CO_2 SEQUESTRATION IN UNCONVENTIONAL RESERVOIRS: Challenges and Opportunities

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CO_2 CAPTURE AND STORAGE
REGIONAL AWARENESS-RAISING WORKSHOP

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Carbon Dioxide Sequestration:

Geologic

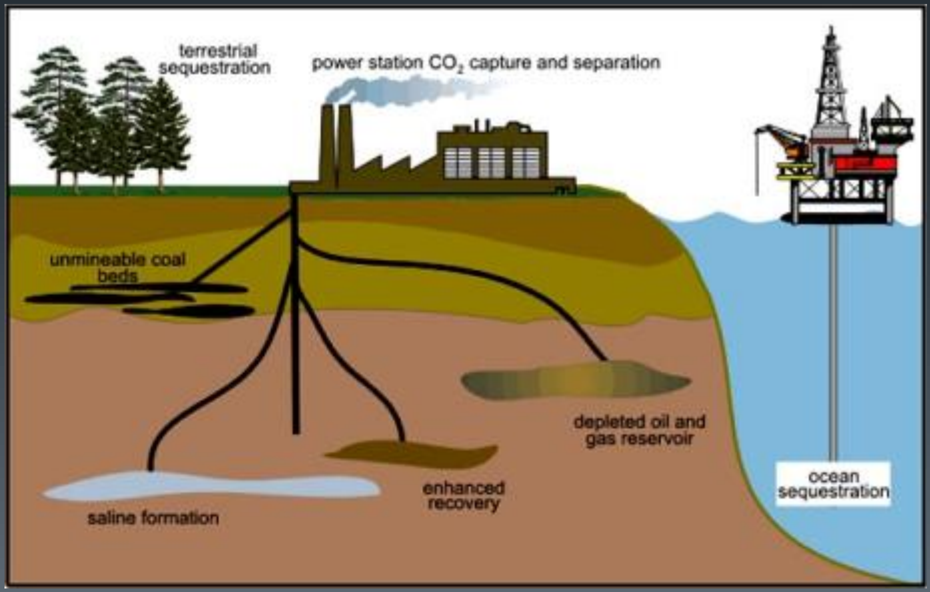
Terrestrial

Ocean

Chemical

Definition:

Capture, Separation and Secure Storage of carbon dioxide that would otherwise be emitted to or remain in the atmosphere.



Natural CO_2 sink—primary types of geologic reservoirs for storing anthropogenic CO_2

- Terrestrial ecosystems
  plants and soils with retention of days to decades
- Oceans
  slow process
- Geological horizons
  retention on a geological time scale
- Chemical processes
  storage in stable carbonate mineral forms

<u>Geological Horizons</u>

Coal Seams
Depleted Oil and Gas Reservoirs
Deep Saline Formations
Methane Hydrates

Terrestrial

Ocean

Chemical

Overview

- Technology advances in drilling and completion over the past several decades including directional/horizontal drilling and hydraulic fracturing have allowed economic development of resources from unconventional reservoirs

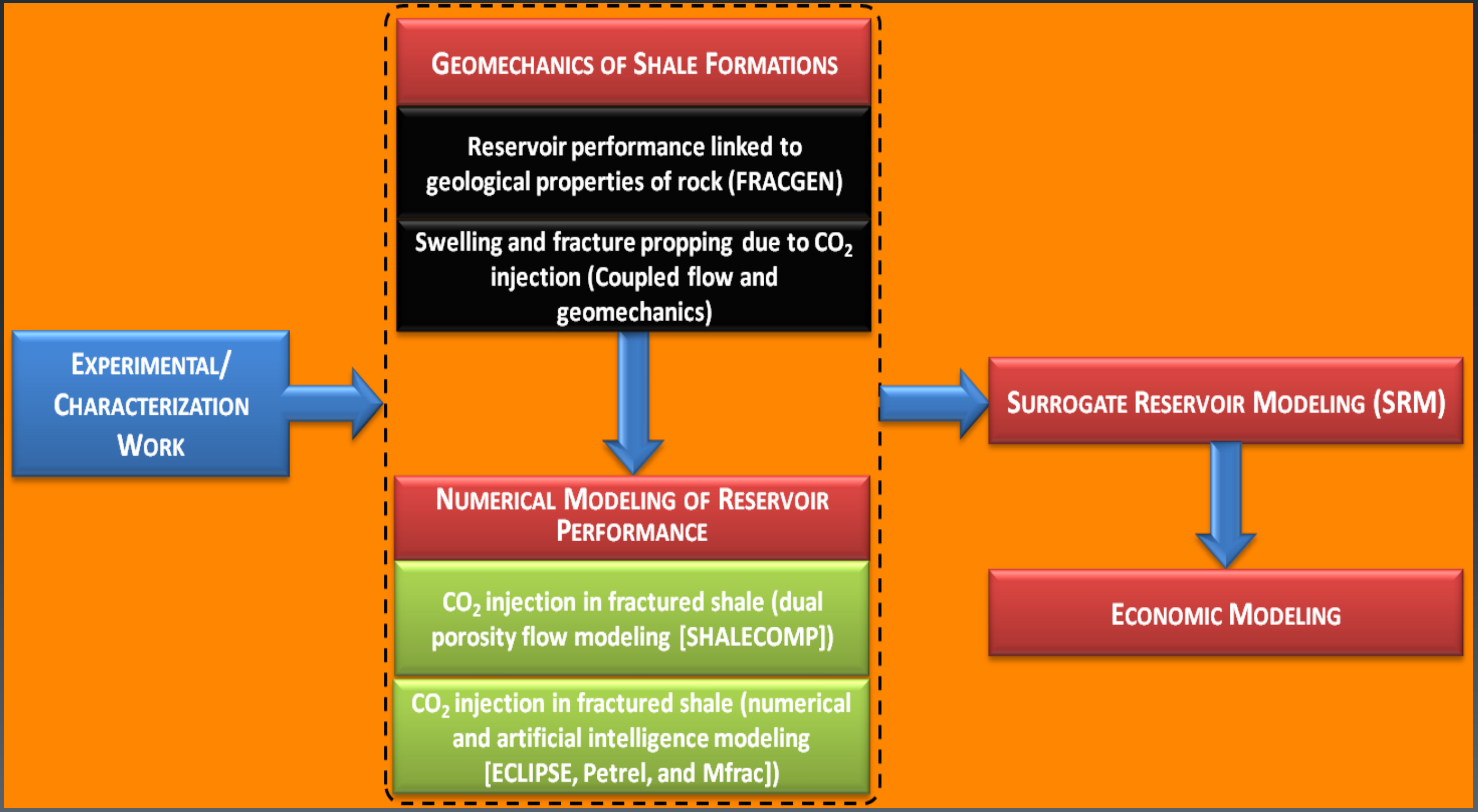
- Industrial carbon storage in unconventional reservoirs is considered to have two attractive features:
  - presence of an established network of fractures
  - potential to use injected CO_2 to enhance production of remaining hydrocarbons

Overview

- **The basic components of a CO_2 sequestration design project are:**
  - Laboratory experiments to determine CO_2 flow dynamics and its retention in cracks and pores by mechanisms of displacement (filling) and sorption
  - Laboratory experiments to understand the thermodynamics of CO_2 – brine and CO_2 – hydrocarbon systems
  - Numerical modeling studies to arrive at potential injection rates and final CO_2 sequestration capacity of the formation in the presence of advanced well structures
  - Economic assessment of the implementation of the project

Overview

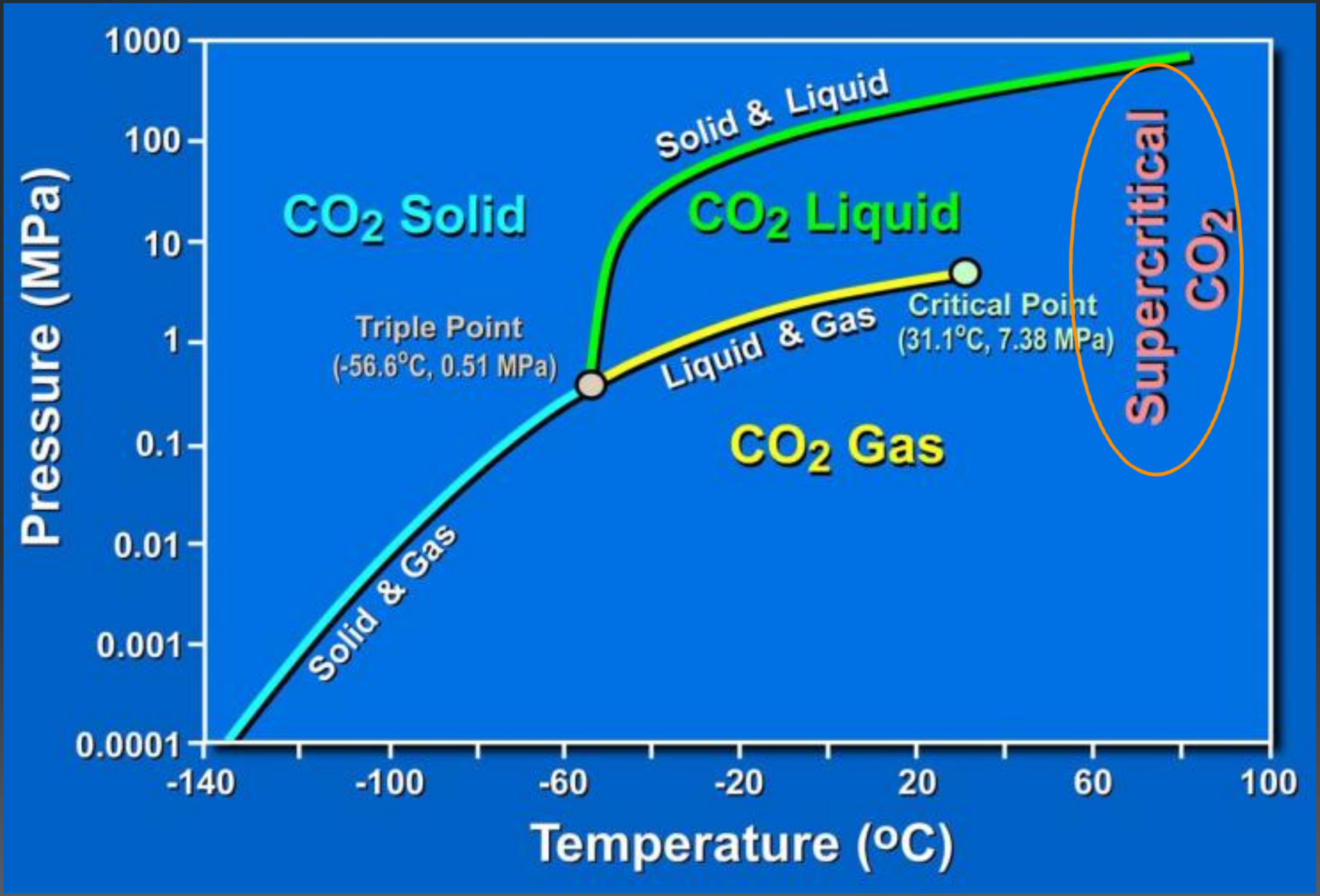
A typical workflow of modeling of CO_2 injection into depleted shale gas reservoirs.



Near-term focus on a variety of geologic storage options

- Safe and permanent containment of CO_2
- Low environmental impact
- Low cost
- Conformity with national and international laws and regulations
- Public acceptability

Phase diagram for CO_2



Factors to confirm the suitability of the geology

- The impermeability of the cap rock
- Storage capacity of the rock formation
- Chemical reactions that occur between CO_2 and reservoir rock and fluids
- If the geological unit can chemically react with CO_2, then, it is a plus
- A lack of faults in the area of injection operation that would avoid migration of fluids

Protocols needed

- **MEASURING:** measure the amount of CO_2 stored
- **MONITORING:** maintain the storage integrity over time
- **VERIFICATION:** ensure the stored CO_2 does not pose any threat to public health or environment

Models — the key to different disciplines

- **GEOLOGIC RISKS – IS THERE CO_2 (AND/OR HYDROCARBON) STORAGE RESERVOIR THERE?**
  - One needs to assign probabilities to each of the following parameters:

    Existence of trap
    Source rock
    Thermal maturation
    Migration and geologic age
    Reservoir (storage capacity)
    Seals
    Injectivity (Productivity)

UNMINEABLE COAL SEAMS

DEPLETED SHALE GAS RESERVOIRS

DEEP SALINE FORMATIONS

METHANE HYDRATE RESERVOIRS

  - The combined probability of finding a productive reservoir is the product of the several of these individual numbers.

Overview

Field development planning considers:

- the well numbers, locations, type, and drilling schedule
- a production/injection forecast must be included
- development philosophy/strategy details the part of the reservoir to develop first and how to attack it
- simulation is used to model the reservoir and the flow dynamics of the reservoir
- Management activity planning sets well design and production/injection methods to optimize the process

CO_2 injection into coal seams

CO_2 injection into unmineable coal seams

- Coal beds below economic mining depth could be used to store CO_2
- CO_2 storage in coal is limited to a relatively narrow depth range, between 600 m and 1000 m. Coal beds greater than 1000 m have decreased permeability for economically viable injection

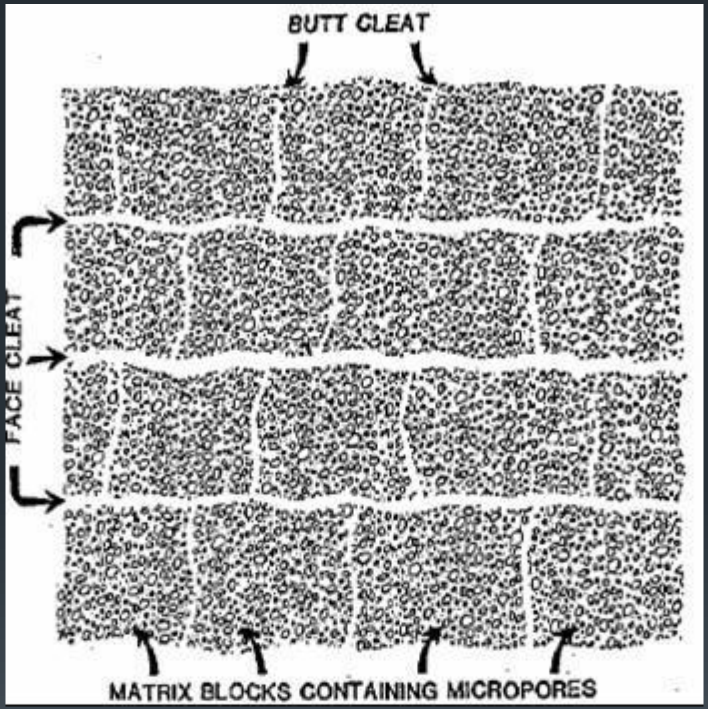
Introduction

Why Coal Seams???

- Coal-seams have large internal surface areas and typically contain large amounts of methane-rich gas that is adsorbed onto the surface of the coal.

- Enhanced recovery of the methane gas can be achieved by CO_2 injection and studies show that CO_2 is more adsorbing on coal than methane thereby giving it the potential to efficiently displace methane and remain adsorbed on the coal surface.

- Coal seams have the potential to play a dual role: a source of methane and a repository for the sequestration of CO_2.



[*Remner et al, 1984*]

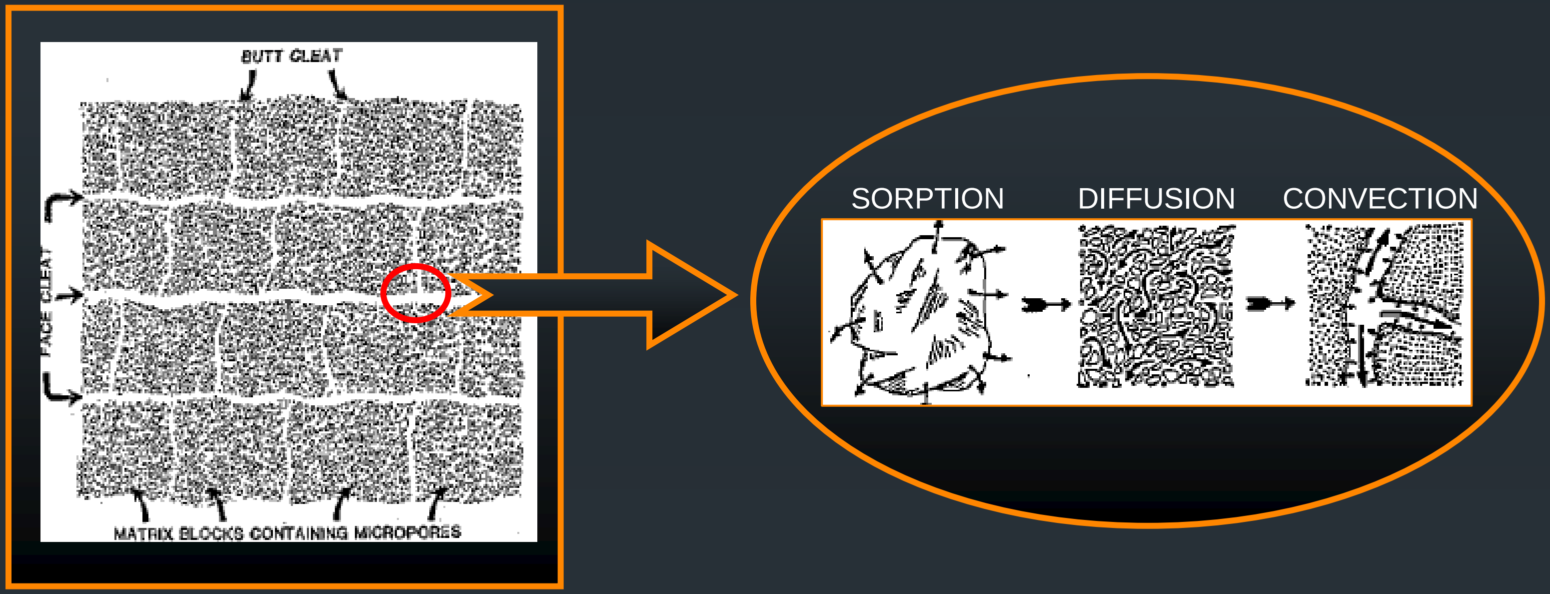
Introduction

- Coal seam properties to be considered :
  - Coal seam Porosity
  - Absolute Permeability
  - Cleat/Fracture Spacing
  - Sorption Parameters
  - Pressure & Saturation conditions

- Operational design parameters to be considered:
  - Type of Injectors/Producers
  - Lengths of Injectors/Producers
  - Orientation of Injectors/Producers
  - Injection/Producing Well Pressures

- In particular, it will be necessary to consider the effects of these properties on:
  - Amount of CO_2 injected into the coal-seam
  - CO_2 breakthrough time
  - Amount of CH_4 produced from the coal seam

Coal Seams – a multimechanistic* formulation

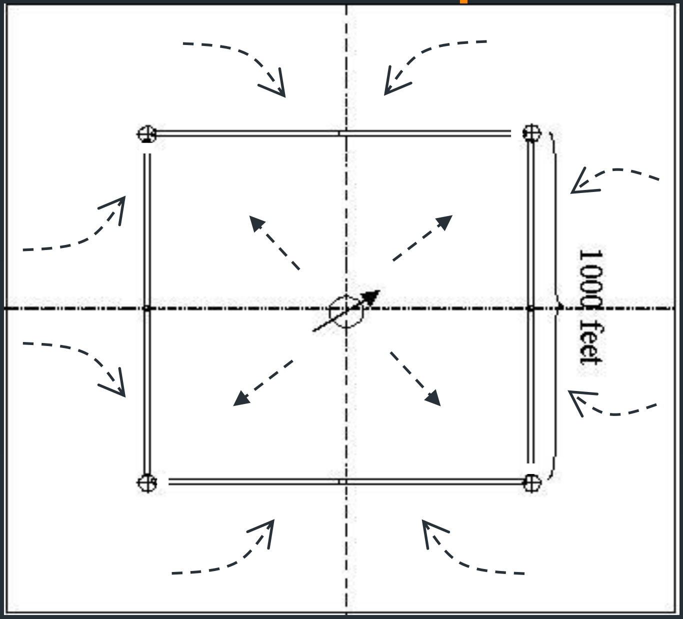


- Coal-seams have large internal surface areas and typically contain large amounts of methane-rich gas that is adsorbed onto the surface of the coal
- Coalbed methane (CBM) accounts for about 12% of total US natural gas production

* *Ertekin et al, 1984*

Objective:
To Study The Effects of Coal Seam Properties

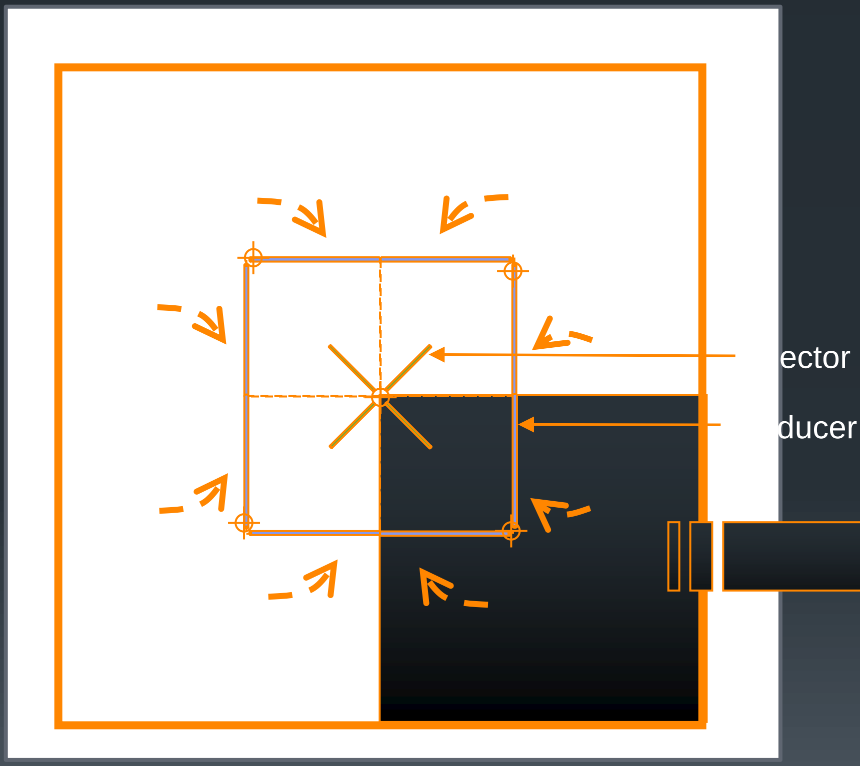
- Data representing a typical coal-seam was selected to define a hypothetical default system.
- A square development pattern with one vertical injector in the center of four horizontal producers was chosen.
- Primary production is to take place for 365 days and then enhanced recovery by continuous CO_2 injection (2MMSCF/D) will take place until breakthrough of CO_2.
- CO_2 breakthrough is defined as the time at which the mole fraction of CO_2 in the production stream is equal to 5%.



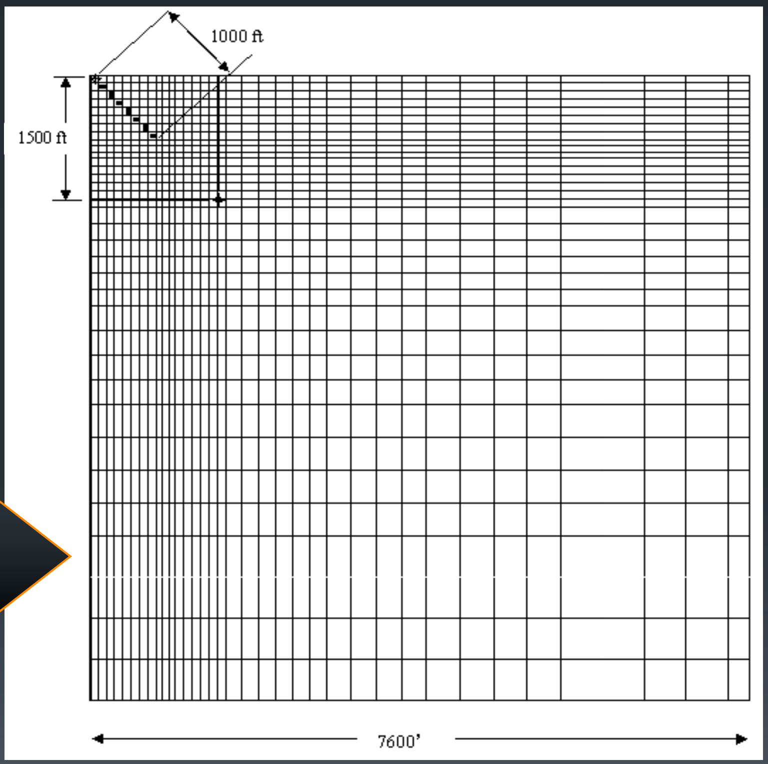
*not to scale

Reservoir Drainage Area	5000ft. x 5000ft. (574 acres)
Reservoir Thickness	10ft
Coal-seam Porosity	2%
Lateral Permeability (absolute)	10md
Initial Pressure	800 psia
Initial Water Saturation	45%

CO_2 Sequestration Pilot Project

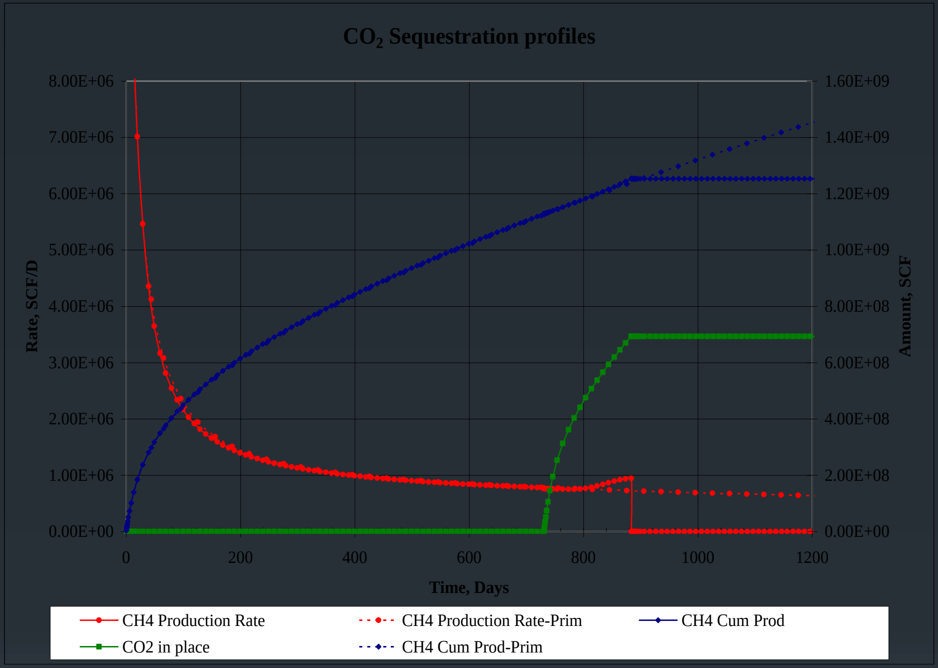


Schematic of pilot project



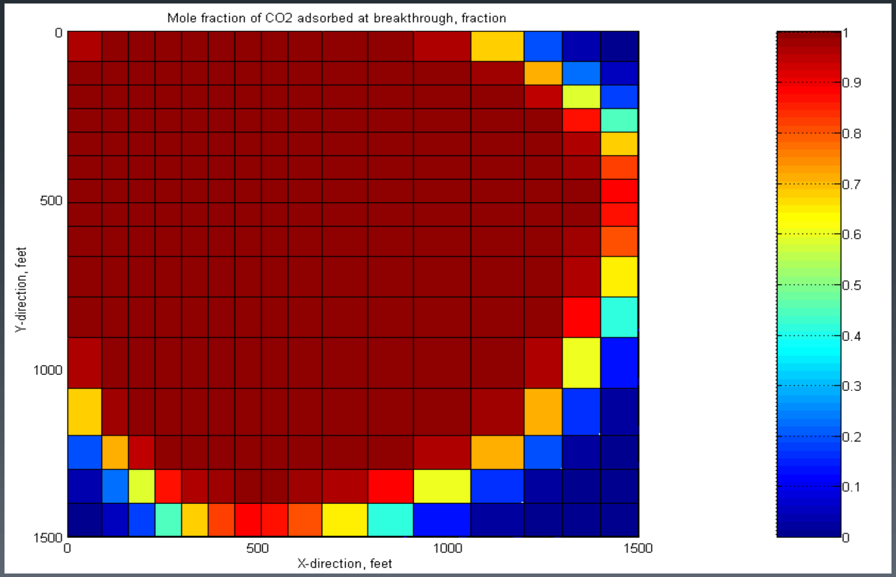
Grid system used in simulations
(1/4 of system)

CO_2 Sequestration Pilot Project: Results – Base Case

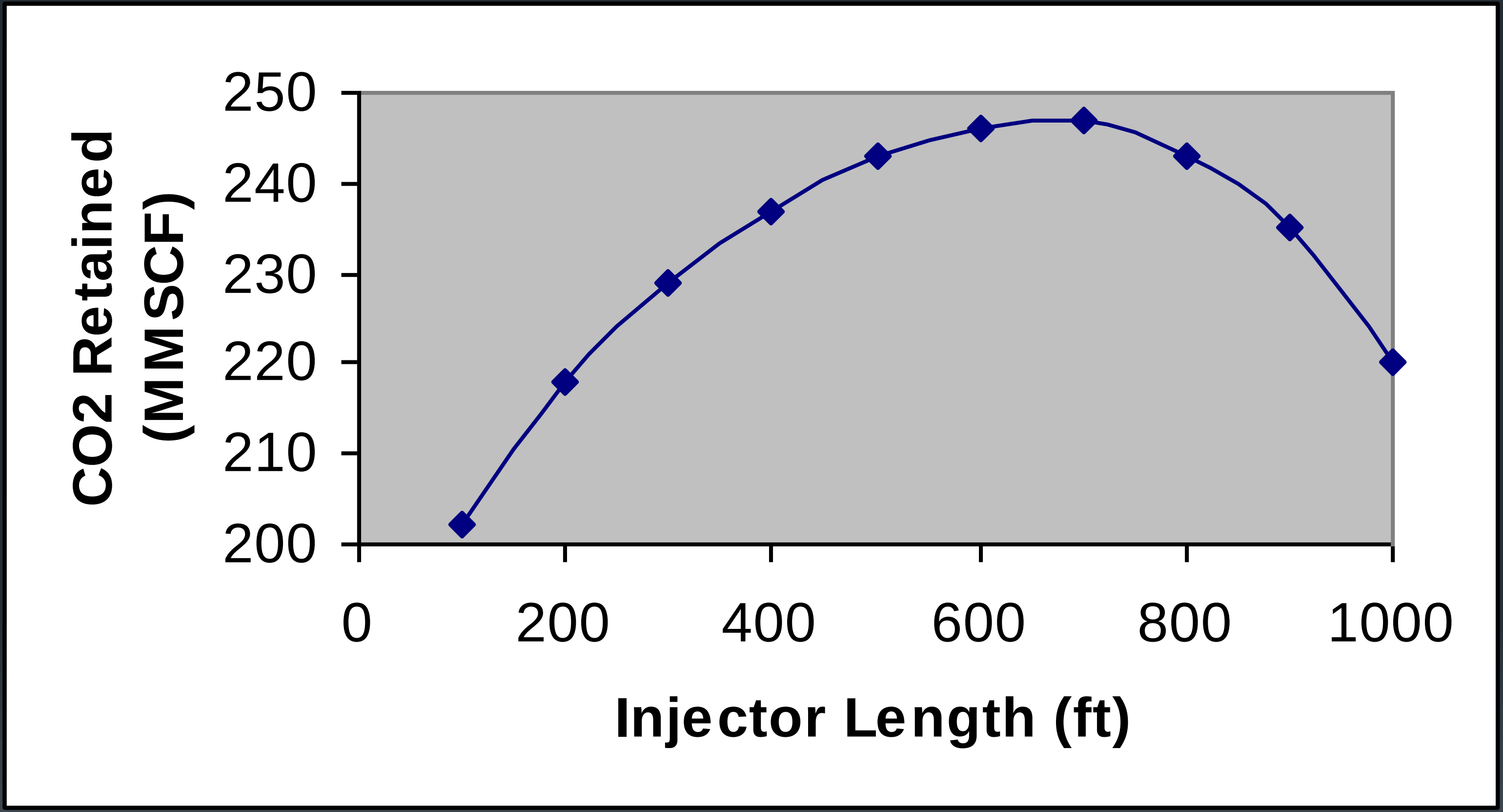


Focus on three CO_2 Sequestration performance indicators:

- CO_2 In Place at breakthrough
- Breakthrough time
- Cumulative CH_4 produced at breakthrough



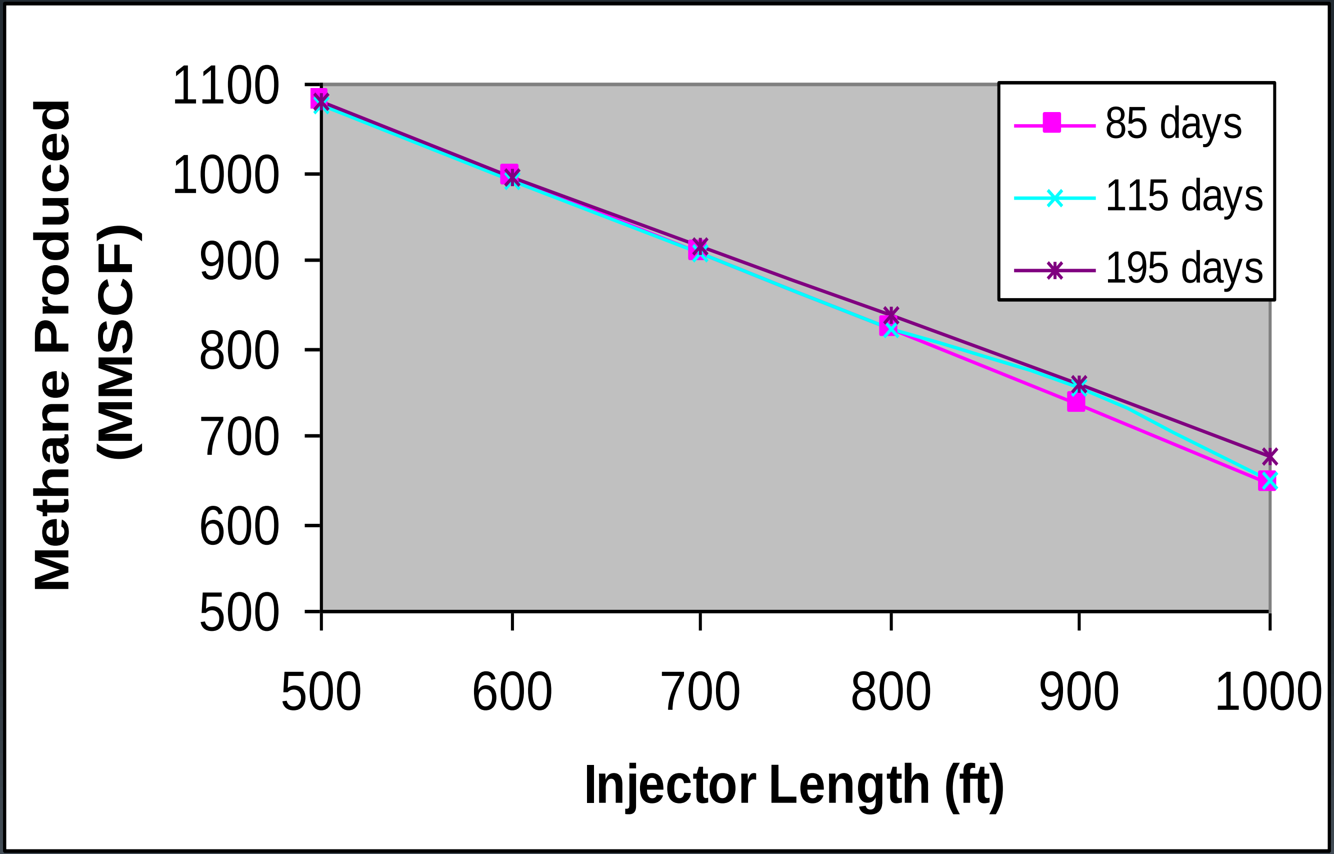
Carbon Dioxide Retained



Production pressure = 14.7psi Injection Pressure = 300psi

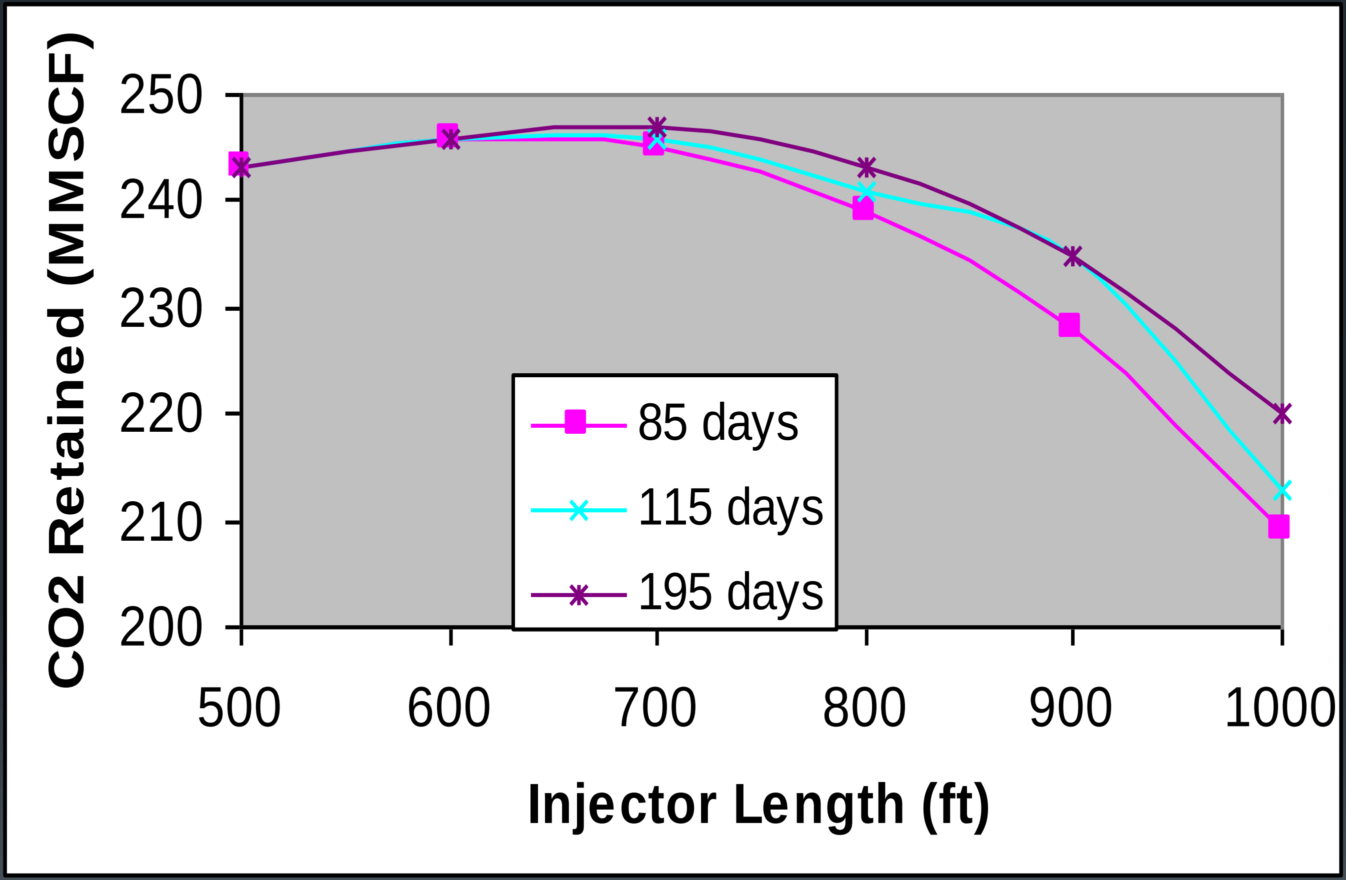
Primary Production = 195 days

Injection start time makes little difference in methane production



Production pressure = 14.7psi Injection Pressure = 300psi

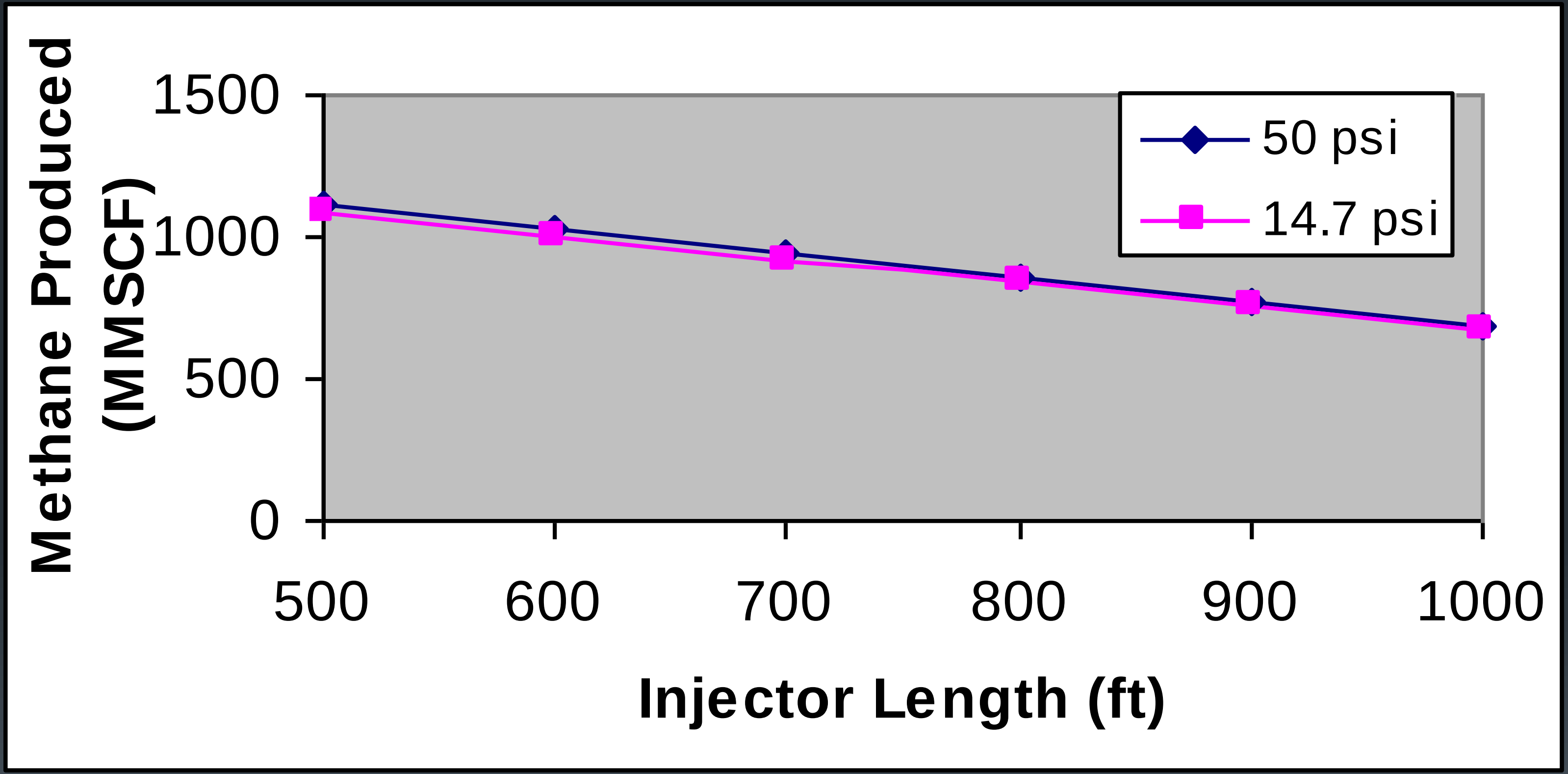
Primary production time has a slightly larger effect on CO_2 retention



Production pressure = 14.7psi

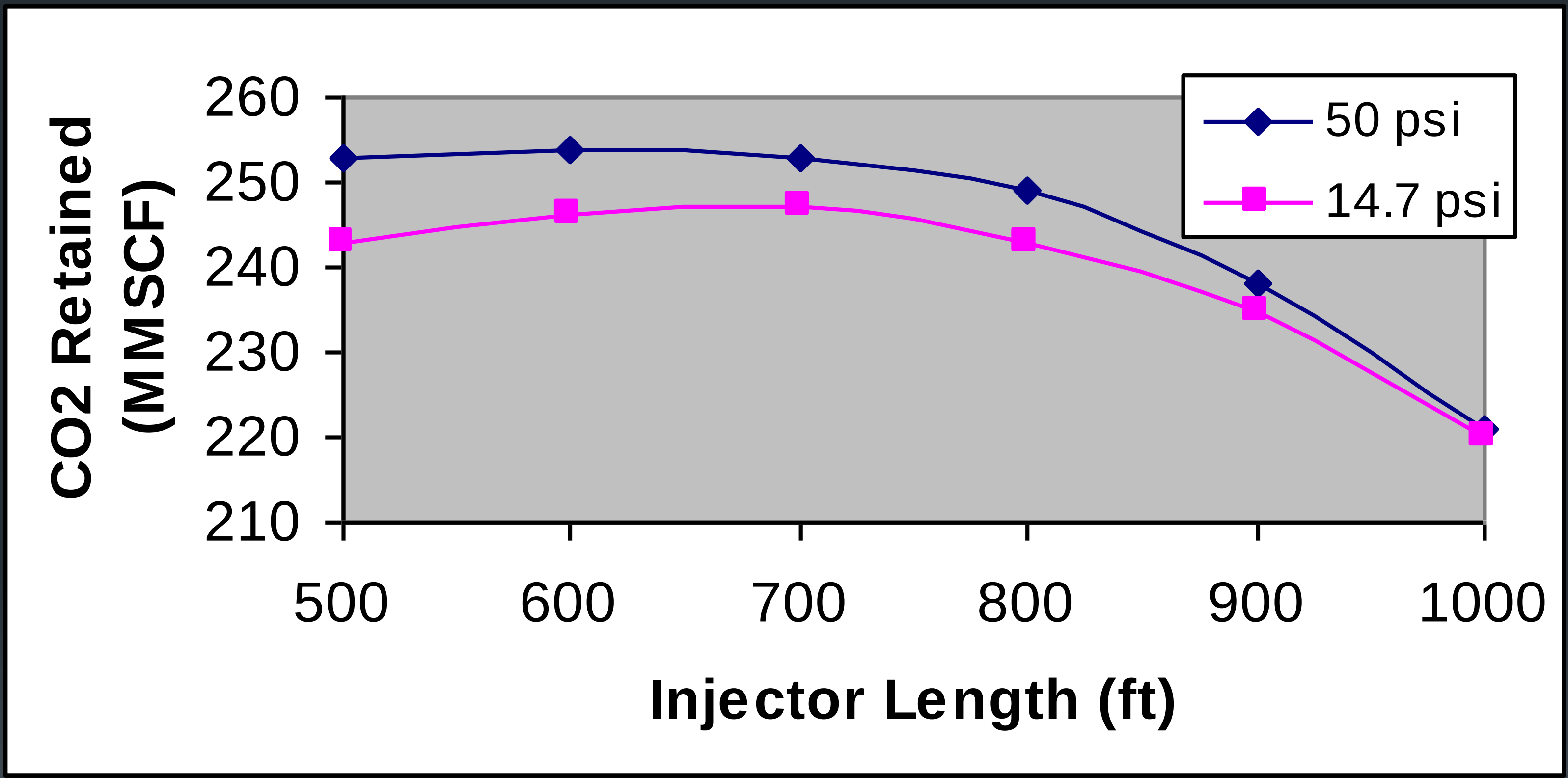
Injection Pressure = 300psi

Increasing production-well pressure does not influence methane production



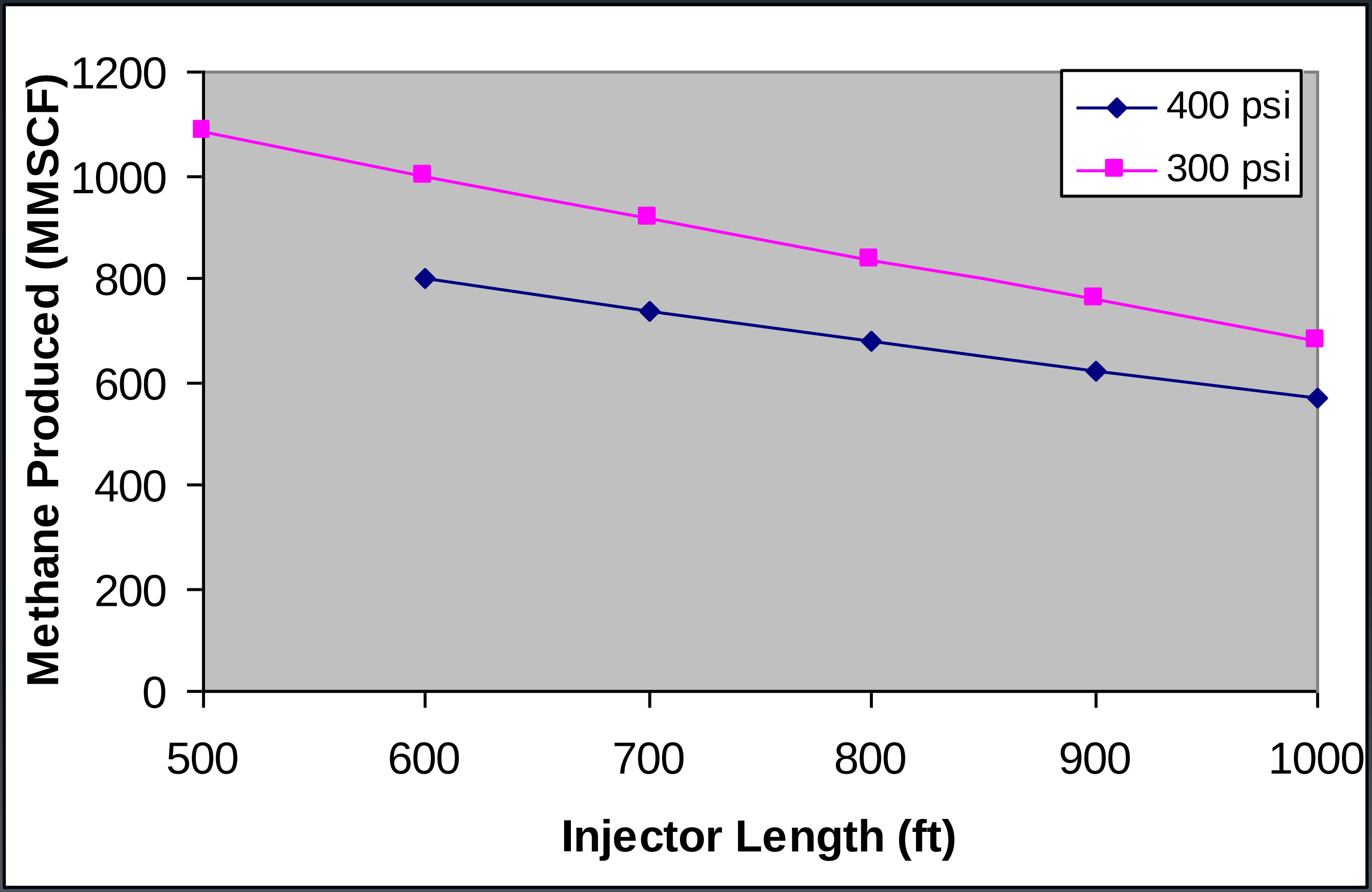
Injection Pressure = 300psi Primary Production = 195 days

Increasing production-well pressure slightly increases CO_2 retained



Injection Pressure = 300psi   Primary Production = 195 days

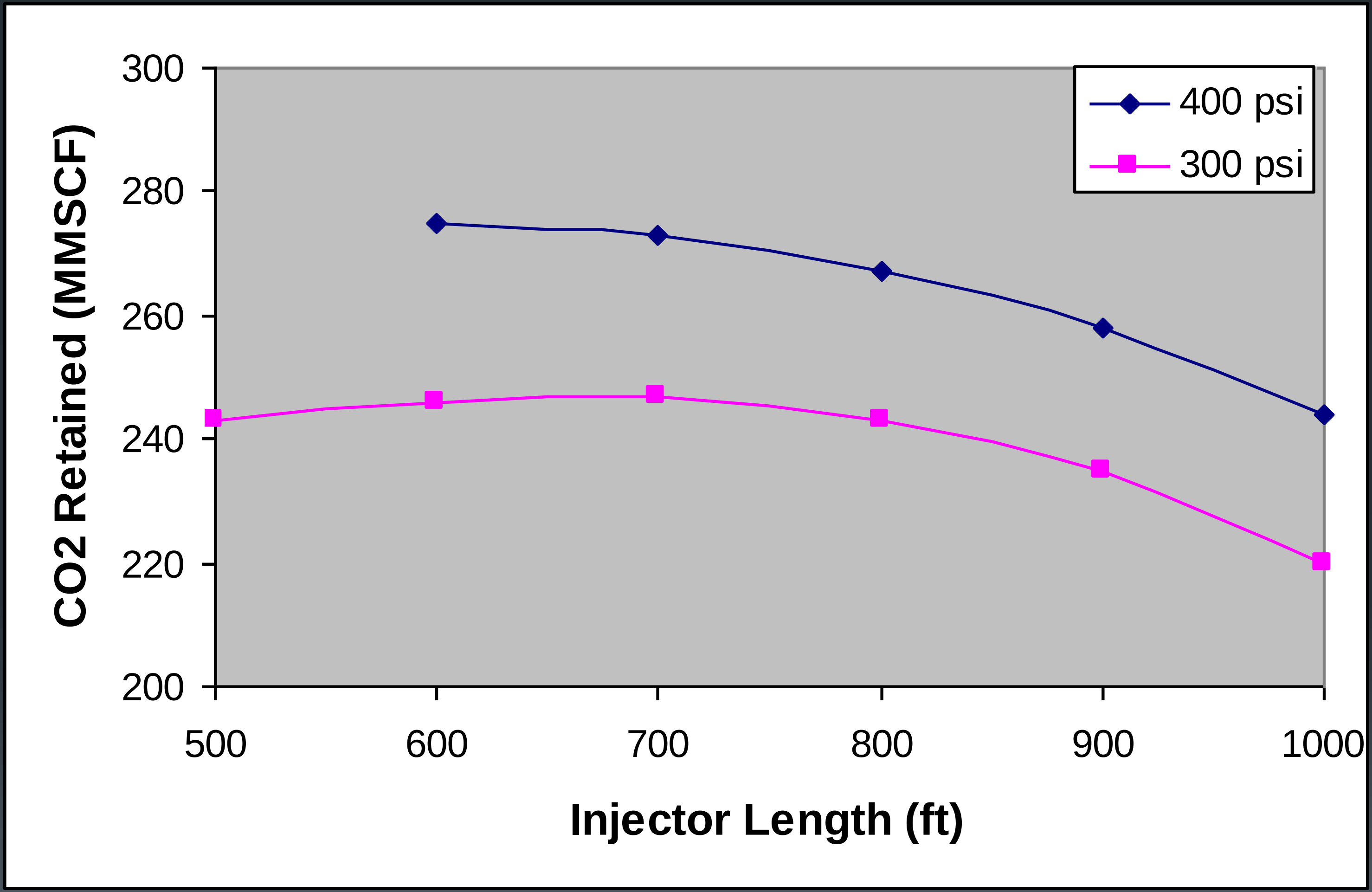
Increasing injection-well pressure noticeably decreases methane production



Production pressure = 14.7psi

Primary Production = 195 days

Increasing injection-well pressure increases CO_2 retention



Production pressure = 14.7psi

Primary Production = 195 days

For reservoir parameters assumed, 600-700ft injector length may be best

- Increases methane production by ~50%
- Maximizes CO_2 sequestered
- Has little effect on time to start of sequestration
- However, increases project time from 750 to 1500 days

Injection well pressure is more important than production well pressure

- Increasing production well pressure (15 to 50 psi) increases methane production and CO_2 sequestration by about 3% each.

- Increasing injection well pressure (300 to 400 psi) decreases methane production by 17%, increases CO_2 sequestration by 10%.

Better data will improve the accuracy and reliability of our simulations

- Seam thickness
- Porosity
- Cleat permeabilities (face and butt)
- Cleat orientation
- Gas in place composition
- Sorption isotherms
- Sorption kinetics
- Spatial dependence of the above for each coal seam

CO_2 injection into depleted shale gas reservoirs

Depleted shale gas reservoirs

- There is high certainty in the integrity of this class of reservoirs with respect to CO_2 storage, as they have held gas for millions of years.
- A major drawback of depleted gas reservoirs is that they are penetrated by many wells of variable quality and integrity, which themselves may constitute leakage paths for the stored CO_2 .

Horizontal Wellbore *vs.* Vertical Wellbore

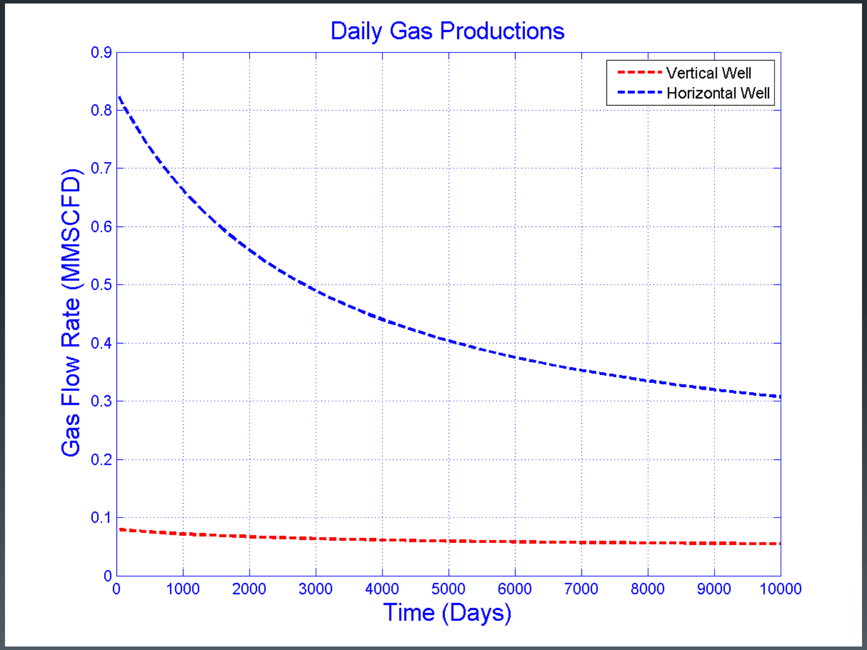
- Performance of horizontal wellbore technology in shale gas is studied
- Reservoir, rock and well parameters are kept the same
- Reservoirs are <u>not</u> stimulated

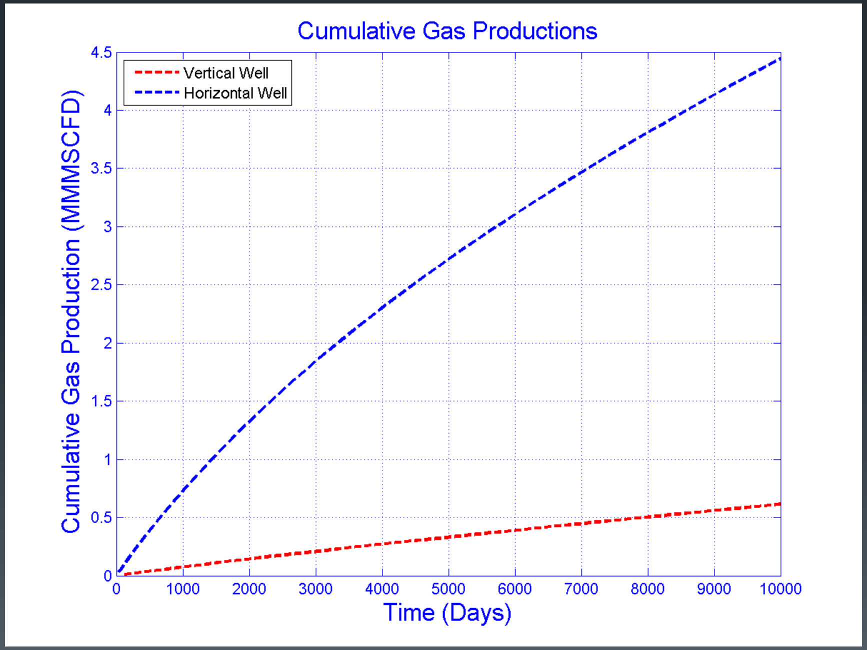
11x11 Simulation Input for Shale Gas Reservoir with a Vertical Well	
Depth	6000 ft
Thickness	200 ft
Area	445 acres
Fracture Porosity	1%
Matrix Porosity	10%
Fracture Permeability	0.001 md
Matrix Permeability	0.0001 md
Res. Temperature	200°F
Average Pressure	5000 psia
S_w in Fracture	0%
S_w in Matrix	0%
Langmuir Volume (CH4)	150 scf/ton
Langmuir Pressure (CH4)	1281 psia
Fracture Spacing	1 ft
P_{sf}	14.9 psia
Wellbore Radius	0.25 ft
Vertical Well Completion Interval	200 ft

11x11 Simulation Input for Shale Gas Reservoir with a Horizontal Well	
Depth	6000 ft
Thickness	200 ft
Area	445 acres
Fracture Porosity	1%
Matrix Porosity	10%
Fracture Permeability	0.001 md
Matrix Permeability	0.0001 md
Res. Temperature	200°F
Initial Pressure	5000 psia
S_w in Fracture	0%
S_w in Matrix	0%
Langmuir Volume (CH4)	150 scf/ton
Langmuir Pressure (CH4)	1281 psia
Fracture Spacing	1 ft
P_{sf}	14.9 psia
Wellbore Radius	0.25 ft
Horizontal Well Length	2000 ft

Horizontal Wellbore *vs.* Vertical Wellbore

- Daily Gas Productions and Cumulative Gas Productions are compared
- The total production from horizontal well at the end of 20th year is 7 times larger than the total production from vertical well

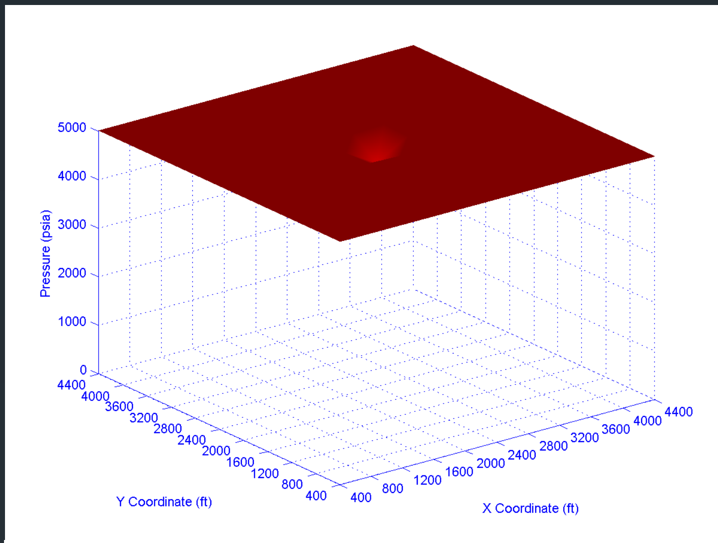




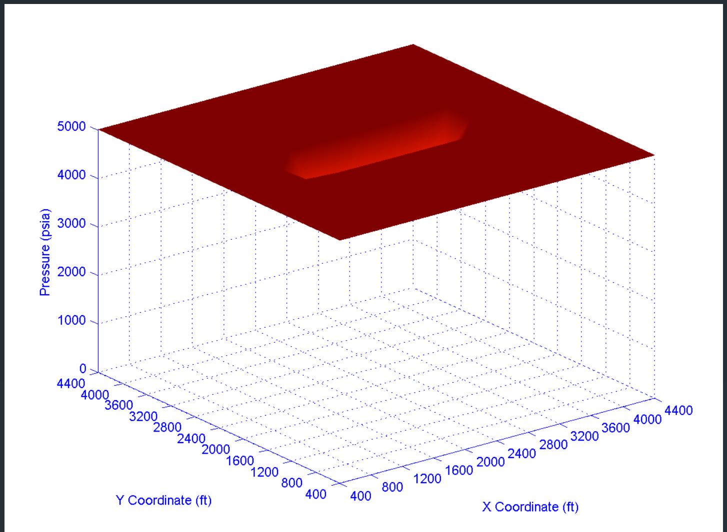
Horizontal Wellbore *vs.* Vertical Wellbore

3D Pressure Distributions

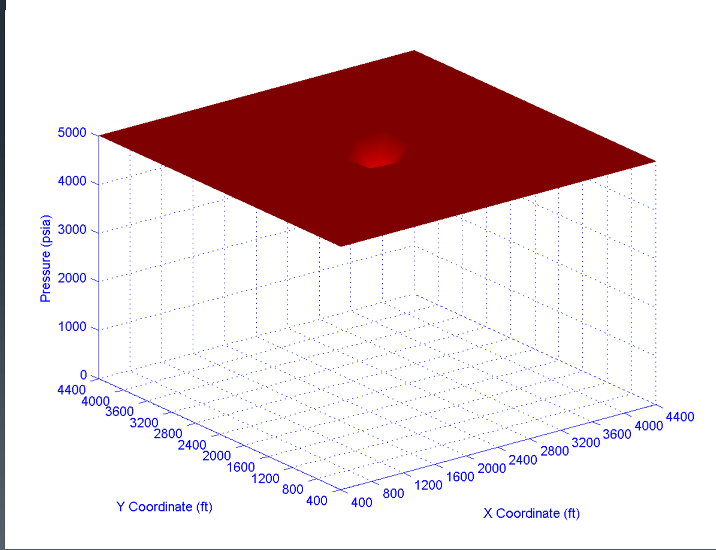
3rd Year



3rd Year



5th Year



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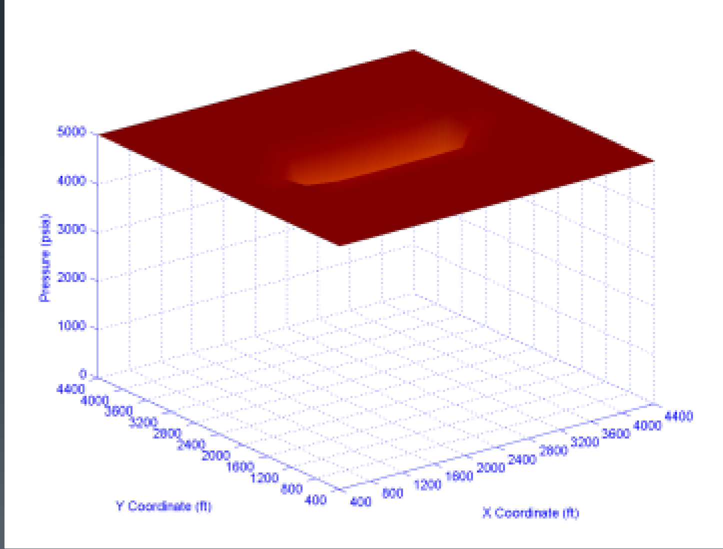


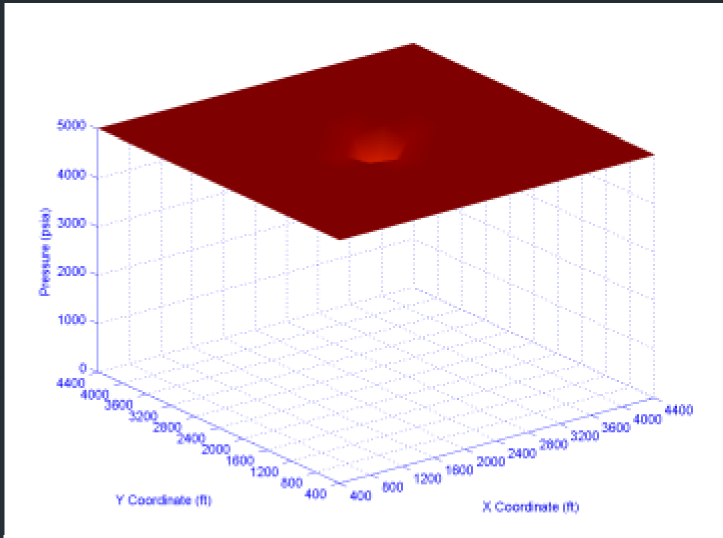
Vertical Well

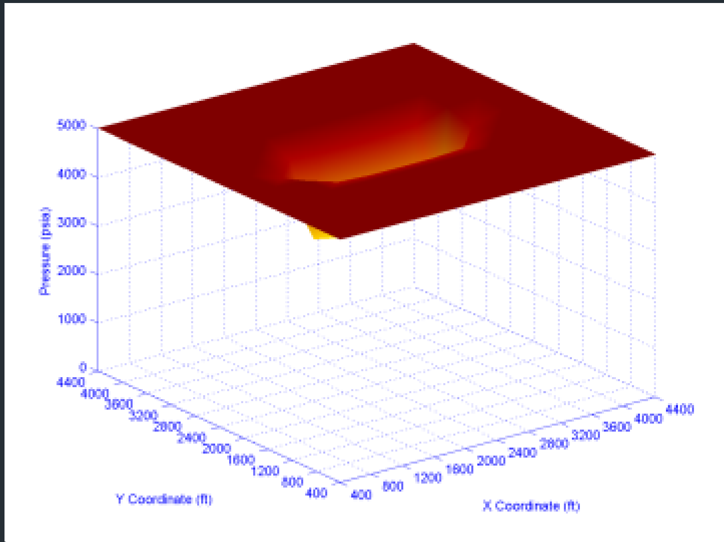
Horizontal Well (Unstimulated)

Horizontal Wellbore *vs.* Vertical Wellbore

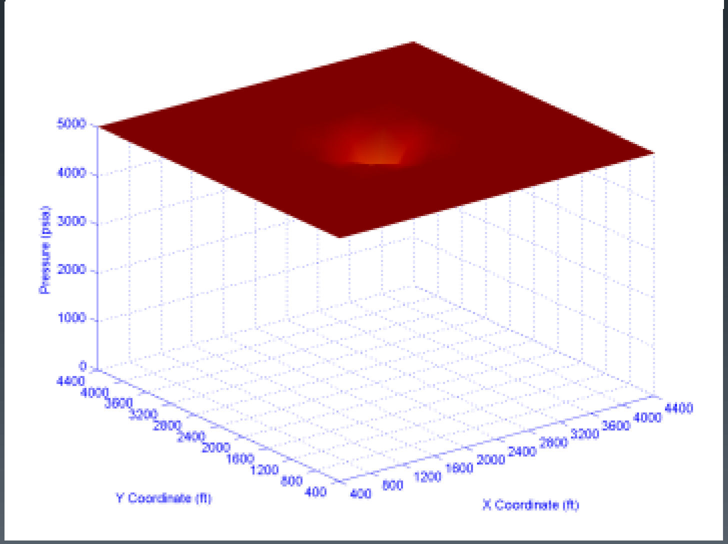
3D Pressure Distributions

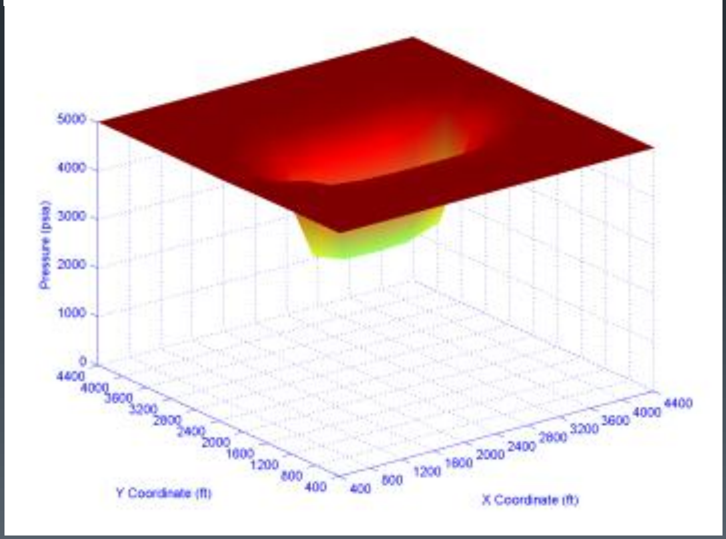
10th Year





20th Year



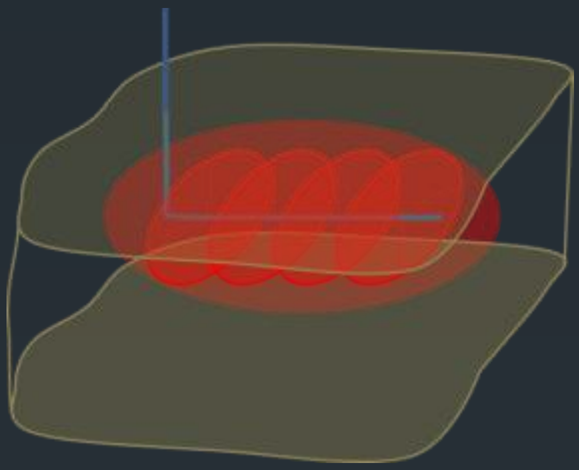


Vertical Well

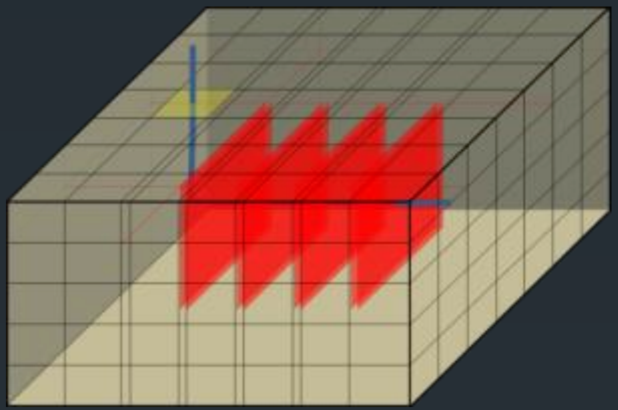
Horizontal Well (Unstimulated)

Stimulated Reservoir Volume Representations

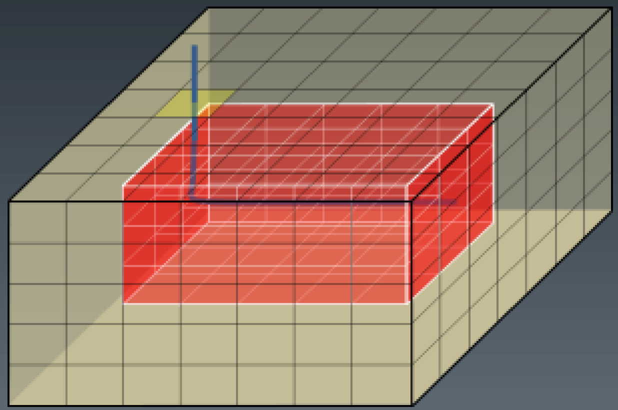
Stimulated Reservoir Volume in Ellipsoidal Shape



Hydraulic Fractures Designed Using Discrete Representation



Hydraulic Fractures Designed as Stimulated Reservoir Volume (SRV) around the HW by changing the properties of the blocks that are considered as SRV.



Hydraulically Fractured Horizontal Well Performance

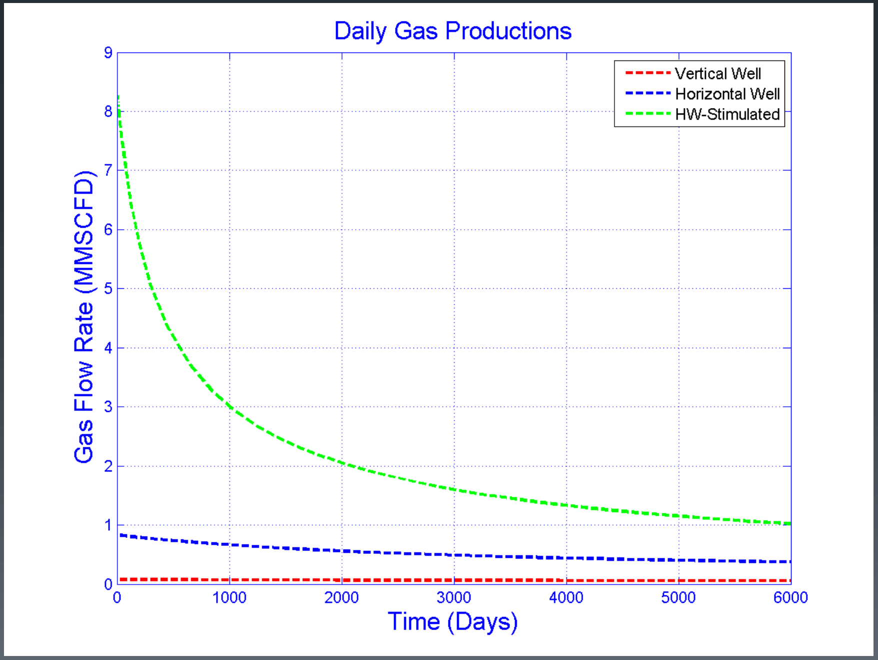
- Both stimulated and unstimulated reservoirs have the same reservoir rock, fluid and well properties.
- Stimulated zone around the horizontal well is represented using a perfect cylinder.

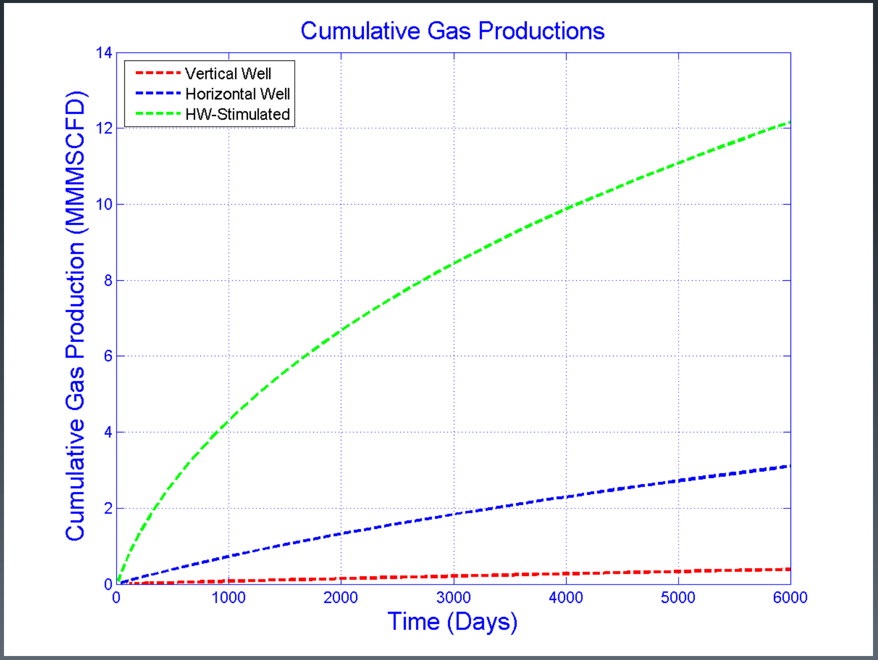
11x11 Simulation Input for Shale Gas Reservoir with Horizontal Well	
Depth	6000 ft
Thickness	200 ft
Area	445 acres
Fracture Porosity	1%
Matrix Porosity	10%
Fracture Permeability	0.001 md
Matrix Permeability	0.0001 md
Res. Temperature	200°F
Initial Pressure	5000 psia
S_w in Fracture	0%
S_w in Matrix	0%
Langmuir Volume (CH4)	150 scf/ton
Langmuir Pressure (CH4)	1281 psia
Fracture Spacing	1 ft
P_{sf}	14.9 psia
Wellbore Radius	0.25 ft

Stimulated Zone Characteristics	
Fracture Porosity	2%
Fracture Permeability	0.01 md
Fracture Spacing	0.1 ft
Fracture Wing	600 ft

Hydraulically Fractured Horizontal Well Performance

- The total production of stimulated reservoir at the end of 20^{th} year is 3.5 times larger than the production from unstimulated reservoir with HW
- It is also 24.3 times larger than the performance of the vertical well

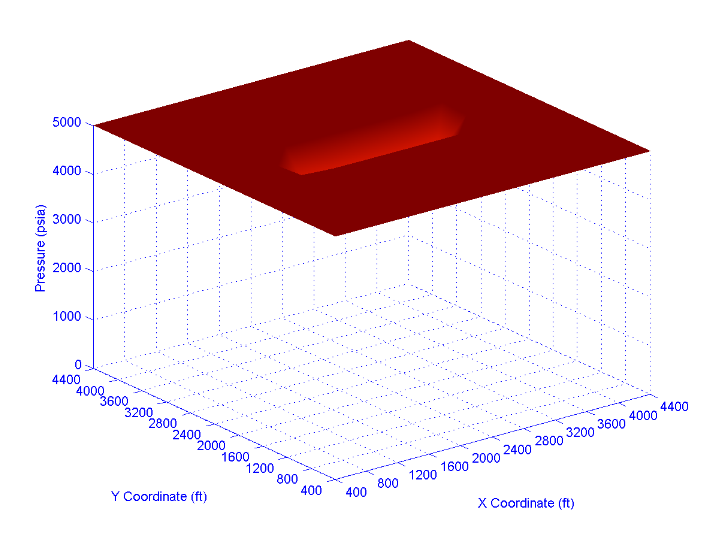




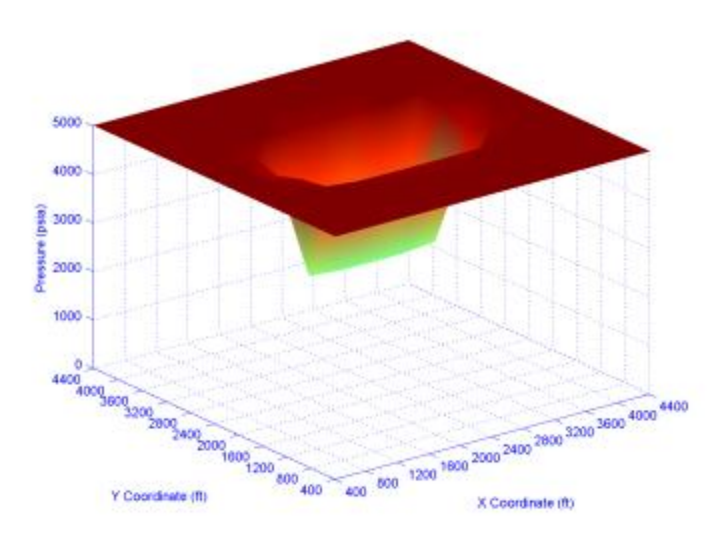
Hydraulically Fractured Horizontal Well Performance

3D Pressure Distributions

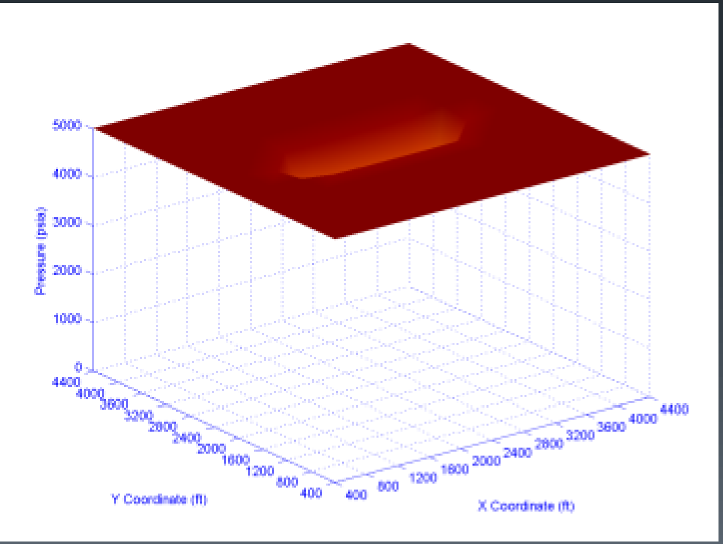
3rd Year



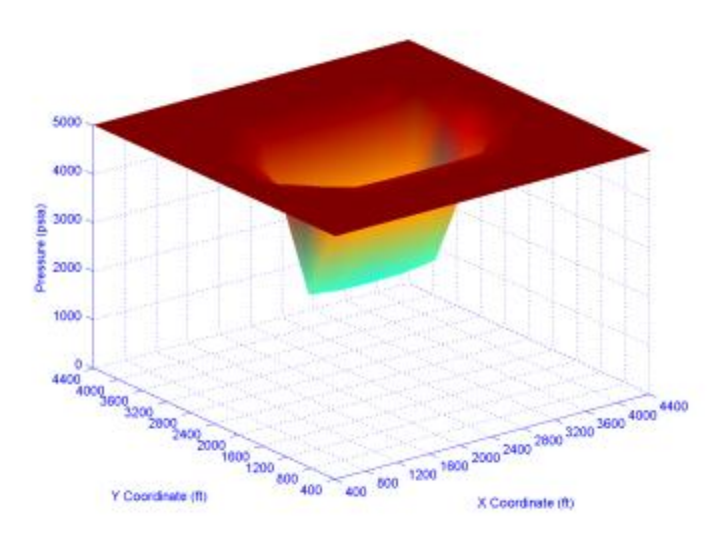
3rd Year



5th Year



5th Year



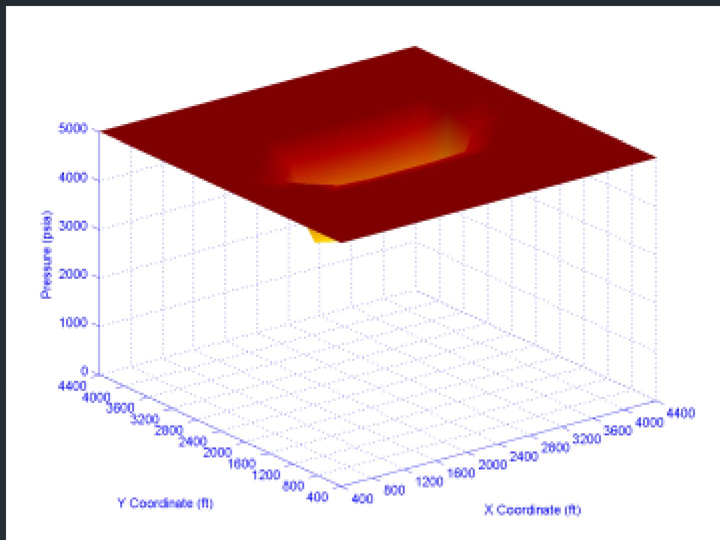
Unstimulated

Stimulated

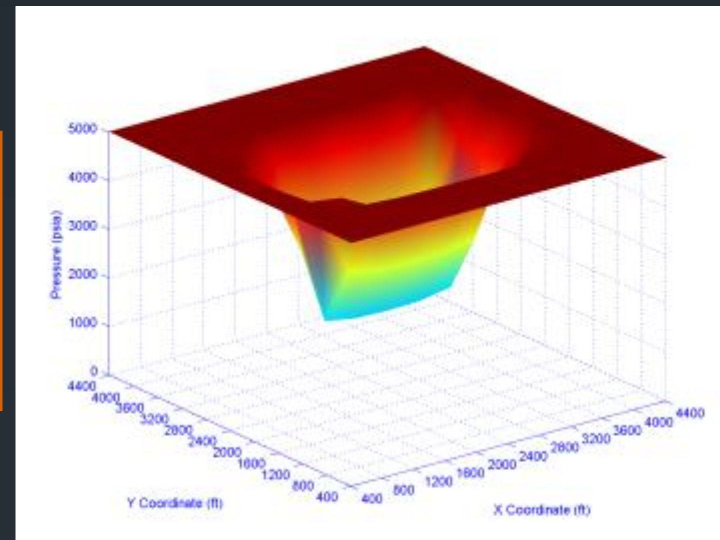
Hydraulically Fractured Horizontal Well Performance

3D Pressure Distributions

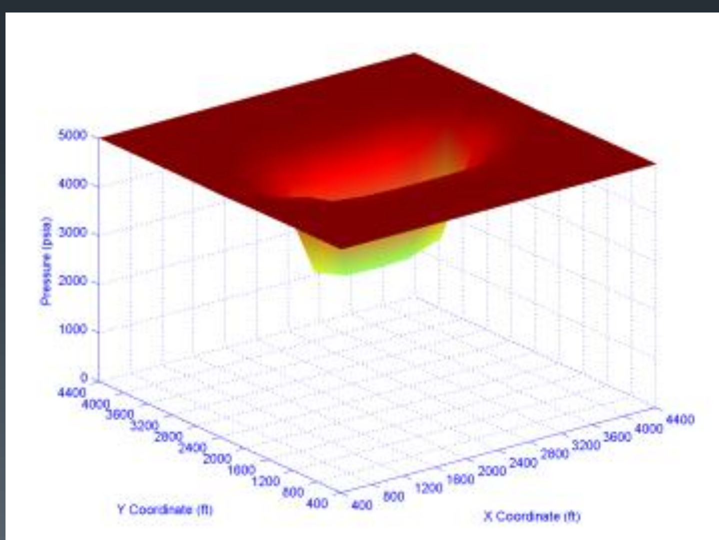
10th Year



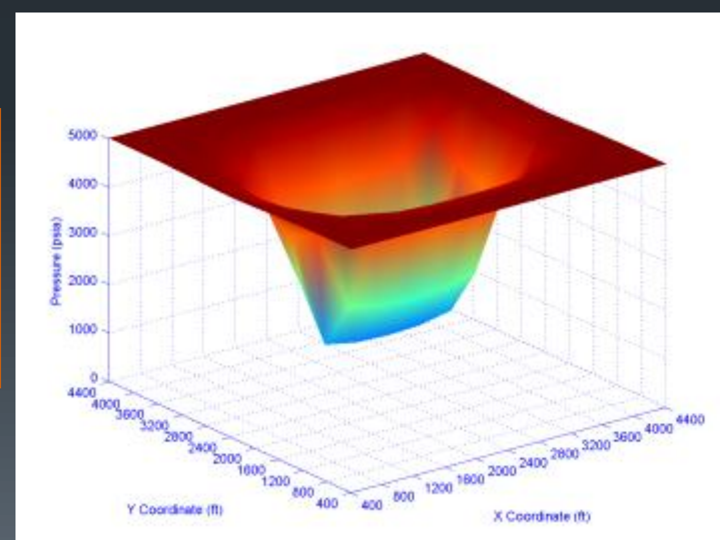
10th Year



20th Year



20th Year



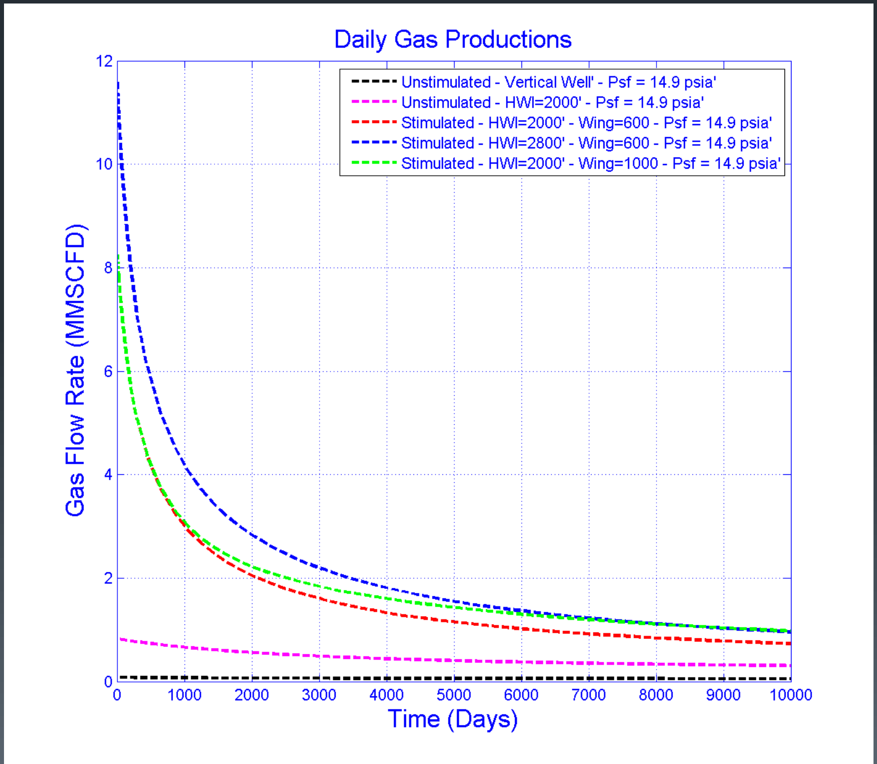
Unstimulated

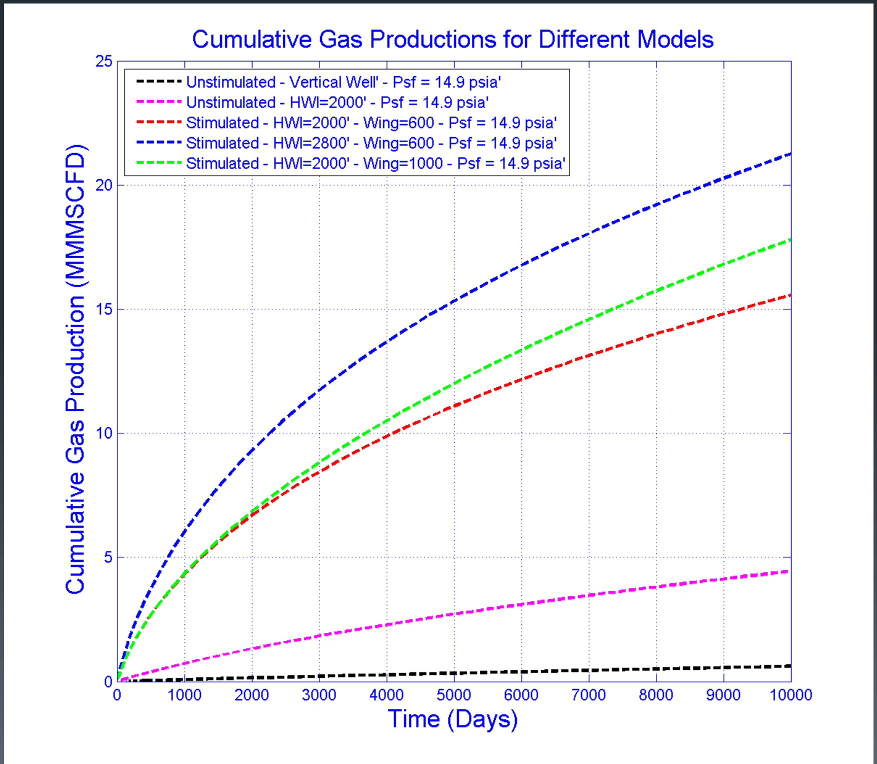
Stimulated

Various Operational Scenarios on Stimulated Reservoirs

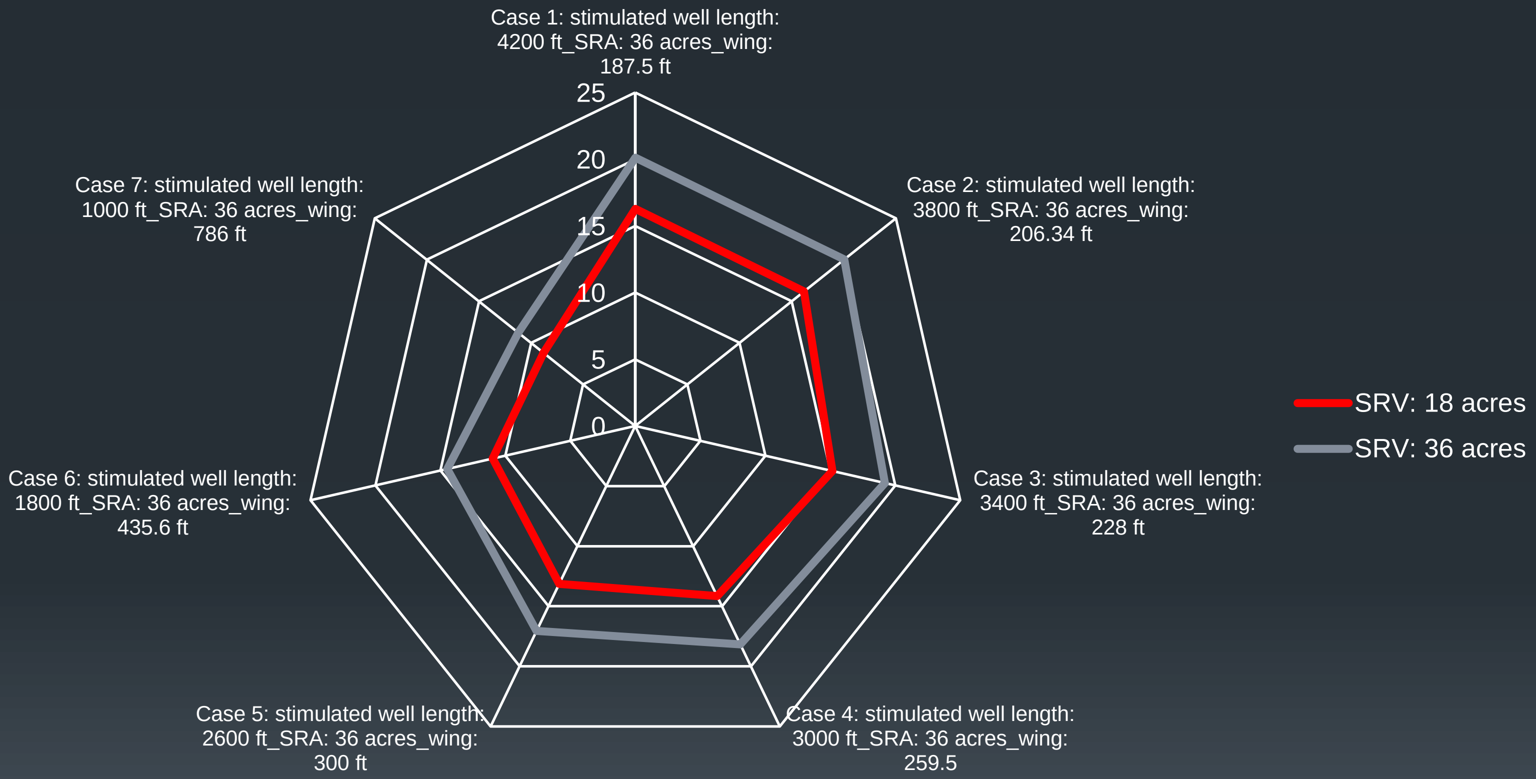
Several operational scenarios are designed to understand the depletion characteristics of these reservoirs for future CO_2 injection planning purposes:

- Horizontal wellbore length is increased form 2000’ to 2800’
- Fracture wing size is increased form 600’ to 1000’





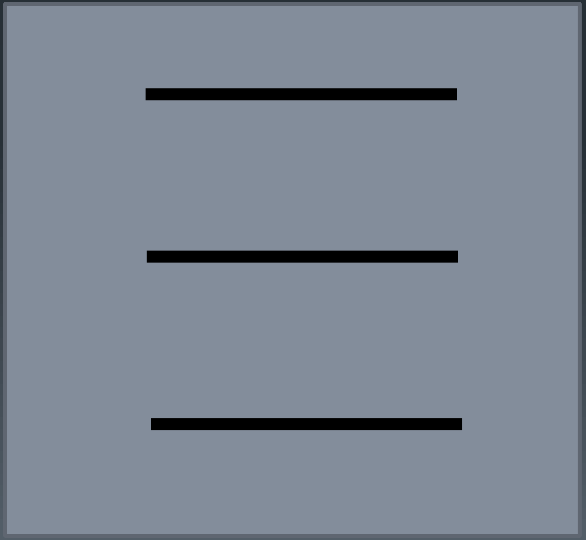
Spider Chart for Recoveries



Reservoir Properties – Shale Gas Reservoir Depletion followed by CO_2 Injection

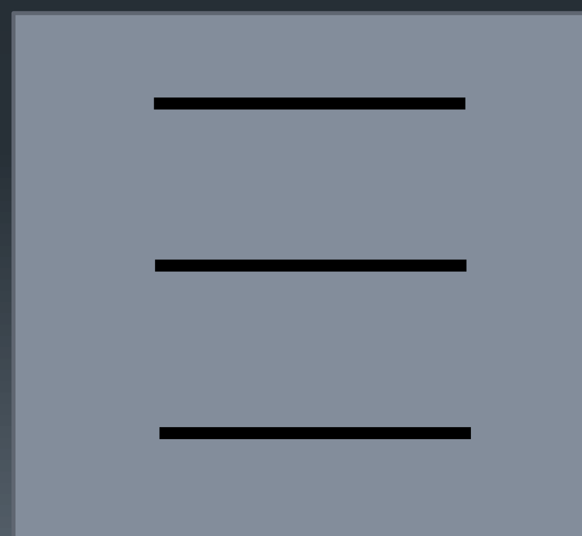
7x7 Simulation Input for Shale Gas Reservoir with a Horizontal Wells	
Depth	6508.5 ft
Thickness	129 ft
Area	323 acres
Fracture Porosity	1%
Matrix Porosity	10%
Fracture Permeability	0.002 md
Matrix Permeability	0.001 md
Fracture Spacing	1.7 ft
Res. Temperature	142°F
Average Pressure	3890psia
S_w in Fracture	10%
S_w in Matrix	010%
Langmuir Volume (CH4)	73scf/ton
Langmuir Pressure (CH4)	726 psia
Langmuir Volume (C02)	75scf/ton
Langmuir Pressure (C02)	400psia
P_{sf}	14.9 psia

SRV Properties	
HW Length (center well)	2250 ft
HW Length (edge wells)	2250 ft
Fracture Wing	625ft
Fracture Porosity	2%
Fracture Permeability	0.02 md
Fracture Spacing	0.17 ft

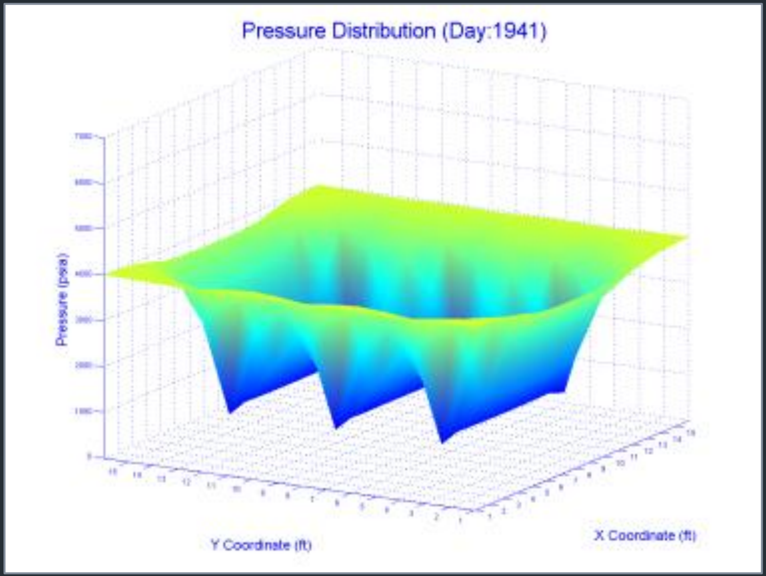


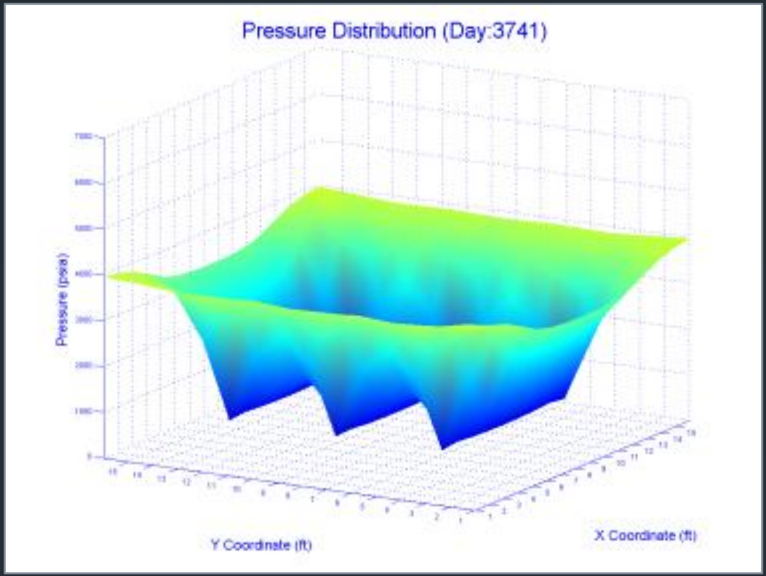
CASE 1
k=0.00001md

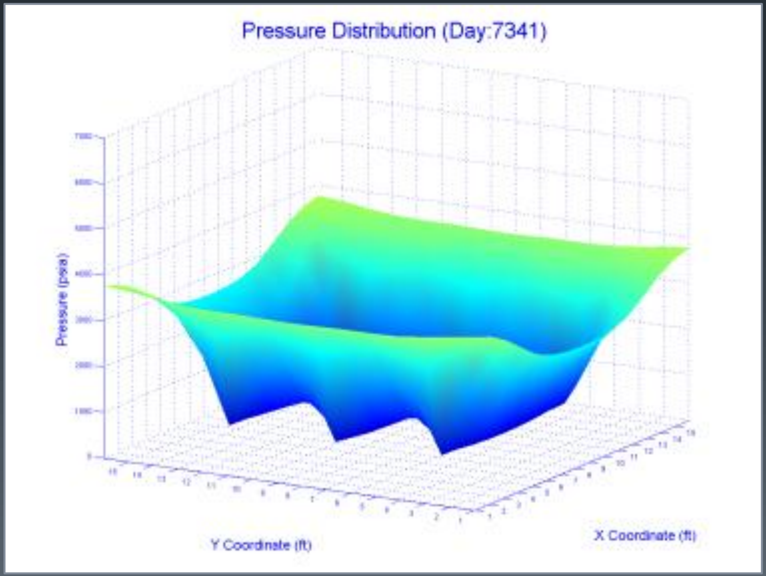
All of the wells are producers for 30 years, then edge wells are switched to CO_2 injectors. Center well continues production

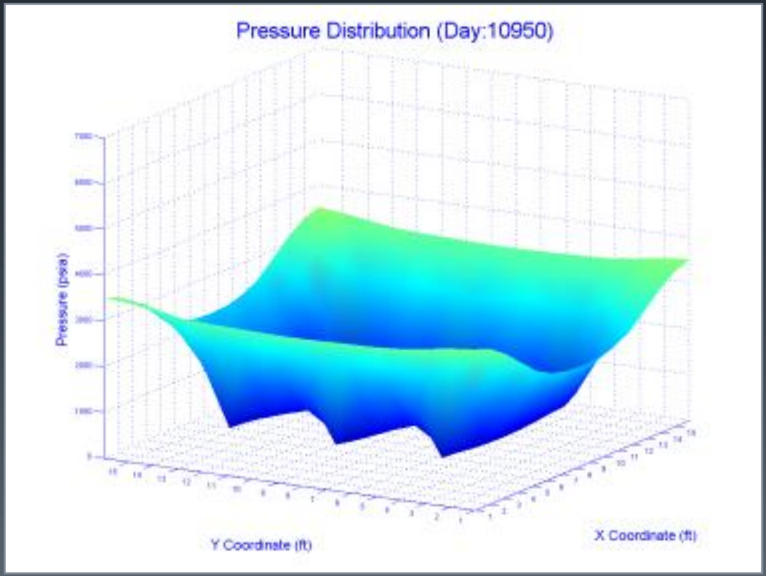


All of the wells are producers for 30 years

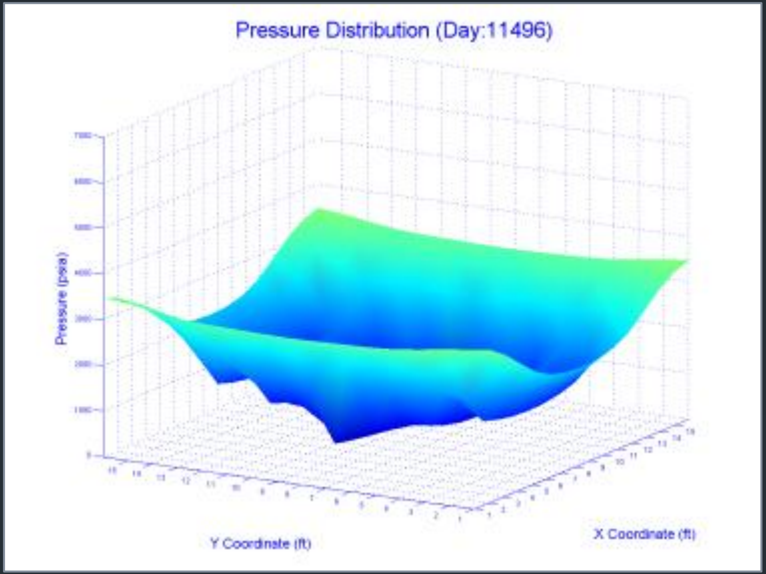


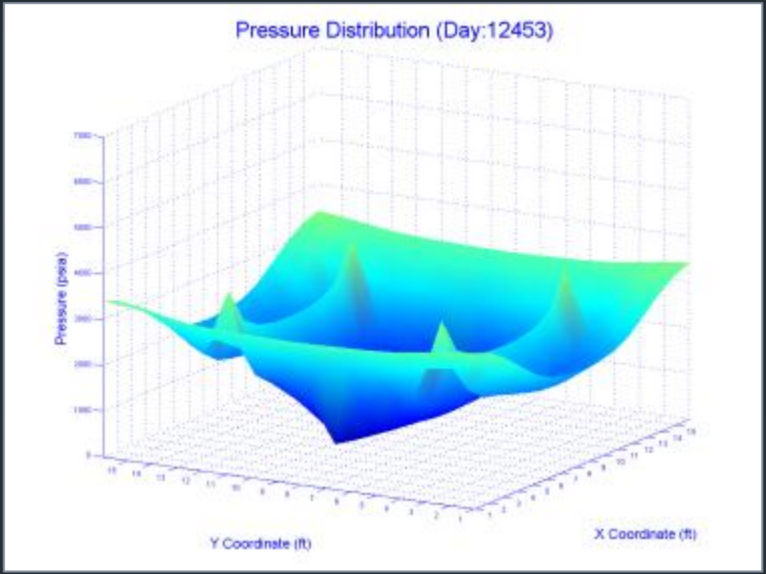


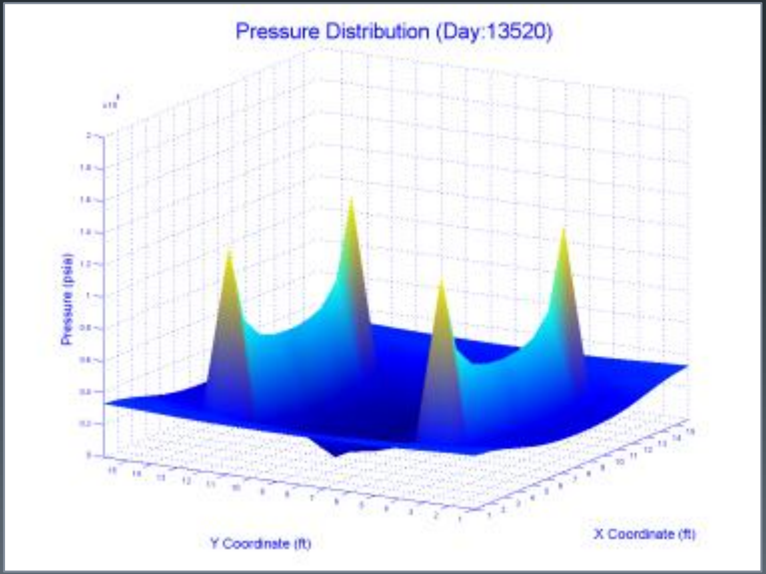


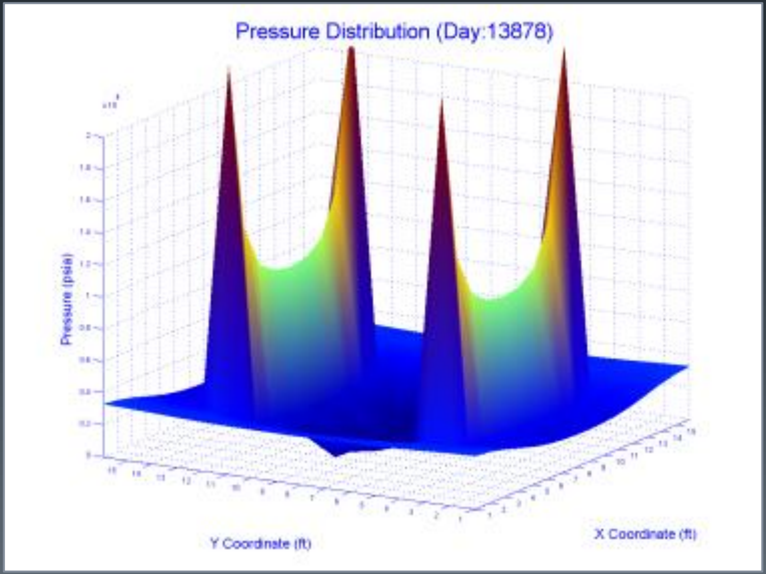


Injection starts at 30th year. Center well continues production



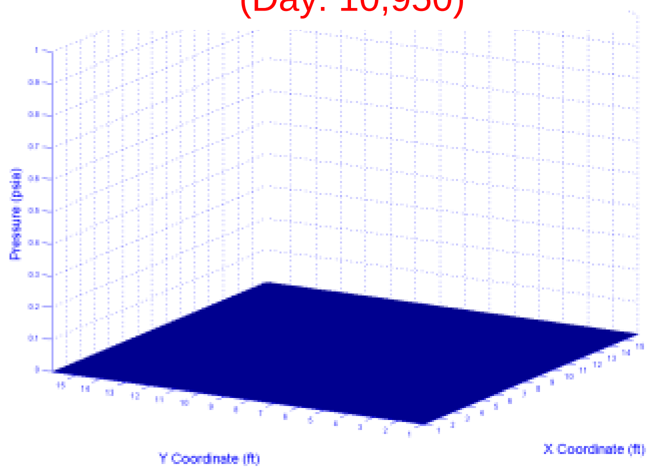




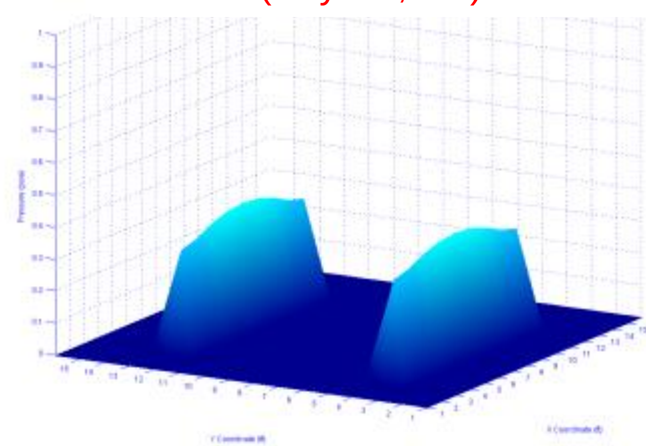


All of the wells are producers for 30 years, then edge wells are switched to CO_2 injectors. Center well continues production

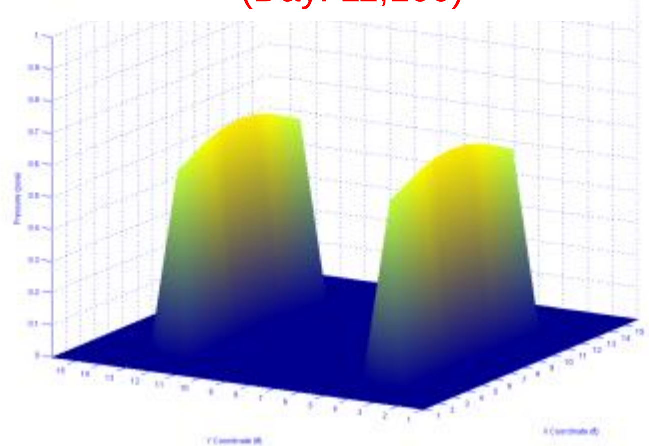
CO_2 Concentration Distribution
(Day: 10,950)



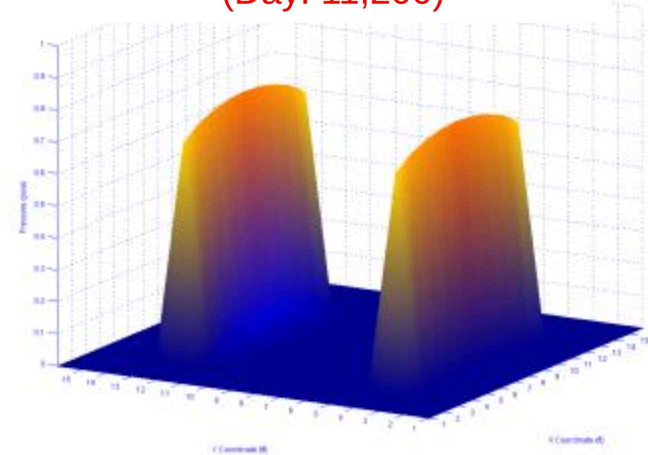
CO_2 Concentration Distribution
(Day: 11,000)



CO_2 Concentration Distribution
(Day: 11,100)

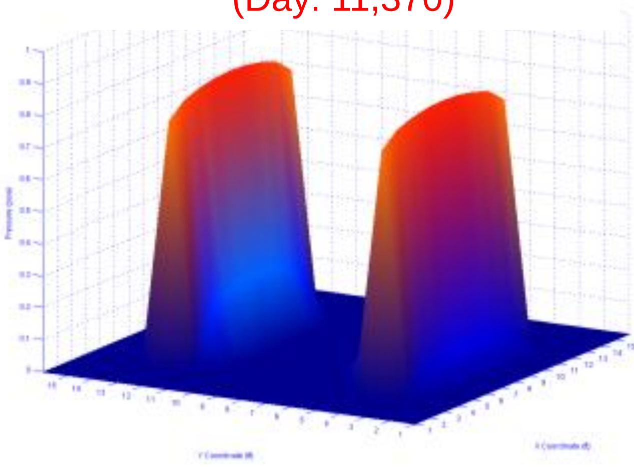


CO_2 Concentration Distribution
(Day: 11,200)

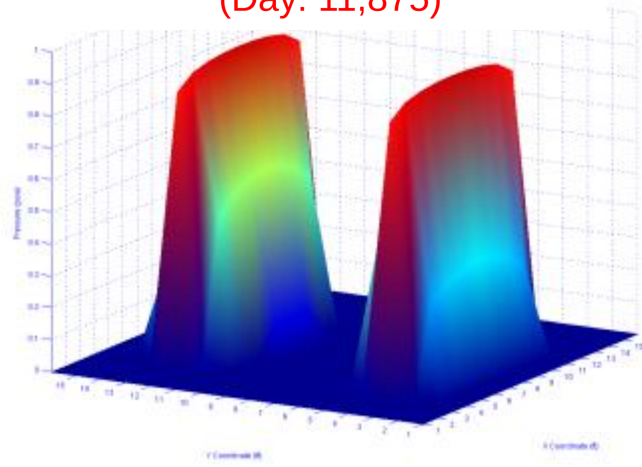


All of the wells are producers for 30 years, then edge wells are switched to CO_2 injectors. Center well continues production

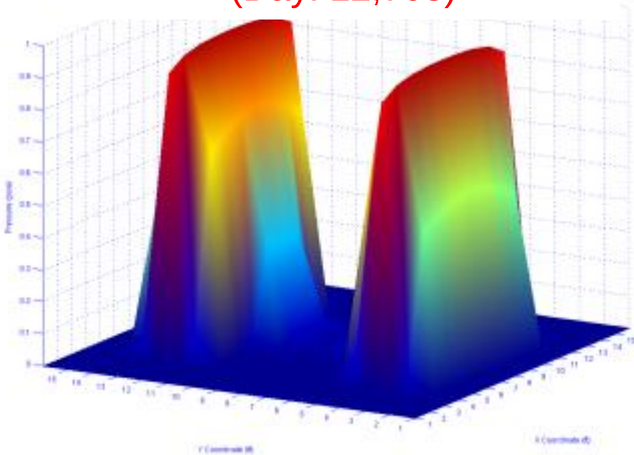
CO_2 Concentration Distribution (Day: 11,370)



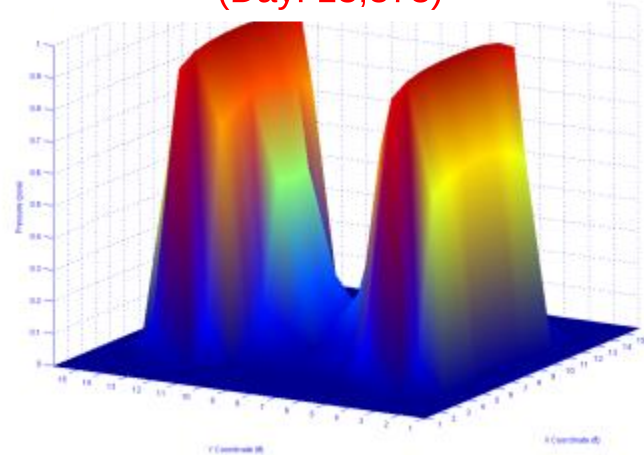
CO_2 Concentration Distribution (Day: 11,875)



CO_2 Concentration Distribution (Day: 12,708)

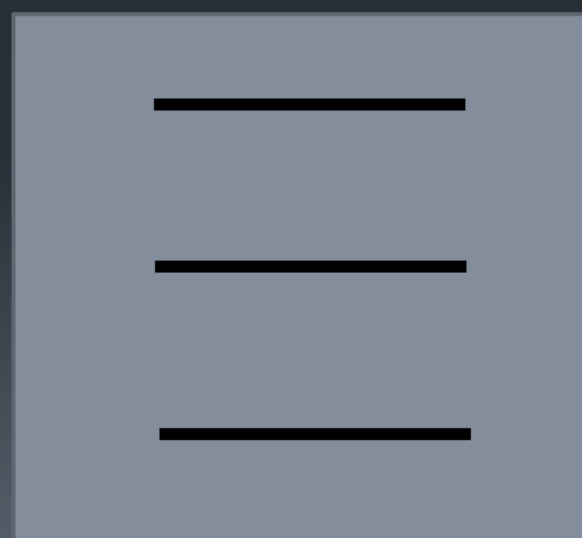


CO_2 Concentration Distribution (Day: 13,878)

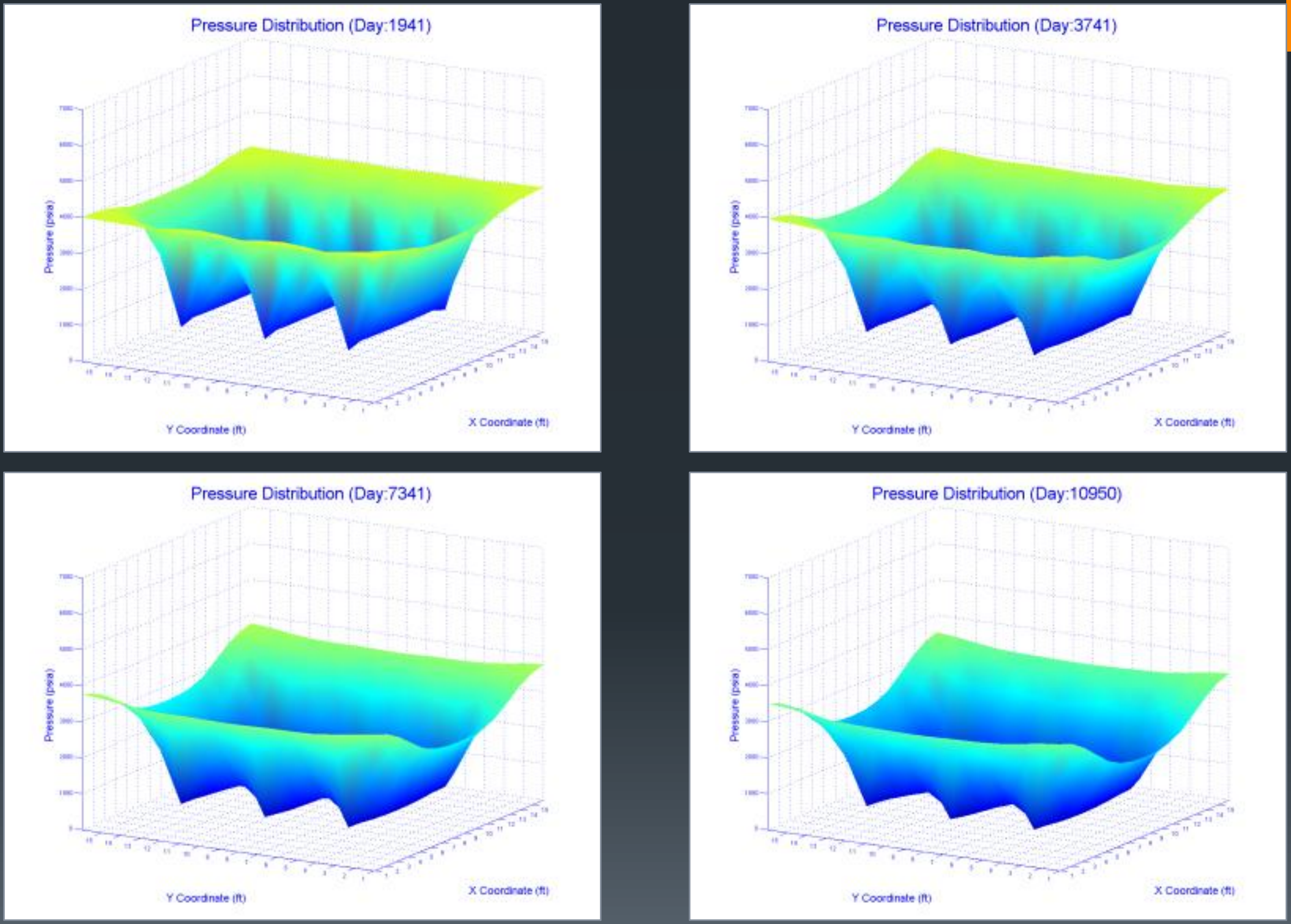


CASE 2
k=0.0001md

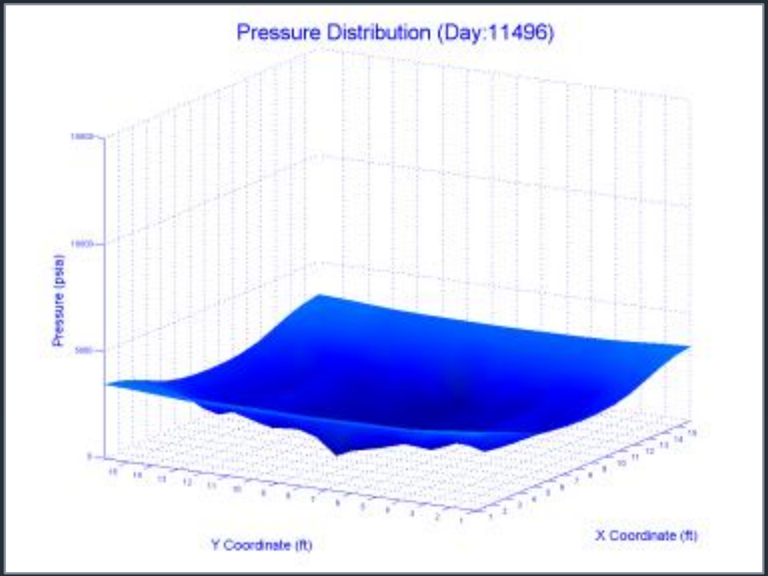
All of the wells are producers for 30 years, then edge wells are switched to CO_2 injectors. Center well continues production

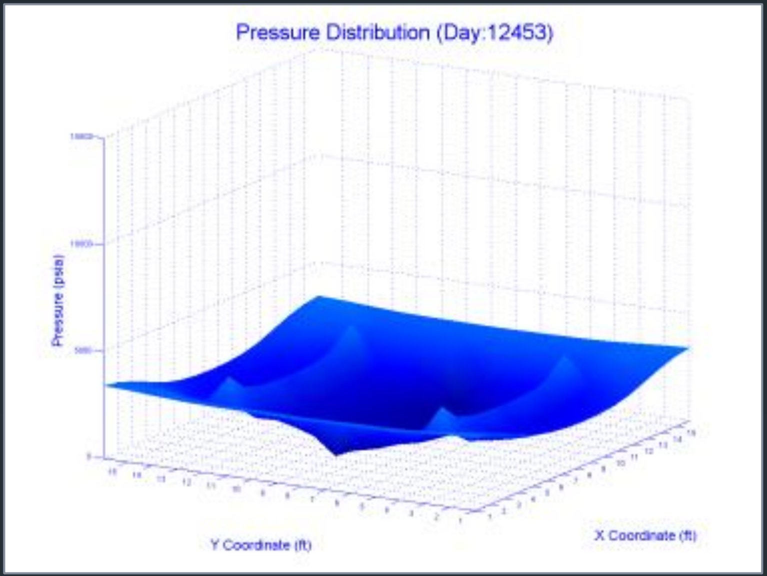


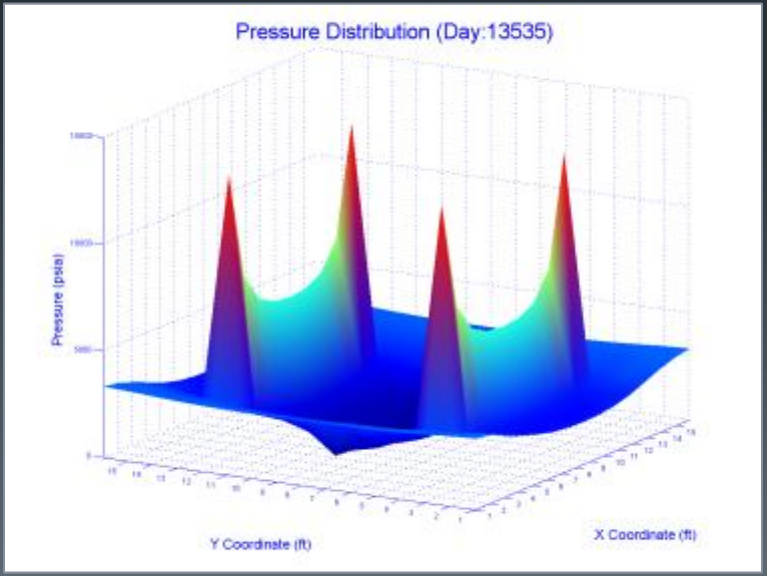
All of the wells are producers for 30 years, then edge wells are switched to CO_2 injectors. Center well continues production



Injection starts at the 30th year. Center well continues production

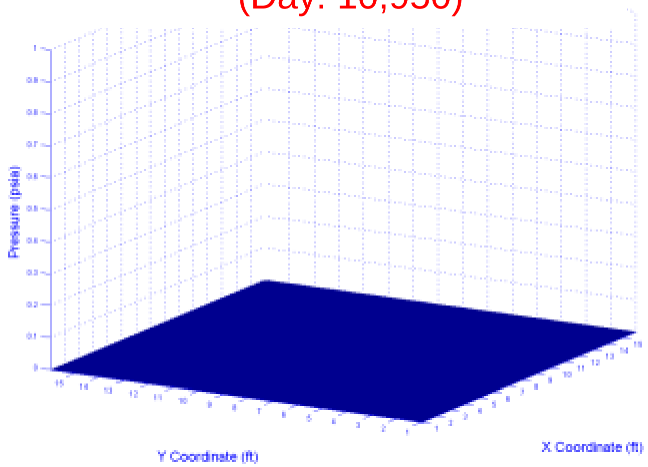




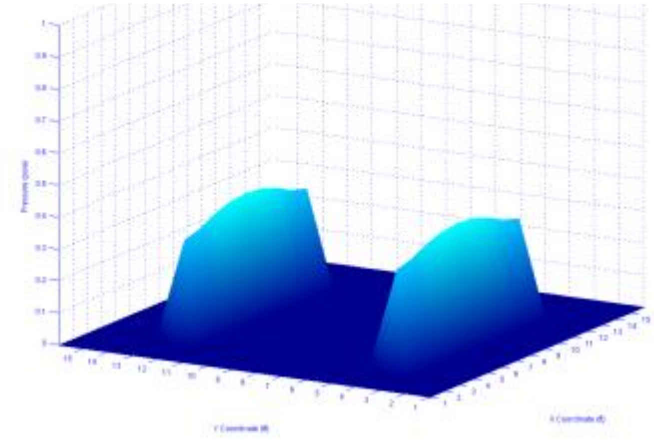


All of the wells are producers for 30 years, then edge wells are switched to CO_2 injectors. Center well continues production

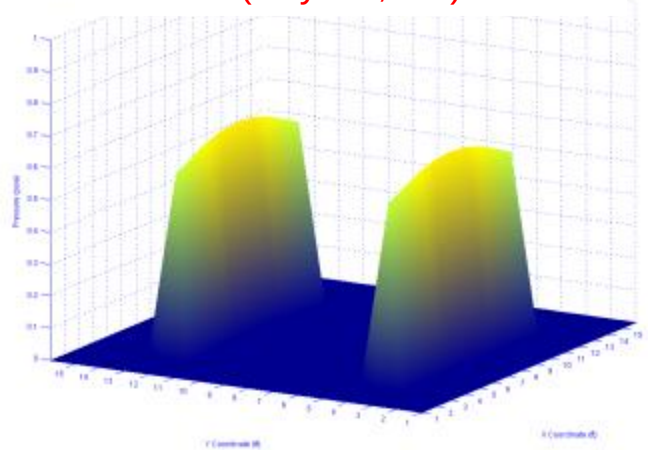
CO_2 Concentration Distribution
(Day: 10,950)



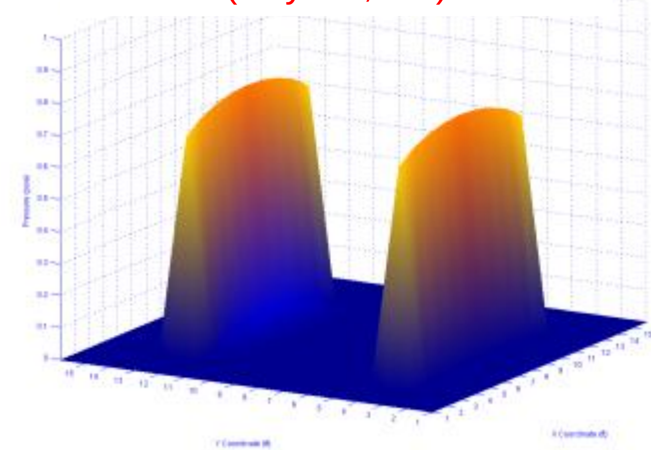
CO_2 Concentration Distribution
(Day: 11,000)



CO_2 Concentration Distribution
(Day: 11,100)

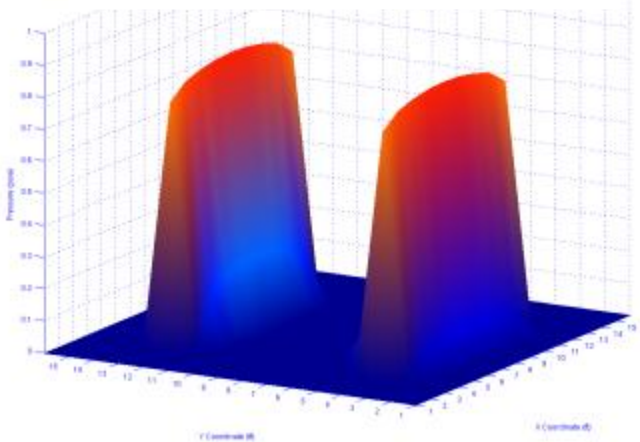


CO_2 Concentration Distribution
(Day: 11,200)

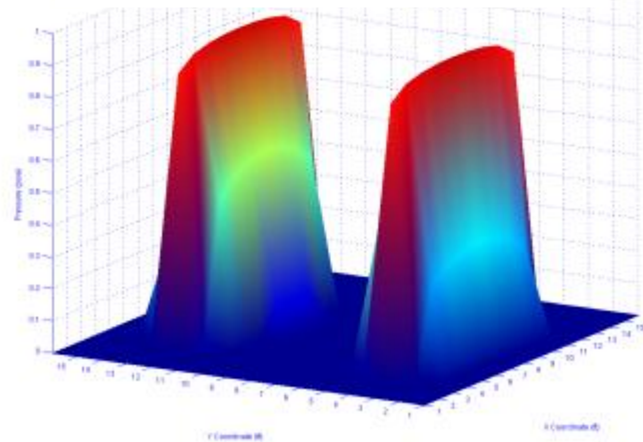


All of the wells are producers for 30 years, then edge wells are switched to CO_2 injectors. Center well continues production

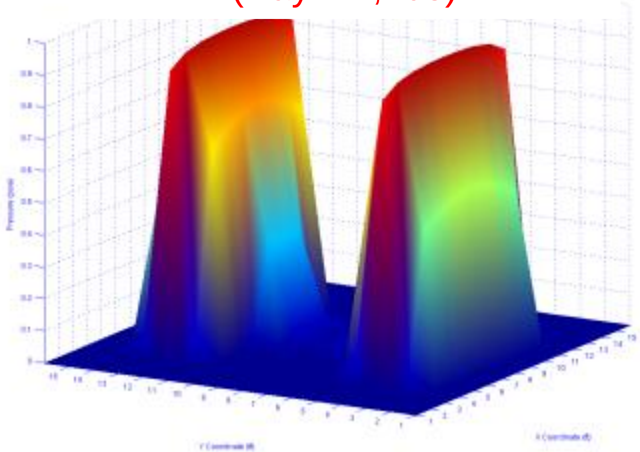
CO_2 Concentration Distribution (Day: 11,370)



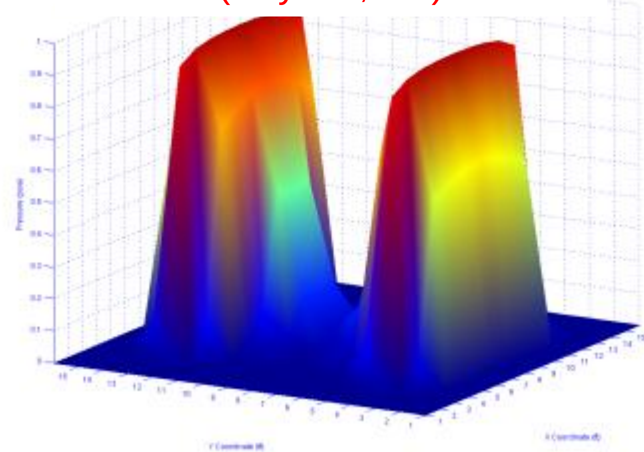
CO_2 Concentration Distribution (Day: 11,875)



CO_2 Concentration Distribution (Day: 12,708)

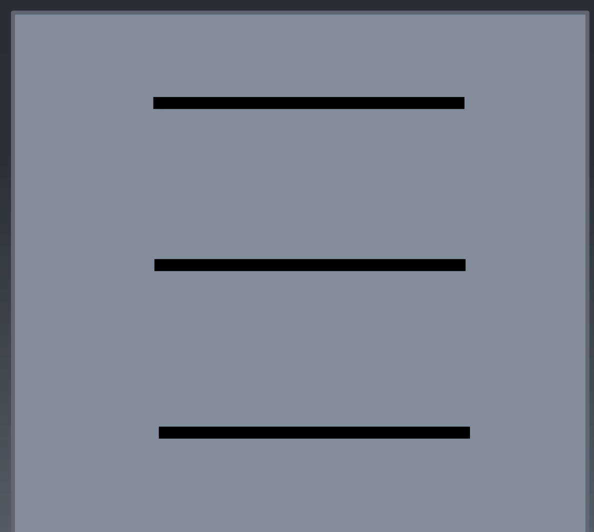


CO_2 Concentration Distribution (Day: 13,535)

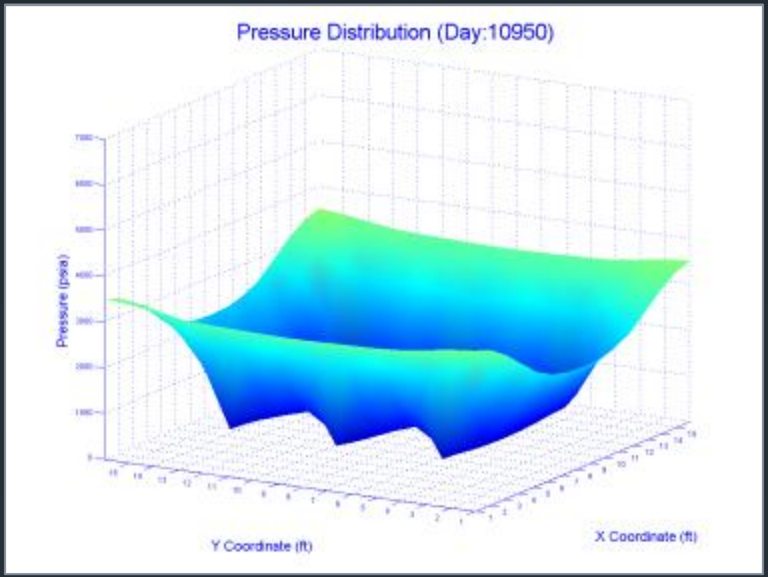


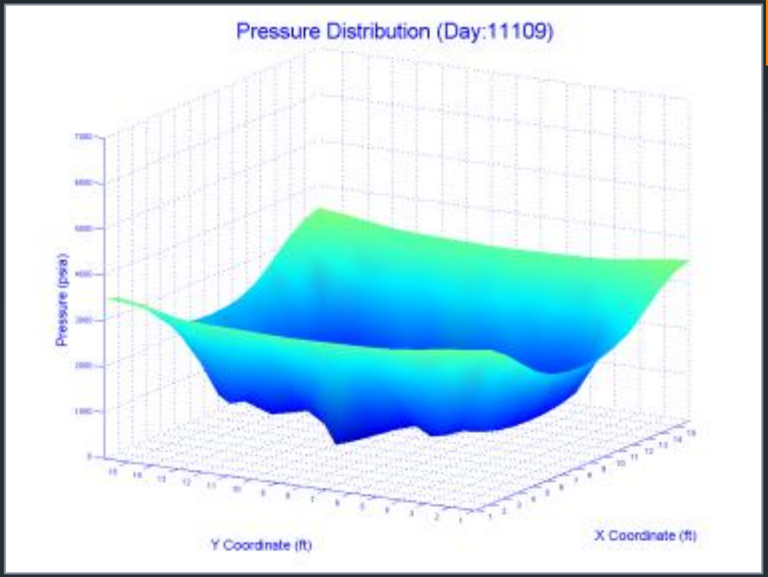
CASE 3
k=0.001md

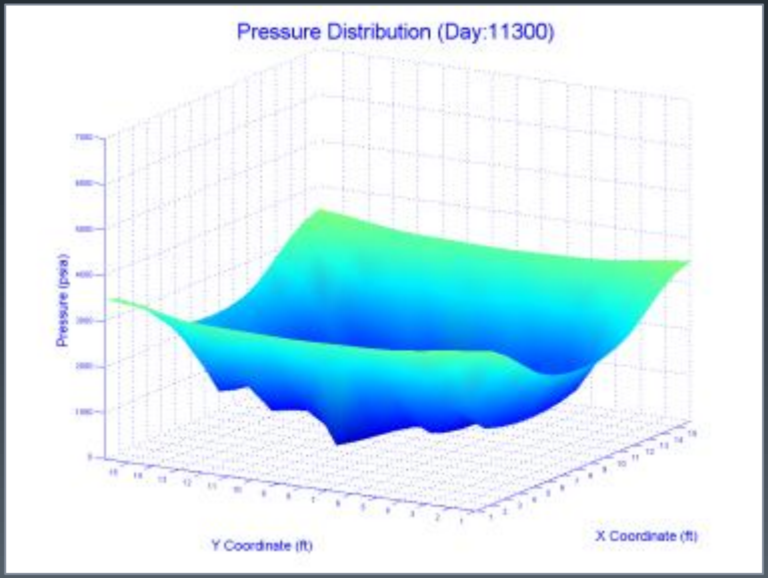
All of the wells are producers for 30 years, then edge wells are switched to CO_2 injectors. Center well continues production.

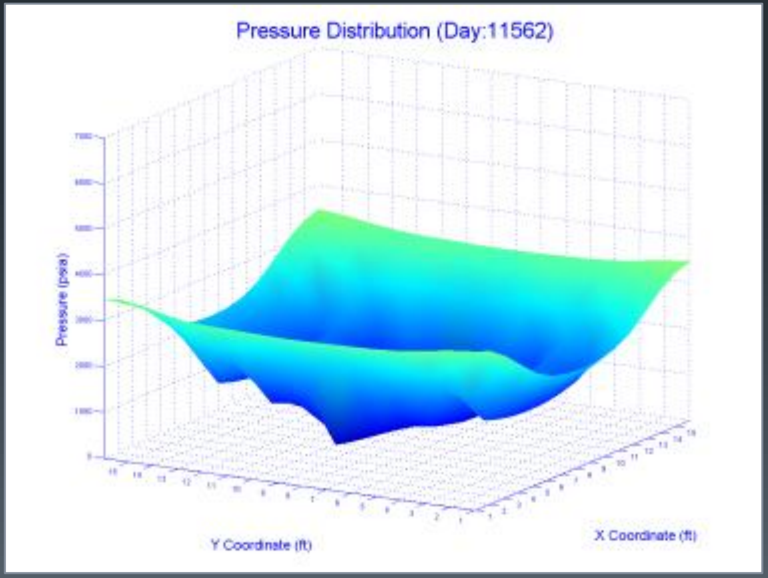


Injection starts at the 30th year. Center well continues production



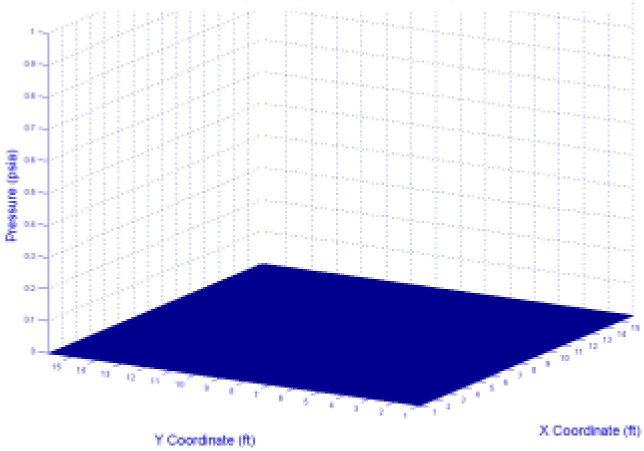




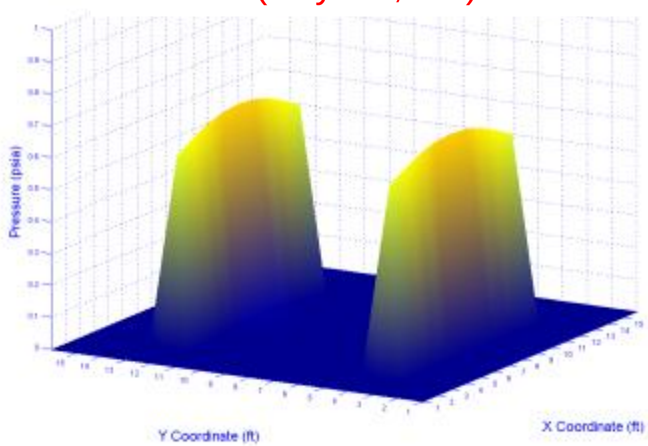


All of the wells are producers for 30 years, then edge wells are switched to CO_2 injectors. Center well continues production

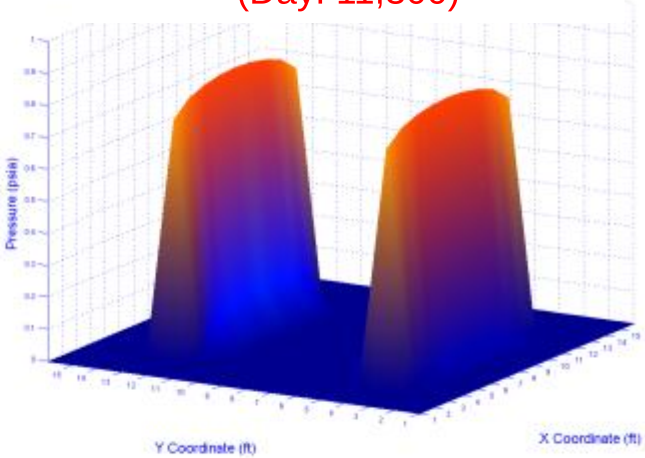
CO_2 Concentration Distribution (Day: 10,950)



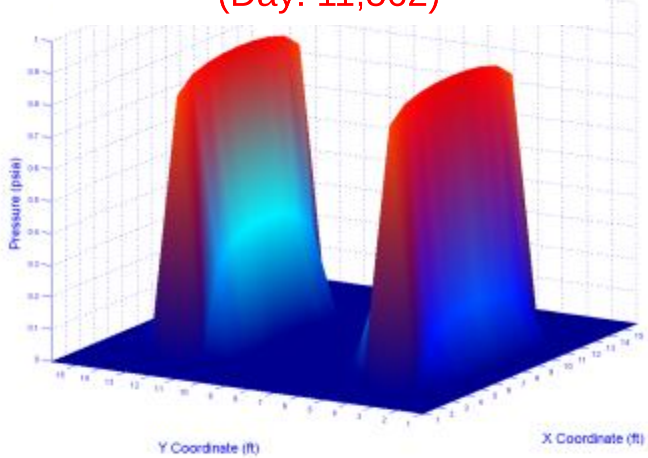
CO_2 Concentration Distribution (Day: 11,100)



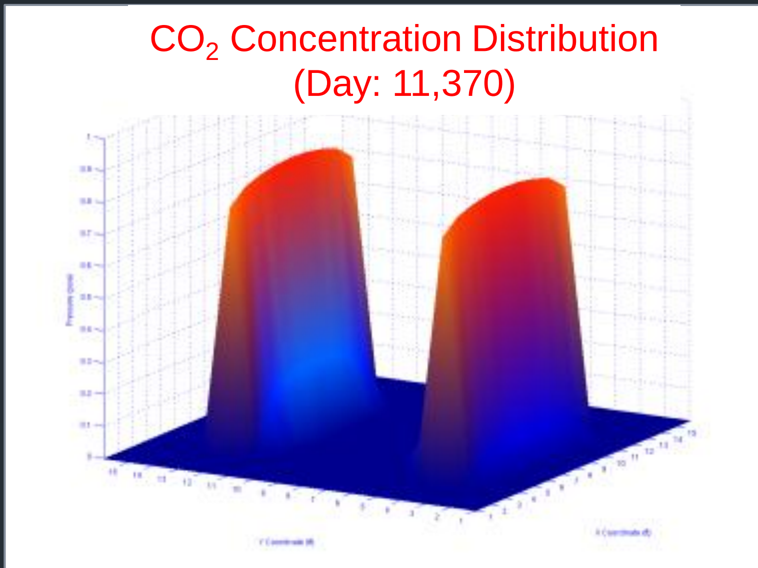
CO_2 Concentration Distribution (Day: 11,300)

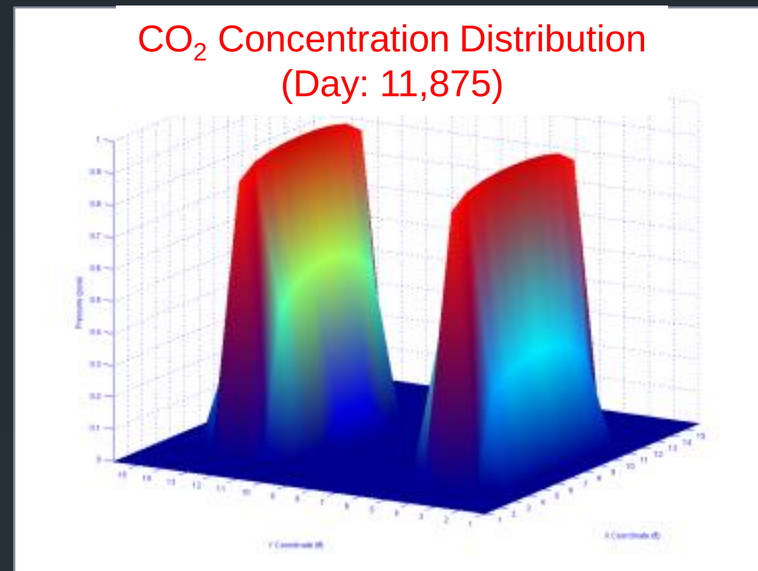


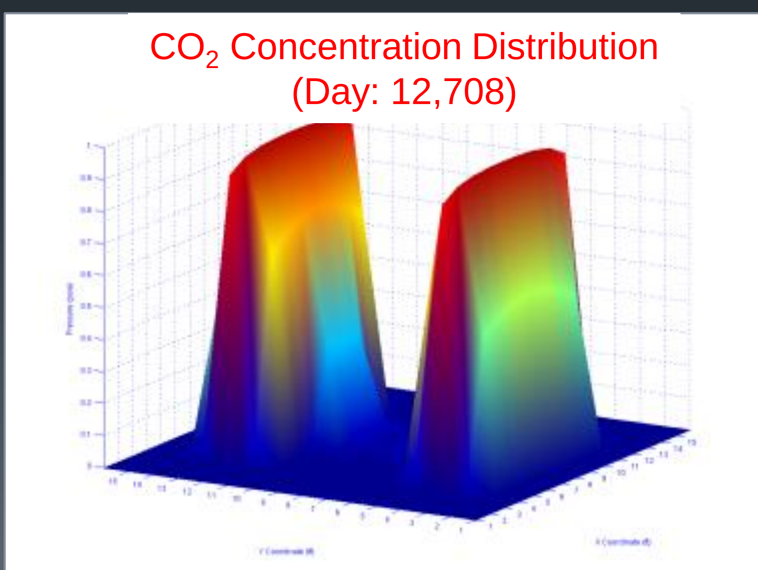
CO_2 Concentration Distribution (Day: 11,562)

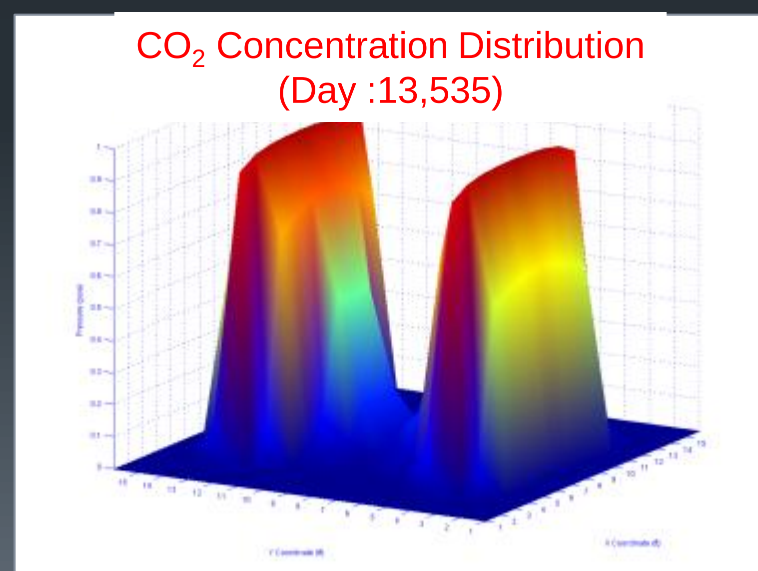


All of the wells are producers for 30 years, then edge wells are switched to CO_2 injectors. Center well continues production



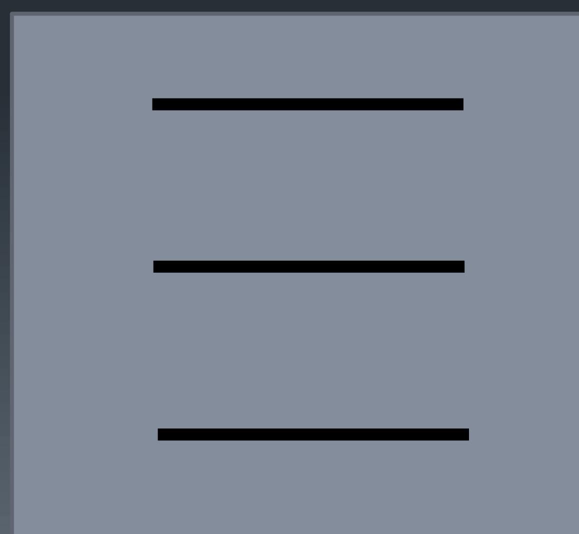




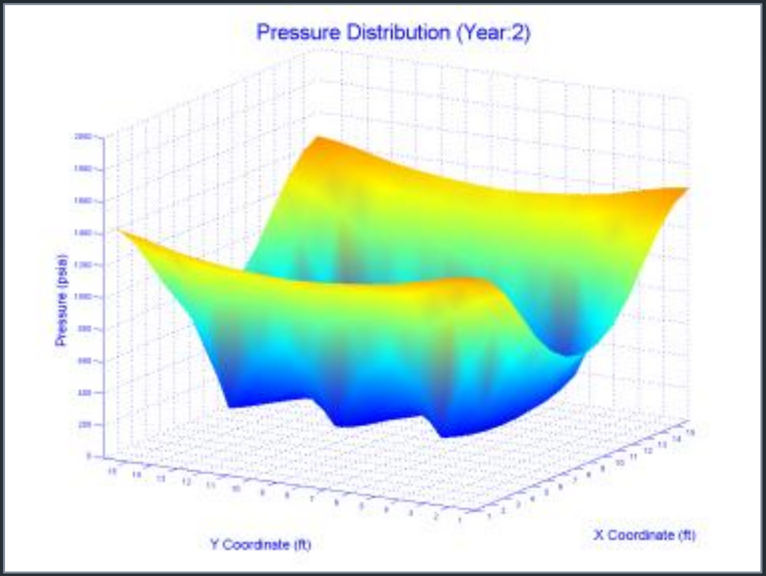


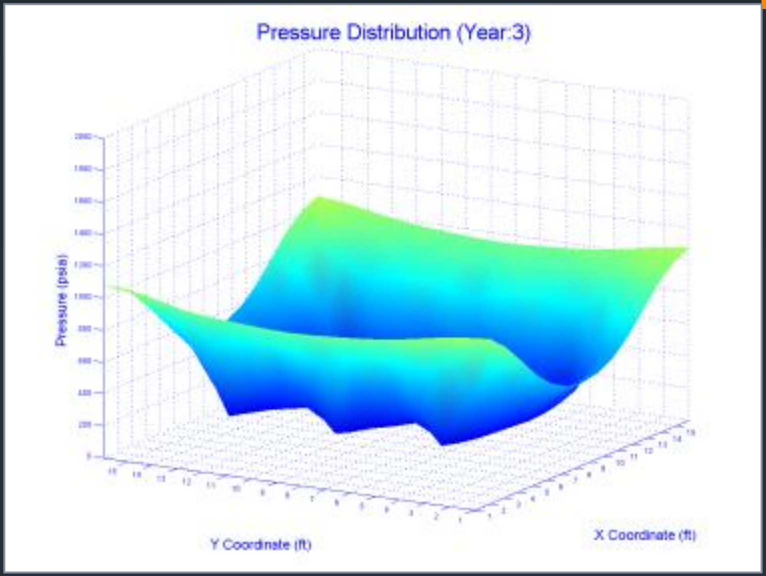
CASE 4
k=0.1md

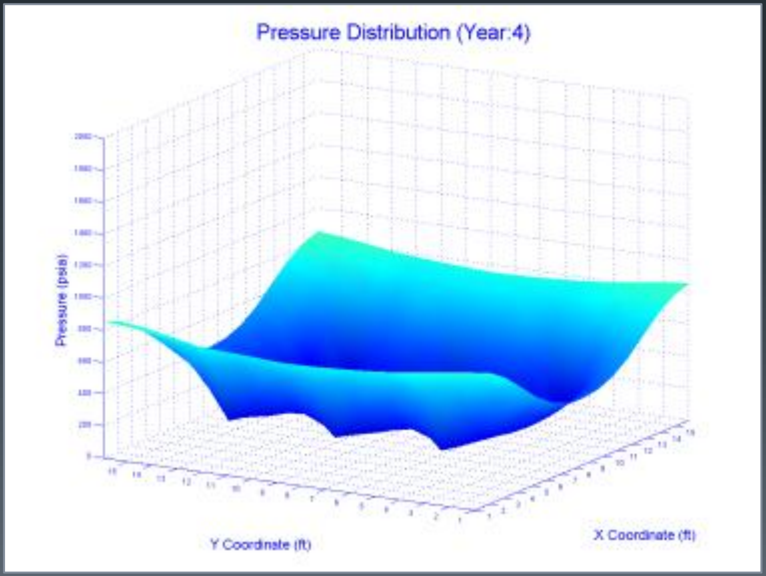
- A permeable system is tested to observe the CO_2 breakthrough at the producer
- First CO_2 production from the center well is seen after 3 years

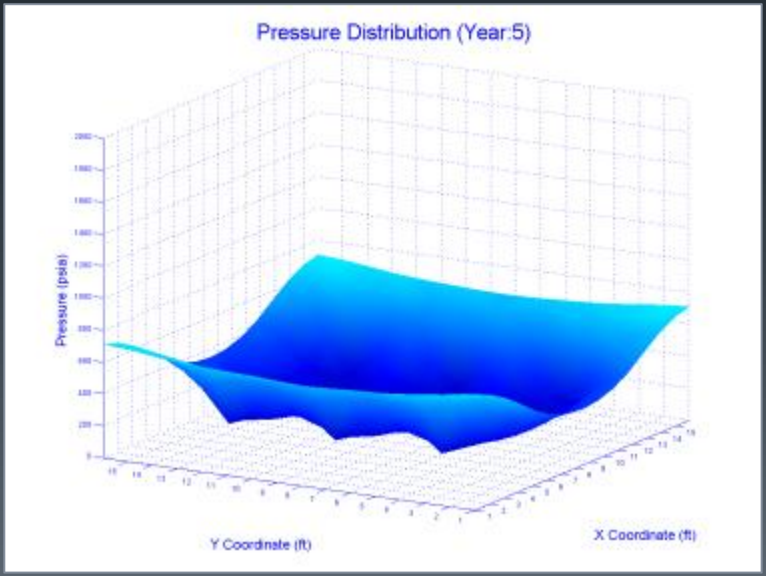


All of the wells are producers initially, then the edge wells are switched to CO_2 injectors at the 5th year. The center well continues production

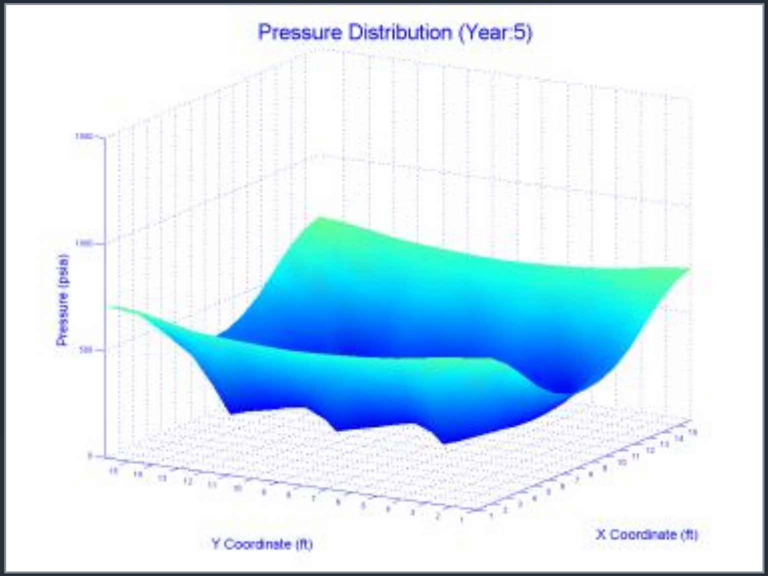


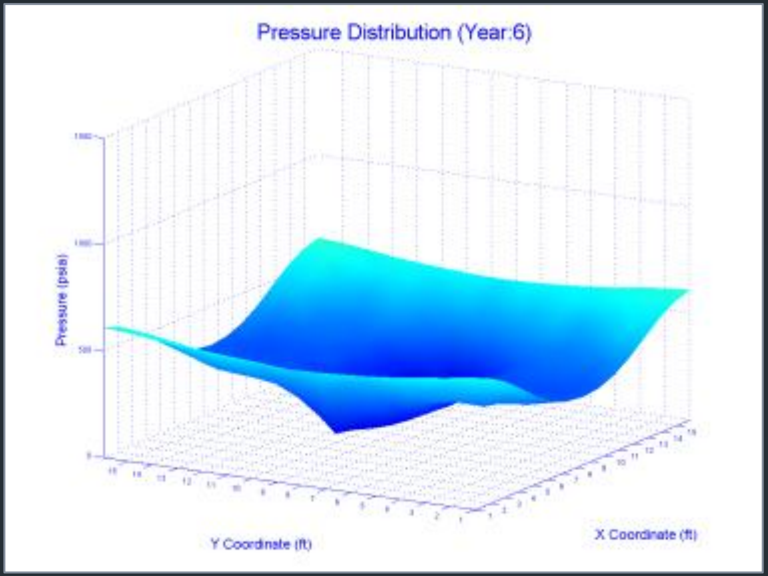


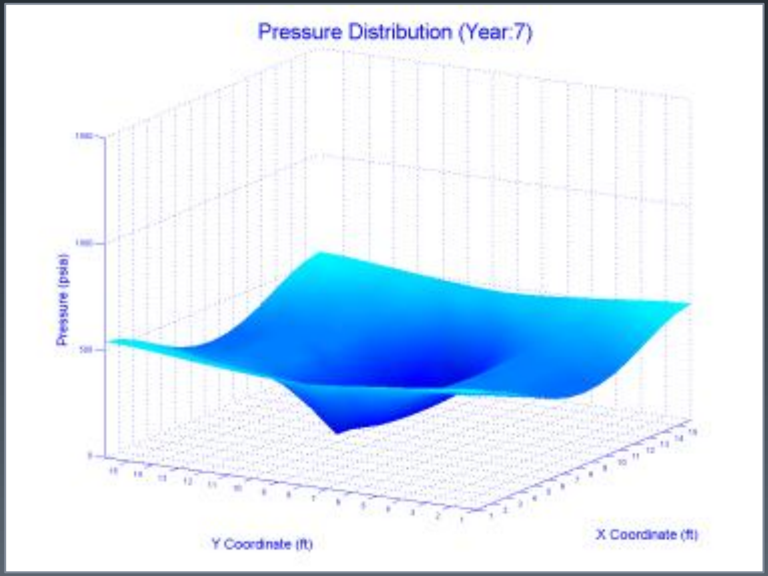


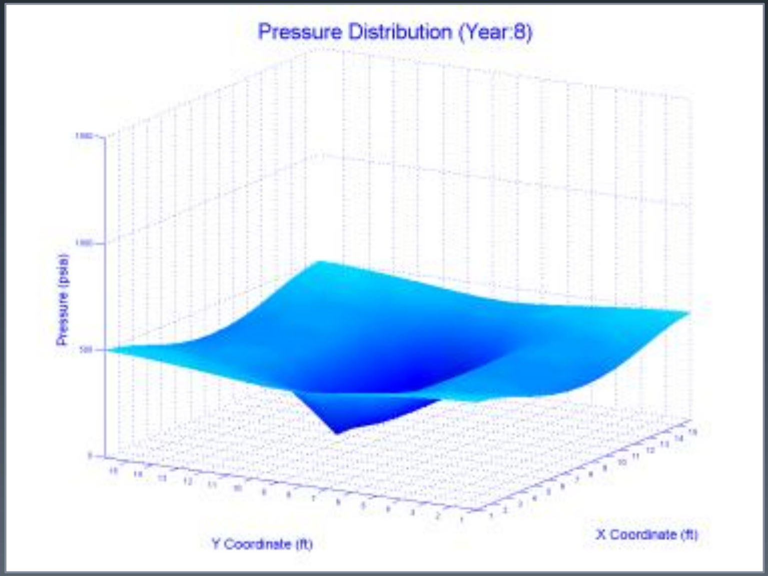


Injection starts at the 5th year. The center well continues production

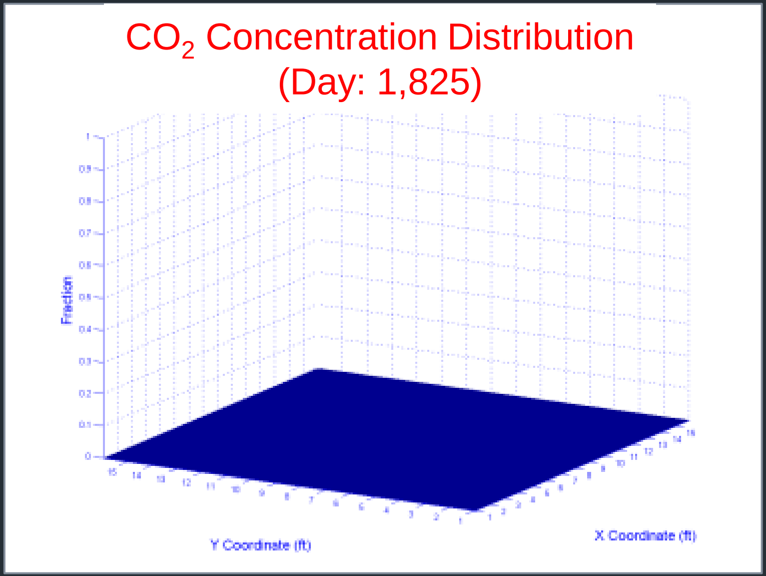


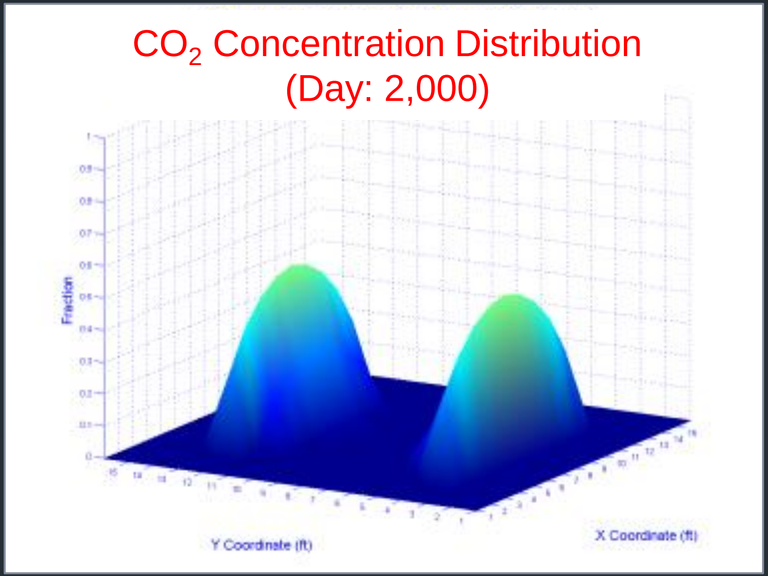


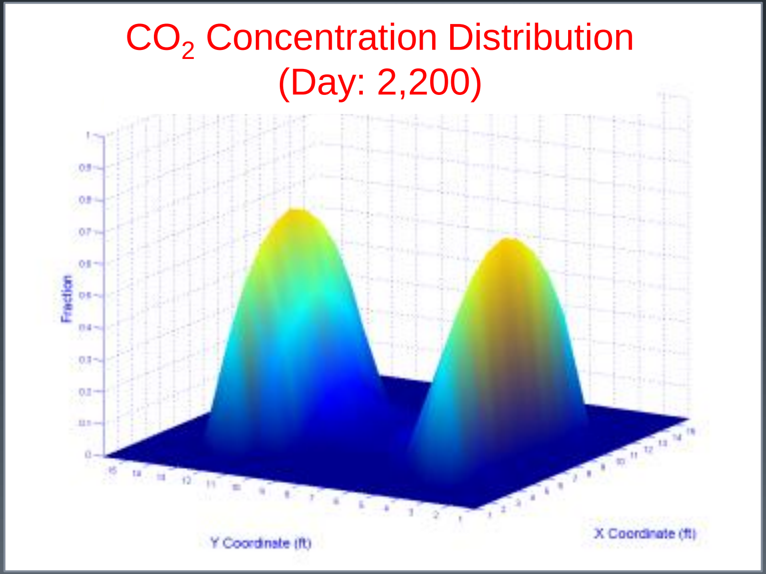


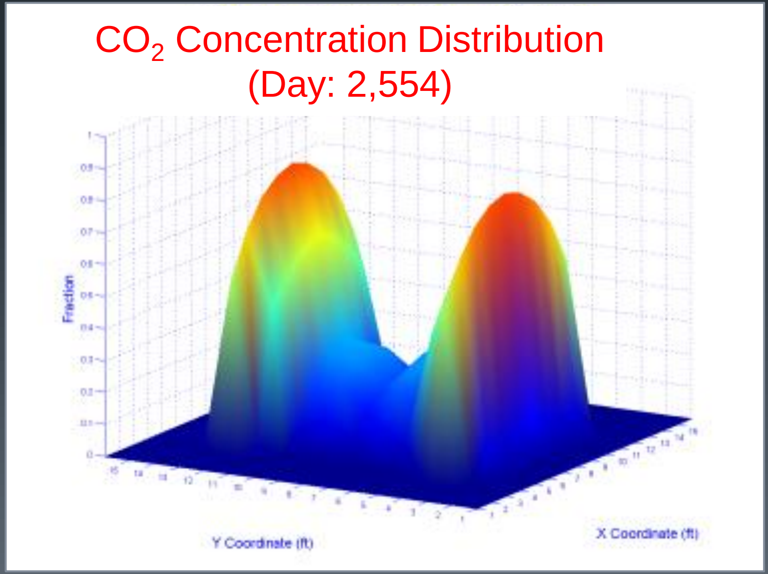


CO_2 mole fraction in the adsorbed phase



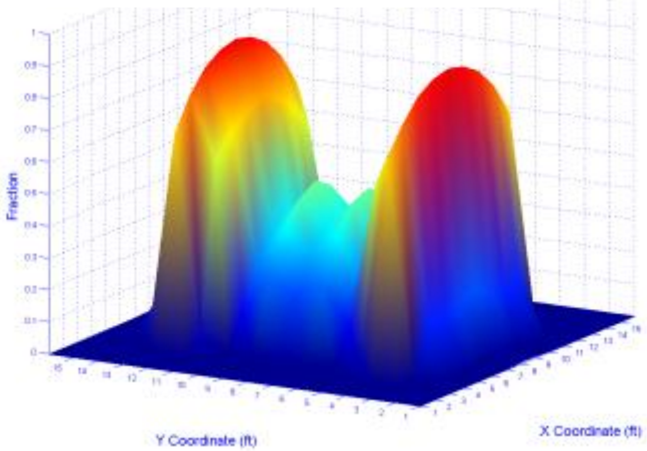




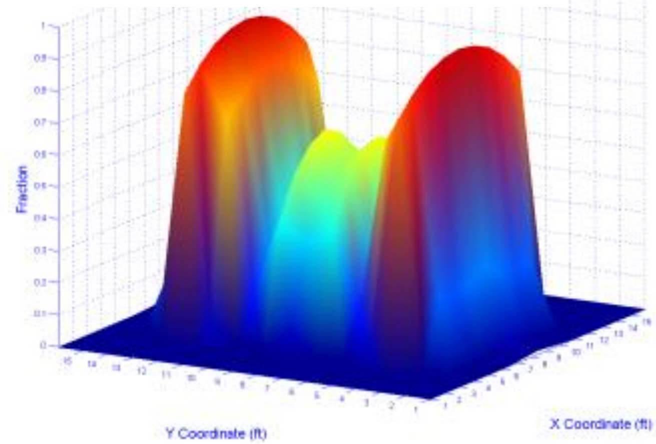


CO_2 mole fractions in the adsorbed phase

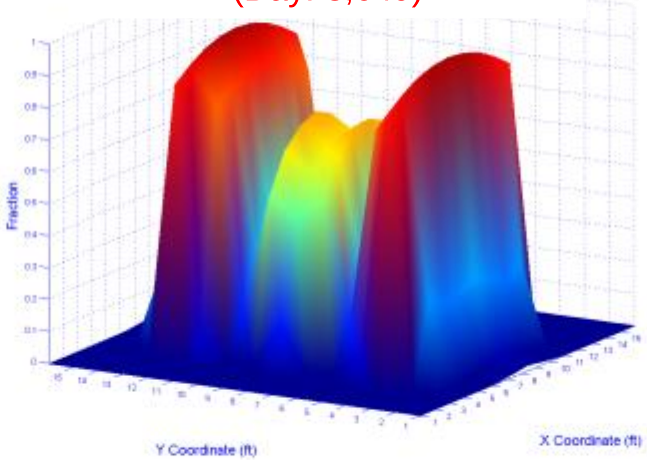
CO_2 Concentration Distribution
(Day: 2,922)



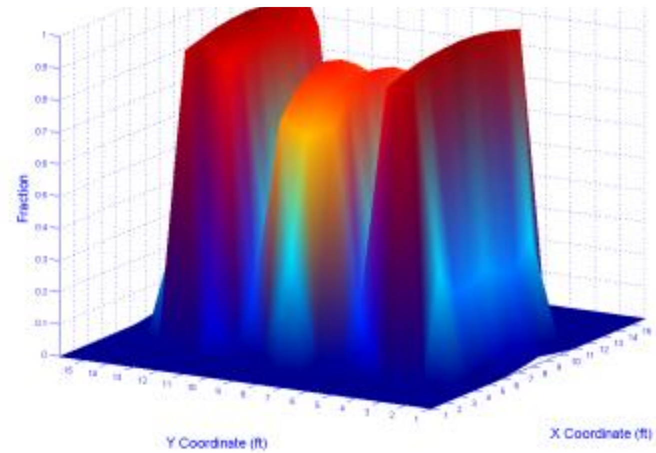
CO_2 Concentration Distribution
(Day: 3,281)



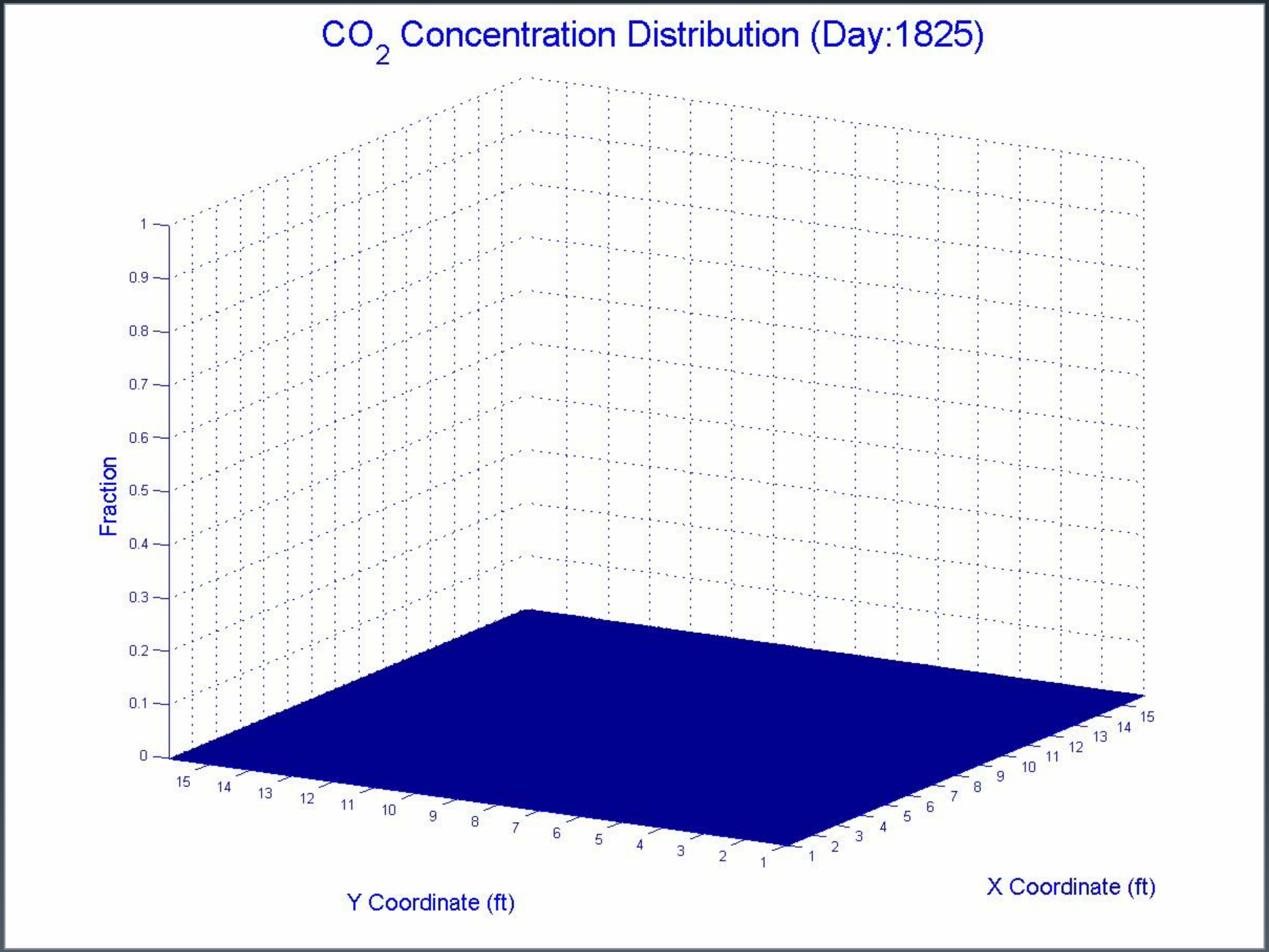
CO_2 Concentration Distribution
(Day: 3,649)



CO_2 Concentration Distribution
(Day: 4,393)



Animation of the CO_2 mole fraction build up

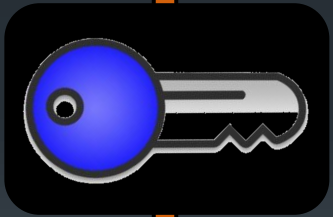


Final Remarks

Increased demand on fossil fuels

Decline in production from fossil fuels

Producing HC from unconventional reservoirs and sequestering CO_2 in: Shale Gas , Tight Gas Sands, Gas Hydrates, Coal Seams and Saline Formations



<u>Through the optimization of:</u>

- **Horizontal wellbore length**
- **Transverse fracture spacing**
- **Fracture wing length**
- **Multilateral well design**
- **Well spacing**
- **Reservoir pressure depletion rate**