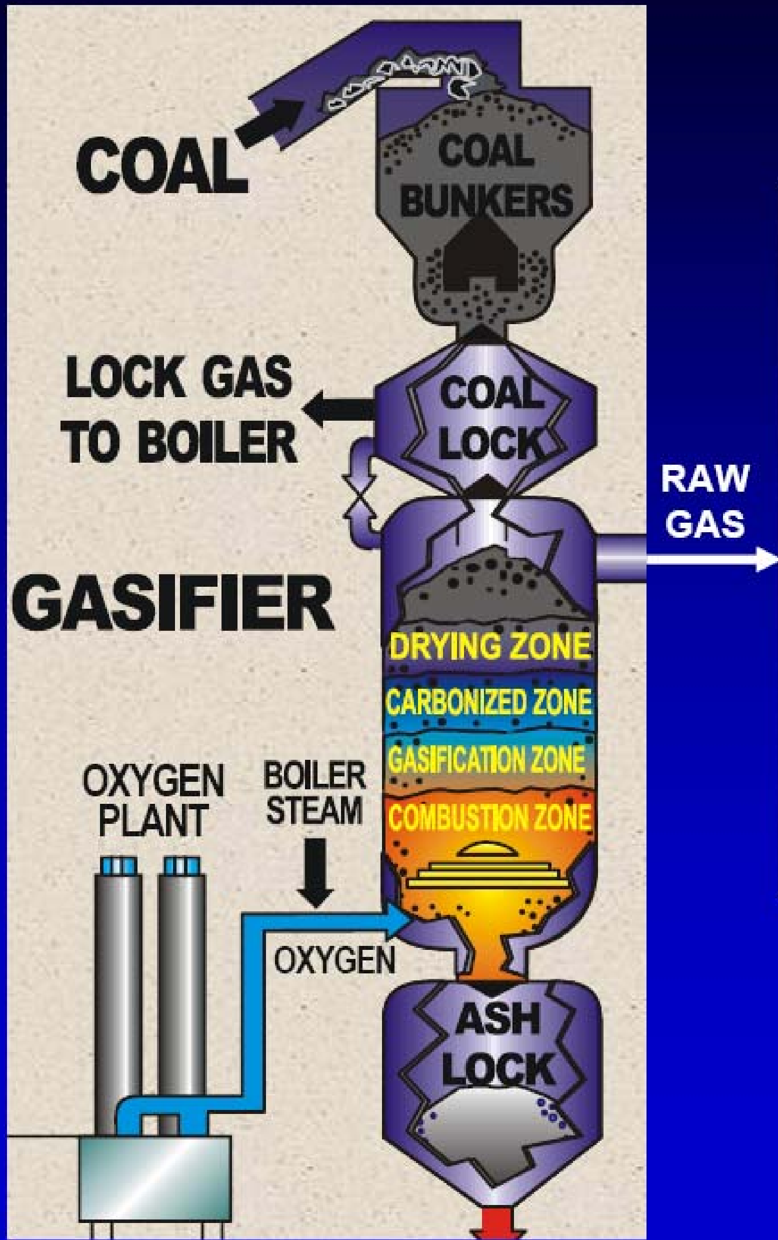
Weyburn CO_2 Project-Forecast



14 Lurgi Mark IV Gasifiers

Typical
Lignite Analysis

- 37% Moisture
- 6% Ash
- 27% Volatile Matter
- 30% Fixed Carbon
- 7000 BTU/lb



Typical Raw
Gas Analysis

- 39% Hydrogen
- 32% CO_2
- 15% CO
- 12% Methane
- 0.8% C_2+
- 0.7% H_2S
- 315 BTU/scf (HHV)

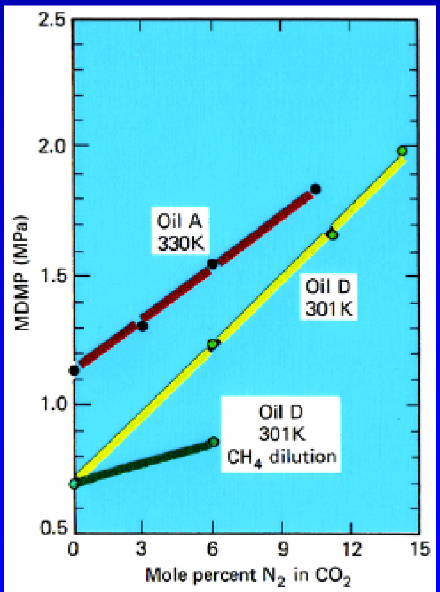
CO_2 Compressors

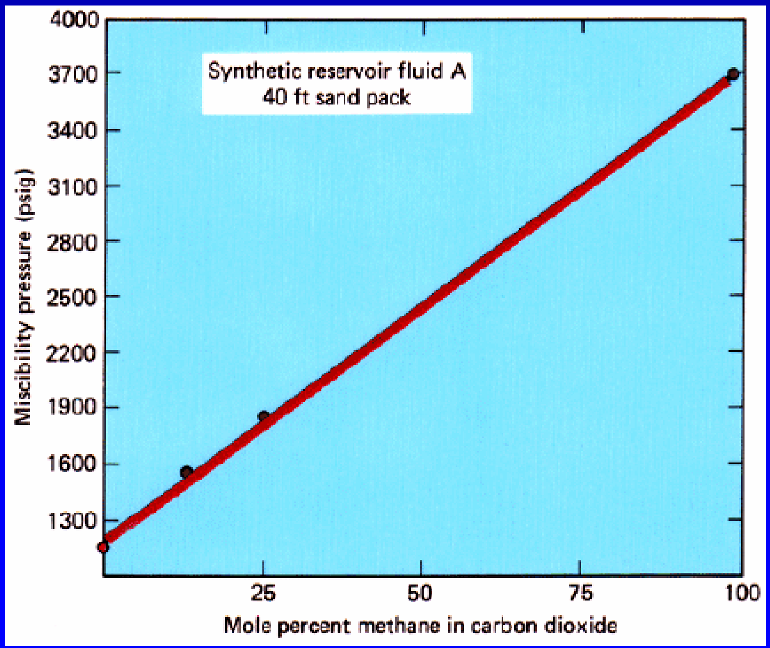
- Two 19,500 hp compressors
- 55 million scf per day each
- 2700 psig discharge pressure

CO2 Quality for Enhanced Recovery

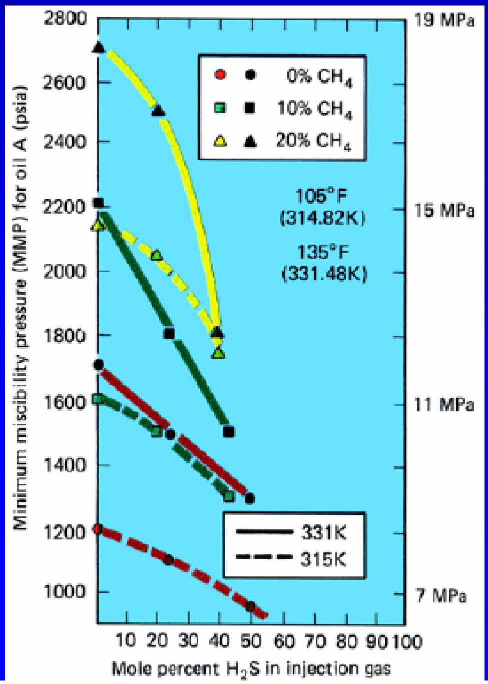
- **DGC Product CO2:**
  - **-100º F** **Dew Point**
  - **96.8%** **Carbon Dioxide**
  - **1.1%** **Hydrogen Sulfide**
  - **1.0%** **Ethane**
  - **0.3%** **Methane**
  - **0.8%** **Other**

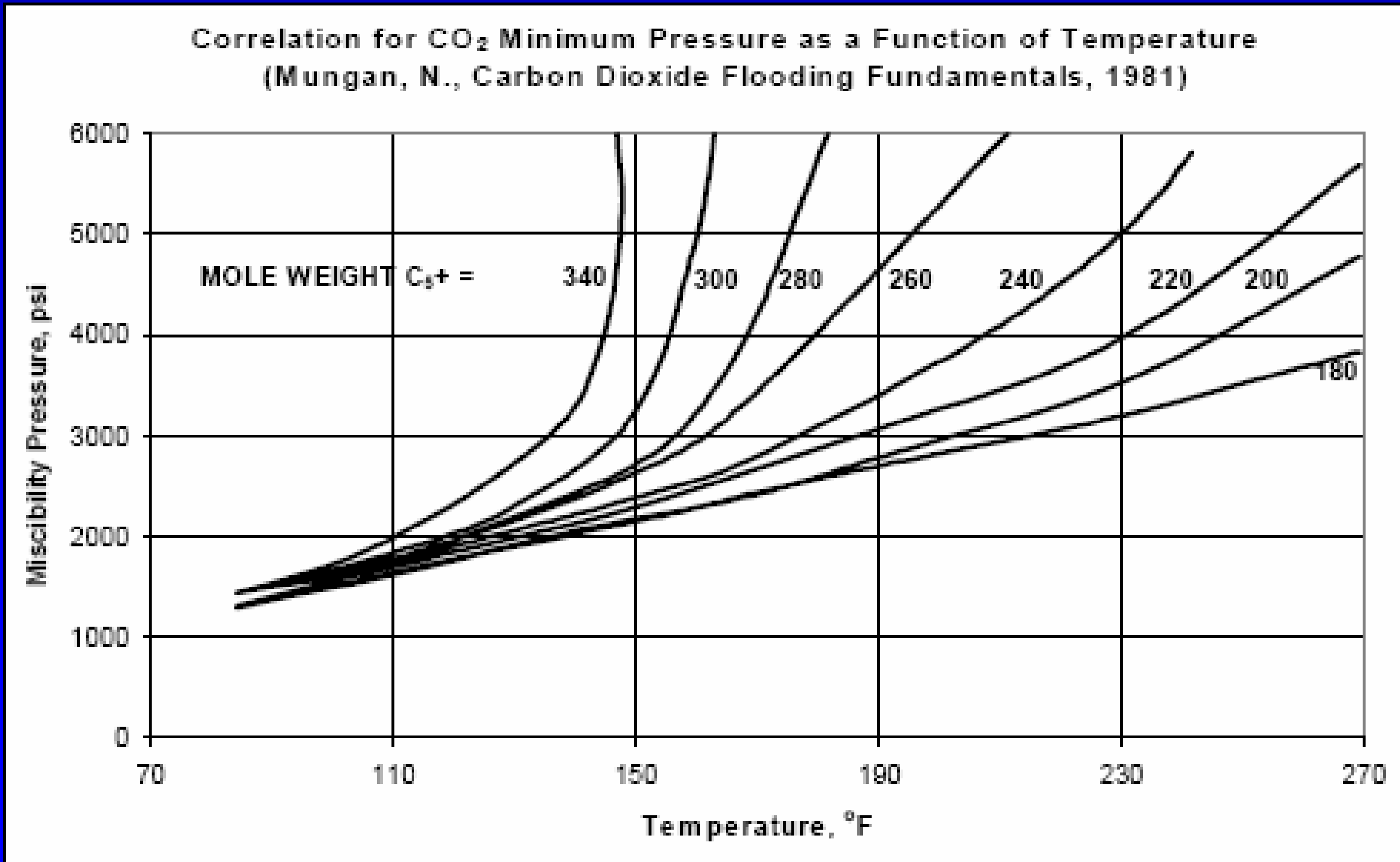
Increasing MMP





Decreasing MMP



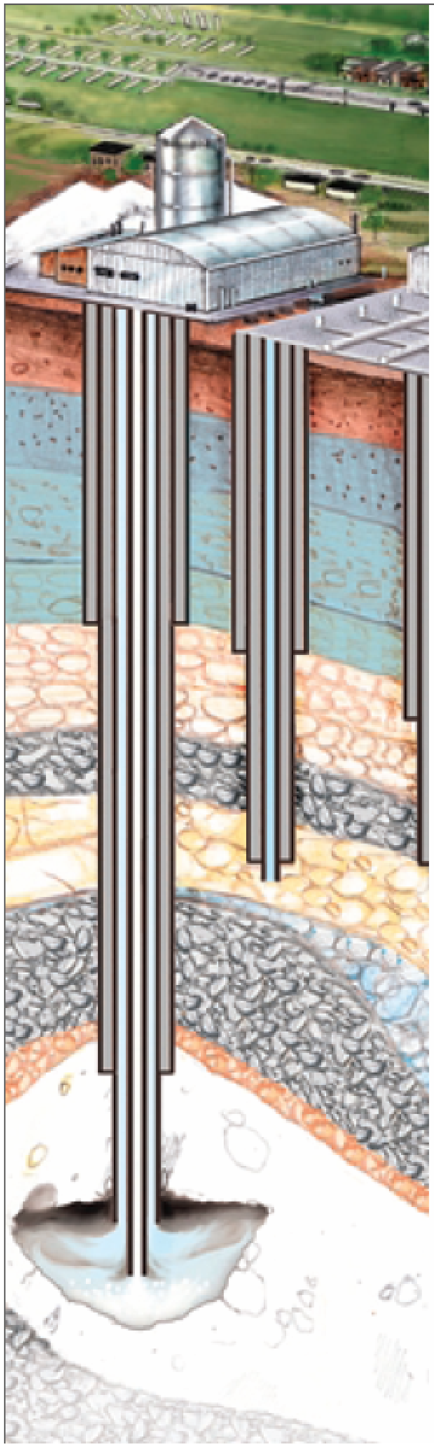


Correlation for CO_2 Minimum Pressure as a Function of Temperature
(Mungan, N., Carbon Dioxide Flooding Fundamentals, 1981)
MOLE WEIGHT C_5+ =
340
300
280
260
240
220
200
180
Miscibility Pressure, psi
6000
5000
4000
3000
2000
1000
0
70
110
150
190
230
270
Temperature, °F

CO2 EOR Potential Oil
Reserves & CO2 Demand

	EOR-MMB	*CO2-BCF*
Texas	3,437	32,651
Oklahoma	305	2,633
California	174	1,735
New Mexico	140	1,521
Colorado	186	1,510
Kansas	181	1,449
Utah	147	1,316
Wyoming	114	1,173
Montana	140	1,110
Illinois	57	513
Florida	65	435
Louisiana	34	369
Mississippi	23	288
Arkansas	20	132
Nebraska	8	80
N. Dakota	10	78
Michigan	1	15
TOTAL	5,042	47,008

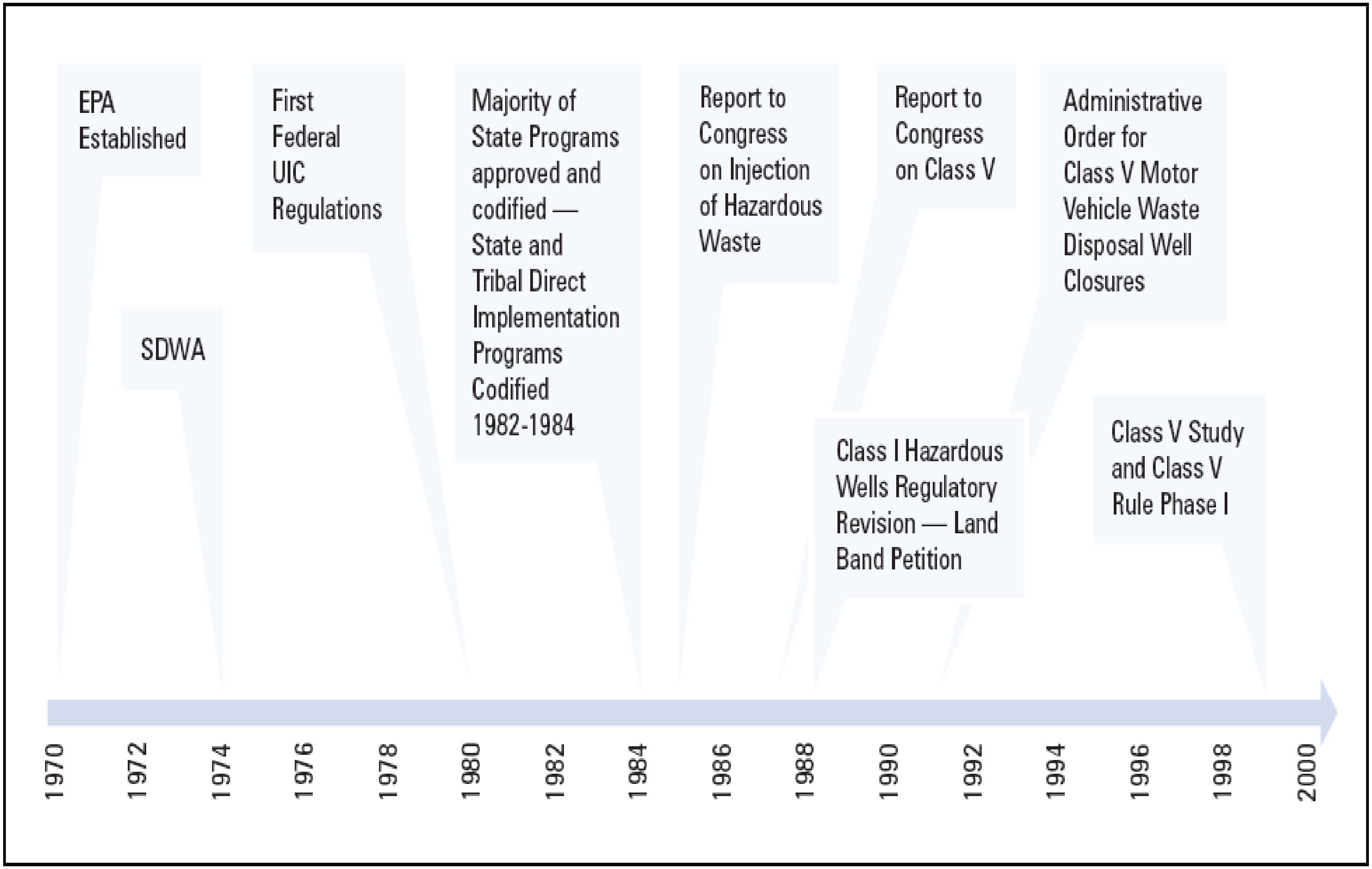
Kinder Morgan CO2 Company, L.P.,
from The American Oil & Gas Reporter, 2001



Protecting Drinking Water Through Underground Injection Control

United States Environmental Protection Agency

UIC Historical Timeline



EPA Injection Well Classification System

Well Class	Injection Well Description	Approximate Inventory
Class I	– Inject hazardous wastes beneath the lowermost USDW – Inject industrial non-hazardous liquid beneath the lowermost USDW – Inject municipal wastewater beneath the lowermost USDW	500
Class II	– Dispose of fluids associated with the production of oil and natural gas – Inject fluids for enhanced oil recovery – Inject liquid hydrocarbons for storage	147,000
Class III	Inject fluids for the extraction of minerals	17,000
Class IV	Inject hazardous or radioactive waste into or above a USDW. This activity is Banned. These wells can only inject as part of an authorized cleanup	40 sites
Class V	Wells not included in the other classes. Inject non-hazardous liquid into or above a USDW.	Range from >500,000 to >685,000

Class II Program Description

Purpose:

Regulate and manage safe injection of fluid brought to the surface in connection with oil and gas related production, or for enhanced recovery of oil or natural gas, or liquid hydrocarbon storage.

Examples of Fluids:

- Produced high salinity brine
- Crude oil (for storage)
- Polymers and viscosifiers for enhanced recovery wells
- Drilling fluids and muds

Protective Requirements:

Construction and siting

- Cased and cemented to prevent movement of fluids into USDWs
- Construction and design of well (casing, tubing, and packer) varies

Class II Program (continued):

Monitoring and testing

- Internal/External MIT
- Periodic monitoring and reporting

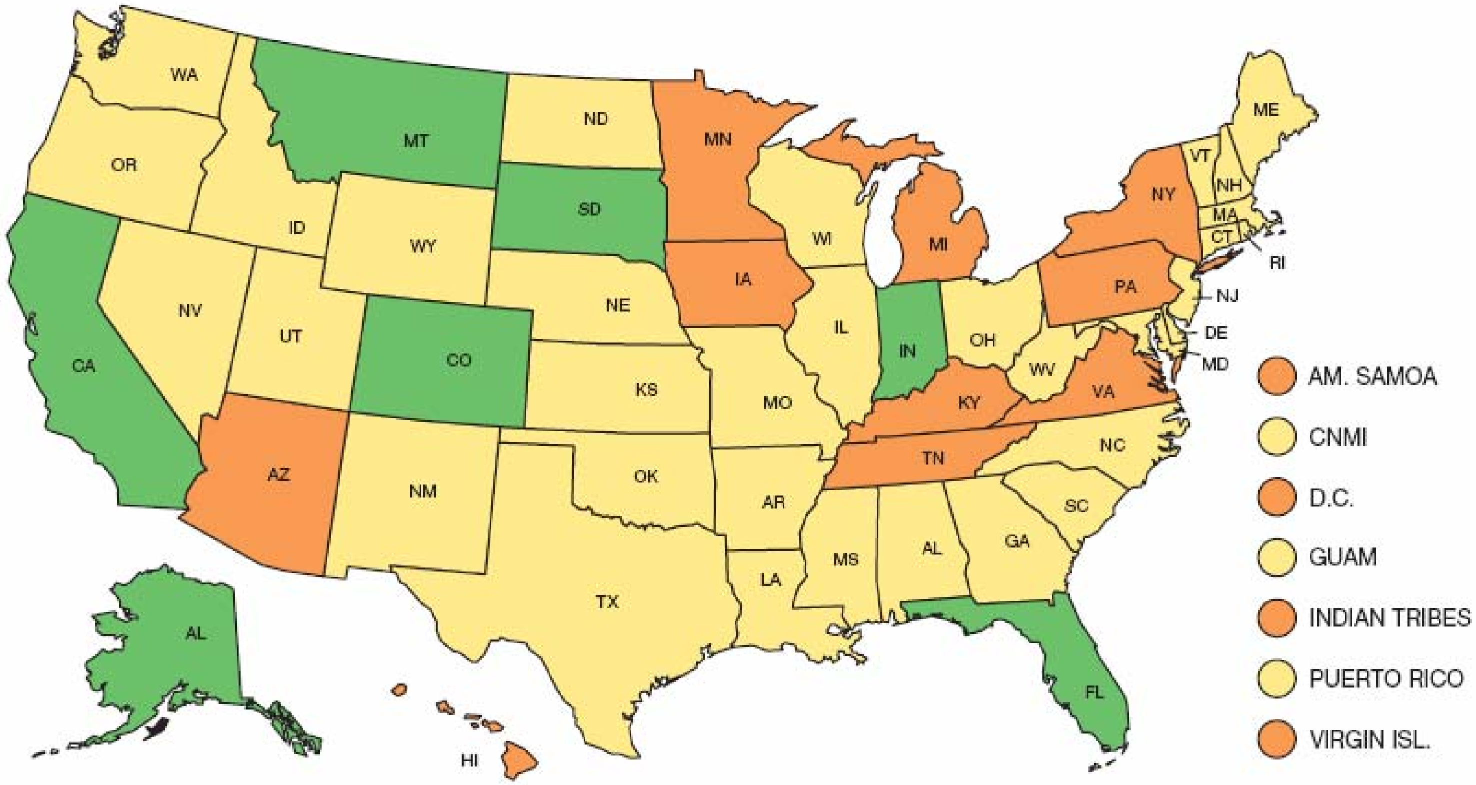
Recordkeeping and Reporting

- Plan for safe plugging and abandoning of wells, including demonstration of financial responsibility

Regulatory Citations:

- 40 CFR 144 General Provisions
- 40 CFR 146 General Provisions
- 40 CFR 146.21 to 146.24

Agencies Responsible for Implementing the UIC Program



- State Underground Injection Control (UIC) Program (33 States and 3 Territories)
- EPA UIC Program (10 States, 2 Terr., D.C., and all Indian Tribes)
- EPA and State share responsibility (7 States)

- Enhanced Recovery of Oil or Natural Gas through injection is covered by MBOGC’s primacy delegation and its existing Statutes and regulations
- Geologic Sequestration through CO2 injection is covered under EPA’s March 2007 Guidance and will be regulated as an experimental activity under the Class V Program
- Montana does not have Primacy for Class V injection wells
- EPA may develop an alternative class (Class VI ?) for sequestration activities and may develop guidelines for delegation to state agencies.

A site that is deemed to be appropriate for pilot CO_2 injection may not necessarily meet future requirements for commercial-scale operations. Therefore, owners or operators intending to eventually expand their pilot projects to commercial-scale operations should understand that additional UIC requirements may apply to the project after conversion to commercial operation.

-EPA, UIC Program Guidance #83 (March 2007)

Finally

- CO_2 is a valuable commodity for enhancing the recovery of oil and natural gas and some (but maybe not all) infrastructure costs can be carried by successful projects
- Regulatory structure for enhanced oil and gas recovery is mature and functional
- Regulatory structure currently proposed for geological carbon capture and storage by EPA does not address elements of appropriate siting, liability, long term monitoring, ownership rights, economic incentives, etc.
- Participants in an enhanced recovery project may not be eligible for any economic incentives for sequestration without extensive re-permitting requirements