Cyclic Pressure Pulsing: A Promising Method to Improve Recovery from Hydraulically-Fractured Stripper Wells of Appalachian Basin*

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Abstract

Cyclic-pressure pulsing is a single-well EOR method that has been successfully applied in naturally fractured systems. The process is driven through diffusion of the injected gas from the fractures into the matrix. After diffusing, the gas displaces remaining oil towards the fractures, which eventually results in higher production rates. In this study, the process is studied for hydraulically fractured wells to understand its effectiveness. Injected gas composition is varied as pure nitrogen, pure carbon dioxide and mixture of these gases. Appalachian Basin is considered as a case study, due to many hydraulically-fractured, stripper wells in the region. A numerical compositional simulation model is constructed and flow around the hydraulic fracture is represented using local grid refinement. A 36 API gravity crude oil taken from Appalachian Basin is defined, and reservoir characteristics represent the Appalachian Basin sandstones. The process is analyzed with a large number of simulation runs from the perspectives of operational, reservoir, and hydraulic-fracture characteristics. Key sensitivity parameters for the operational part are chosen as the injection rate, injection/soaking durations, and the economic rate limit to stop the production and restart the injection. For the reservoir/hydraulic fracturing part, reservoir permeability, hydraulic fracture's effective permeability, thickness and half-length are chosen. After collecting key performance indicators, a proxy model was constructed to obtain a screening tool for future studies and to understand key sensitivities. The study showed that within the ranges studied, cyclic-pressure pulsing with both carbon dioxide and nitrogen can be successfully applied for 1 to 25 cycles within a 20-year project period with discounted injection efficiencies representing net present values greater than zero for any realistic oil price scenario. To ensure maximum efficiency, injection and hydraulic fracture related design parameters must be considered. Injection volume and overall effectiveness of the hydraulic-fracture (width, half-length, permeability) affect the performance significantly. While benefits of soaking are clearly observed, the duration does not significantly affect the process. Economic limit must be optimized for balancing the remaining energy in the reservoir before starting the injection and maximizing barrels of oil recovered as early as possible.

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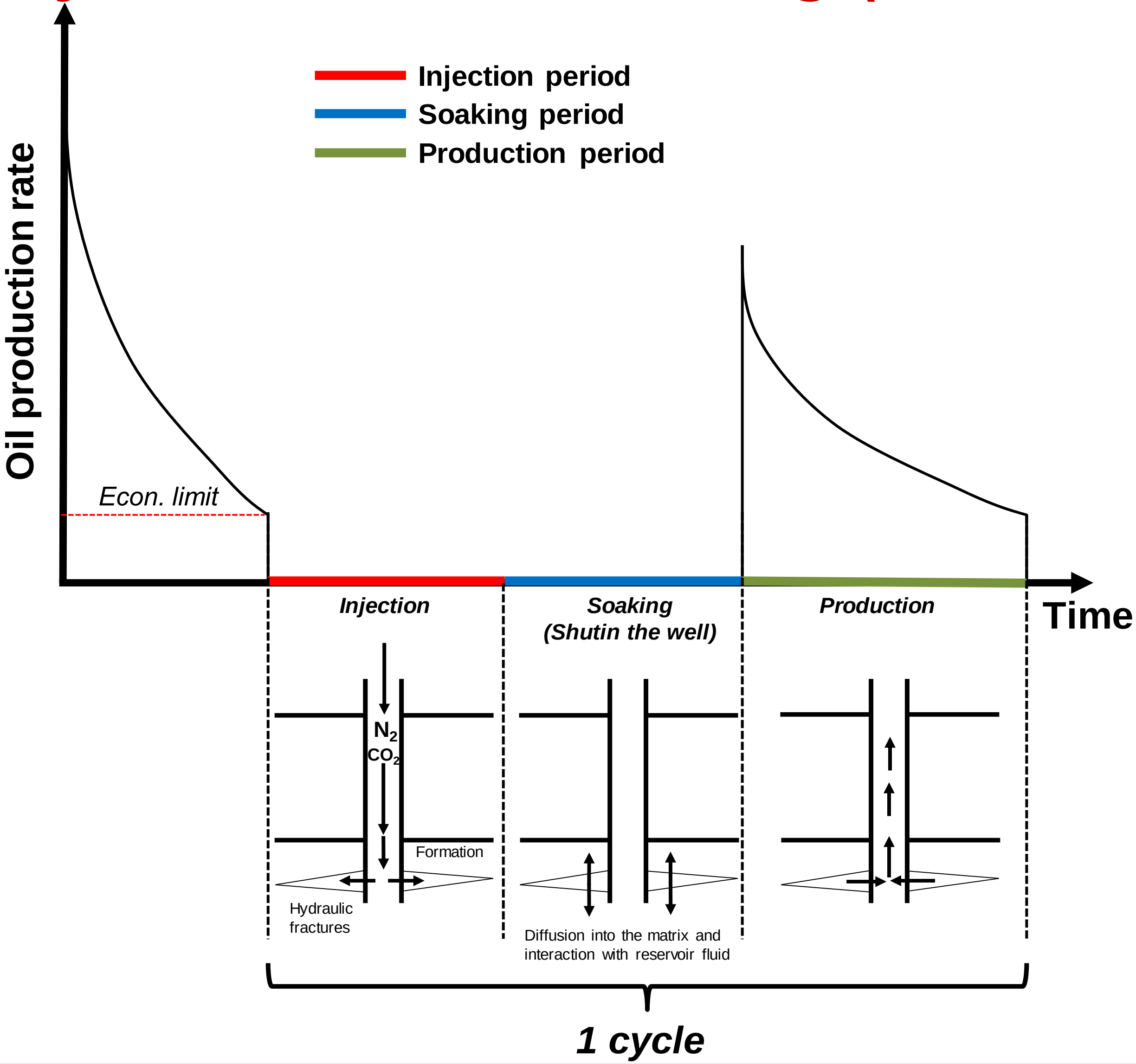
Outline

- Introduction
- Methodology
  - Modeling
  - Experimental Design
  - Performance Assessment
- Results & Discussion
  - Analysis of Operational Parameters
  - Analysis of Reservoir/HF Parameters
  - Performance Screening Tool
- Conclusions

Motivation: Appalachian Basin Sandstones

- Production since early 1900's: Old wells / infrastructure
- Depleted (p < 200 psia)
- Stripper wells ($q \approx$ 1-10 STB/d)
- Secondary recovery: completed
- Hard to justify costly EOR methods
- Hydraulic fractures
- Poorly characterized reservoirs with questionable connectivity between wells

Cyclic Pressure Pulsing (Huff 'n' Puff) with Gas



- Single-well EOR
- Fractured reservoirs (Large surface area for diffusion)
- Various types of gases

Advantages:

- Well-to-well connectivity is not required
- Shorter payback periods

History of Cyclic Pressure Pulsing

- Water: an improved way of waterflooding
  - Owens and Archer (1966); Felsenthal and Ferrell (1967)
- Natural gas
  - Raza (1971); Shelton & Morris (1973)
- CO_2 for heavy oil
  - Khatib *et al.* (1981): *California*
  - Bardon *et al.* (1986): *Bati Raman, Turkey*
  - Gondiken (1987): *Bati Raman, Turkey*
- CO_2/N_2 for light oil (naturally fractured reservoirs)
  - Miller and Gaudin (2000); Artun *et al.* (2010, 2011, 2012): *Kentucky*
- CO_2/natural gas for shale oil reservoirs
  - Sheng (2013, 2014)

Objectives

- Understanding :
  - the applicability of cyclic pressure pulsing with N_2 and CO_2 in hydraulically fractured wells in the Appalachian Basin-like reservoirs and others
  - the impact of various reservoir/hydraulic fracture and operational parameters on the process efficiency
- Development of a screening tool to estimate the process efficiency given reservoir/operational parameters

Reservoir Modeling → Experimental Design → Performance Analysis → Screening Tool

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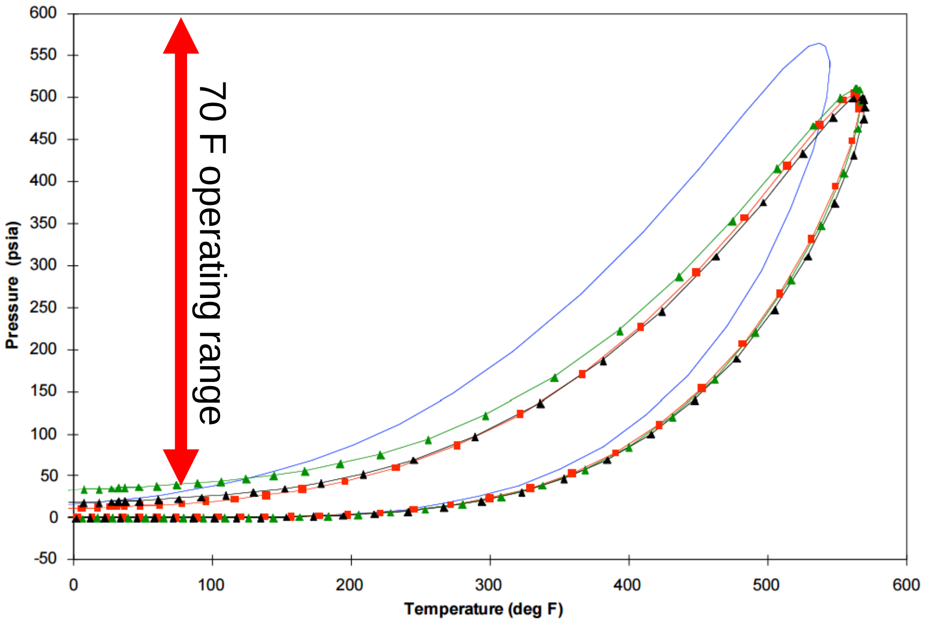
Modeling: Characteristics

- Single-well, compositional, single porosity reservoir model with a Cartesian gridblock system (CMG, 2015)

Porosity	0.1
Thickness, ft	50
Initial pressure, psia	50
Drainage area, acres	100
Water saturation	0.5
Oil saturation	0.5

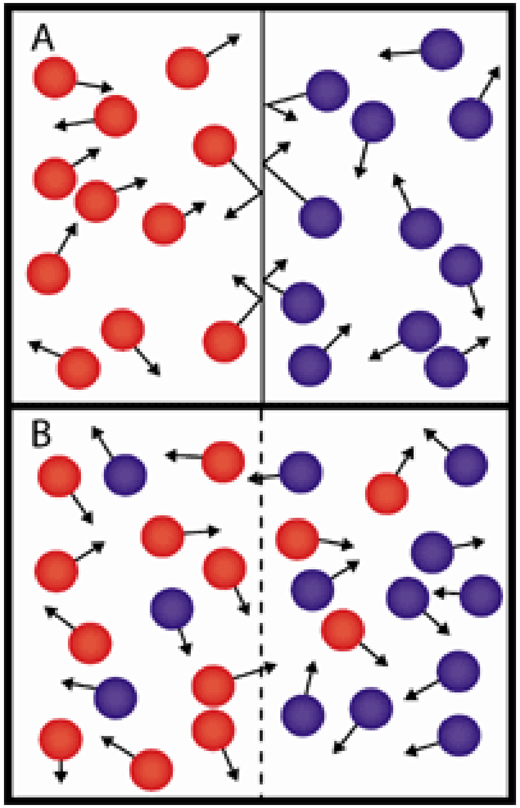
Fluid model:
Mid-Continent (light) crude oil
36º API Gravity
(Abboud, 2005; Farias and Watson, 2007)

Appalachian Basin sandstones
Duda et al., 1967
Boswell et al., 1993



Modeling: Diffusion

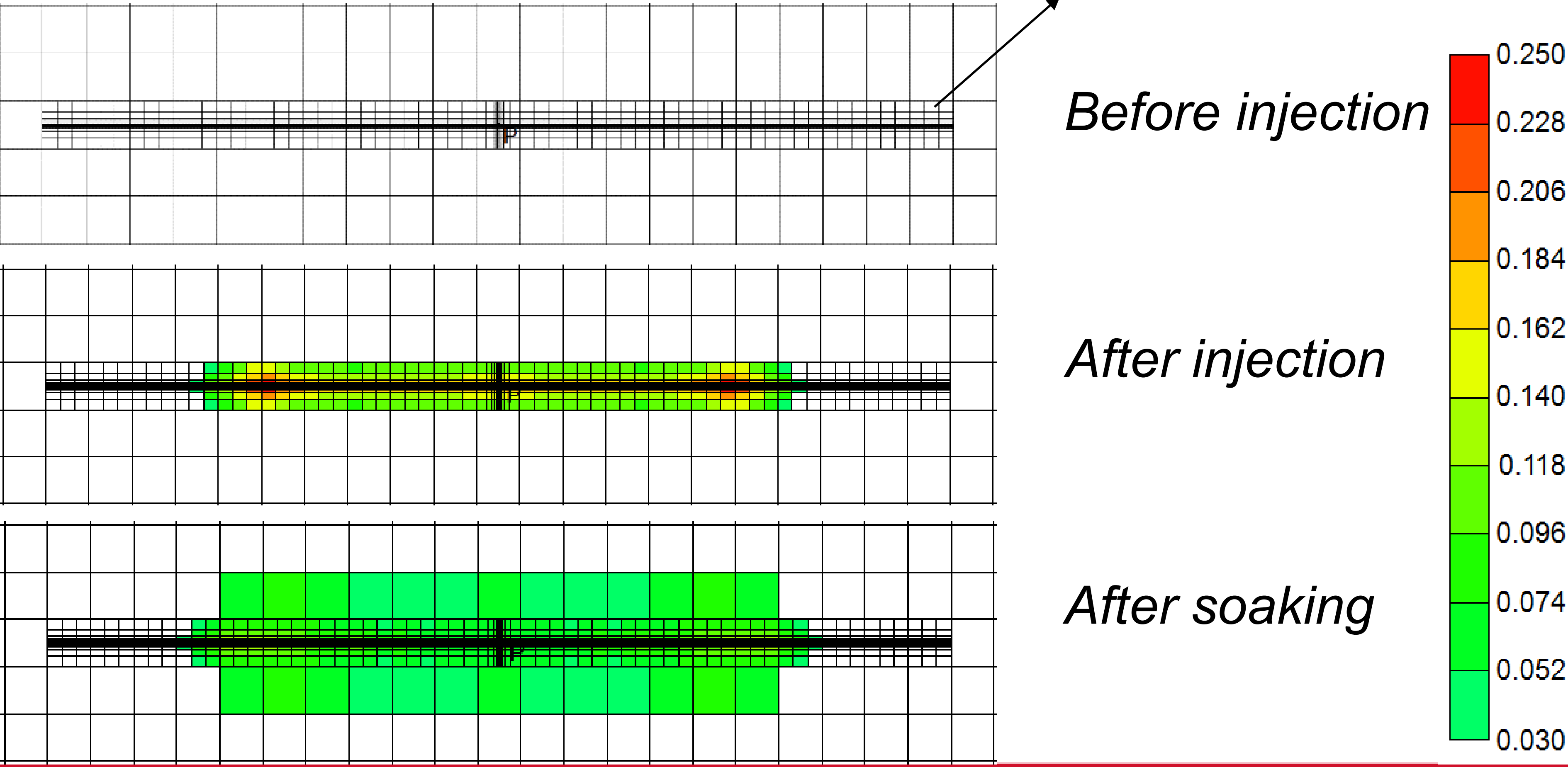
- Sigmund correlation (Sigmund, 1976) for molecular diffusion option is activated for N_2 and CO_2
- A diffusion coefficient of **0.001 cm^2/sec** is used for gas diffusion in reservoir conditions which was determined and validated based on:
  - Chapman-Enskog binary-diffusion theory (Marrero and Mason, 1972)
  - Literature (Silva and Belery, 1989)



Modeling: Hydraulic Fracture

- *Hydraulic fracture represented with a high-permeability streak*
- *Local-grid refinement to capture flow in matrix-fracture interface*

Gas saturation during a cycle of injection



Experimental Design

Injected gas composition: 1) 100% N_2 **2)** 50% CO_2 - 50% N_2 **3)** 100% CO_2

2 Full-factorial designs with 4 variables and 5 levels

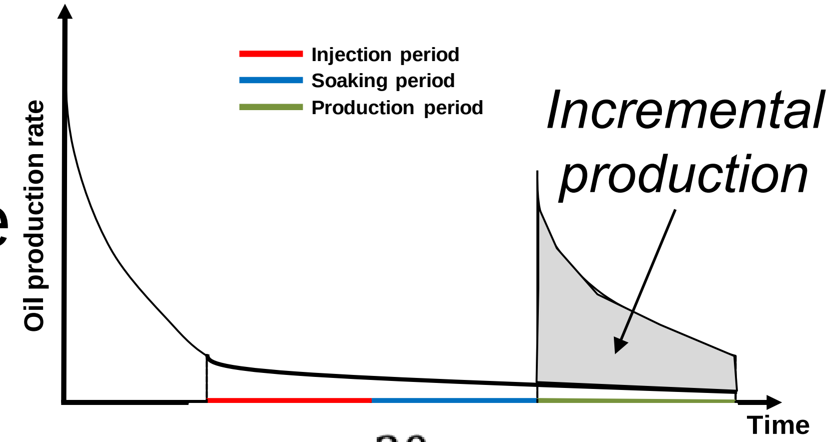
	DESIGN 1: Operational Parameters					DESIGN 2: Reservoir/Hydr. Frac. Parameters				
Levels	*1*	*2*	*3*	*4*	*5*	*1*	*2*	*3*	*4*	*5*
Inj. rate, MCF/d	100	200	300	400	500	300				
Inj. period, days	10	20	30	40	50	30				
Soak. period, days	10	20	30	40	50	30				
Cycle limit, STB/d	1.0	2.0	3.0	4.0	5.0	3.0				
Reservoir perm., md	1					0.1	1	10	50	100
Frac. permeability, mD	5000					1000	2500	5000	7500	10000
Frac. half length, ft	550					150	350	550	750	950
Fracture width, ft	0.1					0.01	0.05	0.1	0.25	0.5

$3*5^4 = 1875$ *runs* $3*5^4 = 1875$ *runs*

Total = 3750 runs

Performance Assesment

- Two key performance indicators for income/costs are incorporated for 20 years of project length:
  - Present value of incremental volume of oil produced
  - Present value of cumulative volume of gas injected



$$N_{\mathrm{pio}} = \sum_{n=1}^{20} \frac{\mathrm{N_{pin}}}{(1+i)^n}$$

$$G_{\mathrm{io}} = \sum_{n=1}^{20} \frac{G_{\mathrm{in}}}{(1+i)^n}$$

Discounted cyclic-injection efficiency $\rightarrow E_c = \frac{N_{\mathrm{pio}}}{G_{\mathrm{io}}}$ STB/MCF

Performance Assesment

- Dimensionless economic efficiency:

$$E_{ce} = E_c \times \frac{Oil\ price}{Gas\ price}$$

Gas price:

N_2 : \$1.5 /MCF

N_2 / CO_2 : \$2.0 /MCF

CO_2 : \$2.5 /MCF

If $E_{ce} > 1$ then NPV > 0

If $E_{ce} < 1$ then NPV < 0

Source for gas price:

N_2: Based on polymeric membrane unit reported (Miller and Gaudin, 2000)

CO_2: Overall market conditions reported (NETL, 2010)

Analysis Methods

1. General Overview:

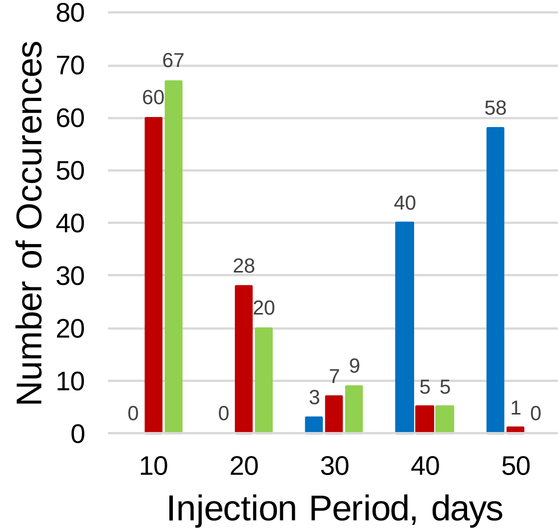
- Range, min., avg., max.
- Minimum oil price that makes the process feasible

Injected gas

100%N2	Efficiency	**0.13**	**0.41**	**0.81**
	No. of cycles	**1**	**2**	**6**
50% CO_2-50% N_2	Efficiency	**0.86**	**1.8**	**4.45**
	No. of cycles	**1**	**2.5**	**7**
100% CO_2	Efficiency	**0.47**	**1.1**	**6.95**
	No. of cycles	**1**	**3**	**7**

2. Top 100 Cases:

- Number of occurrences of each variable within the top 100 efficiency values obtained



3. All Cases:

-Mapping average values obtained from the combination of 2 related variables

100% N_2	**E_c**	**Effective fracture width, ft**					
		0.01	0.05	0.1	0.25	0.5	Avg
Effective fracture half-length, ft	150	1.5	1.7	1.8	1.8	1.9	1.7
	350	1.7	2.0	2.1	2.2	2.3	2.0
	550	1.8	2.2	2.3	2.4	2.5	2.2
	750	1.8	2.1	2.2	2.2	2.2	2.1
	950	1.8	2.2	2.3	2.3	2.2	2.2
	Avg	1.7	2.0	2.1	2.2	2.2	2.1

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Analysis of Operational Parameters

Reservoir permeability	1 mD
Effective frac. permeability	5000 mD
Effective frac. half length	550 ft
Effective fracture width	0.1 ft

Injected gas		**Min**	**Avg**	**Max**
100%N_2	Efficiency	**0.13**	**0.41**	**0.81**
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Analysis of Operational Parameters

$E_c > 0$ for all cases → all scenarios resulted in positive incremental recovery

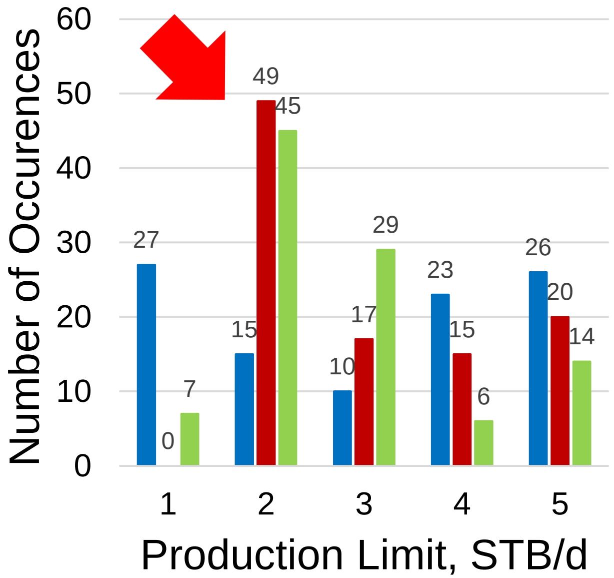
- Based on the minimum efficiency values observed:

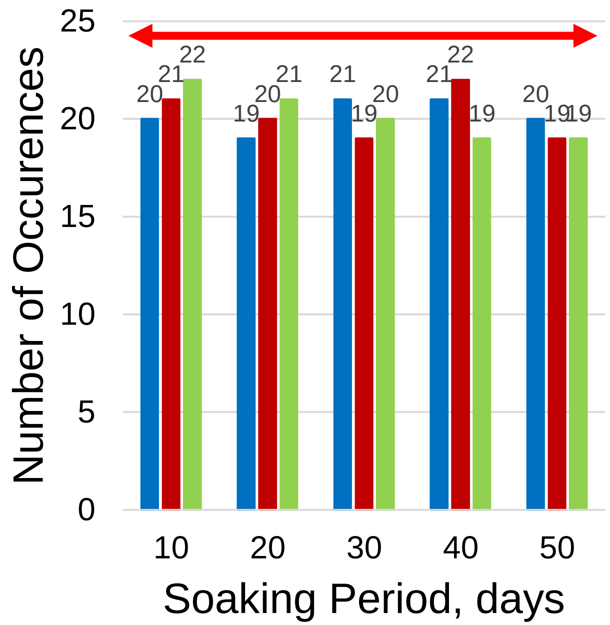
	Min(E_c)		**NPV > 0 as long as**
100% N2	0.13	→	Oil price > $11.5/STB
50% CO_2-50% N_2	0.86	→	Oil price > $2.3 /STB
100% CO_2	0.47	→	Oil price > $5.3 /STB

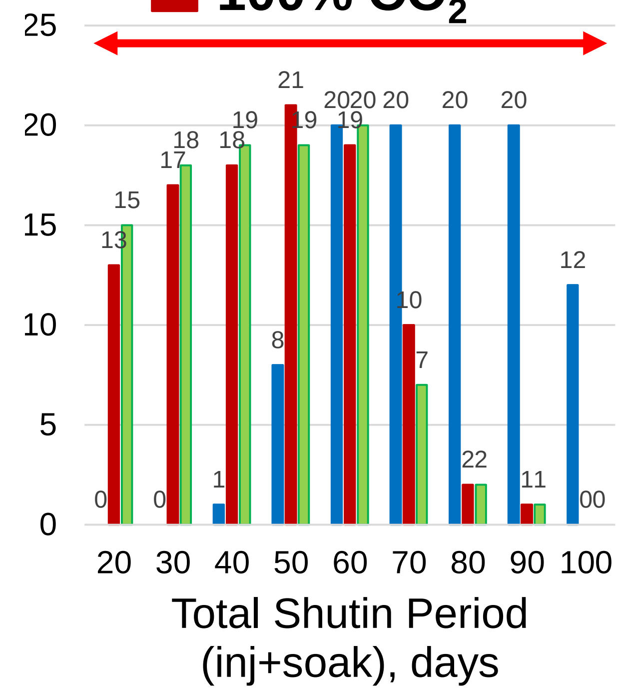
Analysis of Operational Parameters

Top 100 Cases

100% N2
50% CO_2-50% N_2
100% CO_2





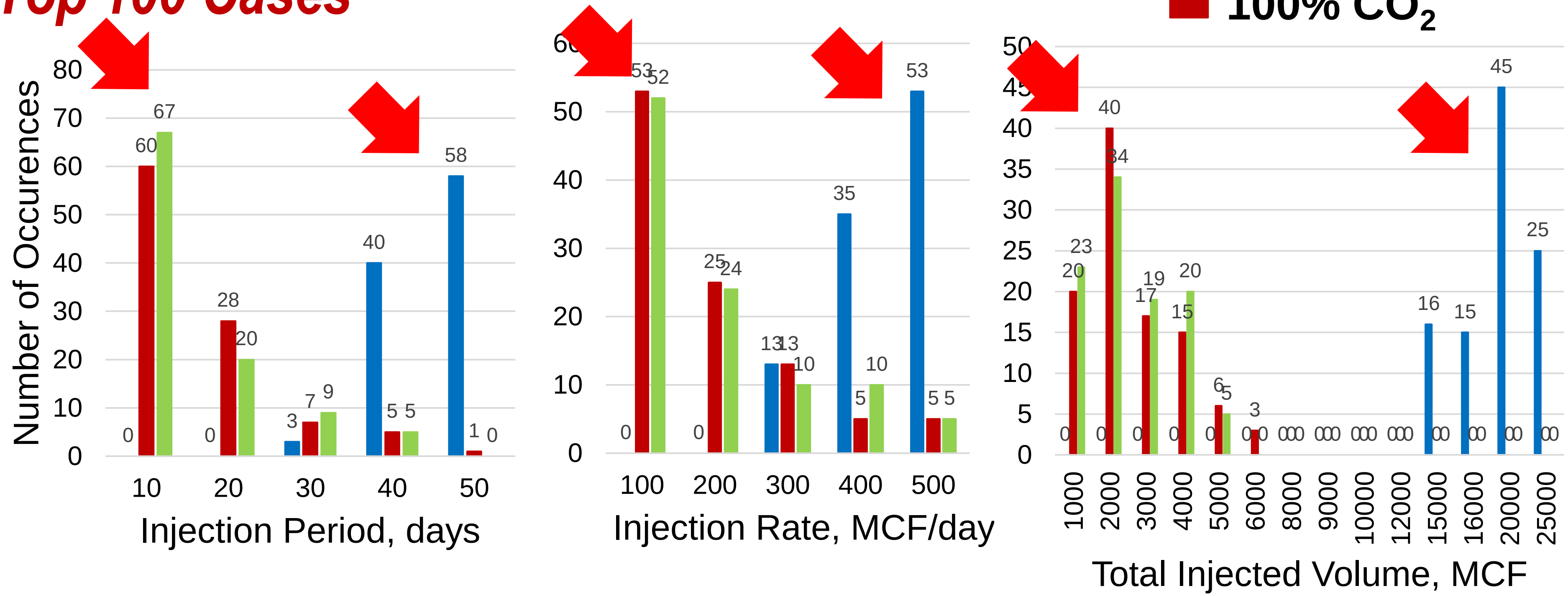


Production limit must be optimized: 2 STB/d is optimum if CO_2 is injected

- Soaking period: necessary for effective diffusion but duration doesn't affect significantly
- Soaking+injection period must be optimized to avoid *pressure dissipation:* 50-90 days

Analysis of Operational Parameters

Top 100 Cases



- N_2: higher volume of gas is needed - keep injecting at a higher rate for a long time
- CO_2: inject at a lower rate for a short time (more effective for miscibility)

Analysis of Operational Parameters

All Cases
(100% N_2)

100% N_2	E_c	Cycle Production Rate Limit, STB/d					
		1	2	3	4	5	Avg
Cycle Injection Volume, MCF	1,000	0.2	0.1	0.2	0.2	0.2	0.2
	2,000	0.3	0.2	0.2	0.3	0.3	0.2
	3,000	0.3	0.2	0.2	0.3	0.3	0.3
	4,000	0.3	0.2	0.3	0.3	0.4	0.3
	5,000	0.3	0.3	0.3	0.3	0.4	0.3
	6,000	0.4	0.3	0.3	0.3	0.4	0.3
	8,000	0.4	0.3	0.3	0.4	0.5	0.4
	9,000	0.5	0.4	0.4	0.4	0.5	0.4
	10,000	0.5	0.4	0.4	0.5	0.5	0.4
	12,000	0.5	0.4	0.4	0.5	0.5	0.5
	15,000	0.6	0.5	0.5	0.6	0.6	0.5
	16,000	0.6	0.5	0.5	0.6	0.6	0.6
	20,000	0.7	0.6	0.6	0.7	0.7	0.6
	25,000	0.8	0.7	0.7	0.8	0.8	0.7
	Avg	0.4	0.4	0.4	0.4	0.5	0.4

- Existing energy in the reservoir helps to achieve better efficiency
- Higher injection volumes are needed for pure N_2 injection

Analysis of Operational Parameters *All Cases*

50% 50%	E_c	Cycle Production Rate Limit, STB/d					
		1	2	3	4	5	Avg
Cycle Injection Volume, MCF	1,000	3.0	4.3	3.8	3.3	3.4	3.6
	2,000	2.4	3.1	2.7	2.3	3.3	2.8
	3,000	2.2	3.0	2.5	2.0	1.7	2.3
	4,000	2.0	2.6	2.4	1.9	1.5	2.1
	5,000	1.8	2.6	2.1	1.8	1.5	2.0
	6,000	1.7	2.2	2.0	1.7	1.4	1.8
	8,000	1.5	2.1	1.7	1.5	1.3	1.6
	9,000	1.5	2.0	1.7	1.5	1.2	1.6
	10,000	1.4	1.8	1.6	1.4	1.2	1.5
	12,000	1.2	1.6	1.4	1.3	1.1	1.3
	15,000	1.2	1.5	1.5	1.2	1.0	1.3
	16,000	1.1	1.4	1.5	1.2	1.0	1.2
	20,000	1.0	1.2	1.3	1.1	0.9	1.1
	25,000	0.9	1.0	1.0	0.9	0.9	1.0
	Avg	1.7	2.2	1.9	1.7	1.5	1.8

100% CO_2	E_c	Cycle Production Rate Limit, STB/d					
		1	2	3	4	5	Avg
Cycle Injection Volume, MCF	1,000	0.7	2.6	2.9	2.4	6.9	3.1
	2,000	1.0	1.9	1.6	1.9	1.9	1.7
	3,000	1.0	1.7	1.3	1.2	1.4	1.3
	4,000	1.0	1.7	1.1	1.1	1.0	1.2
	5,000	1.0	1.5	1.1	1.0	1.0	1.1
	6,000	1.0	1.4	1.2	0.9	0.8	1.0
	8,000	0.8	1.2	1.0	0.9	0.7	0.9
	9,000	0.8	1.1	0.9	0.8	0.7	0.9
	10,000	0.8	1.1	0.9	0.8	0.7	0.9
	12,000	0.8	1.0	1.0	0.7	0.7	0.8
	15,000	0.7	0.9	0.9	0.7	0.6	0.7
	16,000	0.7	0.8	0.9	0.7	0.6	0.7
	20,000	0.6	0.8	0.7	0.6	0.5	0.7
	25,000	0.6	0.8	0.7	0.6	0.5	0.6
	Avg	0.9	1.3	1.1	1.0	1.1	1.1

- Optimum production limit to start another cycle: 2 STB/d
- Lower injection volumes are favorable if CO_2 is injected

Analysis of Operational Parameters

All Cases

100% N_2	E_c	Soaking Period, days					
		10	20	30	40	50	Avg
Injection Period, days	10	0.2	0.2	0.2	0.2	0.3	0.2
	20	0.3	0.3	0.3	0.3	0.4	0.3
	30	0.4	0.4	0.4	0.4	0.4	0.4
	40	0.5	0.5	0.5	0.5	0.5	0.5
	50	0.5	0.5	0.5	0.6	0.6	0.5
	Avg	0.4	0.4	0.4	0.4	0.4	0.4

50% 50%	E_c	Soaking Period, days					
		10	20	30	40	50	Avg
Injection Period, days	10	2.7	2.7	2.7	2.6	2.6	2.6
	20	2.0	2.0	1.9	1.9	1.9	1.9
	30	1.7	1.7	1.7	1.7	1.7	1.7
	40	1.4	1.4	1.4	1.4	1.4	1.4
	50	1.3	1.3	1.3	1.3	1.3	1.3
	Avg	1.8	1.8	1.8	1.8	1.8	1.8

100% CO_2	E_c	Soaking Period, days					
		10	20	30	40	50	Avg
Injection Period, days	10	1.8	1.7	1.7	1.7	1.7	1.7
	20	1.1	1.2	1.1	1.1	1.1	1.1
	30	1.0	0.9	0.9	1.0	0.9	1.0
	40	0.8	0.8	0.9	0.9	0.8	0.9
	50	0.8	0.8	0.8	0.8	0.8	0.8
	Avg	1.1	1.1	1.1	1.1	1.1	1.1

- Soaking period doesn't affect significantly
- If CO_2 is injected, injection duration should be minimized

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Analysis of Reservoir/HF Parameters

Injection rate	300 MCF/d
Injection perio	30 days
Soaking period	30 days
Cycle rate limit	3 STB/d

Injected gas		**Min**	**Avg**	**Max**
100%N2	Efficiency	**0.45**	**2.06**	**3.2**
	No. of cycles	**1**	**2**	**7**
50% CO_2- 50% N_2	Efficiency	**0.18**	**1.31**	**2.35**
	No. of cycles	**1**	**3**	**25**
100% CO_2	Efficiency	**0.13**	**0.76**	**1.21**
	No. of cycles	**2**	**4**	**9**

Analysis of Reservoir/HF Parameters

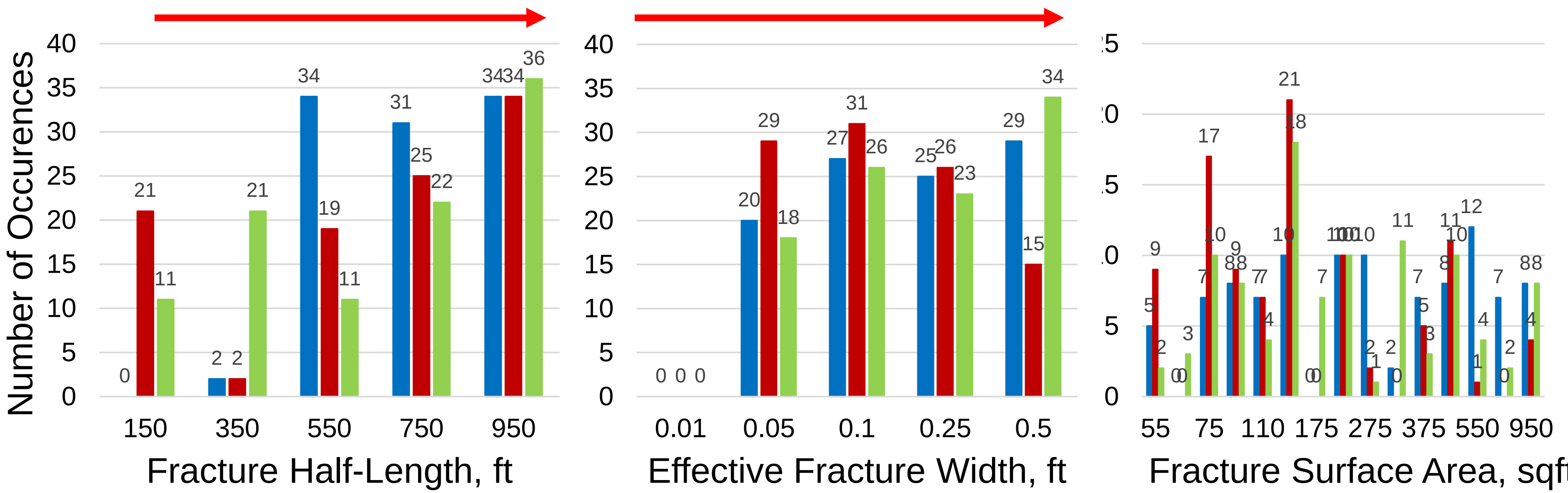
$E_c > 0$ for all cases → all scenarios resulted in positive incremental recovery

- Based on the minimum efficiency values observed:

	Min(E_c)		**NPV > 0 as long as**
100% N2	0.45	→	Oil price > $3.3/STB
50% CO_2-50% N_2	0.18	→	Oil price > $11.1 /STB
100% CO_2	0.13	→	Oil price > $11.5 /STB

Analysis of Reservoir/HF Parameters

Top 100 Cases

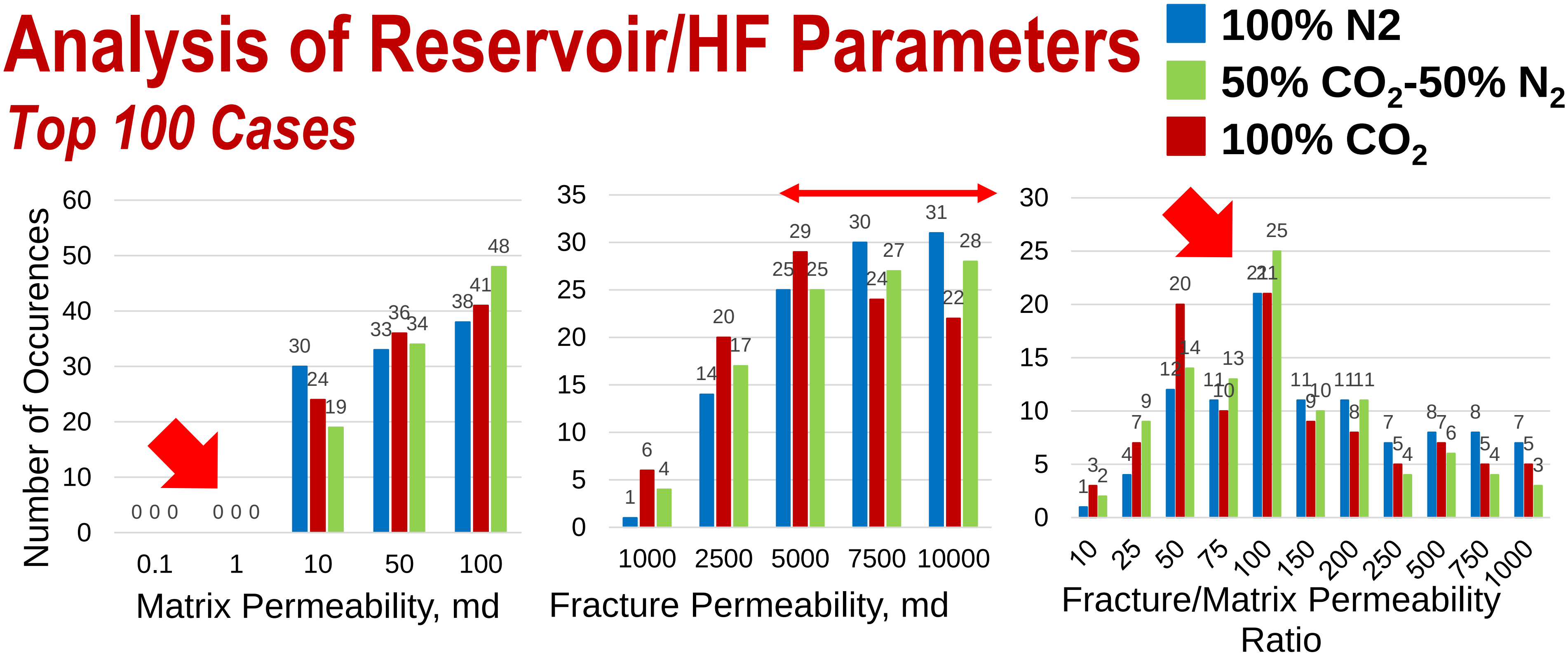


Favorable situations:

- Fracture half-length of 550 ft or more
- Fracture width: 0.05 or more

Analysis of Reservoir/HF Parameters

Top 100 Cases



- No cases with 0.1 or 1 md: Matrix Perm > 10 md are favorable
- Fracture perm of 5000 md and above: most favorable – no significant change beyond 5000 md
- Fracture/Matrix Perm ratio 50-200: is the most favorable range for all cases

Analysis of Reservoir/HF Parameters *All Cases*

100% N_2	E_c	Matrix permeability, md					
		0.1	1	10	50	100	Avg
Fracture permeability, md	1,000	0.9	2.0	2.2	2.1	2.1	1.8
	2,500	1.0	2.1	2.4	2.3	2.3	2.0
	5,000	1.0	2.1	2.5	2.5	2.5	2.1
	7,500	1.0	2.1	2.5	2.6	2.6	2.2
	10,000	1.0	2.1	2.5	2.6	2.7	2.2
	Avg	1.0	2.1	2.4	2.4	2.4	2.1

50% 50%	E_c	Matrix permeability, md					
		0.1	1	10	50	100	Avg
Fracture permeability, md	1,000	0.5	1.2	1.4	1.4	1.4	1.2
	2,500	0.6	1.3	1.5	1.5	1.5	1.3
	5,000	0.6	1.3	1.6	1.6	1.6	1.3
	7,500	0.6	1.3	1.6	1.6	1.7	1.4
	10,000	0.6	1.3	1.5	1.7	1.7	1.4
	Avg	0.6	1.3	1.5	1.6	1.6	1.3

100% CO_2	E_c	Matrix permeability, md					
		0.1	1	10	50	100	Avg
Fracture permeability, md	1,000	0.3	0.7	0.8	0.8	0.8	0.7
	2,500	0.3	0.7	0.8	0.9	0.9	0.8
	5,000	0.3	0.7	0.9	0.9	0.9	0.8
	7,500	0.3	0.7	0.9	0.9	0.9	0.8
	10,000	0.3	0.7	0.9	0.9	0.9	0.8
	Avg	0.3	0.7	0.9	0.9	0.9	0.8

Matrix Permeability

- Cases with 0.1 md resulted in significantly lower efficiencies (too tight regardless of the treatment)
- Above 10 md, no significant impact

Fracture Permeability

- Impact of fracture permeability lower if there is CO_2
- Perm >5,000 md is favorable but not significantly different beyond 5,000 md

Analysis of Reservoir/HF Parameters

All Cases

100% N_2	E_c	Effective fracture width, ft					
		0.01	0.05	0.1	0.25	0.5	Avg
Effective fracture half-length, ft	150	1.5	1.7	1.8	1.8	1.9	1.7
	350	1.7	2.0	2.1	2.2	2.3	2.0
	550	1.8	2.2	2.3	2.4	2.5	2.2
	750	1.8	2.1	2.2	2.2	2.2	2.1
	950	1.8	2.2	2.3	2.3	2.2	2.2
	Avg	1.7	2.0	2.1	2.2	2.2	2.1

50% 50%	E_c	Effective fracture width, ft					
		0.01	0.05	0.1	0.25	0.5	Avg
Effective fracture half-length, ft	150	0.9	1.1	1.2	1.2	1.3	1.1
	350	1.1	1.3	1.3	1.4	1.5	1.3
	550	1.1	1.3	1.4	1.3	1.4	1.3
	750	1.2	1.4	1.4	1.4	1.3	1.3
	950	1.2	1.5	1.5	1.5	1.4	1.4
	Avg	1.1	1.3	1.4	1.4	1.4	1.3

100% CO_2	E_c	Effective fracture width, ft					
		0.01	0.05	0.1	0.25	0.5	Avg
Effective fracture half-length, ft	150	0.7	0.8	0.8	0.8	0.9	0.8
	350	0.7	0.8	0.7	0.7	0.7	0.7
	550	0.7	0.8	0.8	0.7	0.7	0.7
	750	0.7	0.8	0.8	0.8	0.7	0.8
	950	0.7	0.8	0.8	0.8	0.8	0.8
	Avg	0.7	0.8	0.8	0.8	0.8	0.8

- Hydraulic fracture effectiveness can increase the efficiency by 50% if N_2 is injected, 30% if pure CO_2 is injected
- CO_2 injection benefits less from the fractures as compared to N_2
- Diffusion: more critical for N_2

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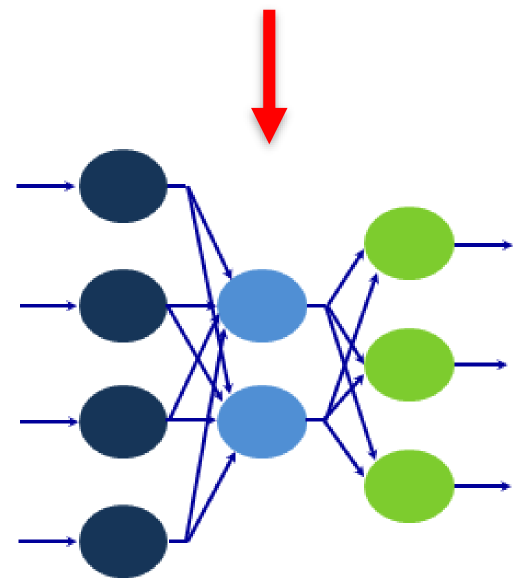
Development of a Screening Tool

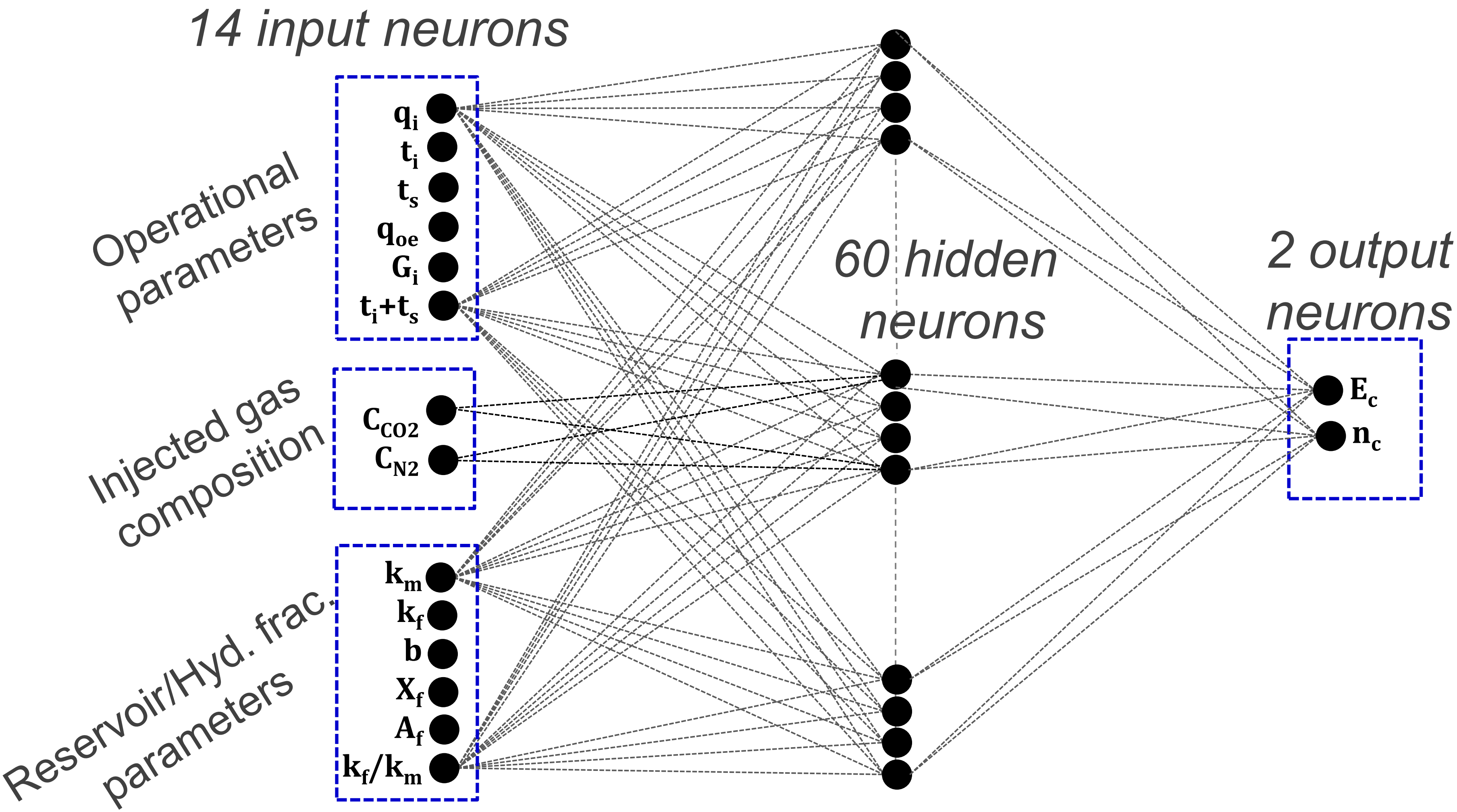
- A screening tool is developed that utilizes artificial neural networks to predict number of cycles and process efficiency
- Levenberg-Marquardt backpropagation algorithm is used for training
- The data set is divided as:
  - 70% training set
  - 15% validation set (testing during training)
  - 15% testing set (blind cases that are not shown during training)

Inj. rate, MCF/d	Inj. period, days	Soak. period, days	Prod. period, months
60	15	20	12
82	20	12	7
76	25	18	9
90	14	34	7
66	34	16	20
⋮	⋮	⋮	⋮
100	22	36	16

500 cases

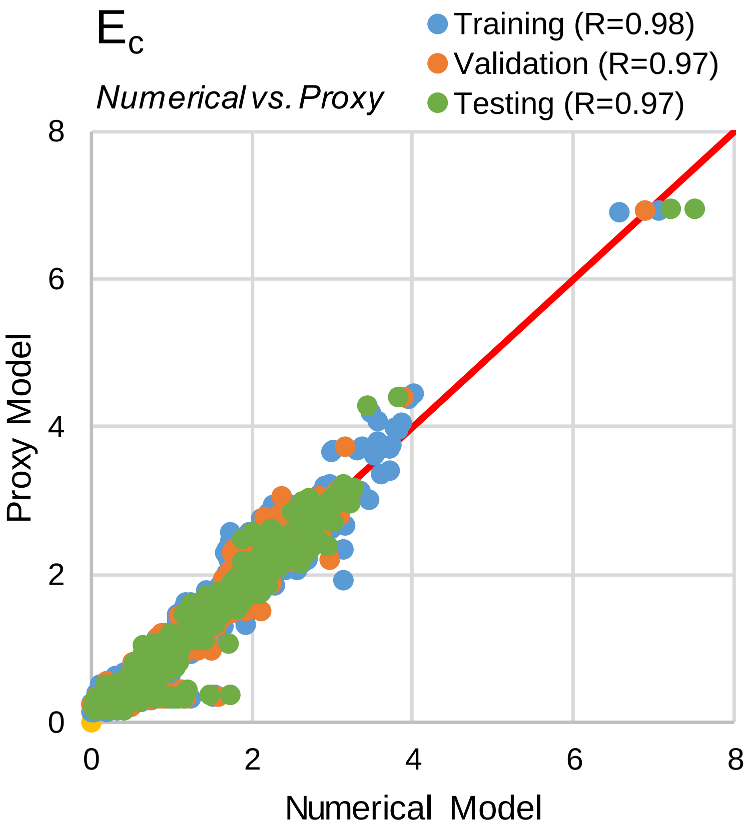


Structure of the Screening Model

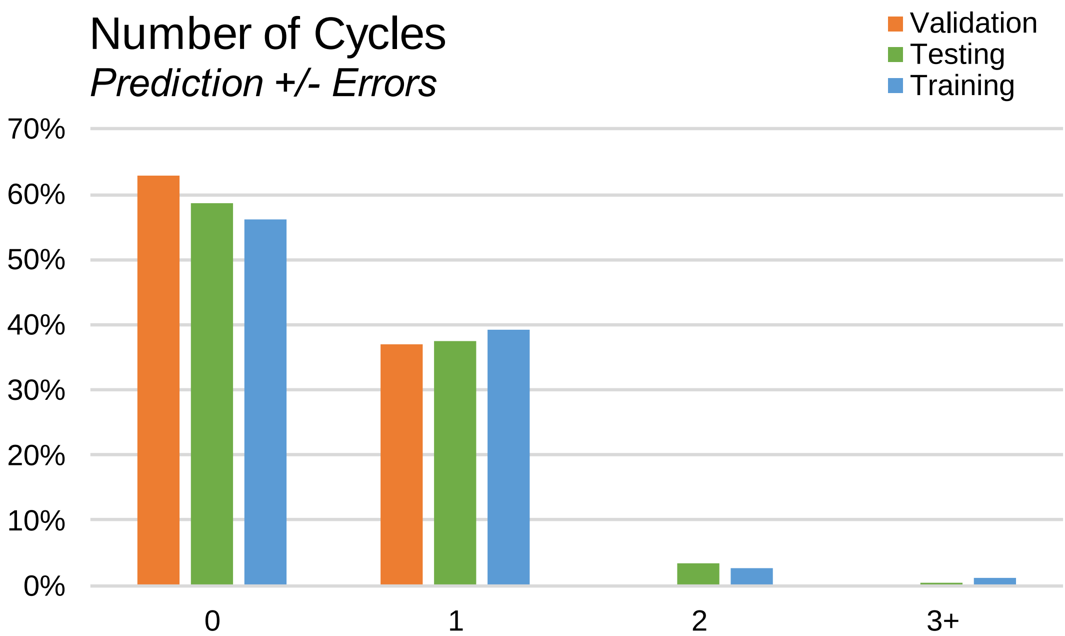


Accuracy of the Screening Model

Given reservoir/hydraulic fracture characteristics, operational parameters and injected gas composition



Efficiency is predicted with a correlation coefficient of **0.97**



Number of cycles is predicted within +/-1 accuracy in **95%** of the cases

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Conclusions: General

- Cyclic pressure pulsing with N_2 and CO_2: an effective and feasible EOR method in hydraulically fractured wells, in reservoirs similar to the Appalachian Basin sandstones
  - All cases within the ranges of parameters studied resulted in positive incremental oil recovery
  - Gas costs indicated favorable economics with positive NPV's for oil prices greater than $11 /STB
- While not significantly different, varying results are obtained depending on the injected gas: 50% CO_2/N_2 was similar to 100% CO_2
- A neural-network based screening tool is trained and validated that can estimate the process efficiency and number of cycles with high accuracy.

Conclusions: Operational Parameters

- Soaking period is necessary for diffusion, but it doesn't affect the efficiency significantly
- The optimum time for total shutin time must be determined
  - *Long shut-in periods (>90 days): dissipation of pressure, reduced efficiency*
  - *Short shut-in periods (<50 days): not sufficient diffusion, reduced efficiency*
- Injection scheme:
  - N_2: higher volume of gas is needed - keep injecting at a higher rate for a long time
  - CO_2: inject at a lower rate for a short time (more effective for miscibility)
- Production limit rate must be optimized: 2 STB/d is optimum if CO_2 is injected

Conclusions: Reservoir Parameters

- Hydraulic fracture effectiveness can increase the efficiency by
  - 50% if N_2 is injected
  - 30% if CO_2 is injected

Diffusion is more critical for N_2

- Cases with matrix permeability of 0.1 md resulted in significantly lower efficiencies (too tight regardless of the treatment).

- Impact of fracture permeability lower if there is CO_2
  - Fracture permeability of 5,000 md and above is favorable for higher efficiency (no significant change above 5,000 md)

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NORTHERN CYPRUS CAMPUS | 10th ANNIVERSARY

Cyclic Pressure Pulsing: A Promising Method to Improve Recovery from Hydraulically-Fractured Stripper Wells of Appalachian Basin

Thank you…

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