Geologic Sequestration of Carbon In Oil And Natural Gas Resources

Presented to:

NETL Workshop on Carbon Capture and Sequestration

Presented by:

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Course Outline

1. Introduction to geologic sequestration of carbon in oil and natural gas reservoirs.
2. Capacity of carbon sequestration in worldwide depleted oil and gas fields.
3. Carbon sequestration with CO2-based enhanced oil recovery (EOR)
   A. Overview of current industry activity
   B. The technology of CO2-EOR
   C. Major domestic CO2-EOR projects
   D. CO2-EOR/Sequestration Economics

Course Outline (cont.)

4. Maximizing Sequestration In Oil Reservoirs.
5. Using depleted natural gas fields for carbon sequestration.
6. Measurement and verification of carbon sequestration.
7. Future R&D challenges and strategies for geologic carbon sequestration.

1 ntroduction

Introduction

Geologic Formations Offer Numerous Options for Sequestering CO_2. Certain of These Options Can Be Classified as "Market Driven" and Are In Selected Use Today:

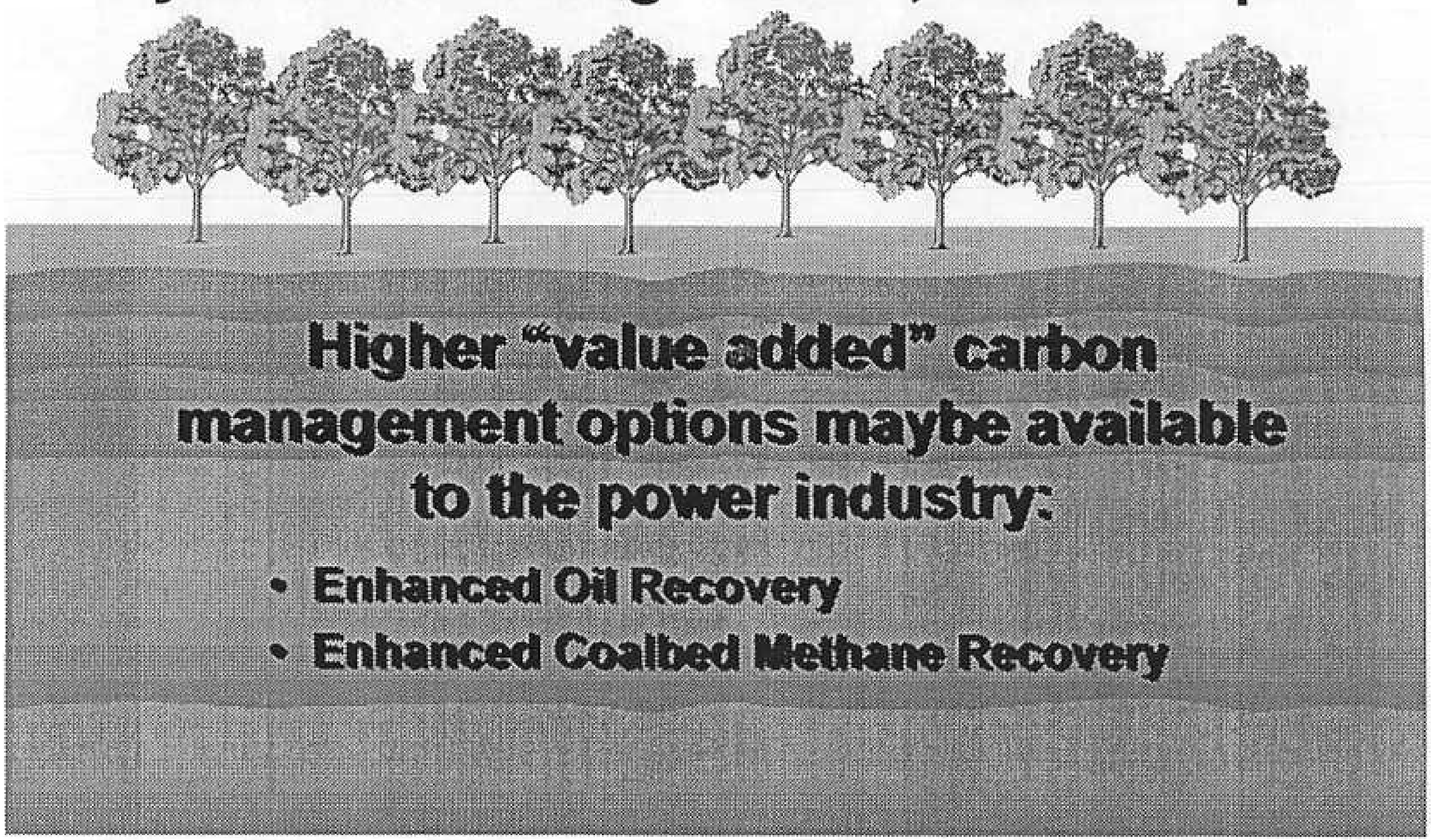
- *Enhanced Coalbed Methane Recovery (ECBM)*
- *Enhanced Oil Recovery (EOR)*

Other Geologic Options, such as Depleted Gas Reservoirs and Saline Aquifers, Also Provide Large Future Potential Sites for CO_2 Sequestration.

Advances in Technology and Credits for CO_2 Sequestration Can Greatly Expand the Value and Use of These Geologic Options.

Power Industry Options for Carbon Management

If you are thinking "trees", think deeper!



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CO_2 Sequestration in the Petroleum Industry

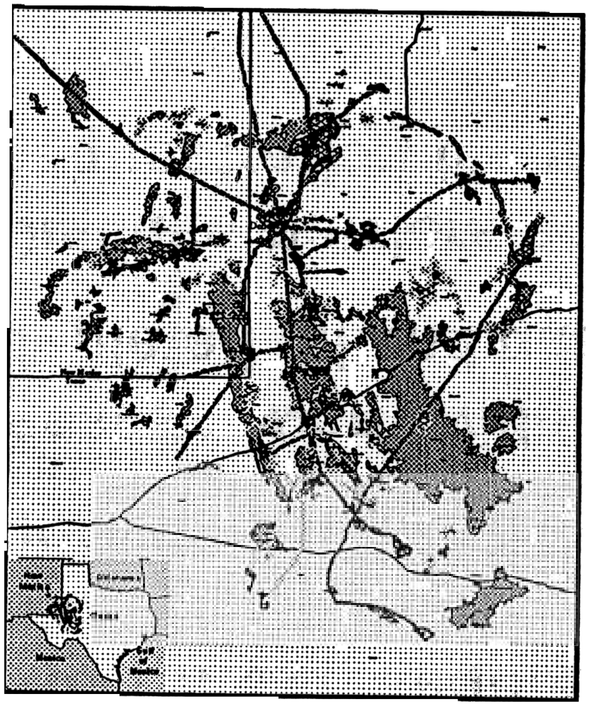
Oil Fields w/CO_2 - EOR:	Currently performed at large scale in geologically favorable settings within the U.S. Less favorable (average) settings would require emissions credits.
Depleted Natural Gas Fields:	Not currently performed, but large storage potential available. Requires emissions credits to cover costs. EGR Potential?

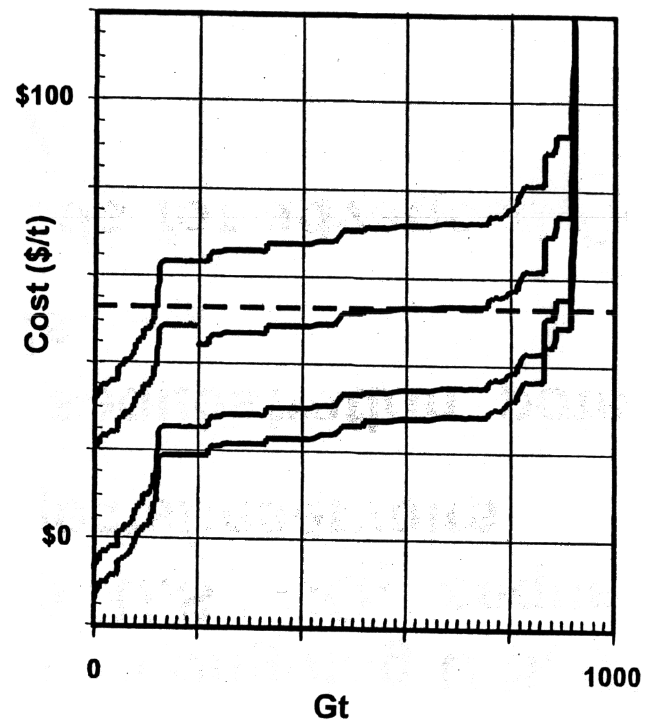
2 Sequestration Capacity

Sequestration of CO_2 in Depleted Oil and Gas Fields:

Barriers to Overcome in Implementation of CO_2 Capture and Storage (Disused Oil and Gas Fields)

IEA/CON/98/31





Prepared for:
IEA Greenhouse Gas R&D Programme

Prepared by:
Advanced Resources International, Inc., Arlington, Virginia USA

Dr. Joseph J. Taber, Socorro, New Mexico, USA

May 26, 1999

IEA CO_2-EOR Study Objectives

- Review CO_2 sequestration in ongoing U.S. CO_2-EOR projects; forecast future U.S. CO_2 sequestration potential in new EOR projects/reservoirs.
- Assess worldwide CO_2 sequestration potential in depleted oil and gas fields.
- Discuss barriers and needs for advanced CO_2-EOR sequestration technology.

*Near-Term Project

Review of Prior Studies

- Winter and Bergman (1993). Identified already depleted and abandoned U.S. oil and gas fields, immediately available for CO_2 sequestration:
  - *1,360 individual fields*

    1.5 Gt of CO_2 sequestration capacity

- Padamsey and Railton (AOSTRA, 1993). Examined five Western Canadian oil fields for CO_2 sequestration using EOR.

**Near-Term Project*

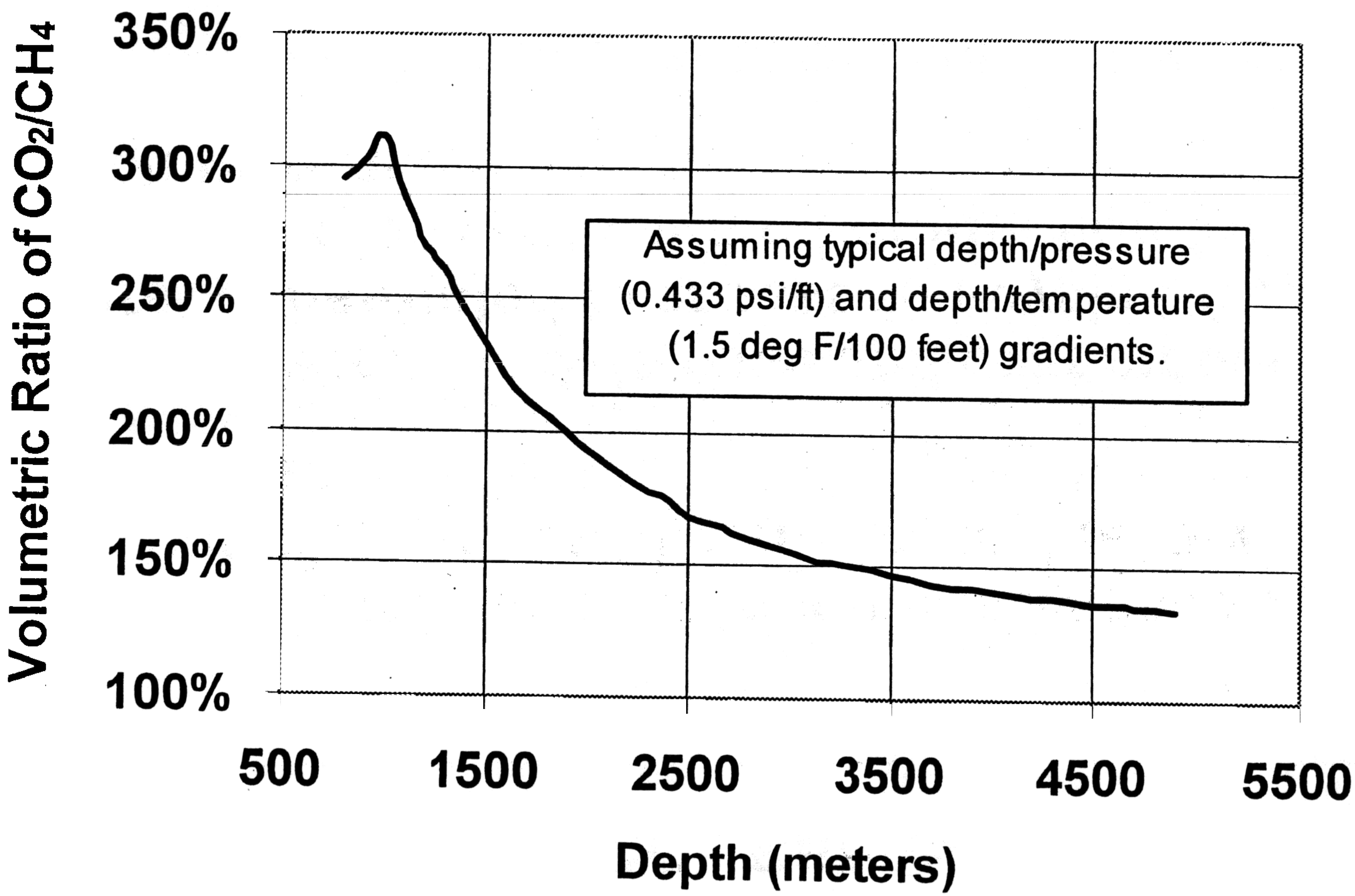
Review of Prior Studies (cont.)

- <u>Van der Meer and Van der Straaten (1993).</u> Estimated worldwide CO_2 storage potential in depleted oil and gas fields. Single estimate for each continent; did not consider CO_2 compressibility, economics or undiscovered resources:
  - *148 Gt (depleted oil fields)*
  - *521 Gt (depleted gas fields)*
- <u>Taber (1994).</u> Performed pioneering study of CO_2 sequestration potential in a subset of worldwide depleted oil fields with CO_2-EOR potential:
  - *61 Gt (depleted oil fields only)*

Study of Worldwide CO_2 Sequestration Potential

- **First, 155 worldwide petroleum provinces were individually assessed, using actual reservoir properties.**
- **Next, a reservoir data base and cost model were constructed to assess full-cycle CO_2 sequestration costs and oil production for each province.**
- **Finally, a series of cost/supply curves were constructed to establish the "net costs" of sequestering CO_2 in oil fields and depleted gas fields.**

The Volumetric Ratio of CO_2 to CH_4 Varies Markedly with Depth



Results and Findings

The Advanced Resources Study for IEA/GHG Programme and U.S. DOE had four results:

1. Identified a large worldwide potential for CO_2 sequestration in depleted oil and gas fields:

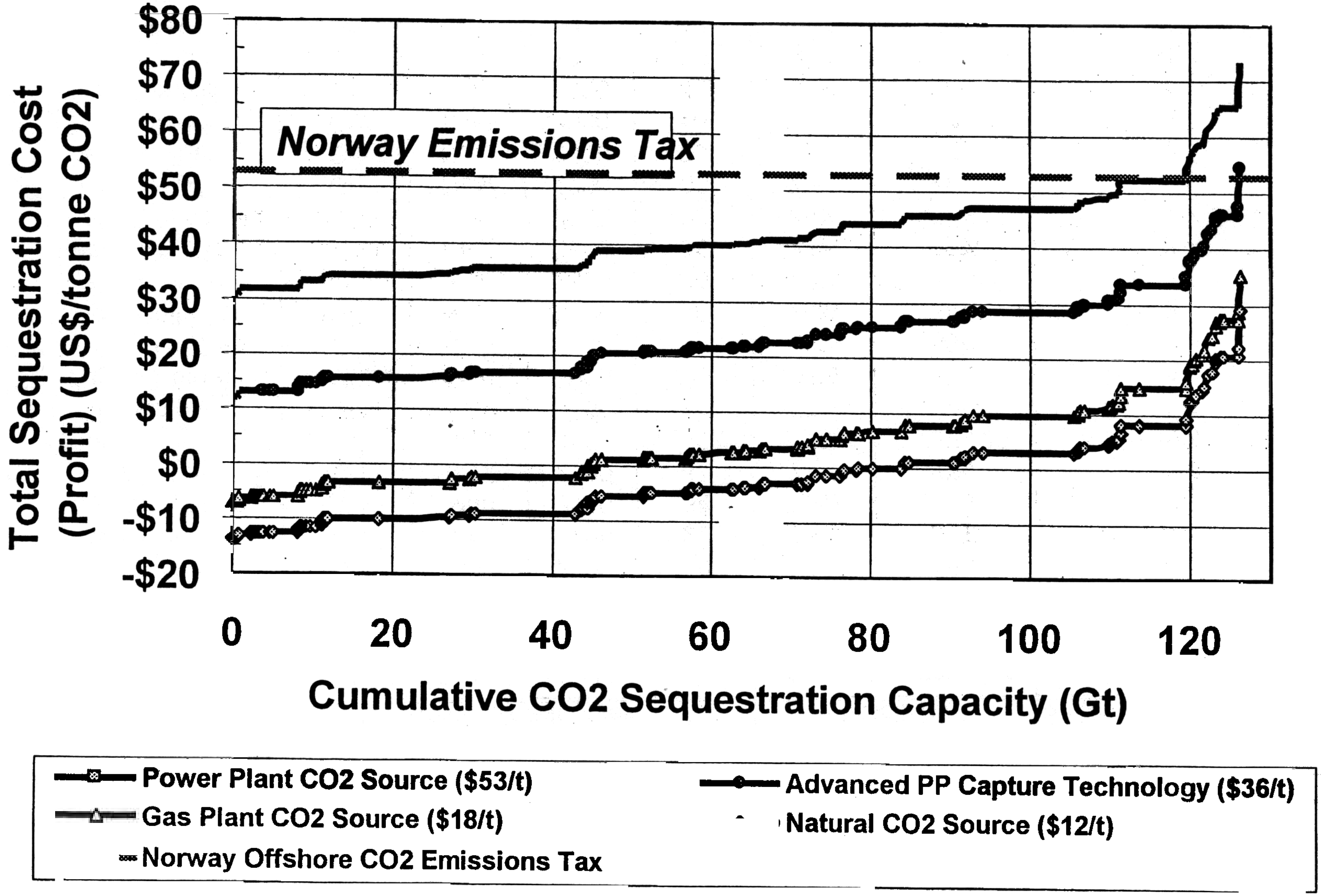
- ***126 Gt (oil fields/EOR)***
- ***797 Gt (gas fields)***

Using 6.6 Gt/year of annual CO_2 emissions from power plants, these geologic formations provide 140 years of CO_2 sequestration capacity.

Results and Findings (cont.)

2. Oil reservoirs (CO_2-EOR) provide 45 to 85 Gt of "Market Driven" CO_2 sequestration capacity (at CO_2 prices of $12 to $18 per ton, delivered).
3. Oil reservoirs (CO_2-EOR) provide 120 Gt of sequestration capacity with "free" CO_2.
4. Depleted natural gas fields, while not a market-driven option, provide large capacity for CO_2 sequestration.

Depleted Oil Fields/Enhanced Oil Recovery: Global CO_2 Sequestration Capacity and Costs



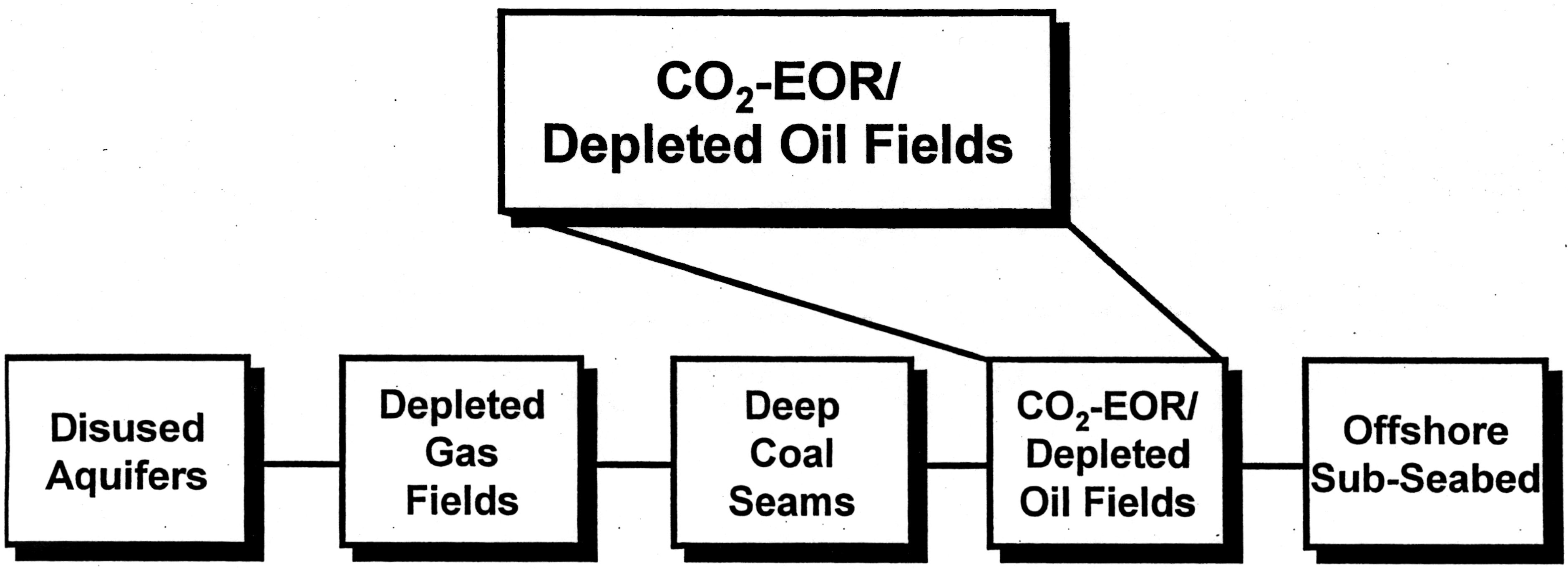
CO_2 Sequestration Capacity: Depleted Oil Fields/EOR

Reservoir Province		Reservoir Attributes				Miscibility		Sequestration Potential
Rank Sqst (Gt)	Province Name	On/Off Shore	Anthro CO_2 Suppy	Avg. Depth (m)	Oil Gravity (API)	Misc. EOR	Immiscible EOR	CO_2 Sequestration Potential (Gt)
1	Mesopotamian	On	Med	2500	30	75%	0%	11.6
2	West Siberian	On	Far	1700	25	25%	50%	10.5
3	Greater Ghawa	On	Med	2110	34	75%	0%	8.3
4	Rub Al Khali B	On	Med	2500	35	75%	0%	5.8
5	North Sea Gra	Off	Med	3500	40	75%	0%	5.3
6	Villahermosa U	On/Off	Near	4300	40	75%	0%	5.2
7	Zagros Fold Be	On	Med	3000	30	75%	0%	4.8
8	Volga-Ural Reg	On	Near	1700	25	25%	50%	3.9
9	Niger Delta	On/Off	Near	3000	40	75%	0%	3.8
10	Sirte Basin	On	Far	2500	40	75%	0%	3.8
11	Maracaibo Basin	On/Off	Near	2500	25	25%	50%	3.3
12	East Venuezuela	On/Off	Near	3000	20	25%	50%	2.7
13	Wester Gulf	On	Near	2200	35	75%	0%	2.6
14	Permian Basin	On	Near	2800	35	75%	0%	2.2
15	S. Caspian Sea	Off	Med	3000	40	75%	0%	2.1
16	West-Central C	Off	Far	3000	40	75%	0%	1.8
17	North Caspian	On/Off	Near	3000	30	75%	0%	1.7
18	Trias/Ghadam	On	Far	3000	48	25%	0%	1.7
19	Bohaiwan	On/Off	Near	2000	25	25%	50%	1.7
20	Alberta Basin	On	Near	2000	36	75%	0%	1.3
1-20								84
21-155	Sub-Total							33
Other	Sub-Total							9
	Total							**126**

VLG001.xls

3 CO_2 - EOR

Geological Options for Sequestering CO_2



3A Overview

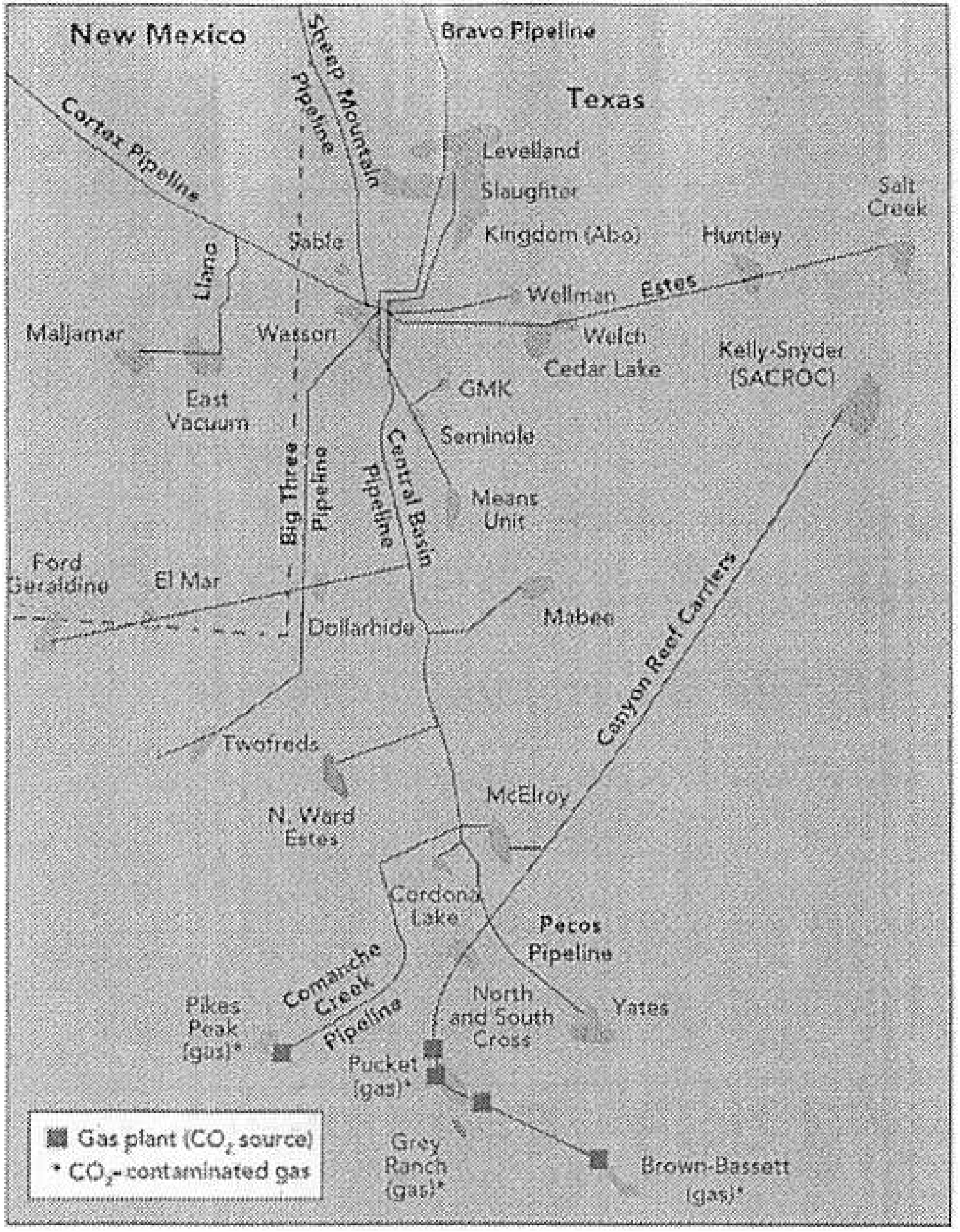
Industry Activity

Considerable “value added” CO_2 sequestration is already underway in U.S. oil fields.

- Large scale Permian basin CO_2 based EOR floods
- Smaller CO_2-EOR projects in Colorado, Oklahoma and other states

“Off-the-shelf” oil field technology can be adapted for CO_2 sequestration.

P peline Network to Transport CO2 to the Permian Basin



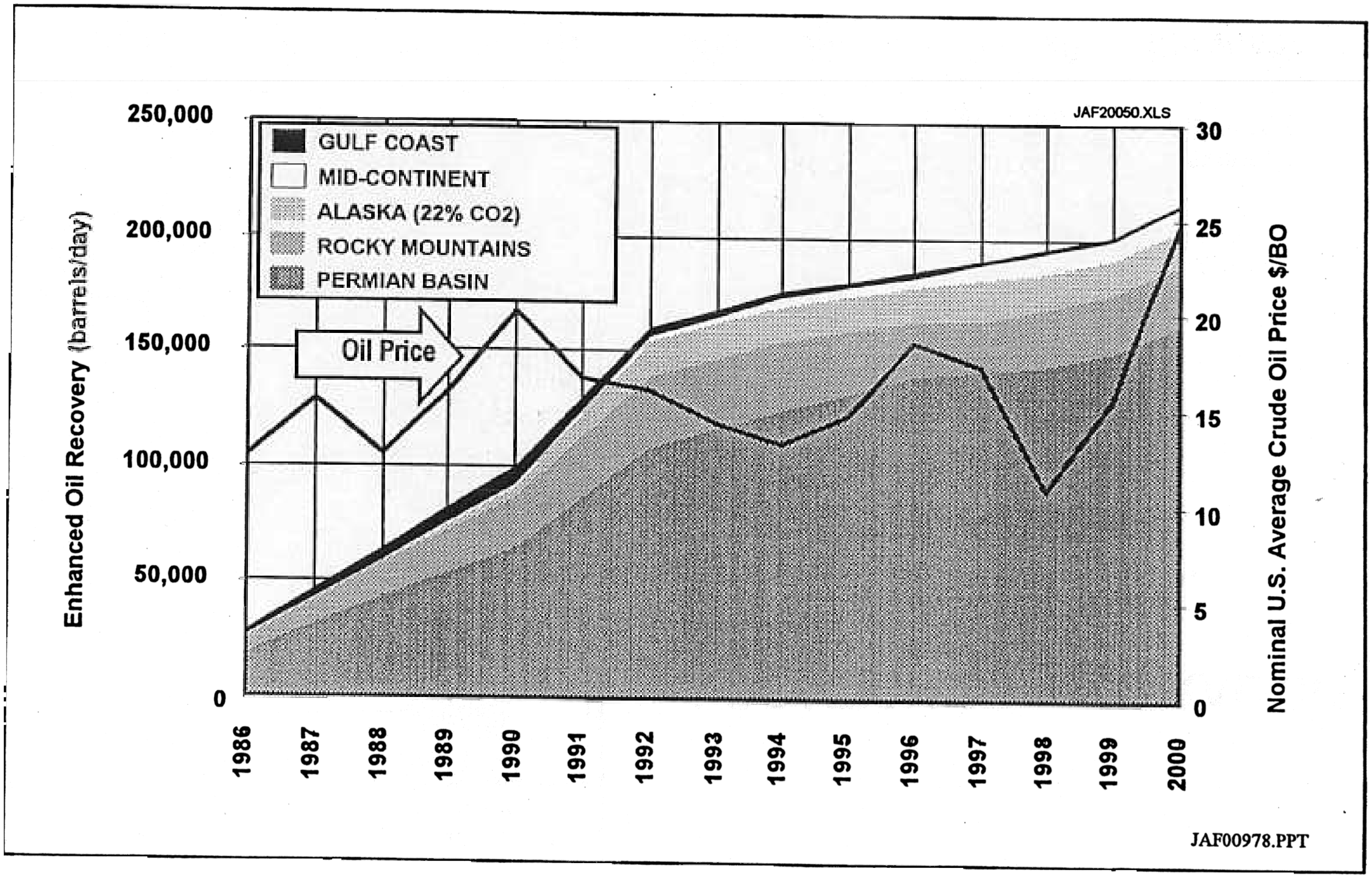
Domestic Gas – EOR Production

Despite a decade of low oil prices, gas- based enhanced oil recovery has grown significantly in the past ten years:

- **CO_2 and hydrocarbon flooding have increased,**
- **Nitrogen and flue gas flooding have declined or ceased.**

	1990	2000	
	(B/D)	(B/D)	(Projects)
CO_2 Miscible	95,600	189,500	63
CO_2 Immiscible	100	100	1
Nitrogen	22,300	14,700	4
Flue Gas	17,300	-	
Hydrocarbon	55,400	124,500	6
	190,600	328,000	74

CO_2 - EOR Production in the U.S.



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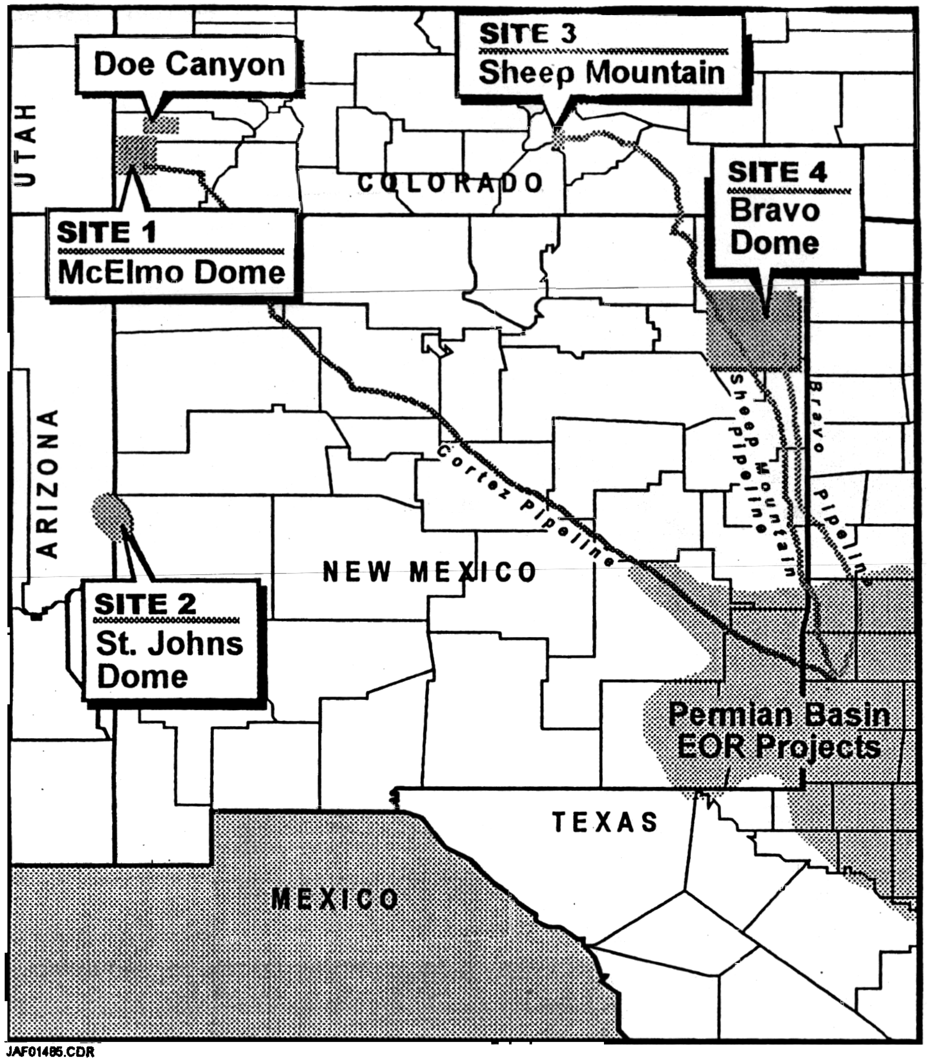


LOCATION OF NATURAL CO_2 FIELDS IN THE SOUTHWESTERN U.S.

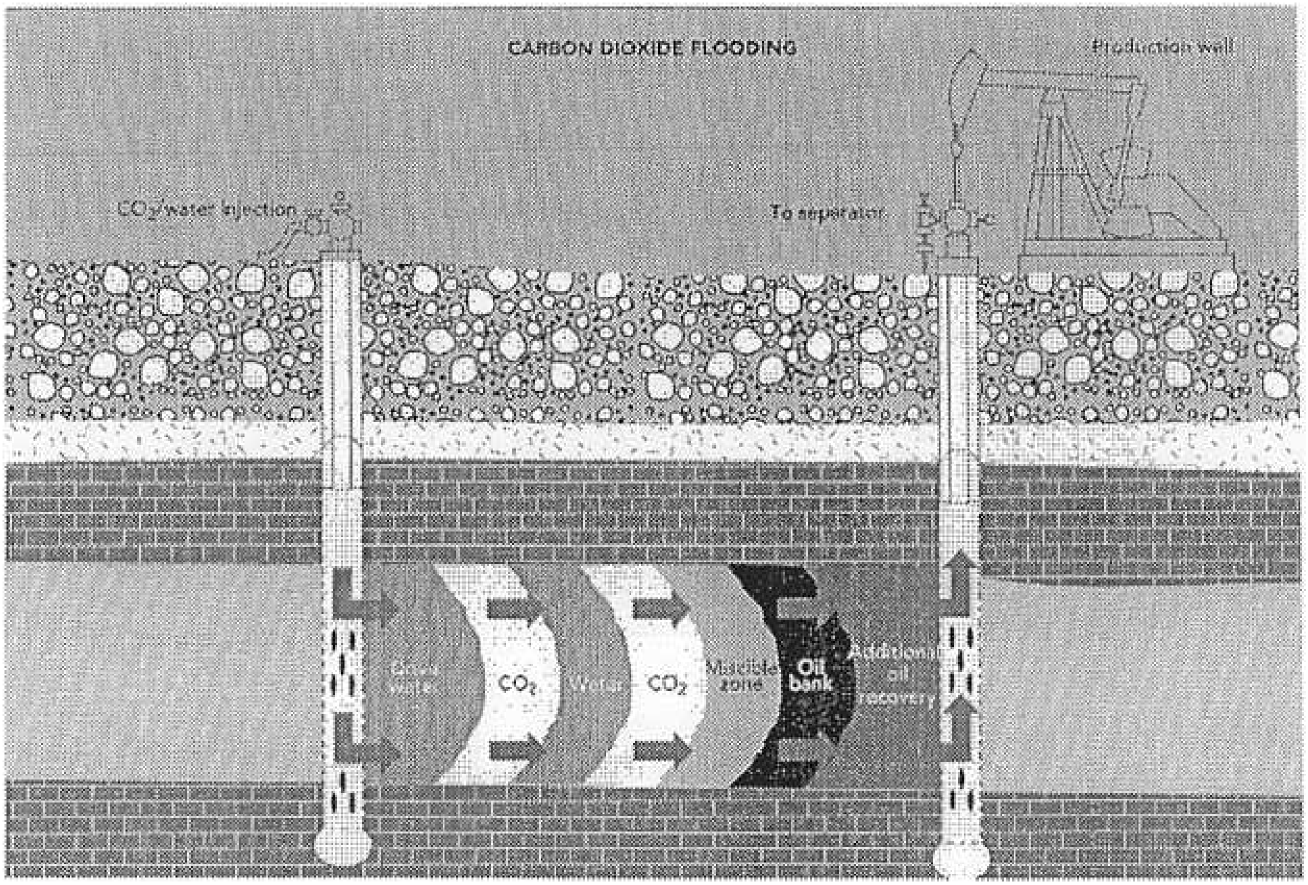
	Original CO_2 in Place		1998 CO_2 Production		Reservoir Lithology	Depth (m)
	10^6 t	Tcf	10^6 t/yr	MMcfd		
McElmo Dome, CO	1,600	30	15.9	820	Carbonate	2,300
St. Johns, AZ	830	16	0	0	Sandstone	500
Bravo Dome, NM	260	5	7.2	375	Sandstone	700
Sheep Mtn., CO	100	2	2.9	150	Sandstone	1,500

Several CO_2-EOR Projects Sequester Anthropogenic Waste CO_2

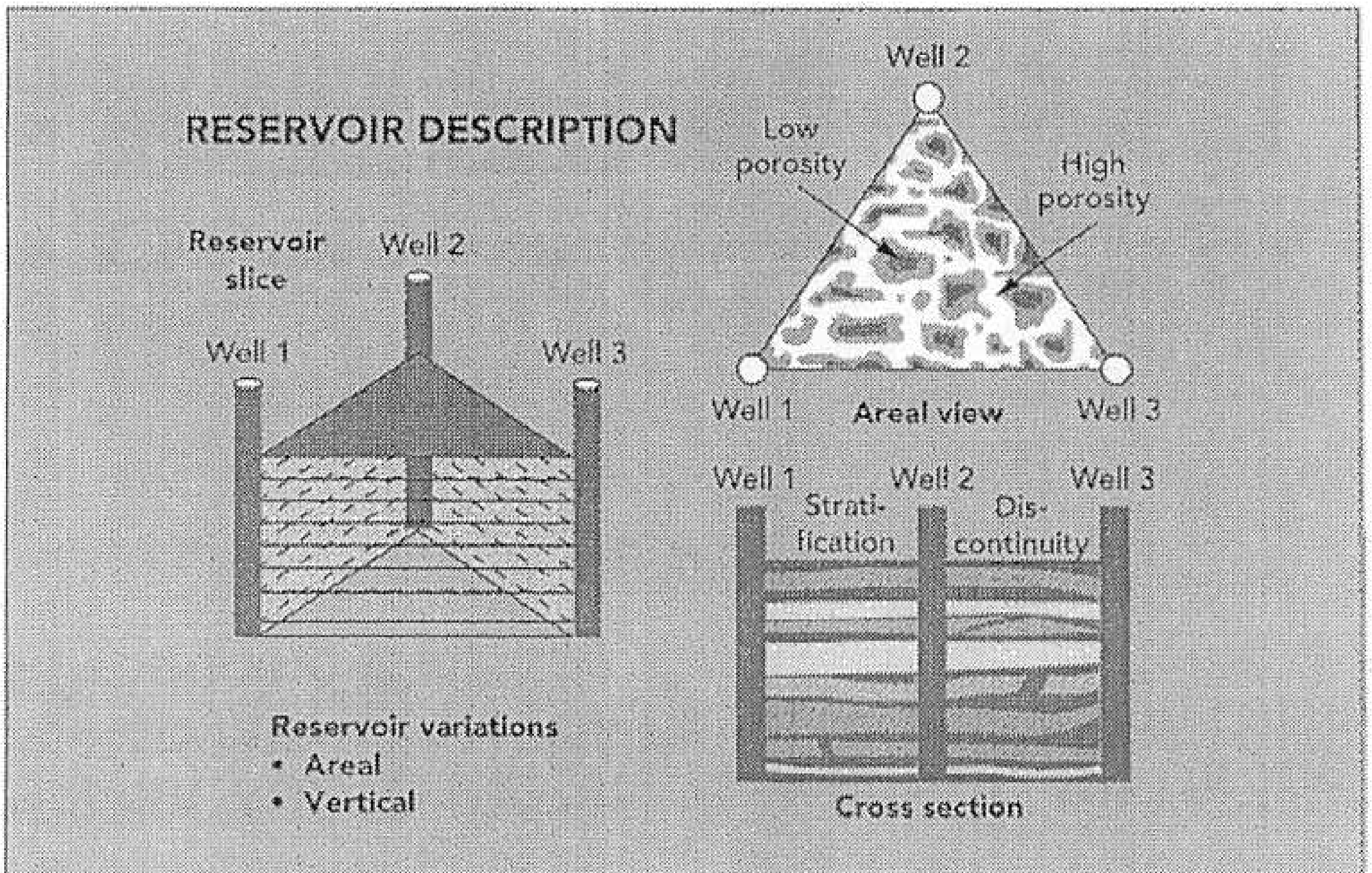
State/ Province	Plant Type	CO_2 Supply		EOR Field(s)	Operator
		MMcfd	t/Day		
Texas	Gas Processing	75	4,000	Sharon Ridge	Exxon/Mobil
Colorado	Gas Processing	60	3,200	Rangely	Chevron
Oklahoma	Fertilizer	35	1,900	Purdy, Sho-Vel-Tum	Anadarko Henry Petroleum
Wyoming	Gas Processing	30	1,600	Lost Soldier, Wertz	Merit Energy
North Dakota/ Saskatchewan	Coal Gasification	95	5,100	Weyburn	Pan Canadian
Total		295	15,800		

3B CO_2 Technology

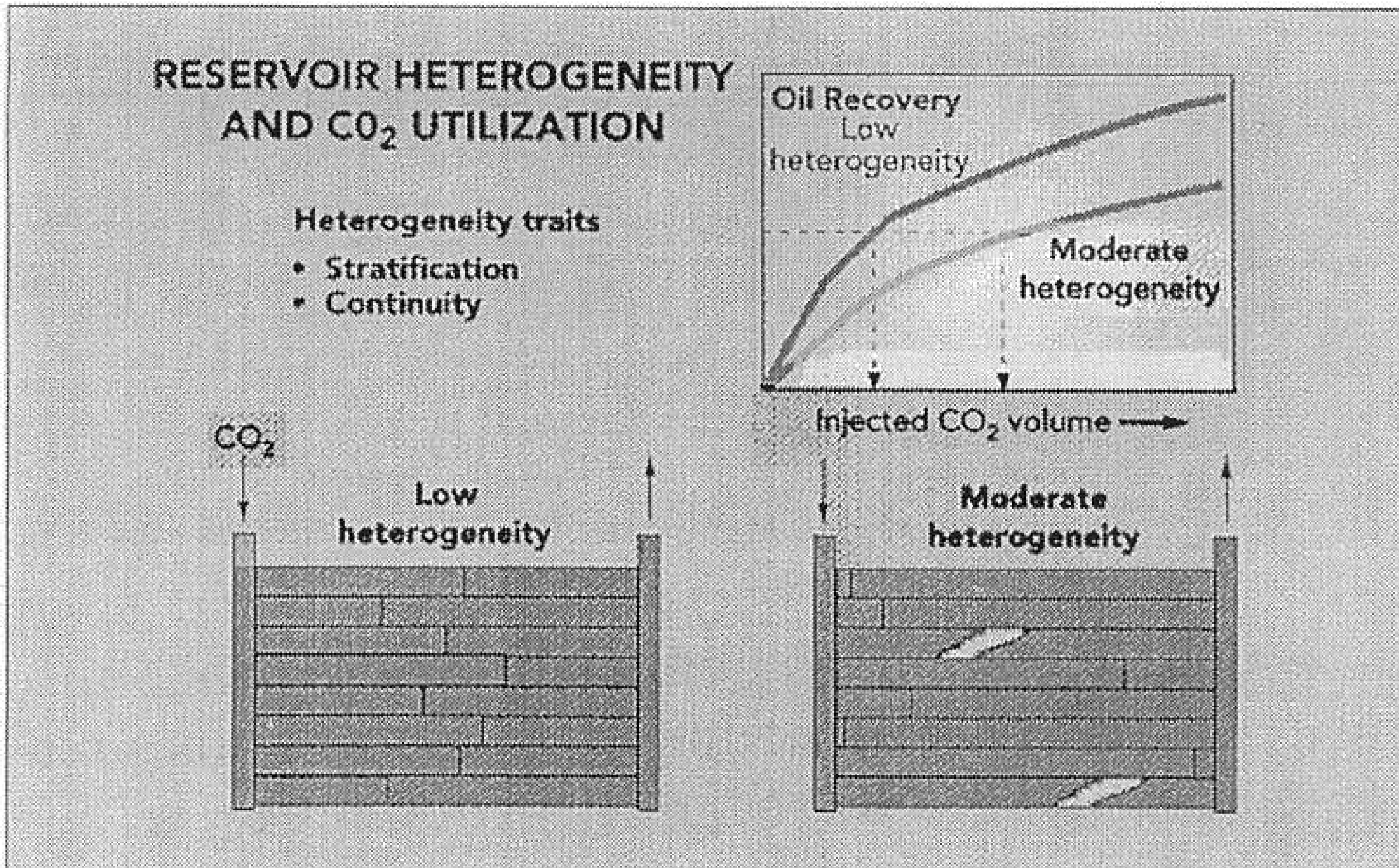
Injected CO2 Helps Recover Immobile Oil Through the Formation of an Oil Bank, Which is then Driven to Producing Wells



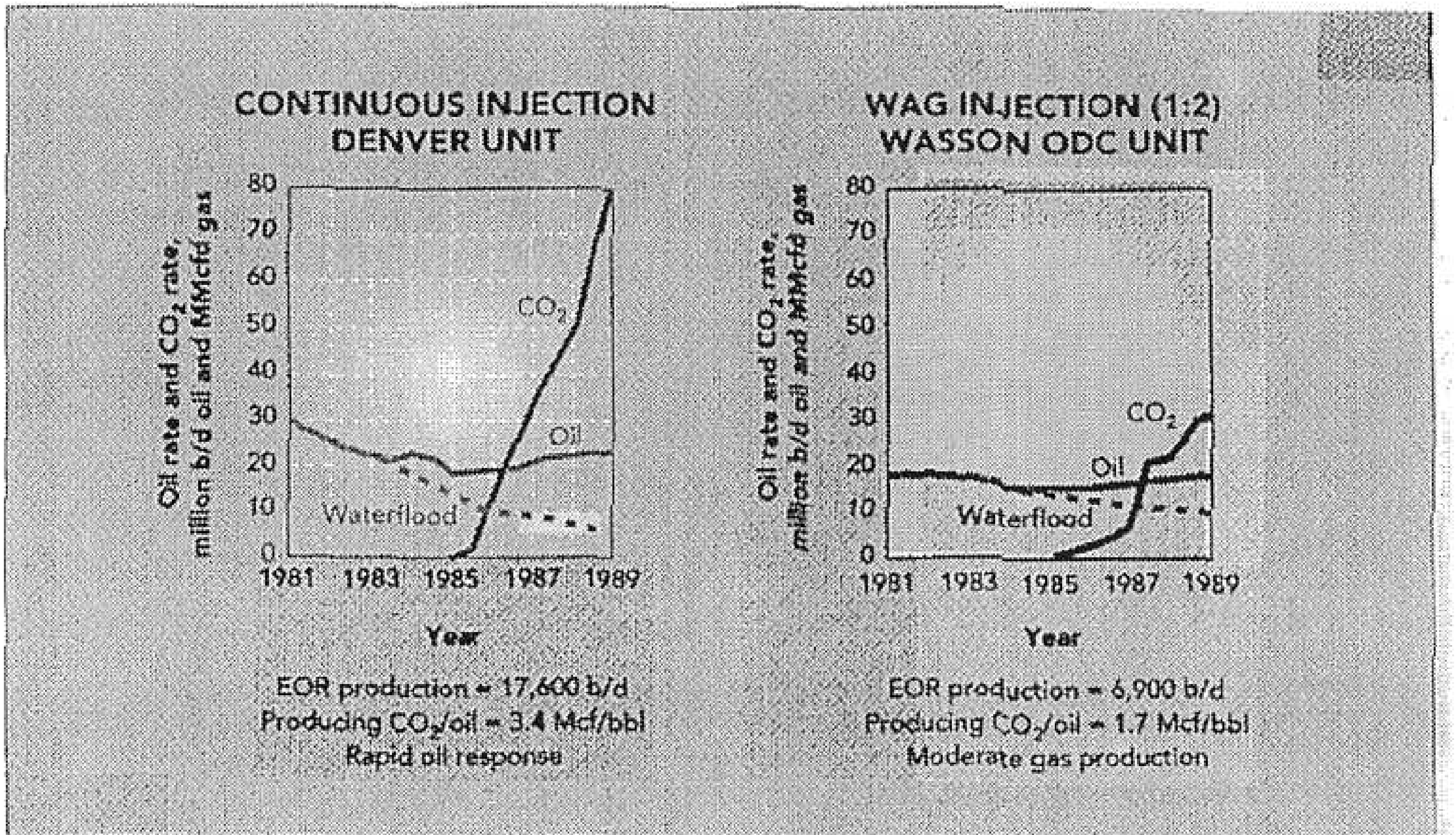
Reservoir Description

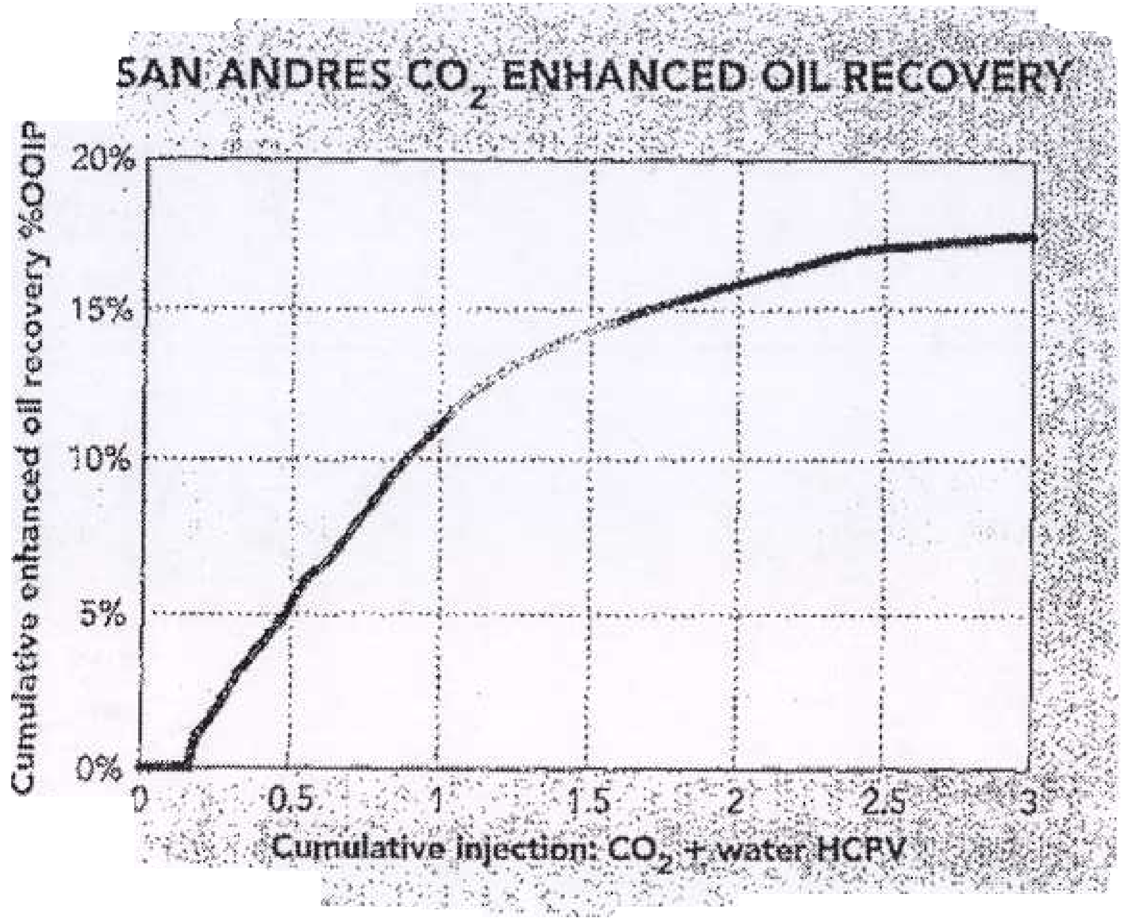


Reservoir Heterogeneity and CO2 Utilization



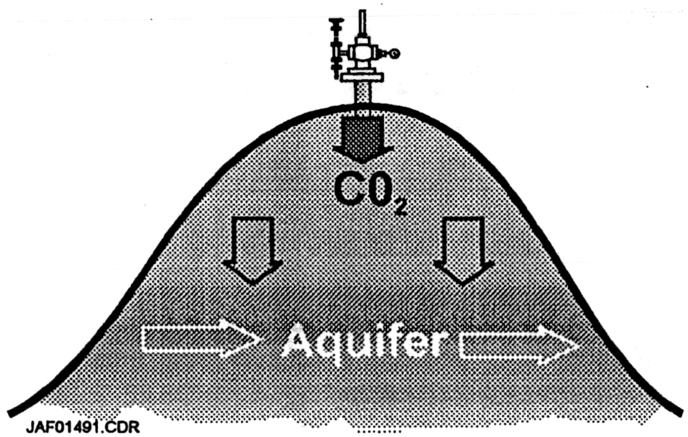
A Continuous CO_2 injection scheme results in a rapid increase in oil production, as well as CO_2 production. A WAG injection scheme results in a slower rise in both oil and CO_2 production.



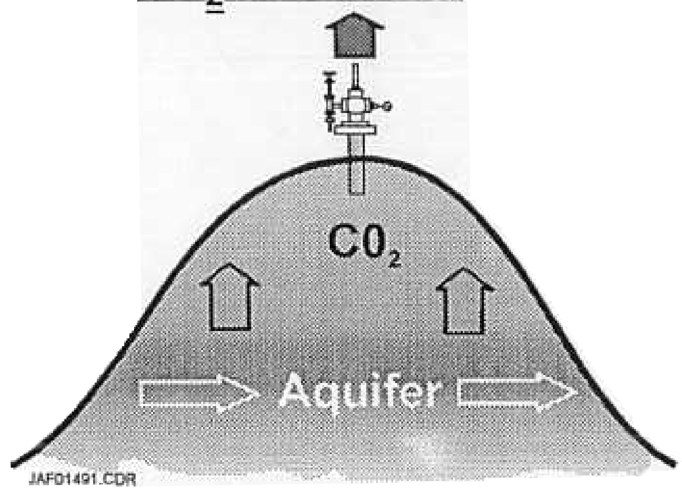

SAN ANDRES CO_2 ENHANCED OIL RECOVERY
Cumulative enhanced oil recovery %OOIP
20%
15%
10%
5%
0%
0
0.5
1
1.5
2
2.5
3
Cumulative injection: CO_2 + water HCPV

APPLICATION OF EOR KNOWLEDGE TO CO_2 SEQUESTRATION

Sequestration Site



CO_2 EOR Field



Need to Understand

Geology

1. Storage Capacity (ϕh)
2. Flow Capacity (kh)
3. Long-Term Integrity of Reservoir
4. Long-Term Integrity of Cap Rock
5. Interactions with Aquifers

Operations

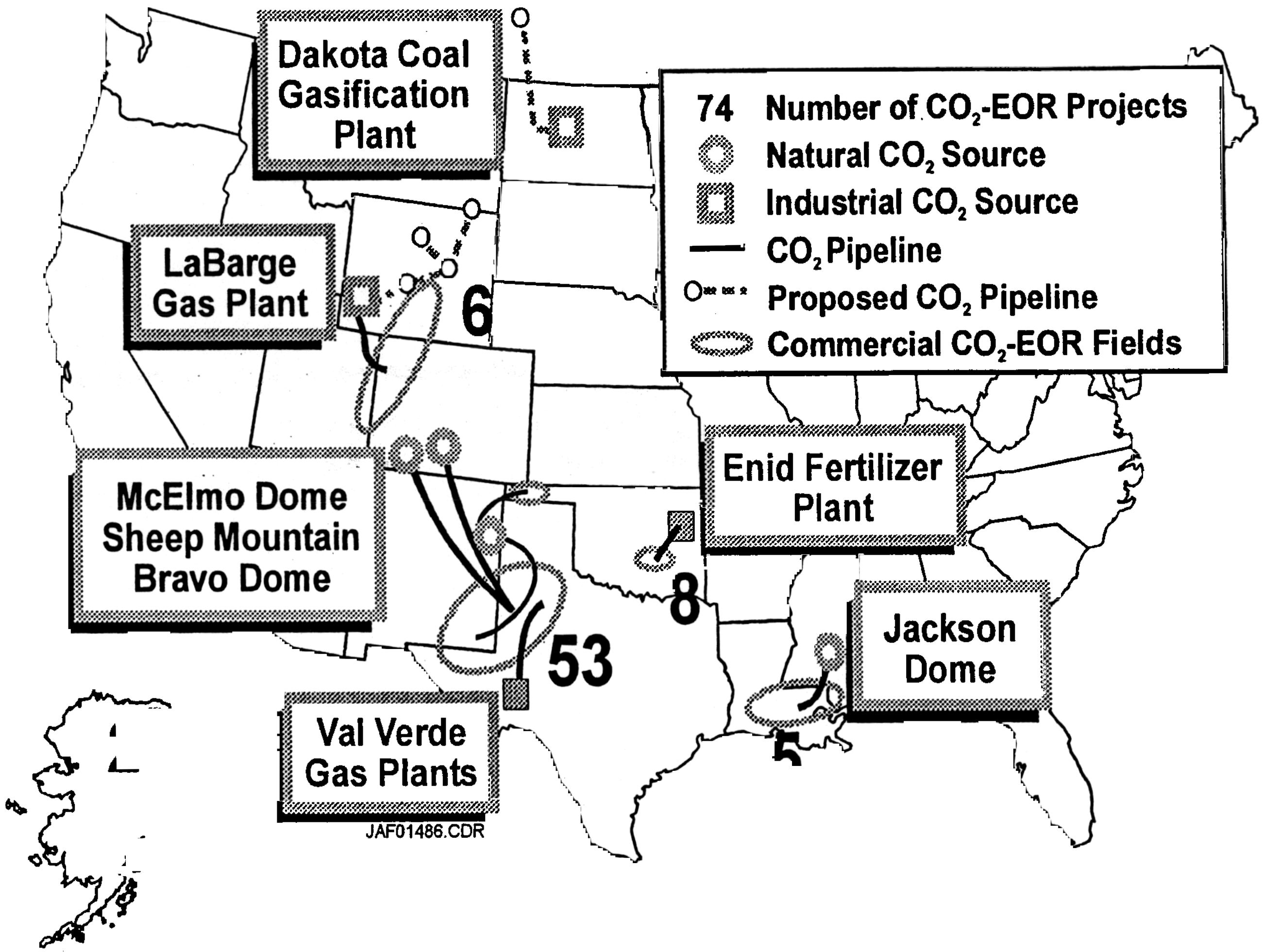
6. Technical Feasibility
7. Economic Feasibility
8. Safety and Reliability

Insights

1. ✔
2. ✔
3. ✔
4. ✔
5. ✔
6. Modeled (cf. EOR, UGS)
7. " "
8. Learn from Study

3C CO_2 Projects

CO_2 Sources and EOR Projects



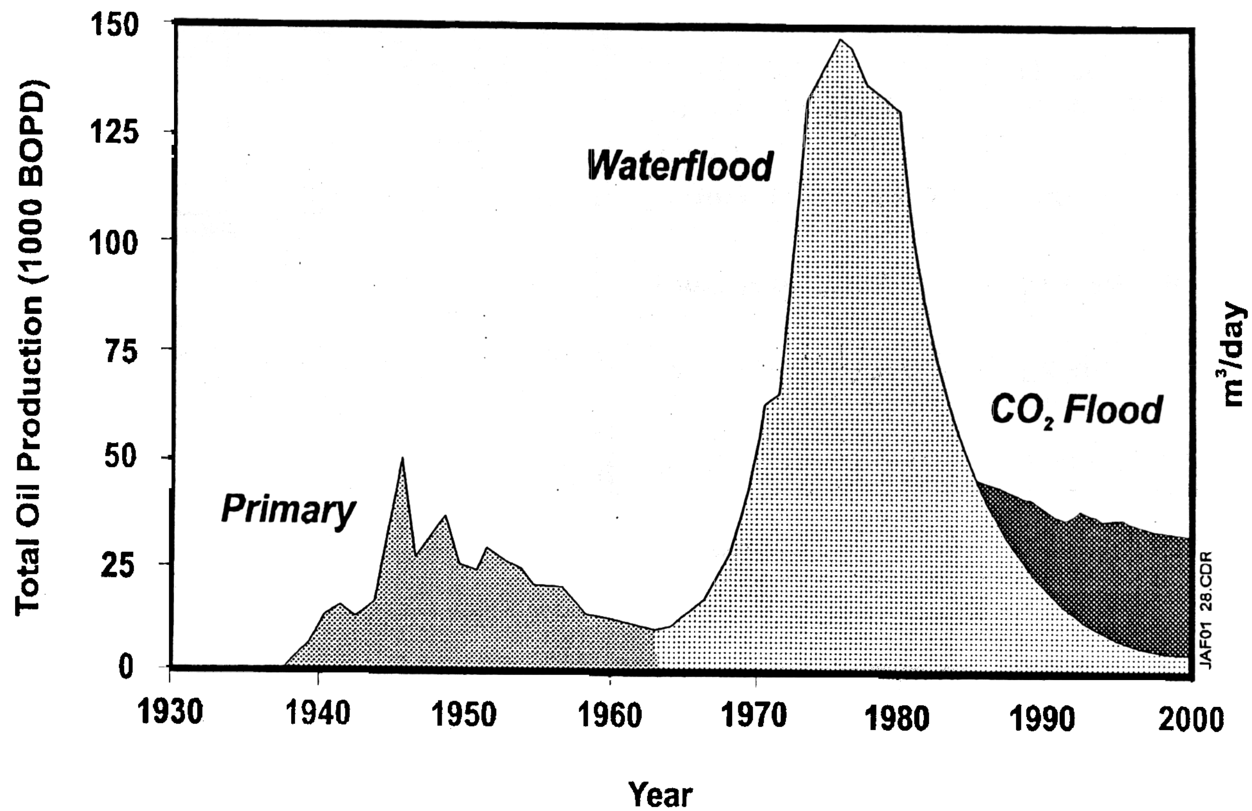
Large Projects Dominate EOR: The Five Largest Active CO_2-EOR Projects Account for Half of Worldwide Production (1998)

						EOR Production		Gross Cum. CO^2 Injected	
Operator	Field	Basin	(km^3)	Prod	Inj.	BOPD	m^3/d	Bcf	10^9 m^3
Altura	Wasson (Denver)	Permian	177	735	365	30,700	4,900	1,683	47.7
Amerada Hess	Seminole (Main)	Permian	64	408	160	30,000	4,800	NA	NA
Chevron	Rangely (Weber)	Rockies	61	204	200	13,881	2,200	811	23.0
Turkish Petrol.	Bati Raman	SE Turkey	44	145	41	13,500	2,150	NA	NA
Mobil	Salt Creek	Permian	49	85	48	12,000	1,900	NA	NA
Total 5 Largest Projects						100,081	15,950		

Shell Wasson-Denver Unit CO_2 Flood

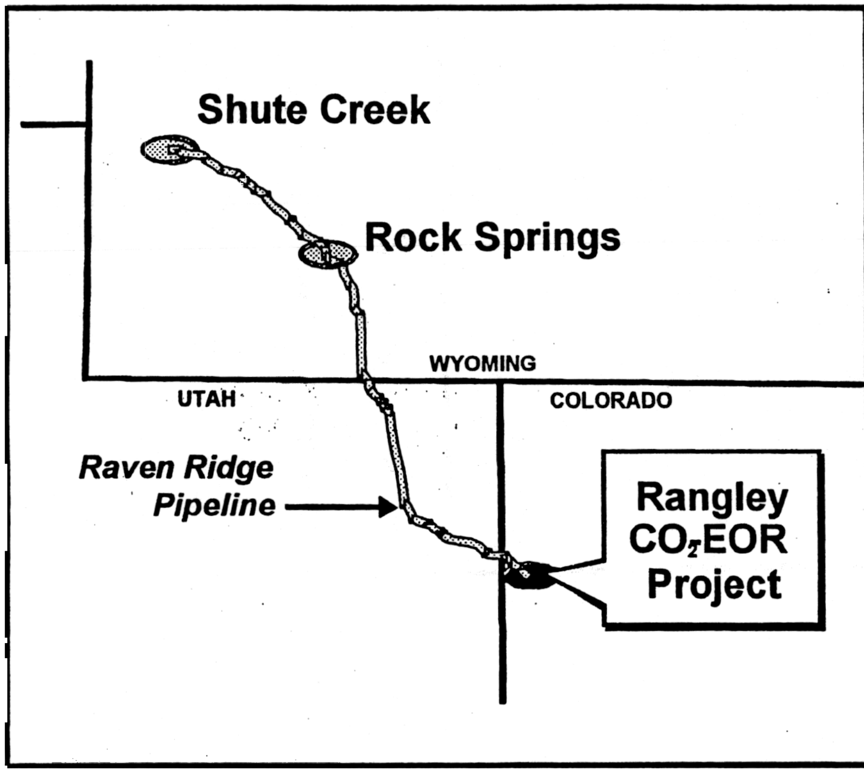
- One of the world's largest CO_2 floods: 28,000 acres, 1,500 injection wells.
- 300 to 400 MMcfd CO_2 injected into San Andres Fm.
- Since 1984, cumulative 2 Tcf CO_2 injected and over 60 million bbl incremental oil produced.
- 150 MMBO EOR ultimate.

Enhanced Oil Recovery Offsets CO_2 Injection Costs (Altura Denver Wasson Unit, West Texas)



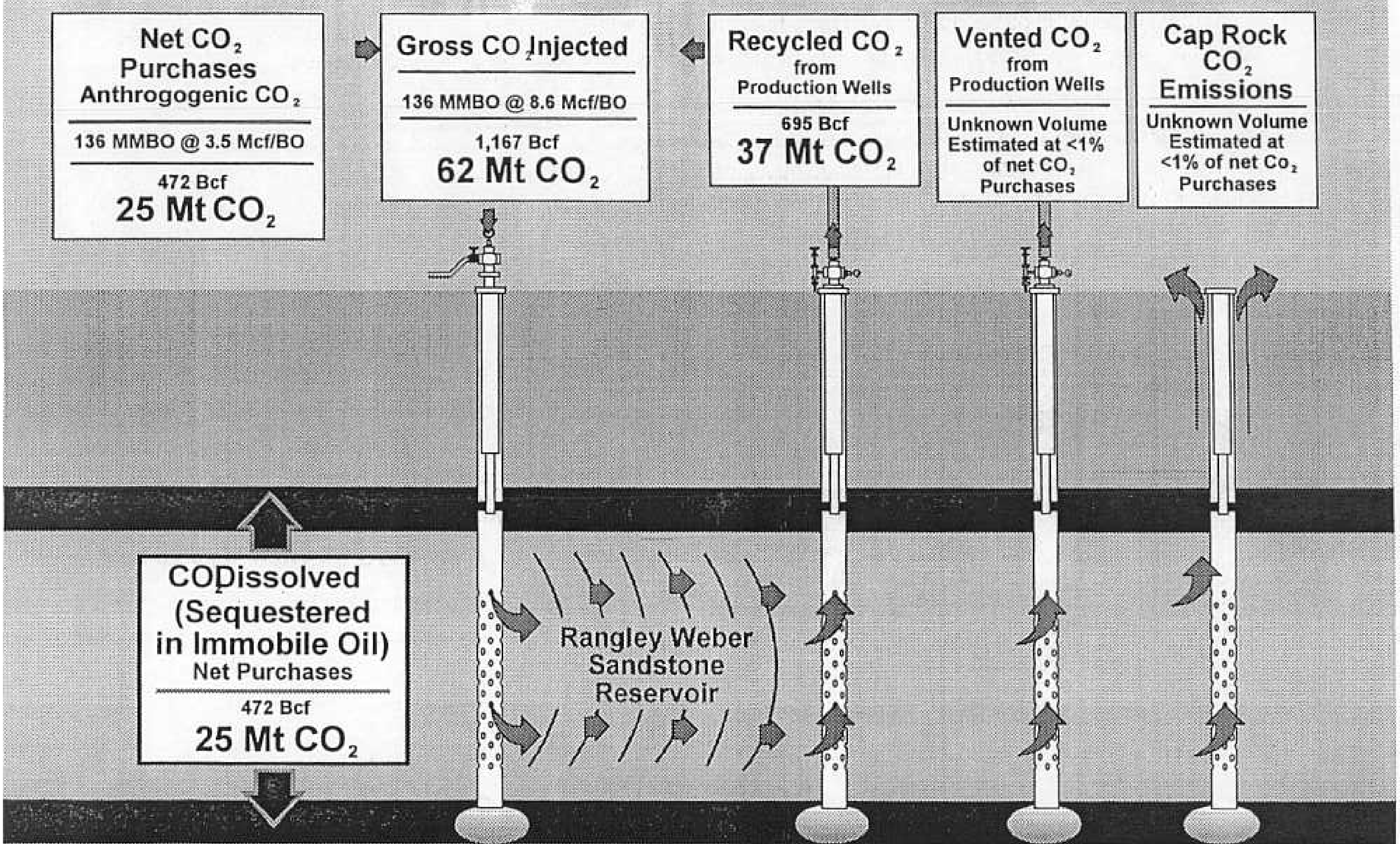
Source: Ward and Cooper, 1996

Chevron's Rangely Weber Unit CO_2-EOR Project, Colorado, USA



Parameter	Metric Units	English Units
Depth	1,680 to 1,980 m	5,500 - 6,500 ft
Current EOR Area	62 km^2	15,000 acres
Number of Wells	378 Producers, 259 CO_2 Injectors	
Original Oil in Place (OOIP)	300 million m^3	1.88 billion barrels
Estimated Ultimate EOR (%OOIP)	22 million m^3 (7.2%)	136 million barrels (7.2%)
Cumulative Gross CO_2 Injection (1996)	3.3 x 10^9 m^3 (62 Mt)	1,167 Bcf
CO_2 Source	Exxon Labarge Gas Processing Plant (Anthropogenic)	

CO_2 Sequestration at Rangely (Estimated Ultimate)



Sources: Operator data, ARI estimates

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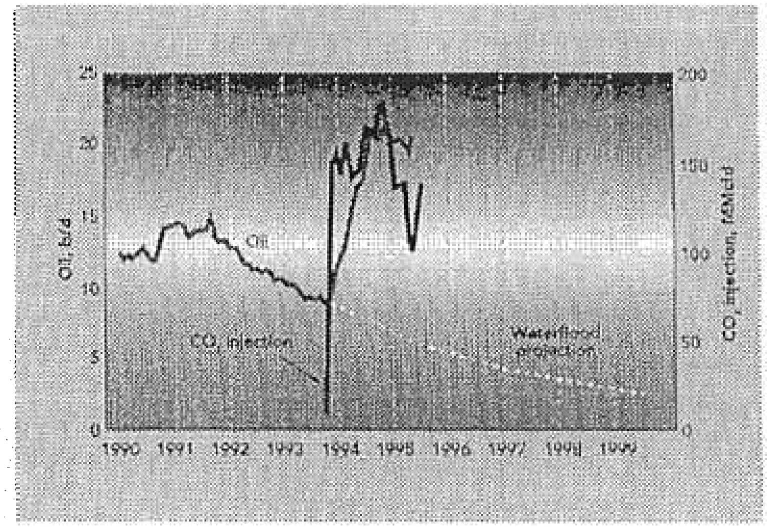
Salt Creek Unit Phase I Area, Kent County, Texas



Operator: Mobil Exploration & Producing U.S.

Reservoir: Canyon Reef

Start CO2 injection: October 1993

Production response: 2 months

Beginning oil production: 9,000 b/d oil

Beginning water production: 230,000 b/d water

Peak production:21,600 b/d oil (December 1994)

Current production: 20,800b/d oil, 190,000 b/d water (June 1995)

Maximum CO2 injection rate: 187 MMcfd

Cumulative CO2 injection: 90 bcf or 7.5% HCPV

Tertiary oil recovery: 1.5% OOIP (June 1995)

Field-wide expansion will continue into phase 3 through the year 2001.

Phase 1 of the Salt Creek Unit CO2 flood was implemented in October 1993, and the project responded quickly with oil production doubling in the first year. Mobil discovered that most waterflood production equipment is suitable for CO2 flood service if it is modified for increased gas handling capacity. Also, gathering gas at higher pressures saved compression costs. Other similarities with waterflooding were found: the same workover procedures can be used for both waterflooding and CO2 flooding, except that high gas/oil ratio (GOR) wells require increased mud weights.

Reservoir management methods were developed to optimize profitability. Smaller slug sizes of 1% hydrocarbon pore volume (HCPV) helped lower GOR breakthrough during water alternating gas (WAG) injection and provided uniform production rates. The more constant flow rates enhanced well test accuracy, a key to the effective reservoir management program. WAG breakthrough problems were identified by monitoring cash flow for each producing well, and WAG ratios were varied on a pattern-by-pattern basis.

Mallet Unit – Slaughter Field, Hockley County, Texas

Operator: Mobil Exploration & Producing U.S.

Reservoir: San Andres

Start CO2 injection: December 1991

Production response: 6 months

Beginning oil production: 1,600 b/d oil

Beginning water production: 25,000 b/d water

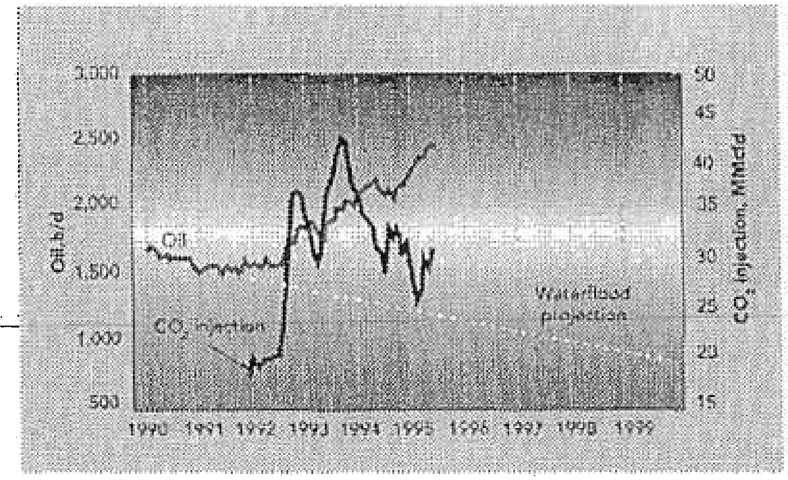
Peak production: 2,500 b/d oil (June 1995)

Current production: 2,500 b/d oil, 21,000 b/d water (June 1995)

Maximum CO2 injection rate: 44 MMcfd

Cumulative CO2 injection: 42 bcf or 10% HCPV

Tertiary oil recovery: 1% OOIP (June 1995)



Field-wide expansion has been completed.

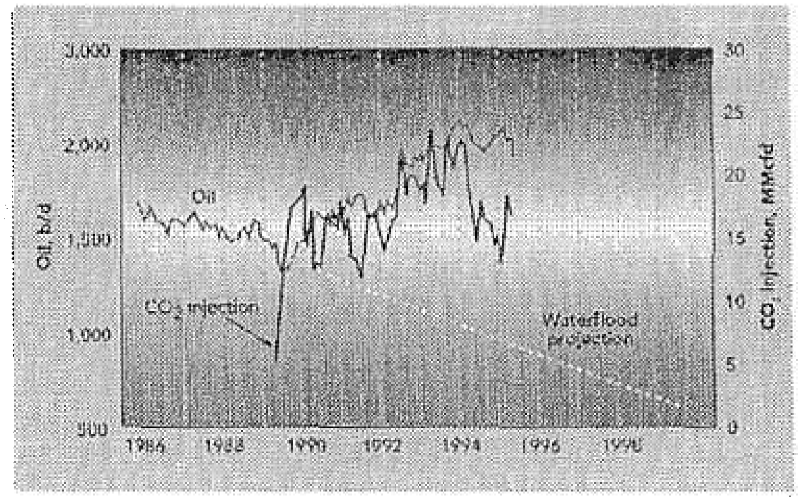
The Mallet Unit, formed in December 1963, was originally developed on 35-acre well spacing. The Permian dolomite reservoir was produced by solution gas drive until 1964, when a line-drive waterflood was initiated. Primary production recovered 12% original oil in place (OOIP) and the waterflood recovered another 24%. CO_2 injection began in late 1991, and oil production has already increased by more than 50%.

From experience in this field, managing tertiary WAG injection on a pattern-by-pattern basis can reduce CO_2 production and increase profits. For 20-acre patterns, CO_2 was injected continuously until breakthrough, and for 10-acre patterns 2% HCPV CO_2 slug sizes were found to be optimal. Injectivity will be increased and areal sweep improved by drilling horizontal injection wells in line-drive patterns.

Mobil performs break-even cashflow analysis on each producer based on the GOR. Data gathering is done electronically to improve timeliness of decision making.

Training personnel in CO_2 field operations was found to be critical for handling high-pressure gas, and H2S contingency plans had to be re-evaluated for handling increased gas volumes associated with rapid CO_2 breakthrough.

East Mallet Unit – Slaughter Field, Hockley County, Texas



Operator: Mobil Exploration & Producing U.S.

Reservoir: San Andres

Start CO2 injection: June 1989

Production response: 4-6 months

Beginning oil production: 1,330 b/d oil

Beginning water production: 19,000 b/d water

Peak production: 2,100 b/d oil (February 1994)

Current production: 1,900 b/d oil, 13,000 b/d water (June 1995)

Maximum CO2 injection rate: 24 MMcfd

Cumulative CO2 injection: 34 bcf or 14% HCPV

Tertiary oil recovery: 1.7% OOIP (June 1995)

Field-wide expansion will continue into phase 3 through the year 2001.

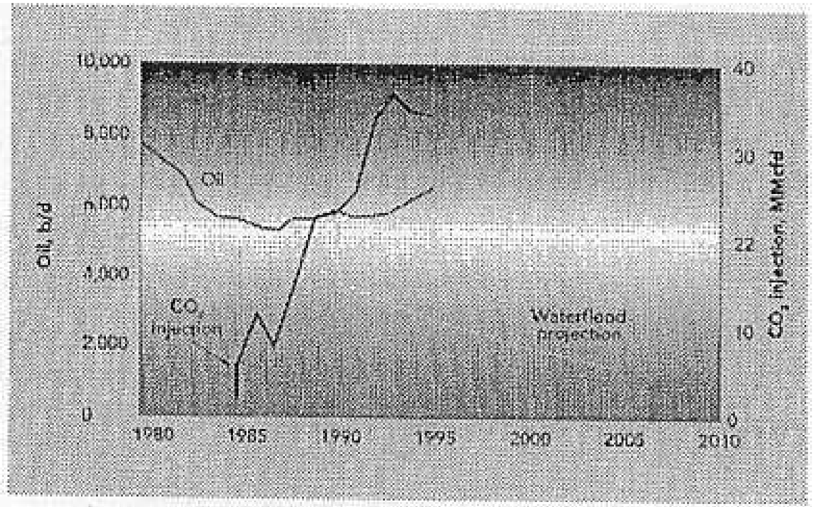
CO_2 injection began in the East Mallet Unit in 1989. The project has shown favorable response, with oil production increasing by 50%. The unit injected continuous CO_2 until breakthrough required a WAG cycle. A line-drive pattern provided was chosen to minimize CO_2 breakthrough problems. Injection rates were maximized by increasing the number of injection wells and by drilling horizontal injections wells.

A computerized monitoring system was installed to quickly detect high-GOR wells and make rapid adjustments to WAG scheme, thereby reducing the cost of gas processing.

Sizing of production vessels was critical for environmental and safety reasons. Increased gas separation and gas gathering capacity was required when CO_2 injection first started. Particular attention was paid to the selection of elastomers in all equipment components in contact with high-pressure CO_2.

McElmo Creek Unit – Greater Aneth Field, San Juan Basin, Utah

Operator: Mobil Exploration & Producing U.S.
Reservoir: Desert Creek
Start CO2 injection: February 1985
Production response: 1-2 years
Beginning oil production: 5,500 b/d oil
Beginning water production: 29,000 b/d water
Peak production: 6,500 b/d oil (February 1995)
Current production: 6,500 b/d oil, 25,000 b/d water (June 1995)
Maximum CO2 injection rate: 36.5 MMcfd
Cumulative CO2 injection: 83 bcf or 8% HCPV
Tertiary oil recovery: 1.3% OOIP (June 1995)



Field-wide expansion has been completed, and further development will involve drilling horizontal wells.

The McElmo Creek Unit of the Aneth field in Southeast Utah, which produces oil from the Pennsylvanian-age Paradox formation, has been waterflooded since 1962. More than 300 pressure transient tests were conducted to assess pressure support from water injection and to ensure that the reservoir pressure was in excess of the minimum miscibility pressure for the miscible CO_2 flood. The CO flood was initiated in 1985; production has been steadily increasing since then.

Ongoing profile monitoring and profile modifications were critical in maintaining good vertical sweep during the project. In the case of low-permeability zones, injection rates are maximized by drilling horizontal injection wells. Pattern-by-pattern performance is being analyzed for evaluation of automated WAG control system to optimize WAG timing.

Because gas plant capacities had limited flexibility, CO_2 reinjection was evaluated as an alternative to gas processing. Mobil remaining committed to their long-term CO_2 injection scheme to meet injected CO2 target volumes.

Educating the community was vital for successful project implementation and operation.

North Cross Devonian Unit, Crane and Upton Counties, Texas

Operator: Shell Western E&P.

Reservoir: Devonian

Start CO2 injection: 1972

Production response: 1 Year

Beginning oil production: 1,550 b/d oil

Beginning water production: 140 b/d water

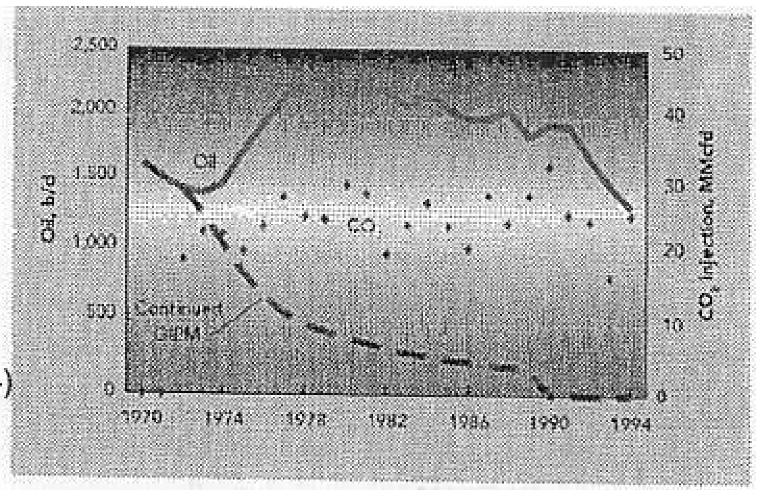
Peak production: 2,340 b/d oil (1978)

Current production: 1,340 b/d oil, 610 b/d water (December 1994)

Maximum CO2 injection rate: 33 MMcfd

Cumulative CO2 injection: 150 bcf or 84% HCPV

Tertiary oil recovery: 24% OOIP (December 1994)



Field-wide expansion has been completed, and further development will involve drilling horizontal wells.

Shell's first CO_2 flood was at the North Cross Unit. It was implemented as a secondary flood instead of the more common tertiary flood due to expectations that water injectivity would be very low. The first response was observed after 1 year of injection, and it took about 2 years to see a field-wide oil production response. Since that time, the flood has been very successful and has proved that the CO_2 flood process can work over an extended period of time. In fact, 24% of the OOIP has already been recovered due to CO_2 injection.

Over the years that this flood has been in operation, many important concepts about CO_2 flooding have emerged. A pressure core taken from an area of the reservoir swept by CO_2 showed that the residual oil saturation was reduced to approximately 3%, indicating very efficient sweep and displacement of the oil. Planning and designing for sufficient gas processing and recycle compression capacity is critical to prevent limitations on production. Formation of hydrates and paraffin can be a problem, but techniques were developed to help control these obstacles. And reducing the pressure drop between producers and compression facilities helps lower compression costs and controls some of the hydrate formation problems.

South Wasson Clearfork Unit, Gaines County, Texas

Operator: Shell Western E&P

Reservoir: Clearfork

Start CO2 injection: 1986

Production response: 1 year

Beginning oil production: 6,000 b/d oil

Beginning water production: 25,000 b/d water

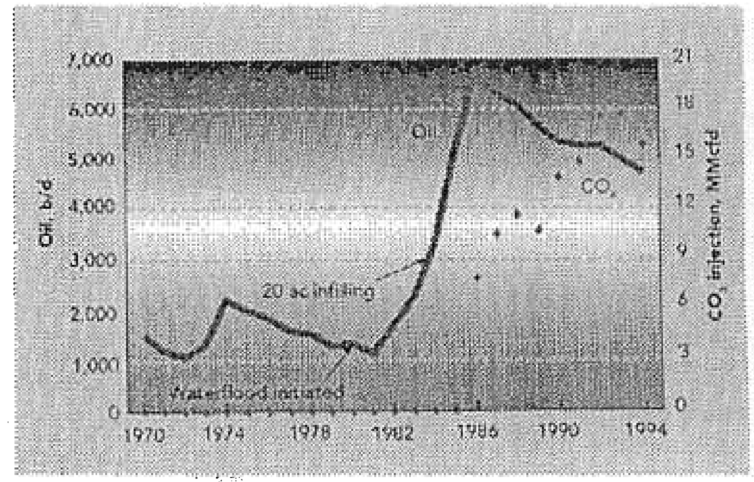
Peak production: 6,800 b/d oil (December 1986)

Current production: 4,700 b/d oil, 24,600 b/d water (December 1994)

Maximum CO2 injection rate: 18 MMcfd

Cumulative CO2 injection: 46 bcf or 6% HCPV

Tertiary oil recovery: 1% OOIP



Production response was delayed due to starting the CO2 flood on 2:1 WAG. Field-wide expansion has been completed.

The industry's only Clearfork CO_2 flood is at the Shell operated South Wasson Clearfork Unit. Because this CO_2 flood was implemented in the early stages of the waterflood, the economics of the project were enhanced by sharing the infrastructure costs between the water flood and CO_2 flood investments. The CO_2 flood was expanded in stages. It was started with an 8:1 WAG ration in a small area of the field and was later expanded in two additional phases and converted to a 2:1 WAG scheme after the project proved successful in the original area. Some of the key learnings from this flood are discussed below.

EOR injection and sweep efficiency have generally been good. Quick breakthrough of CO_2 did occur in some wells, primarily due to fractures, but these problems were minimized. Water injectivity after CO_2 injection is not significantly reduced in most wells; however, Shell encountered some difficulties associated with fill which reduced injectivity, altered profiles and resulted in costly workover. A focus on water quality and early identification of problem wells increased injection rates. The WAG cycle length is managed on a well by well basis to take into consideration the operational impact of response at offset injectors.

3D Economics

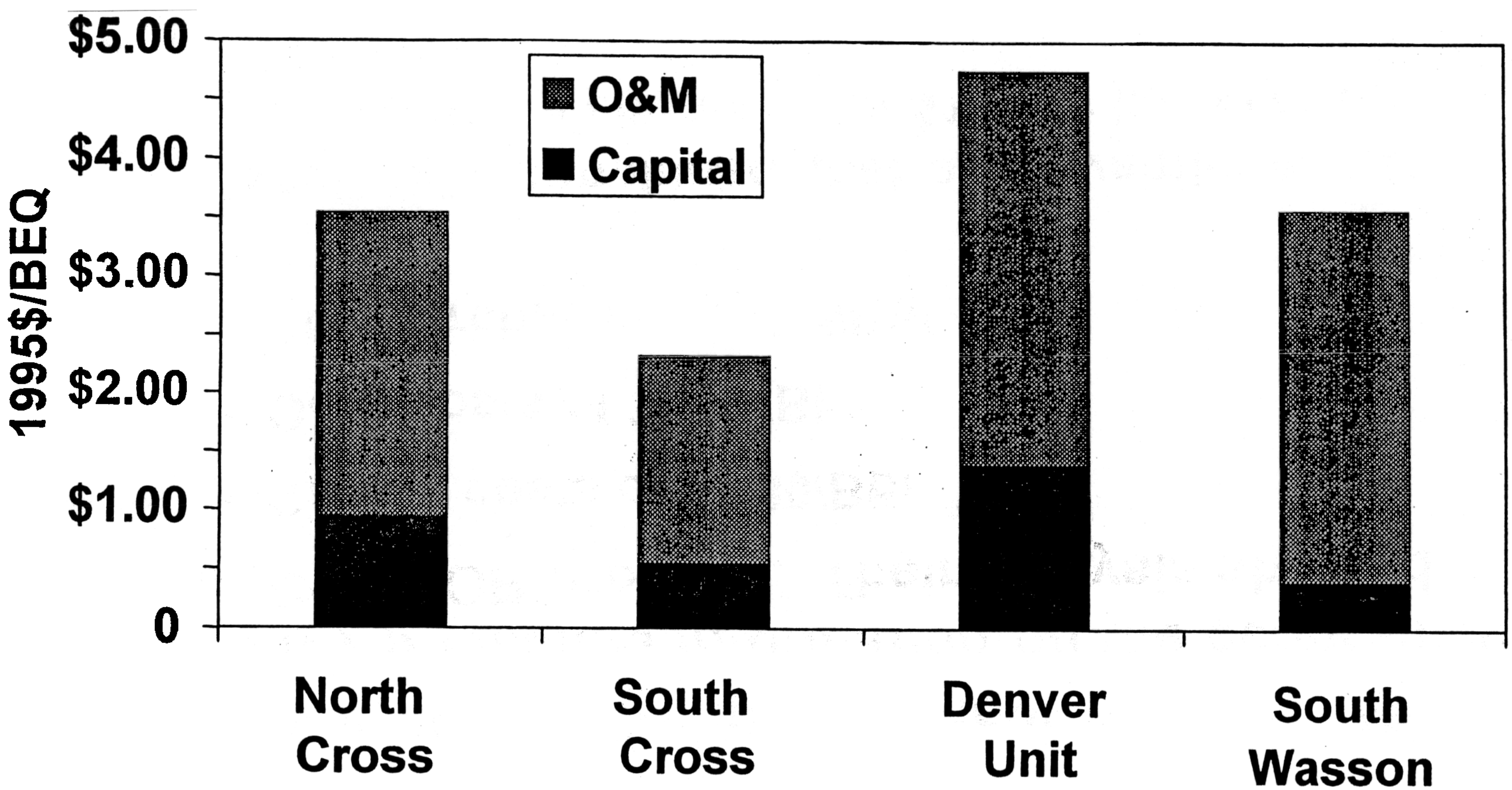
CO_2 EOR Economics

Shell CO_2 Company (now Kinder Morgan) recently published information on the economics of four CO2 EOR projects. Their analysis showed:

- Capital costs of $0.80/Bbl
- O&M costs of $2.70/Bbl
- CO_2 purchase of 5 Mcf/Bbl

Shell CO_2 concluded that a conventional CO2 EOR project would be economic at $18 per barrel of oil.

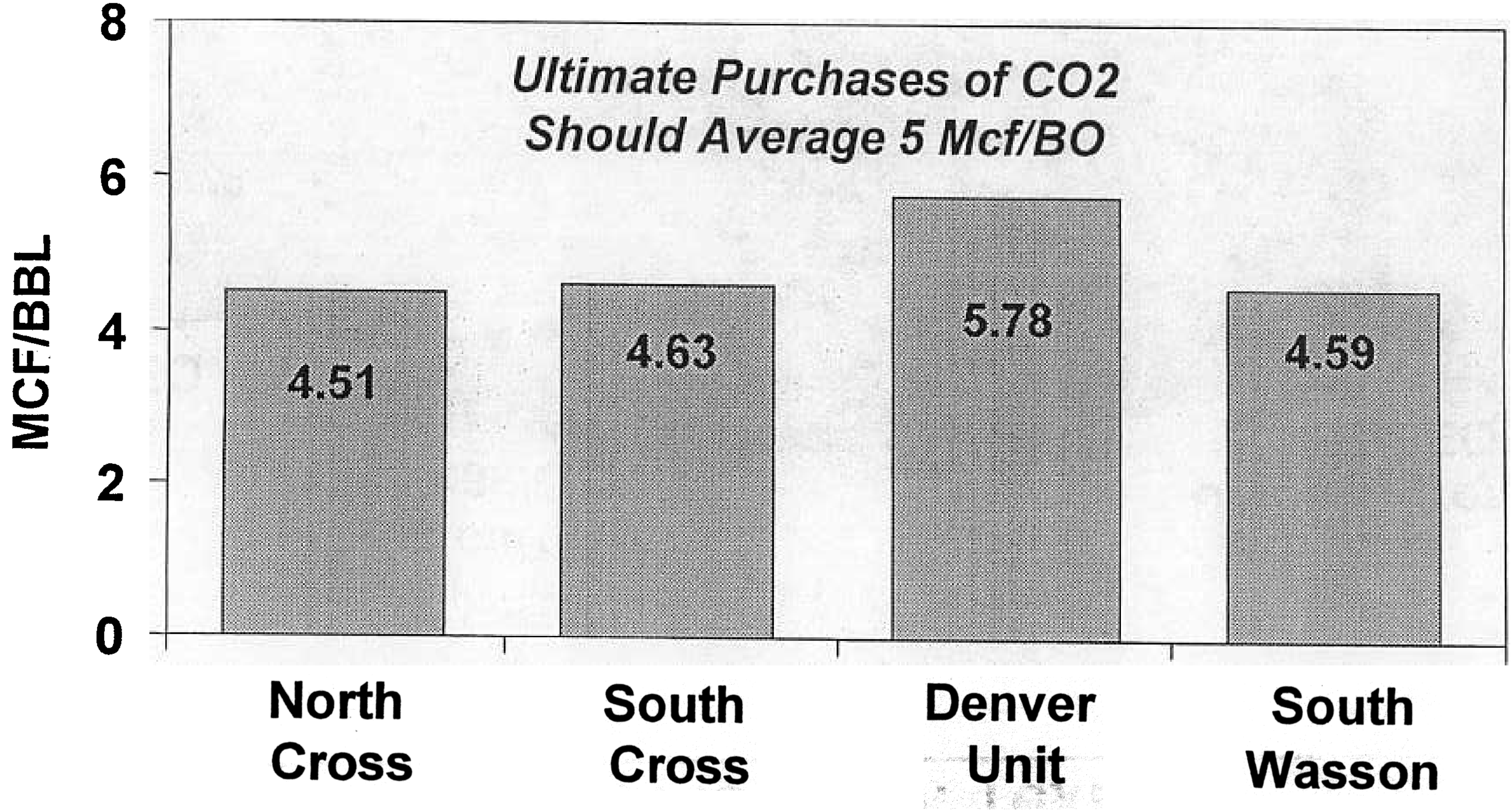
CO_2 Development Costs



- *Capital Costs Average $0.80/BEQ*
- *Operating Costs Average $2.70/BEQ*

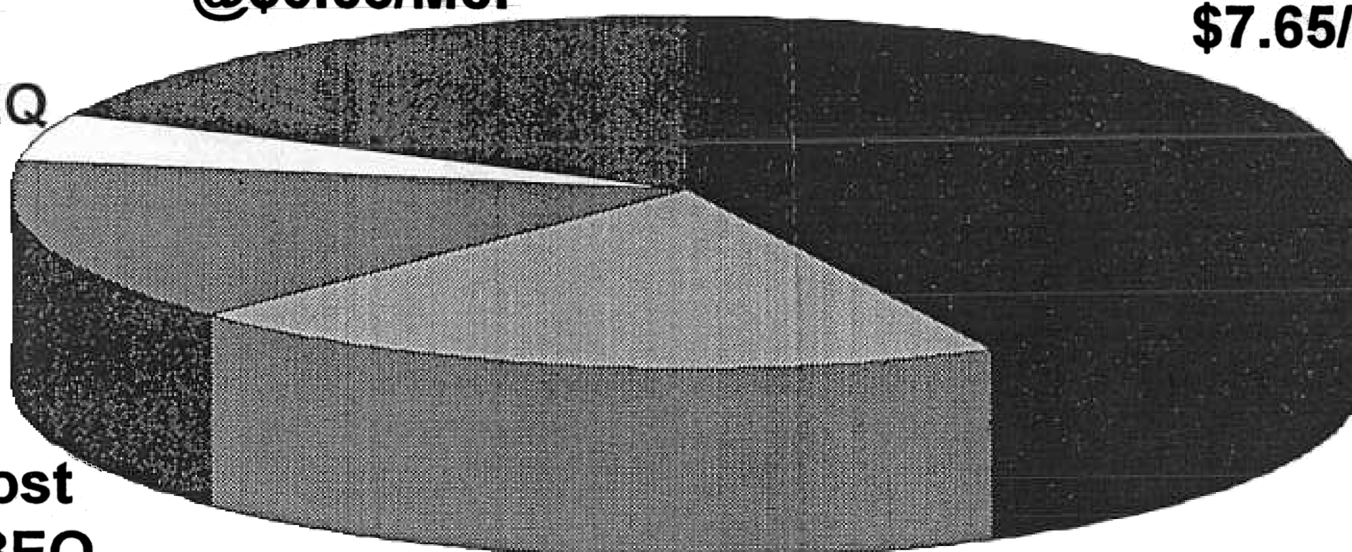
Source: Shell CO_2 Co.

Ultimate Net CO_2 Utilization



Source: Shell CO_2 Co.

New CO_2 Flood (W. Texas)

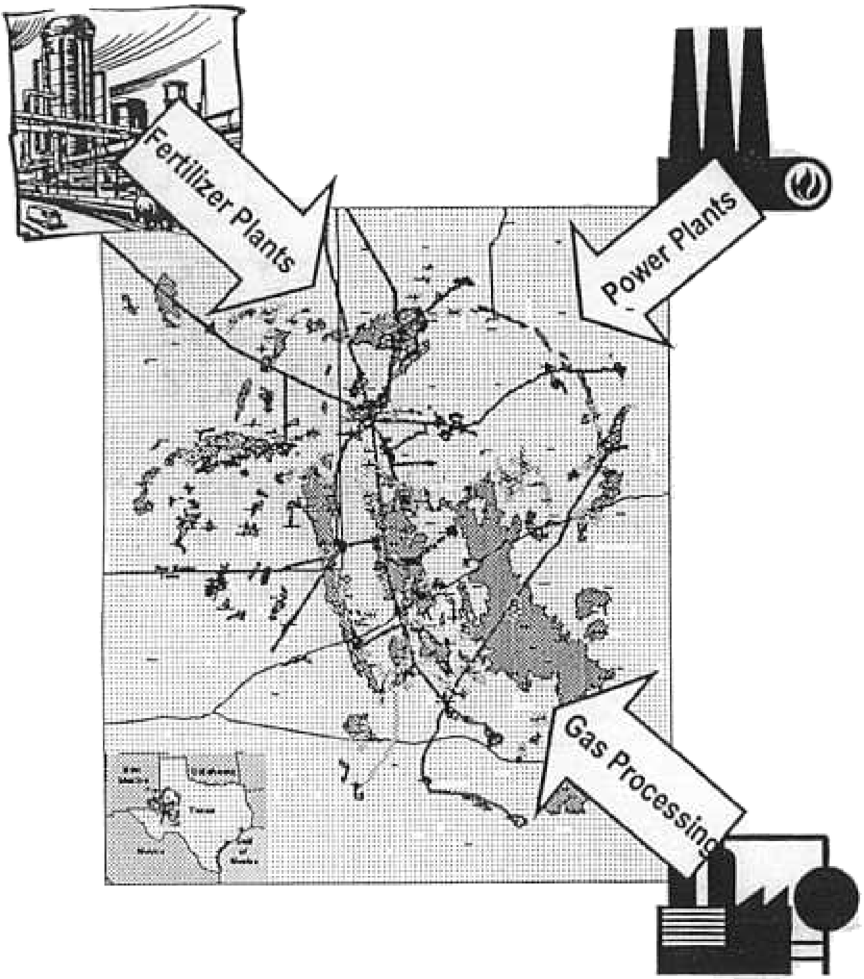


Source: Shell CO_2 Co.

*$18/BEQ

Scenario 2020

Permian Basin CO_2 EOR / Sequestration BU



500,000 BOPD EOR (West Texas, New Mexico)

5 Bcfd CO_2 njection emissions from **15,000MWe)**

0 Mcf CO_2 / BO EOR Ratio

$ 0/t CO_2 Incentives Credits

Gross Oil Revenues @$25 BO = $4.6 B

Net Oil Revenues $0 4 B

CO_2 Emission ncentives Credits = $0.9 B

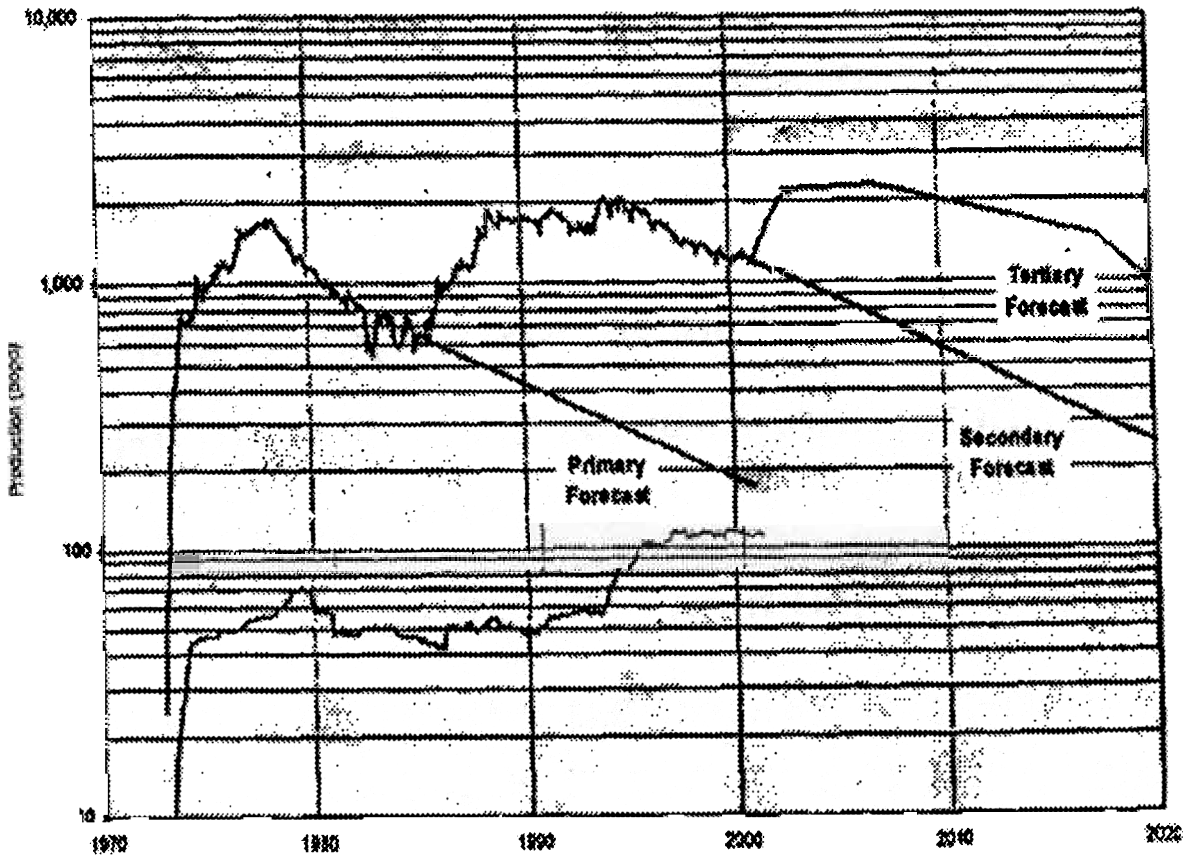
CO_2 Emission Incentives / Credits Make A Marginal EOR Project Economic

CO2 EOR Sequestration Project Economics

	With Infill Dr.	W/O Infill Dr.
1. Capital Expenditures		
Drill Infill Producers (50)	$12,000,000	-
Drill CO2 Injectors (40)	8,000,000	-
Workover Producers	2,000,000	2,000,000
Equipment CO2 Injectors	4,000,000	4,000,000
Install Surface Facilities	4,000,000	4,000,000
2. CO2 and O&M Costs		
CO2 Purchase (@$0.80/Mcf)*	$40,000,000	$40,000,000
Well O&M Costs (@$5/Bbl)	50,000,000	25,000,000
3. Estimated Oil Recovery (Bbls)	10,000,000	5,000,000
4. Economics		
• Cost of Reserve Adds	$7.00/Bbl	$10.00/Bbl
• Net Revenues (After Royalty/Prod Tx)	75%	75%
• Minimum Required Oil Price (@2X(Capex + CO2 cost) + O&M)	$25/Bbl	$33/Bbl

**Assuming 50 Bcf of purchased CO2, at 10 Mcf CO2 per 1 Bbl oil, without infill drilling reserves*

CO_2 EOR Sequestration



CO2 EOR Sequestration Project

An EOR project with the aim of sequestering CO2 will be more costly than a traditional CO2-EOR project:

- Higher CO2 purchase volumes
- Less CO2 recycling
- Higher well costs for long term integrity
- Higher O&M costs for monitoring and verification

Full cycle economics show that with CO2 sequestration, an EOR project will cost for $25 to $33 per barrel.

A $10/ton CO2 sequestration credit would make these projects economic at $20 to $25 per barrel oil price.

4 Max mizing Sequestration In O l Reservoirs

Objective and Context

Maximizing Sequestration in Oil Reservoirs

- Maximize sequestration of CO_2 in oil reservoir while maintaining oil production performance.
- Conventional reservoir management seeks to minimize the amount of CO_2 trapped sub-surface.

Near Term Technology Needs

- Understand sequestration process
  - Laboratory measurements
  - Optimize solvent purity / composition
  - Reservoir characterization
  - Analog data (existing EOR floods / source reservoirs)
- Manage volume of injected water
  - Timing of EOR initiation
  - GOR management strategy
- Learn as you go

Medium Term Technology Needs

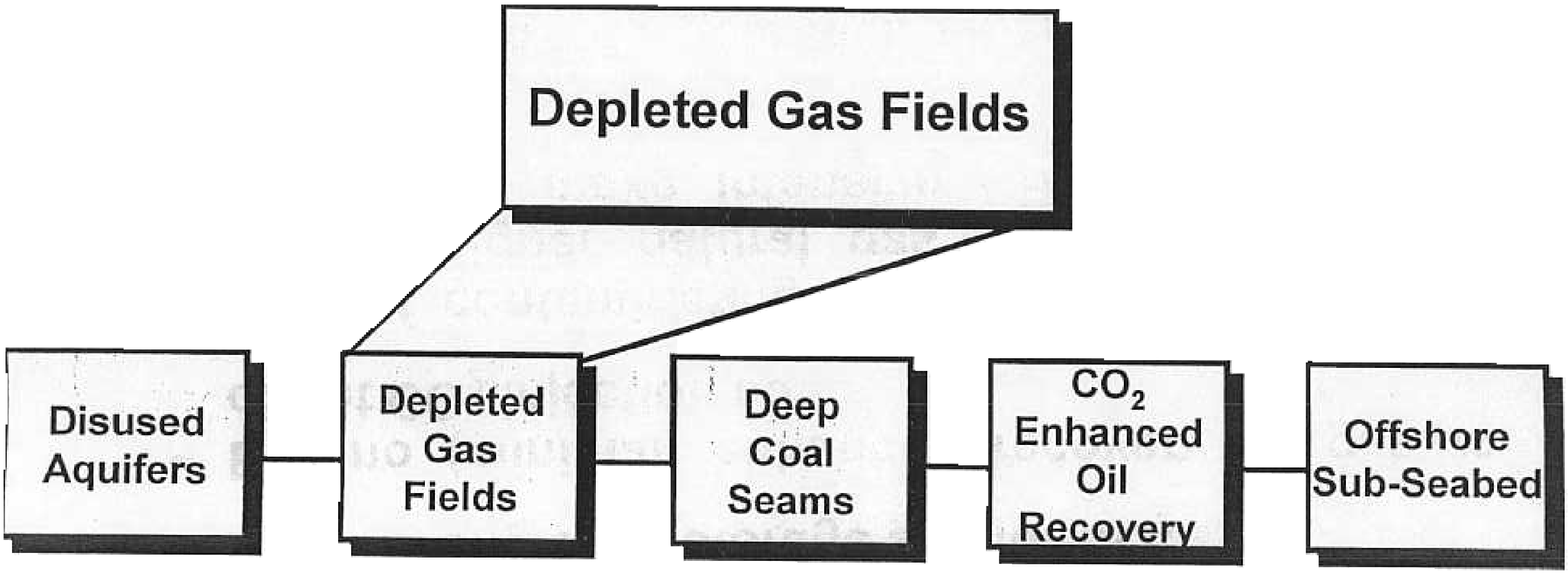
- Improve sweep to maximize both EOR recovery and storage volume available for sequestration
  - Viscosifiers
    Cheaper miscibility enhancers
    Enhanced CO_2 solubility
- Pilot test / phased development to maximize understanding of reservoir
- Access new technology through collaboration

Long Term Technology Needs

- **National and local policies to encourage sequestration**
  - **Public engagement**
  - **Long term R&D funding**
- **Advanced modeling tools**
- **Effective 4D fluid imaging**
- **Abandonment strategy**

5 Depleted Gas Fie ds

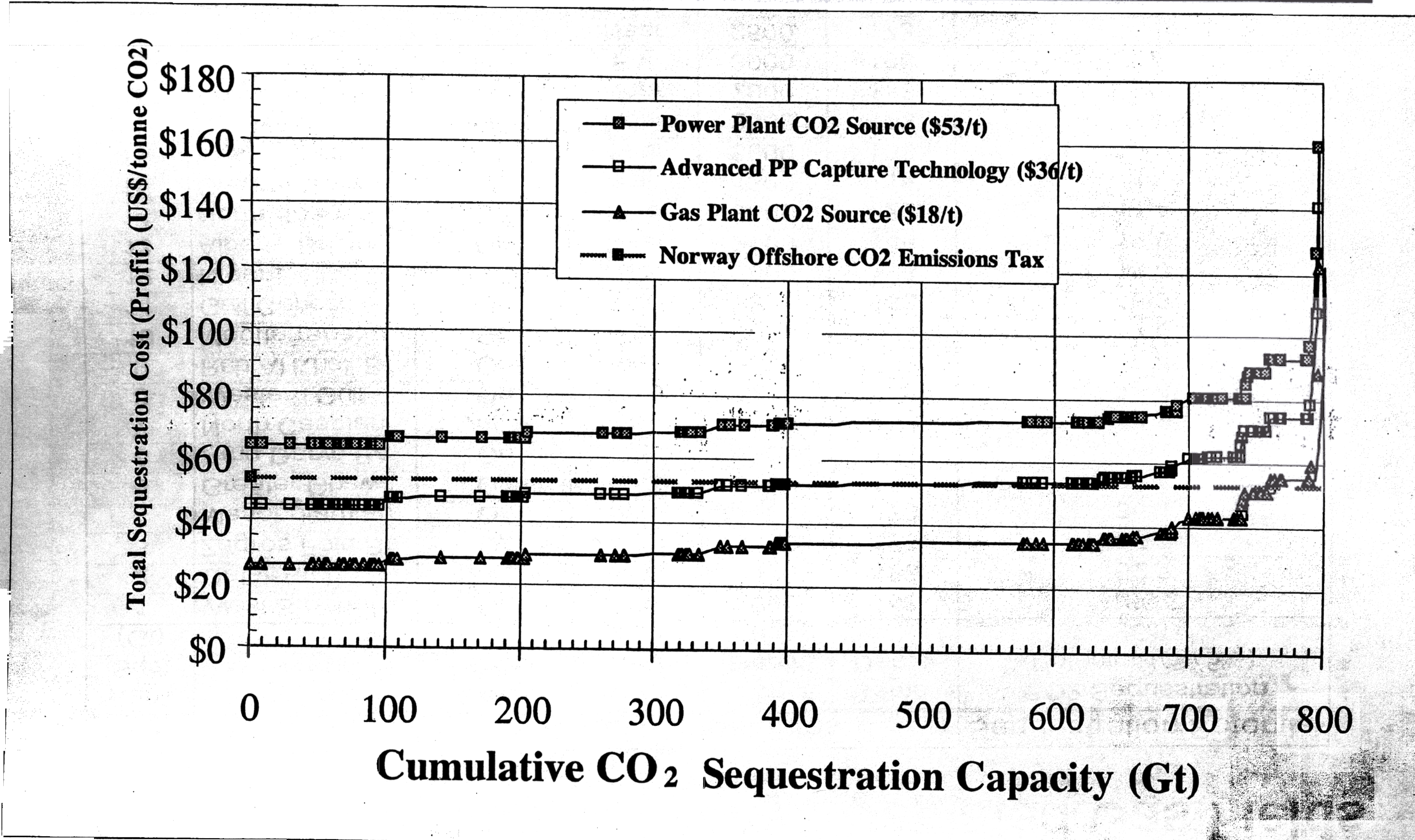
Geological Options for Sequestering CO_2



Depleted Natural Gas Fields

- Proven long-term storage site for CO_2.
- But no (minimal) enhanced recovery of gas to offset CO_2 injection costs.
- Risk of contaminating remaining CH_4 resources, should higher natural gas prices or improved technology make intensive CH_4 recovery more attractive.
- Large worldwide potential, albeit at higher costs (>$50/t CO_2).

Depleted Natural Gas Fields: Global CO_2 Sequestration Capacity and Costs

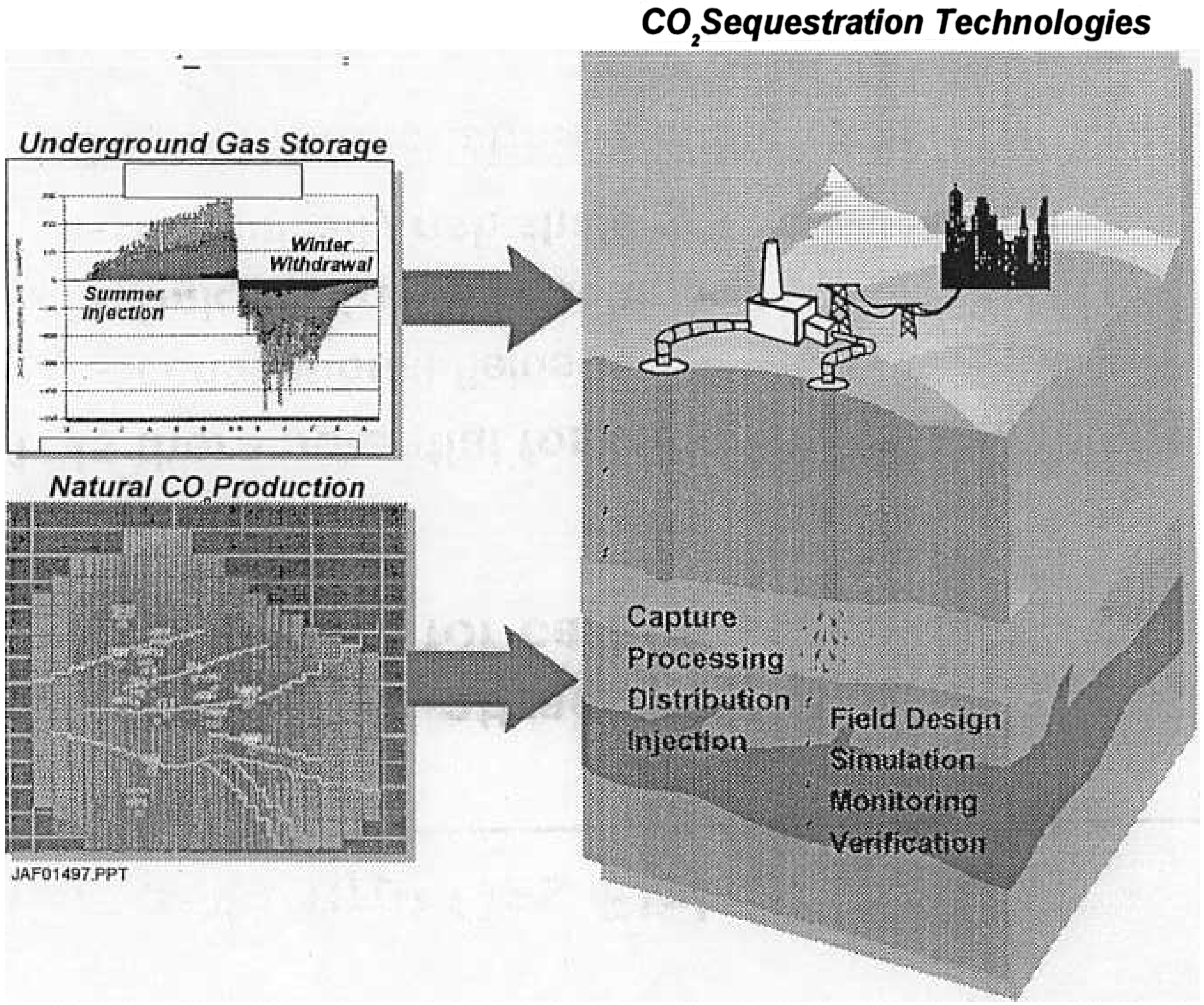


CO_2 Sequestration Capacity: Depleted Gas Fields

Reservoir Province		Reservoir Attributes				Sequestration Potential
Rank Sqst (Gt)	Province Name	On/Off Shore	Anthro CO2 Suppy	Avg. Depth (m)	Temp. Deg. F	CO2 Sequestration Potential (@75%) (Gt)
1	West Siberian	On	Far	2000	148	166.2
	[redacted]	On/Off	Near	2100	153	52.2
	[redacted]	On	Med	3000	198	37.2
	[redacted]	On	Med	2500	173	30.1
	[redacted]	On	Med	2100	153	27.8
	[redacted]	On	Far	2500	173	20.3
	[redacted]	On/Off	Near	3000	198	18.9
	[redacted]	On	Near	2200	158	18.4
	[redacted]	On	Med	2500	173	18.4
	[redacted]	Off	Far	3000	198	17.0
	[redacted]	Off	Med	2300	163	16.3
	[redacted]	On/Off	Near	3000	198	15.0
	[redacted]	On	Near	2000	148	14.8
	[redacted]	Off	Med	3500	222	11.4
	[redacted]	On/Off	Far	1300	114	11.1
	[redacted]	On/Off	Near	3000	198	10.2
	[redacted]	On/Off	Near	2500	173	9.4
	[redacted]	On	Near	2000	148	7.9
	[redacted]	On	Far	3000	198	7.7
	[redacted]	On	Near	2500	173	7.1
	[redacted]					510
	[redacted]					230
	[redacted]					[redacted]

[redacted]

POTENTIAL "OFF-THE-SHELF" TECHNOLOGIES FOR SEQUESTRATION



Advanced Resources International

Depleted Natural Gas Fields

The economic attractiveness of using depleted natural gas fields for carbon sequestration depends on the following:

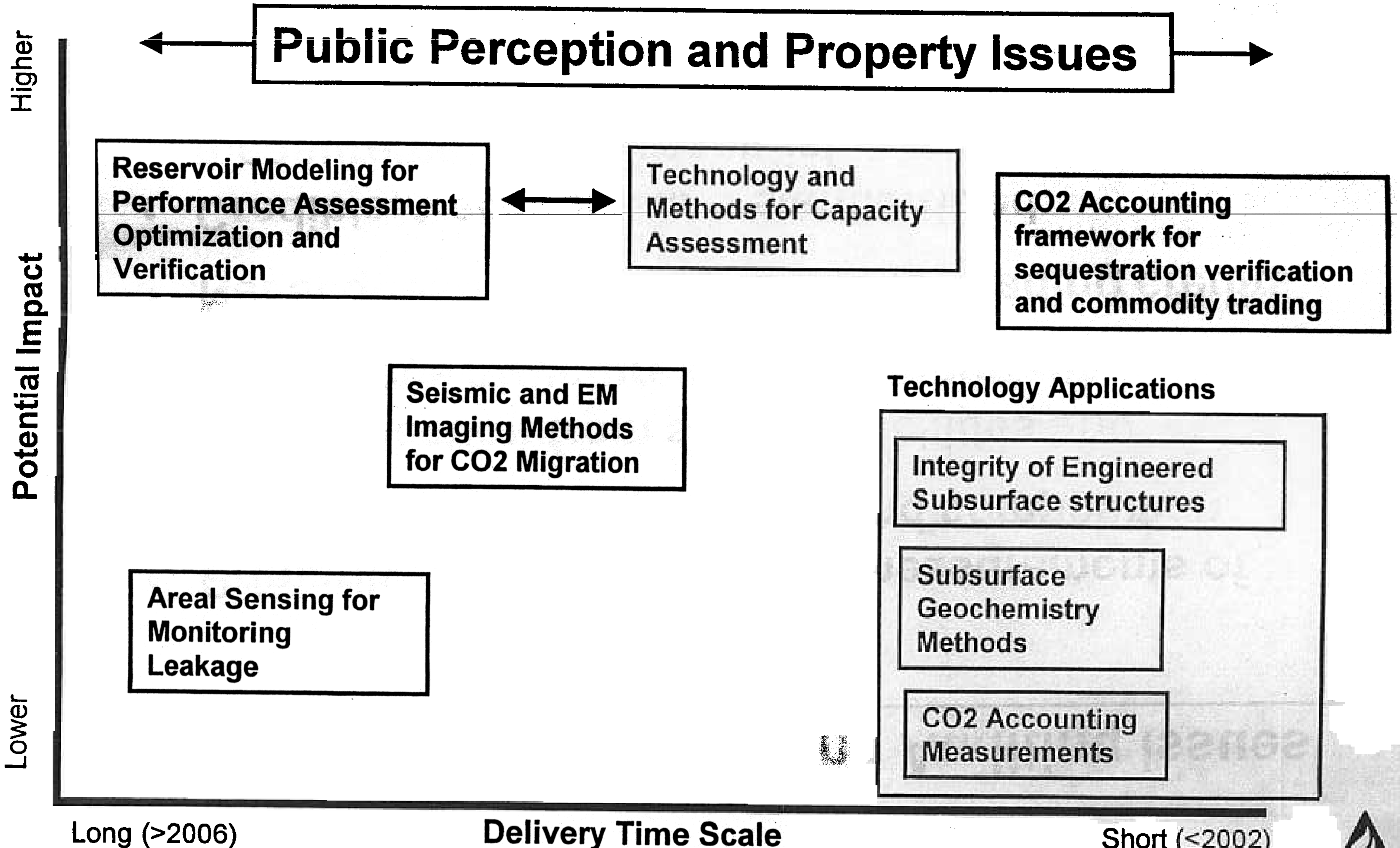
1. Is there potential for enhanced gas recovery:
   - conventional fields
   - Unique structural settings
   - Organically rich shale gas reservoirs
2. Geographic location relative to carbon emission sources
3. Low cost adaptation of existing infrastructure

6 Measurement and Verification

Objective and Context

- Develop a cost-effective measurement and verification program that is acceptable to all stakeholders.
- Measurement of sequestered volumes will be necessary for receiving credits, tax incentives, or participation in trading programs.
- Stakeholders:
  - Sequestration Provider (repository operator)
  - CO_2 Generators
  - Government including regulators
  - Scientific community
  - Public / community
  - NGO's
  - Auditors
  - CO_2 Traders
  - Standard Providers

Measurement & Verification



Monitoring for Verification and Auditing Issues

- Primarily depend on surface measurements of rate, pressure, temperature, and composition.
- Leak detection from surface facilities and subsurface structures is also important.
- Net sequestration is the basis for trading credits.
- Credible, traceable, and standardized measurements are essential.
- Measurement programs should build on established gas transfer practices.

Monitoring Subsurface Migration of CO_2

- Monitoring for sequestration, verification, and auditing may not be sufficient.
  - EOR & ECBM Optimization
  - Migration across property lines or out of structure
  - Brine Formations
  - Validating model predictions

- Multiple subsurface techniques are needed
  - Seismic and electrical geophysics
  - Geochemical methods
  - Logging
  - Pressure testing

Improvements in Subsurface Monitoring

- All monitoring techniques need improvement
  - Higher spatial resolution
  - Lower cost
  - Improved quantification
- Reservoir models need improvement for CO_2 interactions with coal, brine, and minerals
- Improved subsurface property measurements are needed

Technology Advancement and Sharing

- Field Pilots are needed now!
  - Different scales
  - Different formations

- Cost savings can be achieved through
  - Aggressive pilot testing
  - Avoiding costly mistakes on full projects

Public Perception

- Monitoring and verification are a critical part of gaining public acceptance.
- Sequestration technology must be understood by the public
- Risk analysis is needed
- Regulators, public, and NGO's must be engaged

7 Future R&D Challenges/Strateg es

CO_2 Sequestration Unknowns and Barriers

1. How much CO_2 is actually being sequestered?
2. What is the long-term security/safety of sequestered CO_2?
3. What is the long-term effect on the reservoir of CO_2?
4. What is the added cost of sequestration in ongoing EOR projects?
5. How do EOR and sequestration operations complement/compete?

STUDY ISSUES

1. Geology

- How long can CO_2 be safely stored?
- Long-term chemical and physical effects of CO_2 on reservoir rock, matrix, fluids and cap rock?
- Do different reservoir lithologies react differently? (sandstone vs. carbonate)
- Are fault seals or conduits for CO_2?
- Interactions between aquifers and CO_2?

2. Candidate Screening

- Most effective petrologic, geochemical, seismic, remote sensing, and other analytical techniques?
- Key screening criteria for aquifers, depleted oil and gas fields, and other geological settings?

Study Issues (cont.)

3. Field Operations

- Are operations at natural CO_2 fields safe?
- Risks (blow out, non-conformance), can they be minimized?
- Effect of CO_2 on wells, cement, surface facilities?
- Capital and operating costs.
- "Best practices" for drilling, completing, stimulating and operating CO_2 sequestration wells and projects?
- Monitoring – What can be learned?

4. Costs/ Economics

- How much will well and facility investment costs increase due for sequestration?
- What will be additional costs of monitoring and verification?
- How will environmental compliance and adaptation of field operations for sequestration influence economies?

Future R&D Needs for Geologic CO_2 Sequestration

- Build scientific foundation and models
- Select "representative" pilot location(s)
- Involve industry/operators
- Invest in technology development and optimization
- Build monitoring and forecasting systems