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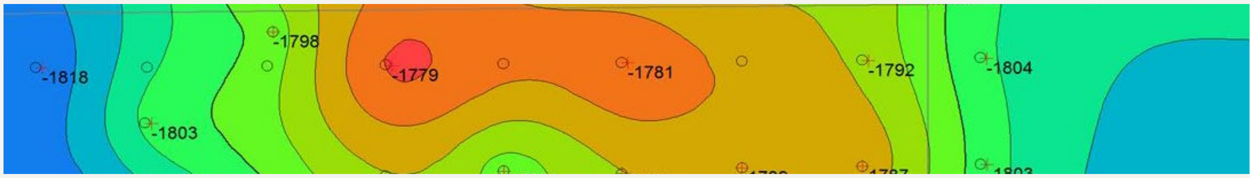

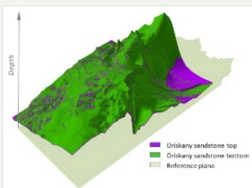

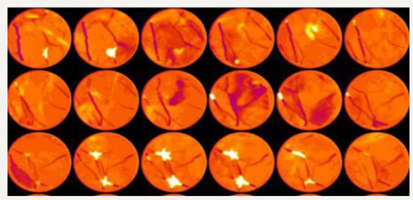

Reservoir Simulation of Enhanced Tight Oil Recovery: Eagle Ford Shale

April 22, 2019
DOE/NETL-YYYY/####

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DOE Contract Number DE-FE0025912

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List of Exhibits

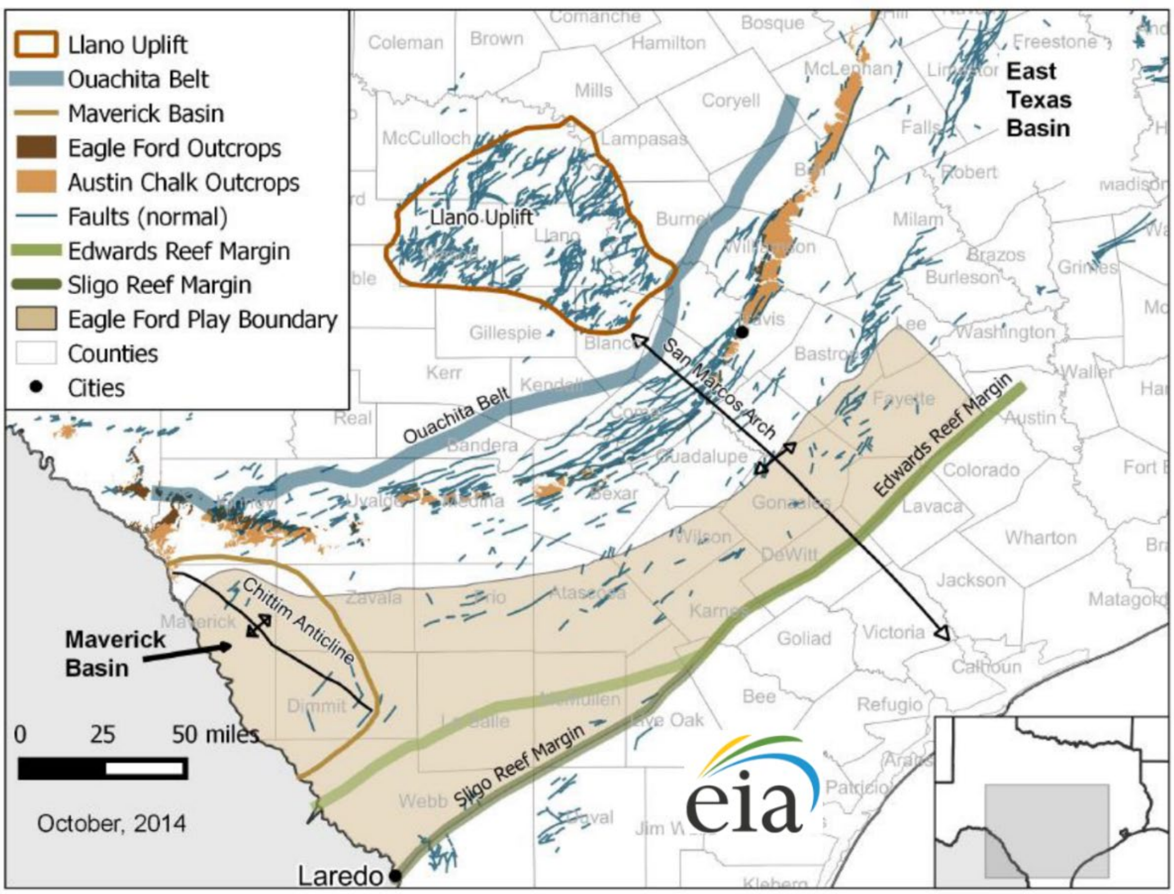
ACRONYMS AND ABBREVIATIONS

Ai	Initial decline parameter
API	American Petroleum Institute
ARI	Advanced Resources International
b	Long-term decline parameter
B	Barrel
bbl	Barrel
BOE	Barrel of oil equivalent
BOED	Barrels of Oil Equivalent per Day
bpd	Barrels per day
C_1	Methane
C_2	Ethane
C_3	Propane
C_4	Butane
CCS	Carbon capture and sequestration
CMG	Computer Modeling Group
CO_2	Carbon dioxide
D&C	Drilling and Completion
DOE	Department of Energy
EIA	Energy Information Administration
EOR	Enhanced oil recovery
EOS	Equation of State
EPA	Environmental Protection Agency
EUR	Estimated ultimate recovery
ft	Foot, Feet
GOR	Gas-oil ratio
Hz	Horizontal
IOR	Improved oil recovery
IP	Initial production
LEF	Lower Eagle Ford
MBbl	Thousand barrels
MBOED	Thousand Barrels Oil Equivalent per Day
Mcf	Thousand cubic feet
mD	Millidarcy
MESA	Mission Execution and Strategic Analysis
Mi^2	Square mile
MM	Million
MMB/D	Million barrels per day
MMcfd	Million Cubic Feet per Day
MMP	Minimum miscibility pressure
MMscf	Million standard cubic feet
MMscfd	Million standard cubic feet per day
N_2	Nitrogen
NETL	National Energy Technology Laboratory
NGL	Natural gas liquids
O&M	Operation and maintenance
OGIP	Original gas in-place
OOIP	Original oil in-place
psi	Pounds per square inch
R&D	Research and development
RB/STB	Reservoir barrels/stock tank barrels
Ro	Vitrinite reflectance
Scf/B	Standard cubic feet per barrel
SRV	Stimulation Reservoir Volume
TOC	Total Organic Carbon
U.S.	United States
UEF	Upper Eagle Ford
°C	Degrees Celsius
°F	Degrees Fahrenheit

1 Geologic Setting

The Upper Cretaceous Eagle Ford Shale contains a highly complex and diverse hydrocarbon resource. The formation's geologic and reservoir properties range widely across its 20,000 square mile shale deposition area, particularly within the 10,000 square mile area under active development. The Eagle Ford Shale area addressed by this reservoir simulation study is located west of the San Marcos Arch, south of the Ouachita Belt and north of the Sligo Reef and Edwards Reef Margins, Exhibit 1. East of the San Marcos Arch, the Eagle Ford Shale becomes interbedded with the Woodbine tight sand. This area is labeled the Eaglebine by industry and is not addressed by this reservoir simulation study.

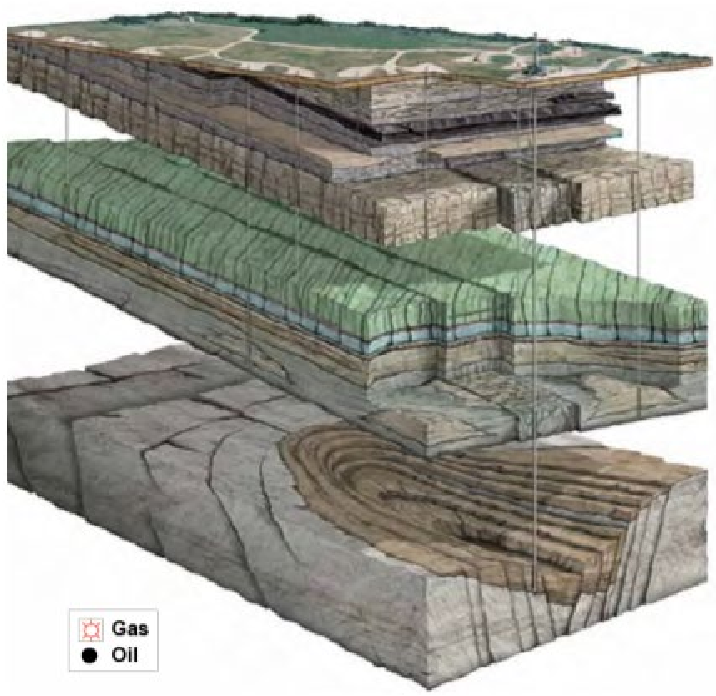
Exhibit 1 Eagle Ford Shale Geologic Features and Location Map



Source: U.S. Energy Information Administration, 2014

The Eagle Ford Shale in the study area lies above the Buda Limestone and is overlain by the Austin Chalk, as illustrated for the Maverick Basin on Exhibit 2. This area contains a stack of oil and gas producing Cretaceous-age formations, including the recently active Austin Chalk.

Exhibit 2 Eagle Ford Shale Stratigraphic Column



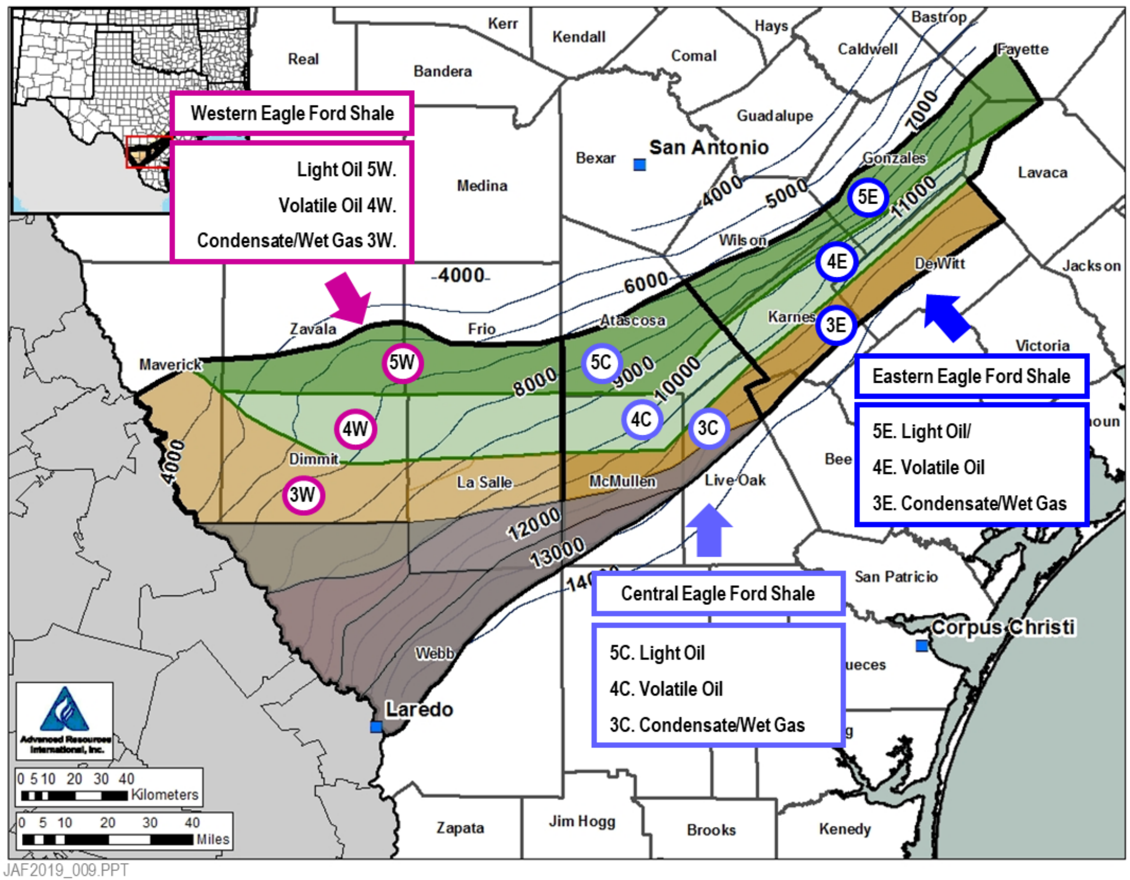
Maverick Basin		Fort Trinidad
☼ Escondido	Cretaceous	☼ Navarro
☼ Olmos/CBM		☼ Taylor
● San Miguel		Pecan Gap
● Anacacho		● Austin Chalk
● Austin Chalk		● Eagle Ford/ Woodbine
● ☼ Eagle Ford		☼ ● Buda
● Buda		Del Rio
Del Rio		☼ Georgetown
☼ ● Georgetown		☼ Edwards
☼ ● Pryor		☼ ● Glen Rose Shoals
☼ McKnight		☼ James
☼ ● Glen Rose Shoals/Reefs Porosity		Pine Island
☼ Pearsall / James		☼ Pettet
☼ Pine Island		☼ Hosston
☼ Sligo		
Hosston		
☼ Jurassic	Jurassic	☼ Bossier

Source: TXCO Resources, 2009

A notable feature of the Eagle Ford Shale is its numerous hydrocarbon "windows", linked to the thermal maturity and depth of the shale. These hydrocarbon "windows" range from a deep (13,000 ft) dry gas setting on the southwest of the shale area, to a moderately deep (10,000 ft to 12,000 ft) condensate and wet gas setting in the center of the shale area, and to a (6,000 ft to 10,000 ft) shallower volatile/light oil setting along the northwestern portion of the shale area.

Exhibit 3 shows the location of the oil dominant (condensate/wet gas, volatile oil and light oil) play areas in the northern and eastern portions of the Eagle Ford Shale. Along with production of oil and condensate, the Eagle Ford's oil dominant area also provides significant volumes of wet associated natural gas with high natural gas liquids content.

Exhibit 3 Eagle Ford Shale Oil Dominant Play Areas



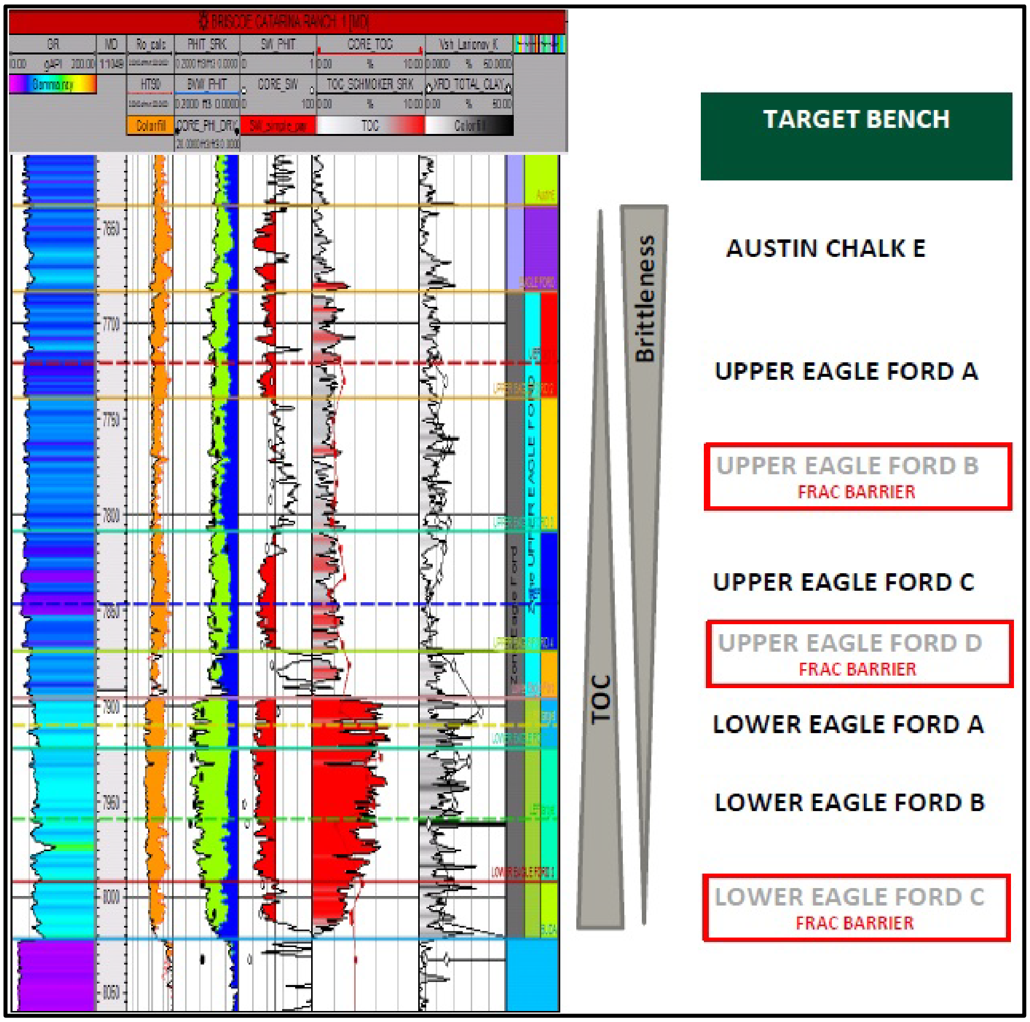
Source: Advanced Resources International, 2018

A series of additional <u>dry and wet natural gas dominant</u> play areas exist in the southwestern portion of the Eagle Ford Shale, primarily in southern LaSalle and McMullen counties and in Webb County. The natural gas dominant play areas also provide by-product production of moderate volumes of oil and condensate.

2 Study Area

The area selected for the reservoir simulation study is located in the Central Eagle Ford Shale's oil dominant area, in northern McMullen County, labeled Play #4C. Volatile Oil on Exhibit 3. The Eagle Ford shale in this area has an Upper and a Lower Shale Unit, with a low permeability interval separating the two shale units, as illustrated on Exhibit 4.

Exhibit 4 Upper, Middle and Lower Units of the Eagle Ford Shale

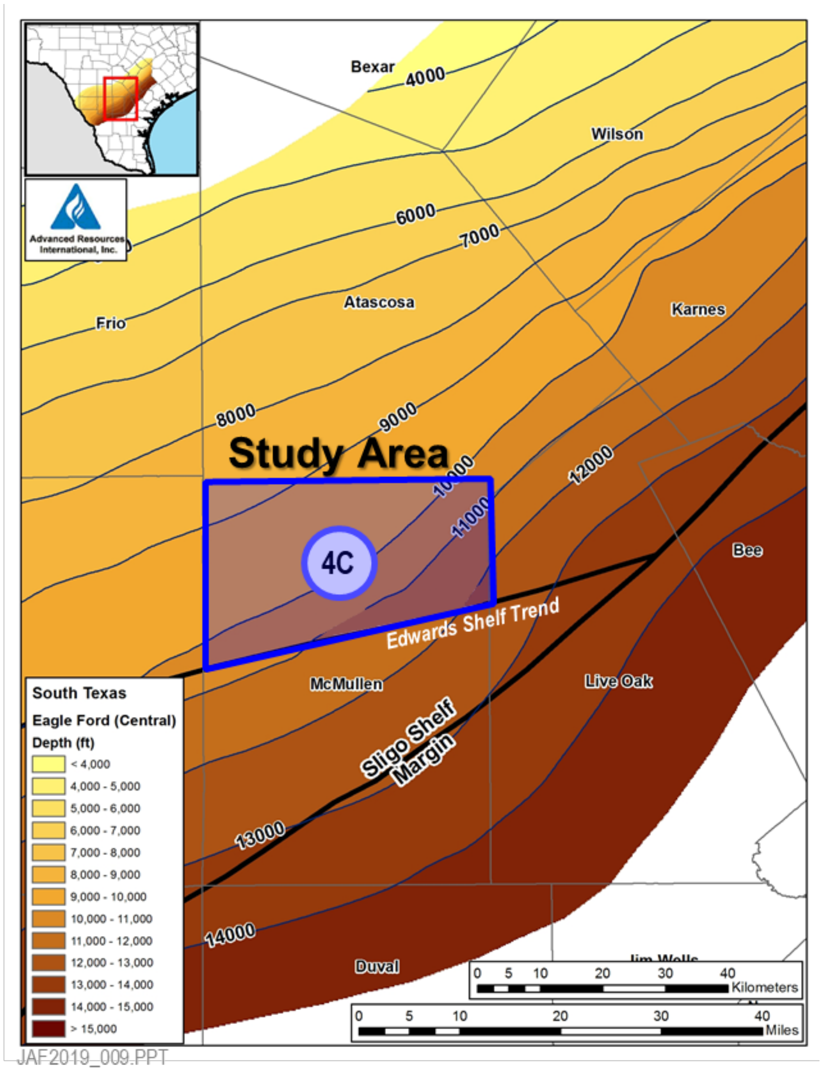


Source: Sanchez Energy, 2017

The Eagle Ford Shale Reservoir Simulation Study Area is at a depth of 10,000 ft. in northern McMullen County and is located north of the Edwards Shelf Trend, Exhibit 5. The Eagle Ford

Shale Study Area extends across a 584 mi^2 (373,760-acre area) and has seen considerable development. The reservoir simulation study focusses on a 112-acre representative area within this larger Central Eagle Ford Shale volatile oil area.

Exhibit 5 Outline of Reservoir Simulation Study Area, Northern McMullen County

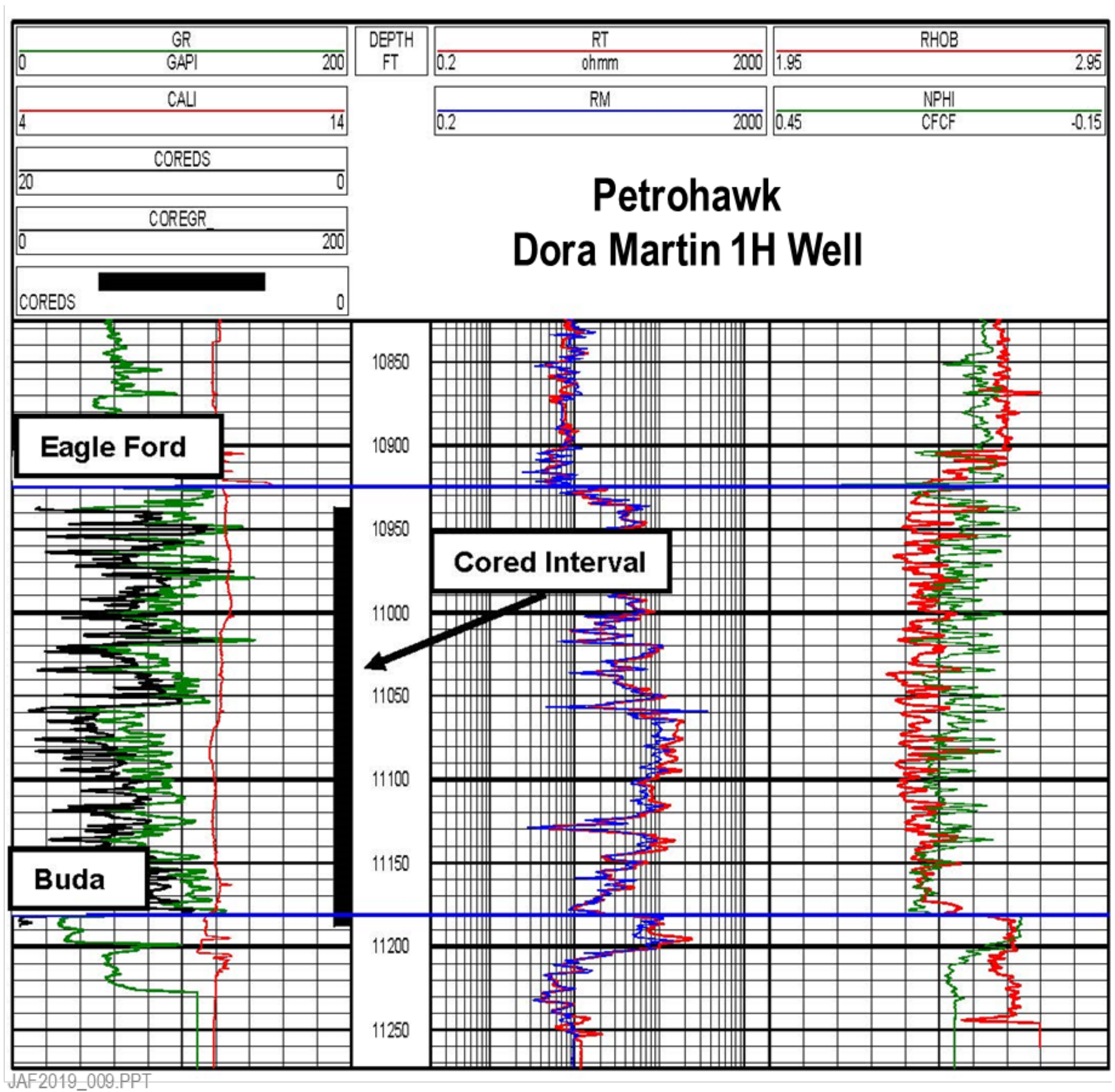


Source: Advanced Resources International, 2018

3 SOURCES OF DATA FOR RESERVOIR PROPERTIES

The reservoir properties used for the Study Area have been assembled from a variety of sources, including log and core information from the Petrohawk Dora Martin 1H Well to the south and west of the Study Area in northern LaSalle County, Exhibit 6.

Exhibit 6 Log Analysis for Petrohawk's Eagle Ford Dora Martin 1H Well in LaSalle County



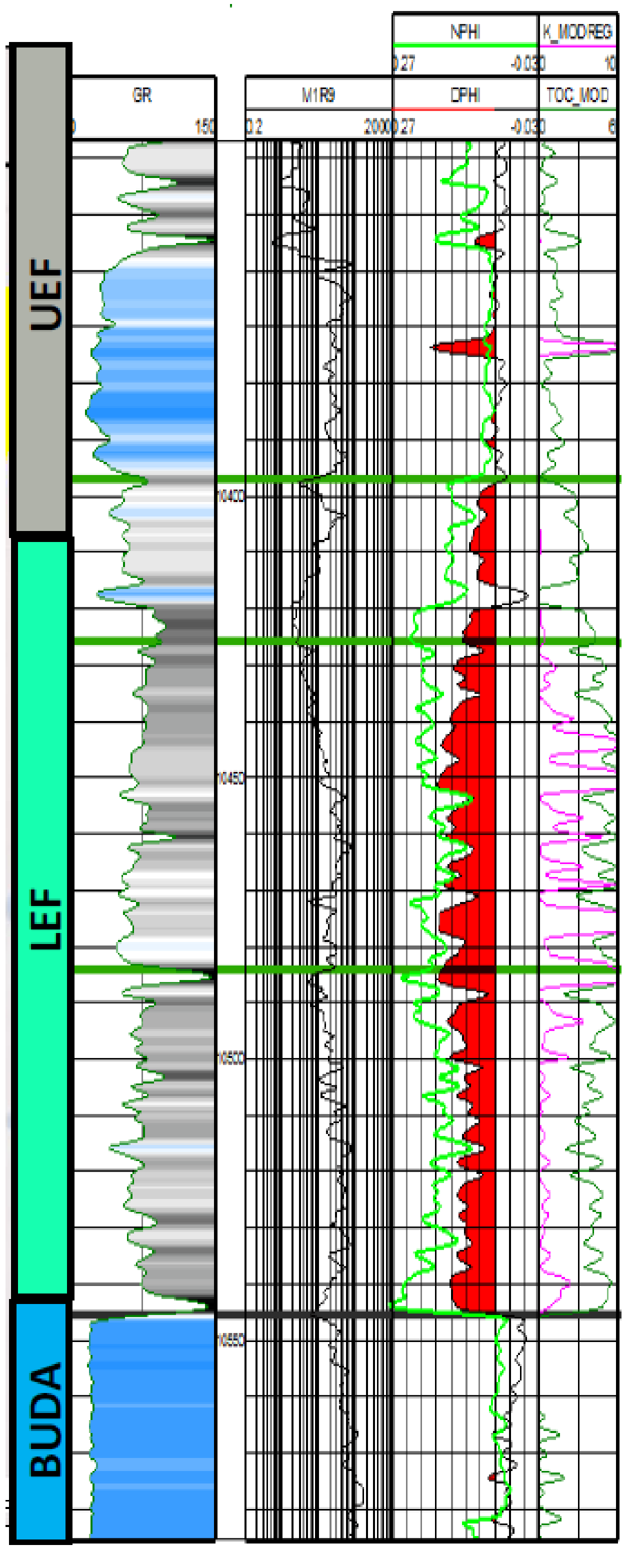
Source: Petrohawk, 2009

The Dora Martin 1H well is located in a deeper and thicker shale area south of the Study Area, called the Hawkville Trough. In this area, the total Eagle Ford Shale extends across an interval of about 250 ft. Data provided in an industry presentation on the reservoir properties of this well include a depth (to top) of 10,900 ft, a porosity of 10 to 11 percent, a TOC of 4.5 percent, a temperature of 280ºF, and a pressure gradient of 0.65 psi/ft. While the shale is thicker in the Hawkville Trough than in the Study Area, the other reservoir properties of the Dora Martin 1H well are representative of the Study Area.

Additional information has been gained from log analysis of the Sanchez Energy's Wycross Unit well drilled in 2014 in the Study Area in northern McMullen County, Exhibit 7. The Lower Eagle Ford Shale in the Sanchez Energy Wycross well is at a depth of 10,400 ft, has an interval of 120 ft with higher gamma ray (higher TOC) and higher porosity in the Lower Eagle Ford (LEF) Shale, a 25-foot low porosity interval at the top of the Lower Eagle Ford Shale, and a low gamma ray (low TOC) and lower porosity 60-foot interval in the Upper Eagle Ford (UEF) Shale.

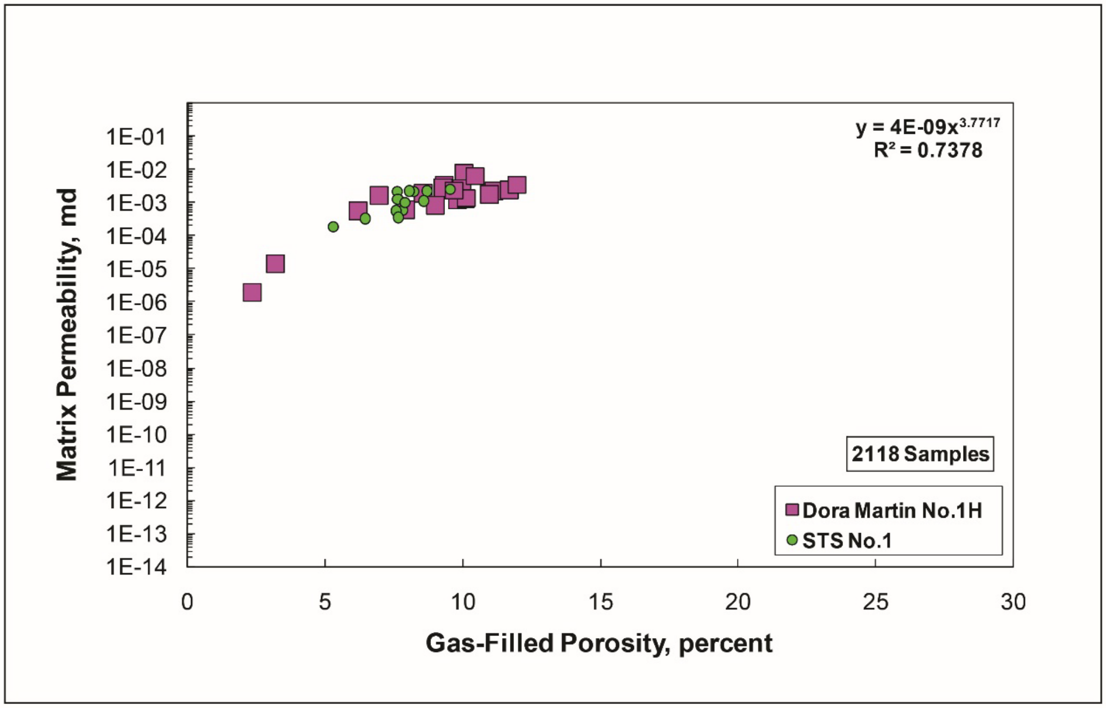
Particularly valuable information on the relationship of gas-filled porosity and reservoir permeability was available from core analyses of the Dora Martin 1H well, Exhibit 8. The Exhibit shows two rock samples with low gas-filled porosity of 3 to 4 percent corresponding with low matrix permeabilities of $1 * e^{-5}$ and $1 * e^{-6}$ md (presumably at surface pressure conditions). Numerous rock samples with higher gas-filled porosity values of 8 to 12 percent correspond with higher matrix permeabilities of $5 * e^{-3}$ and $5 * e^{-4}$ md.

Exhibit 7 Log Analysis for Sanchez Energy's Wycross Well, Northern McMullen County



Source: Sanchez Energy, 2014.

Exhibit 8 Relationship of Matrix Permeability to Gas Filled Porosity



Source: Petrohawk, 2009.

4 Reservoir Properties and Oil Composition Used for Reservoir Simulation

4.1 Representative Reservoir Properties

Exhibit 9 provides a comprehensive listing of the reservoir properties for the Lower Eagle Ford Shale used in performing reservoir simulation for the Study Area.

Exhibit 9 Lower Eagle Ford Shale Study Area Reservoir Properties

Reservoir Properties	Units
Pattern Area	112 acres
Well Pattern Dimensions	
▪ Length	7,500 ft
▪ Width	650 ft
Depth (to top)	10,000 ft
Net Pay	120 ft
Porosity	
▪ Matrix	9%
▪ Fracture	0.1%
Oil Saturation	
▪ Matrix	80%
▪ Fracture	90%
Saturation Gas/Oil Ratio	1.2 Mcf/B
Formation Volume Factor	1.64 RB/STB
Pressure	6,425 psia
Temperature	260 ^{o} F
Bubble Point	3,456 psia
Formation Compressibility	5 * e $^{-6}$/psi
Oil Gravity	43^{o} API

Source: Advanced Resources International, 2018

4.2 Oil Composition

The oil composition data, reflecting a saturation gas/oil ratio of 1,200 scf/B, is provided below for the Lower Eagle Ford Shale in the Study Area, Exhibit 10. It has been constructed by interpolating from oil composition data for GOR's of 1,000 scf/B and 2,000 scf/B.

Exhibit 10 Lower Eagle Ford Shale PVT and Oil Composition Data

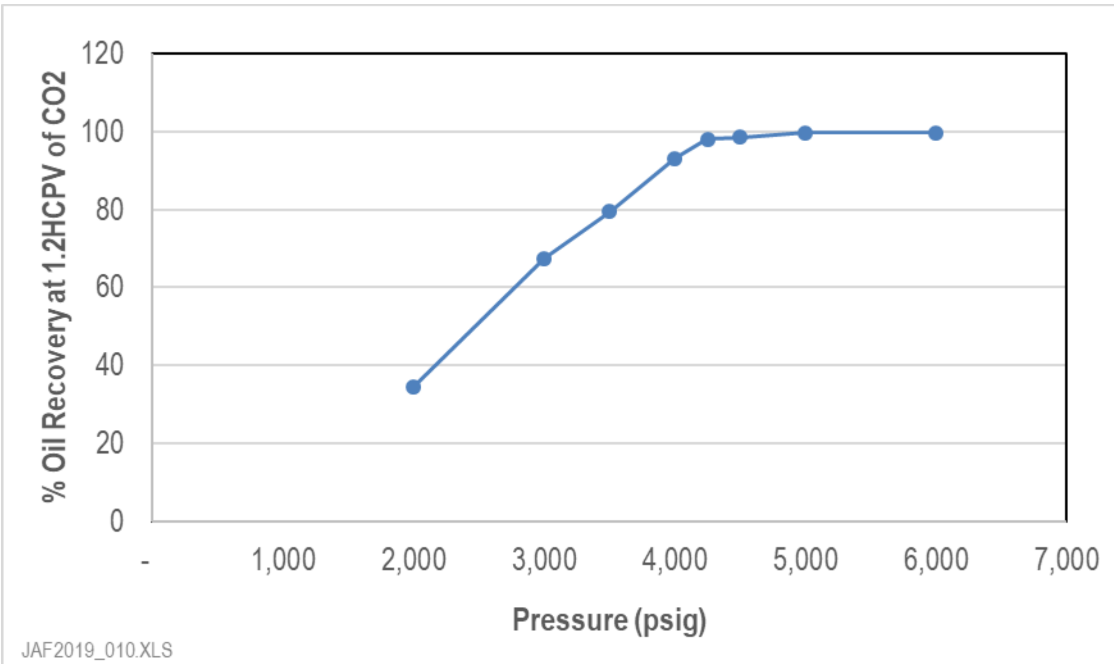
	GOR (scf/Bbl)			
	500	**1000**	**1200 (Interpolated)**	**2000**
C1	31.231	44.522	47.929	56.447
N2	0.073	0.104	0.112	0.132
C2	4.314	5.882	6.284	7.288
C3	4.148	4.506	4.598	4.827
CO2	1.282	1.821	1.960	2.306
iC4	1.35	1.298	1.285	1.251
nC4	3.382	2.978	2.874	2.615
iC5	1.805	1.507	1.431	1.24
nC5	2.141	1.711	1.601	1.325
nC6	4.623	3.28	2.936	2.076
C7+	16.297	11.563	10.350	7.316
C11+	12.004	8.94	8.078	5.924
C15+	10.044	7.127	6.379	4.509
C20+	7.306	4.762	4.186	2.745

Source: Modified by Advanced Resources Int'l from Gala, D., and Sharma, M. , 2018.

4.3 Estimating Minimum Miscibility Pressure for CO_2 and the Reservoir's Oil

To estimate the minimum miscibility pressure (MMP) between CO_2 and the oil composition for the Study Area Eagle Ford Shale reservoir, Advanced Resources International conducted a suite of slimtube simulations (using GEM) to establish a MMP of 4,000 to 4,250 psi, Exhibit 11.

Exhibit 11 Minimum Miscibility Processes (MMP) for CO2 for Study Area Oil Composition



Source: Advanced Resources International, 2019

4.4 Estimated Original Oil and Gas In-Place

Given the geologic and reservoir properties on Exhibit 9, the Study Area well pattern area contains 4.62 million barrels of original oil in-place (OOIP) and 5.54 Bcf of original gas in-place (OGIP).

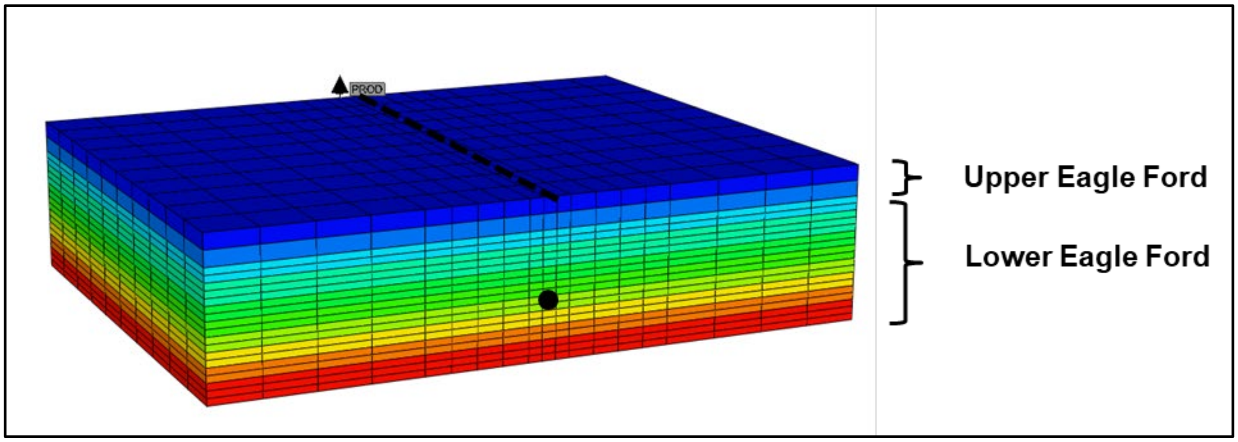
5 RESERVOIR MODEL

5.1 MODEL DIMENSIONS, LAYERS AND GRID BLOCKS

The reservoir model and grid blocks constructed to replicate the Eagle Ford Shale geologic and reservoir setting in the Study Area is illustrated on Exhibit 12:

- The model is 500 feet parallel with the horizontal (Hz) well (1/15th of the 7,500 foot Hz type well) and 650 feet perpendicular to the well (typical well spacing in the area). The reservoir model uses 10 grid blocks, each 50 feet in length to capture the 500 feet (1/15 th of the 7,500 foot Hz type well) of reservoir parallel with the Hz well. To provide greater resolution near the Hz wellbore, the reservoir model used three 16.7 foot grid blocks adjacent to the Hz well (with the Hz well located in the center of these three grid blocks). It then used four 25 foot grid blocks followed by four 50 foot grid blocks on either side of the Hz well to represent the overall 650 foot well spacing for the Study Area well.
- Based on available isopach maps from the Eagle Ford shale in northern McMullen county, an overall Eagle Ford Shale thickness of 150 feet was deemed representative of the shale in the Study Area, with the net pay of the Lower Eagle Ford Shale set at 120 feet. The thickness of the shale was subdivided into 20 vertical layers - - 2 layers of 15 feet each to represent the Upper Eagle Ford Shale Unit and 18 layers of 6.7 feet each to represent the Lower Eagle Ford Unit. With the Lower Eagle Ford being the target, the well was completed in layer 13. A transmissibility barrier was implemented between the Upper and Lower Eagle Ford Shale.

Exhibit 12 Reservoir Model and Grid Blocks Used for Eagle Ford Shale Study



Source: Advanced Resources International, 2019.

The reservoir property values previously provided on Exhibit 9 and the oil composition and PVT values previously provided on Exhibit 10 were used to populate the reservoir model and its 3,800 grid blocks.

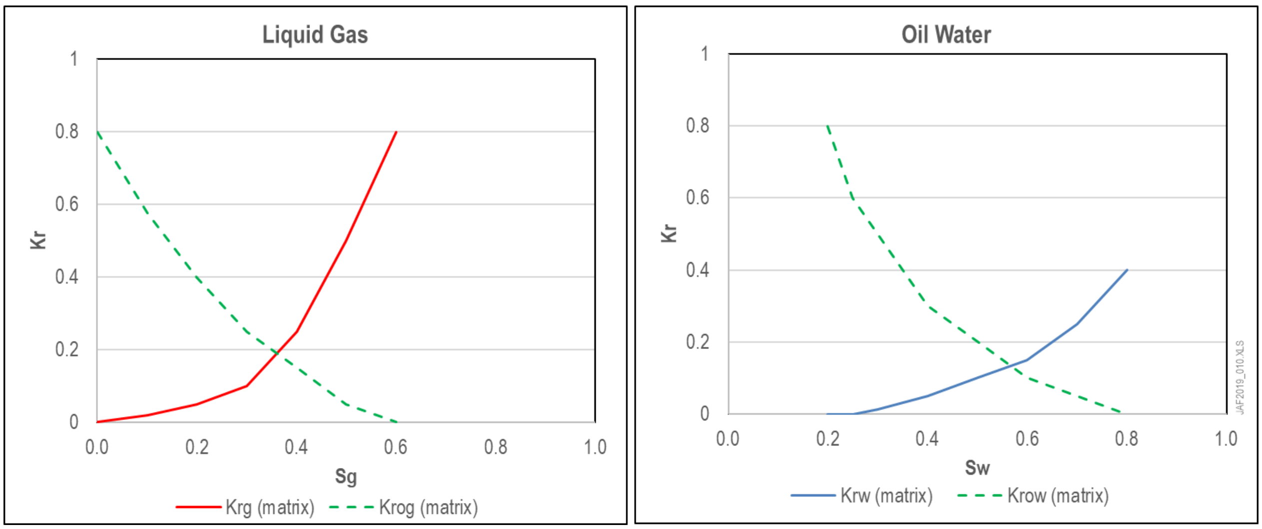
5.2 Reservoir Simulator

The GEM reservoir simulator from Computer Modeling Group (CMG) was utilized for the study. GEM is a robust, fully compositional, Equation of State (EOS) reservoir simulator used widely by industry for modeling the flow of three-phase, multi-components fluids through porous media.

5.3 Relative Permeability

In addition to information on the relationship of matrix permeability to gas filled porosity, shown previously on Exhibit 8, laboratory information derived from the technical literature was used for establishing the relative permeability shape and end points for oil and water in the matrix and in the fractures of the Eagle Ford Shale, Exhibit 13.

Exhibit 13 Eagle Ford Shale Relative Permeability Curves

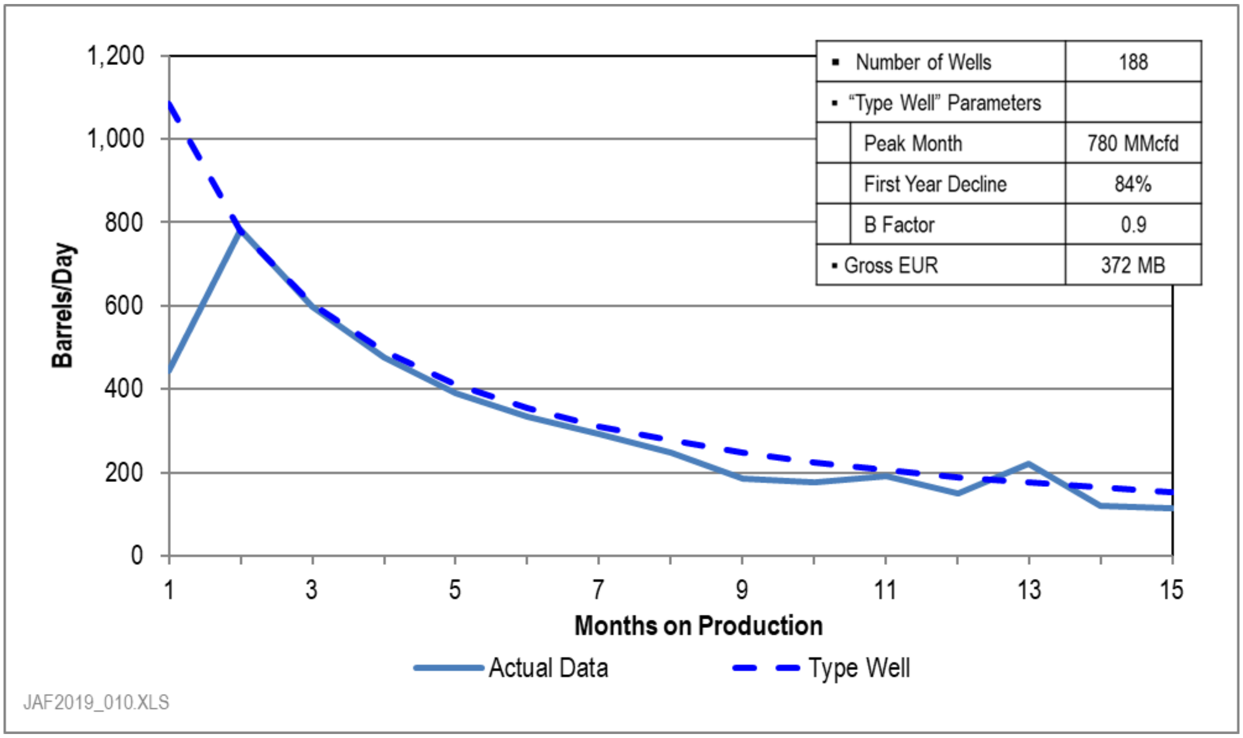


Source: Gala, D., and Sharma, M. , 2018.

6 TYPE WELL FOR STUDY AREA

The Study Area well chosen for the history match is the “type well” for the Central Eagle Ford Volatile Oil Area completed in the Lower Eagle Ford Shale. The “type well” represents the composite performance of 188 wells drilled in 2017 and early 2018 and has 15 months of oil and gas production, Exhibit 14. The well’s longer term, 30-year performance was estimated using an “IP” of 1,320 Mcfd, an “Ai” of 5.5 and a “b” of 0.9.

Exhibit 14 Study Area Type Well Oil Production



▪ Number of Wells	188
▪ “Type Well” Parameters	
Peak Month	780 MMcfd
First Year Decline	84%
B Factor	0.9
▪ Gross EUR	372 MB

Source: Advanced Resources International, 2019.

The “type well” in the Study Area has a spacing of 8 wells per section (8 wells per 640 acres) and a Hz lateral of 7,400 feet. It has an estimated 30-year oil recovery of 372,000 barrels.

The reservoir simulation model uses 1/15th of these values for the 500-foot Hz segment representative of the longer 7,500-foot Hz lateral to give a 30-year oil recovery of 24,800 barrels for the segment “type well”.

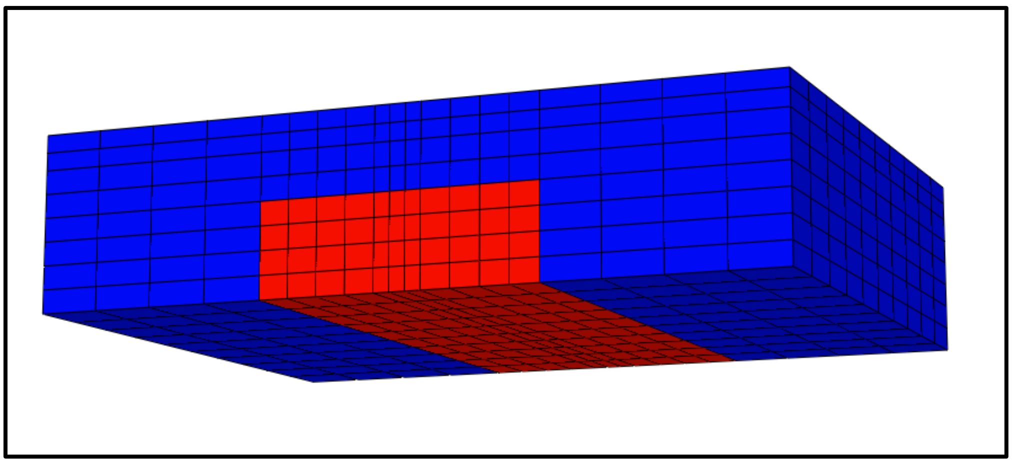
7 REPRESENTING THE IMPACT OF HYDRAULIC STIMULATION

7.1 STIMULATED RESERVOIR VOLUME (SRV)

To capture the impact of the hydraulic stimulation on the horizontal well, a Stimulated Reservoir Volume (SRV) was established in the model, assuming an enhanced permeability in the SRV for both the fractures and the matrix.

The "segment" well was assumed to be stimulated over its full length (500 feet of section) with the fracture half-length (length of the fracture on each side perpendicular to the well) used as a variable during the history-matching process. Vertically, because of the existence of a baffle between the Upper and Lower Eagle Ford, the fracture height, also used as a variable during the history-match process, was limited to the Lower Shale Unit, Exhibit 15.

Exhibit 15 Representative Stimulated Reservoir Volume for "Segment" Well



Source: Advanced Resources International, 2019.

7.2 GUIDANCE FOR ESTABLISHING THE SRV

We used the URTec 2670034 paper by K.T. Rateman and others (2017) to help guide the history matching for the dimensions of the SRV. This paper reports on the work performed by ConocoPhillips to sample the rock volumes adjacent to a horizontal Eagle Ford producer prior to and immediately following hydraulic stimulation. ConocoPhillips' SRV research pilot consisted of four horizontal producers, one vertical pressure monitoring well, and five deviated observation wells. These wells were used to characterize the SRV at different locations adjacent to one of the production wells (Well P3). Acoustic and image logs, micro seismic, DTS/DAS and pressure gauges, as well as 200 feet of core, were used in the five deviated observation wells to evaluate the dimensions and proppant distribution of the hydraulic fractures created in production Well P3.

The major findings gained from this valuable pioneering effort to characterize the location, dimensions and intensity of natural and hydraulic fractures surrounding a horizontal producer were as follows:

- The collection of 200 feet of core before hydraulic stimulation from horizontal Well S2 contained 4 non-mineralized natural fractures for an average natural fracture spacing of 50 feet.
- The hydraulic fractures occurred as swarms, with widespread fracture branching.
- Hydraulic fracture intensity decreased more rapidly with height than with lateral distance (the SRV volume is two to three times as wide as it is tall.)
- Hydraulic fracture density was greatest near the producer and declined upward and outward from the producer.
- Little evidence existed for abundant proppant transports at distances greater than 75 feet from the production well.

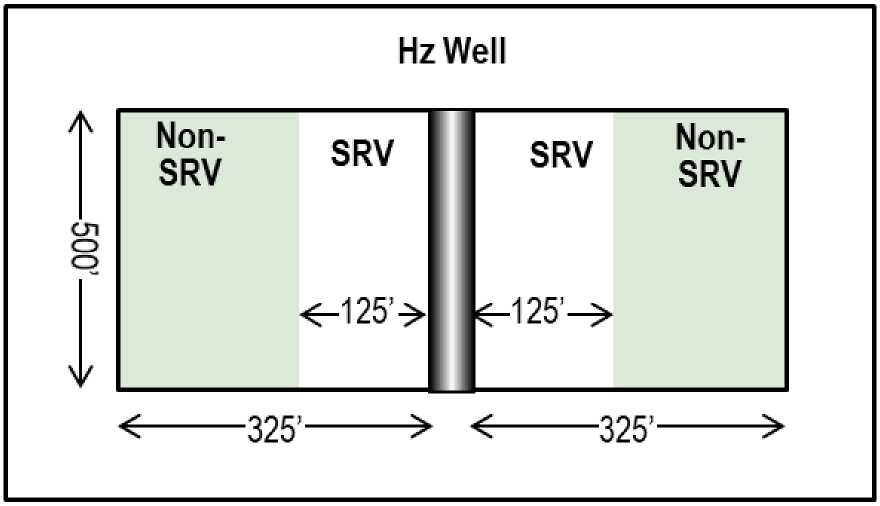
7.3 SRV Dimensions from History Match

The final SRV dimensions for the Study Area well, based on guidance from the technical literature and on the well performance history matching, are discussed below and illustrated on Exhibit 16.

- The SRV is 250 ft wide, consistent with a propped fracture half-length of 125 ft.
- The SRV is 80 ft high, encompassing about two-thirds of the vertical interval.
- The SRV length extends along the entire horizontal wellbore, equal to 500 ft for the “segment” well, representative of 1/15 of the total horizontal lateral.

Exhibit 16 Estimated SRV Dimensions from History Match of Well Performance

A. SRV Dimensions, Plan View



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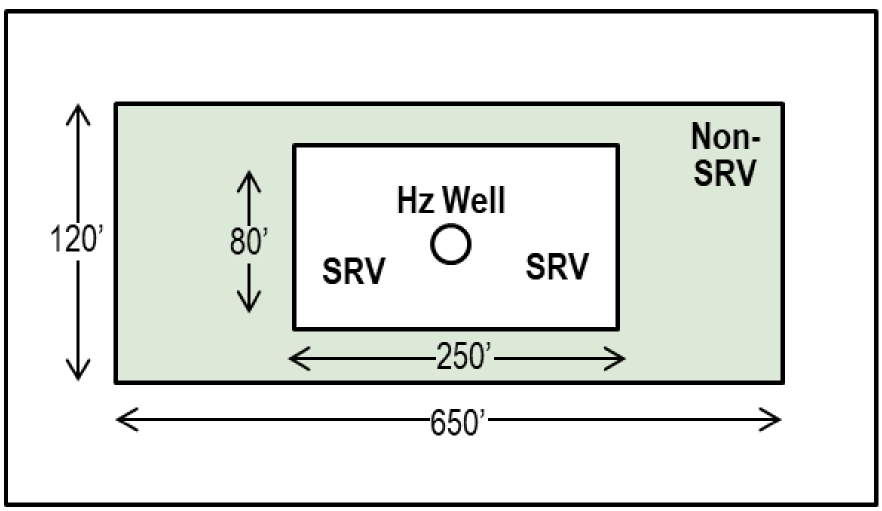
B. SRV Dimensions, Side View



JAF2019_009.PPT

Source: Advanced Resources International, 2019.

7.4 Permeability Values from History Match

The matrix and fracture permeability values along with the SRV dimensions discussed above used for the history match of the "type well" are shown in Exhibit 17.

Exhibit 17 Permeability Values Used for History Match (md)

	Matrix
Non-SRV	
• Horizontal	$115 * 10^{-6}$
• Vertical	$11.5 * 10^{-6}$
SRV*	0.085 md

Source: Advanced Resources International, 2019.

8 HISTORY-MATCHING OIL AND NATURAL GAS PRODUCTION

8.1 HISTORY MATCH

Using the key history matching parameters of SRV dimensions and permeability, reservoir simulation achieved an excellent history match with the "type well" for the Study Area. With an OOIP of 308,000 barrels for the Hz "segment" well (1/15 of total Hz well), the oil recovery efficiency is 8 percent of OOIP.

Exhibit 18 provides a tabular comparison of the "type well" and history matched Study Area well performance for two selected years of oil production. Exhibit 19 provides similar data for the "type well" and the history matched Study Area well performance for natural gas production. The history match for the 30-year time period is in-line with actual oil production. The history match for the 5-year time period is reasonably in-line given limited information on early time production pressures or well shut-in effects.

Exhibit 18 Comparison of Oil Production for Type Well and History Matched Study Area Well

Oil Production Time Period	Type Well* (Bbls)	History Matched Well (Bbls)
5 years	17,600	15,900
30 Years	24,800	24,500

*For 1/15 of actual data for the type well in the Study Area.

Source: Advanced Resources International, 2019.

Exhibit 19 Comparison of Natural Gas Production for Actual and History Matched Study Well

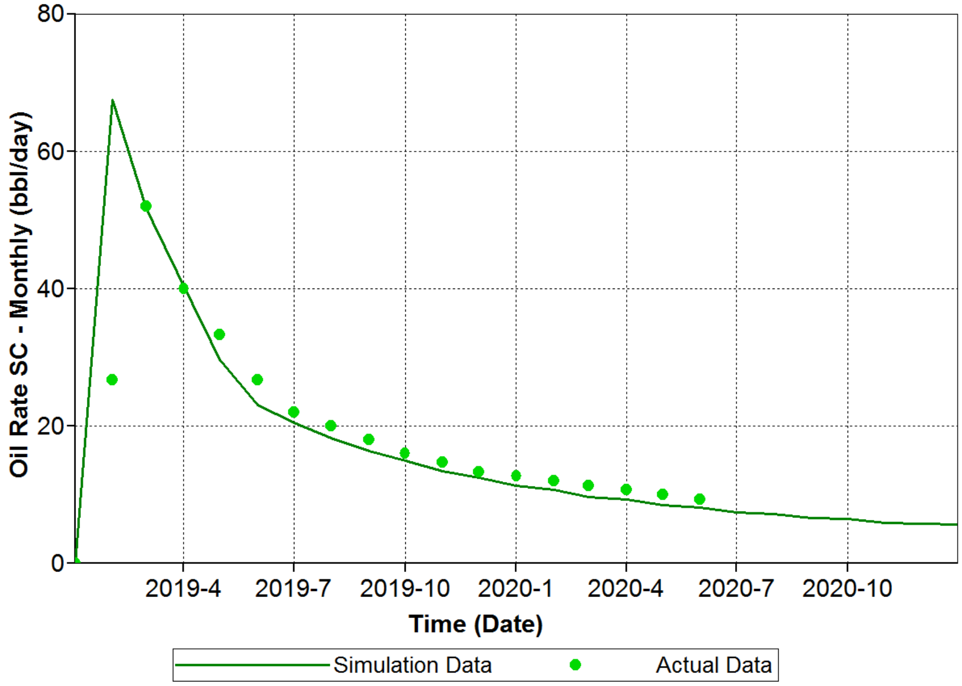
Gas Production Time Period	Type Well* (MMcf)	History Matched Well (MMcf)
5 years	23.0	20.6
30 Years	36.8	36.2

*For 1/15 of actual data for the type well in the Study Area.

Source: Advanced Resources International, 2019.

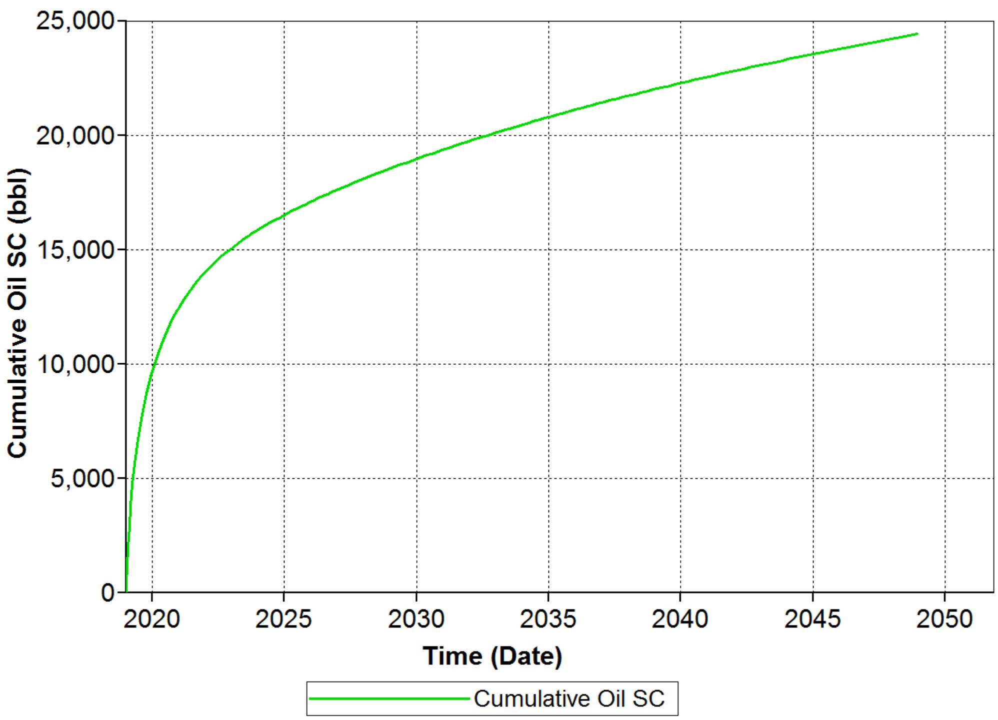
Exhibit 20 and Exhibit 21 show the near-term and longer-term reservoir simulation-based history match of oil and natural gas production for the Study Area well.

Exhibit 20 History Match of Monthly Oil Production



Source: Advanced Resources International, 2019.

Exhibit 21 Projection of 30 Years of Primary Production



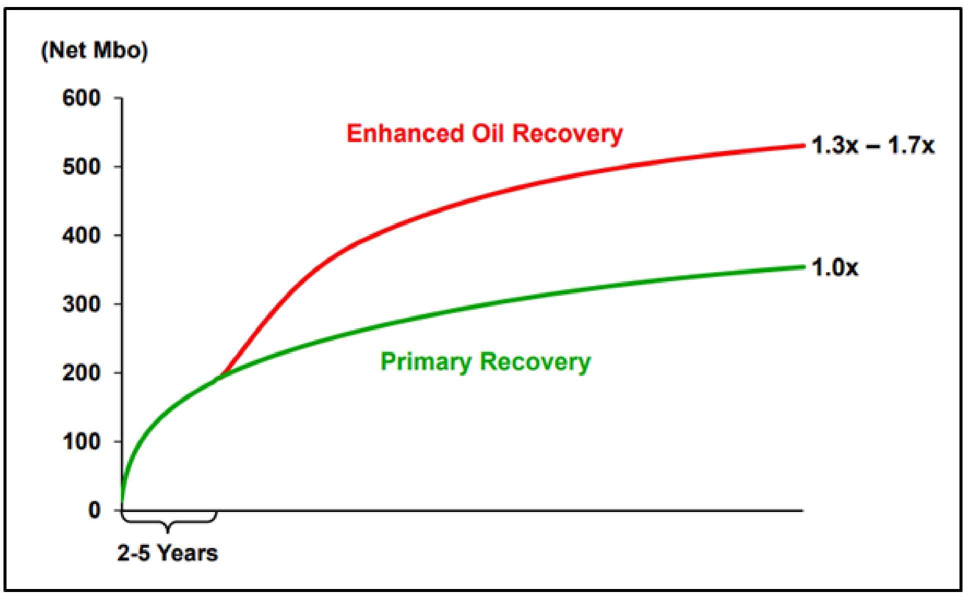
Source: Advanced Resources International, 2019.

9 USING CYCLIC GAS INJECTION FOR ENHANCED OIL RECOVERY

9.1 PERFORMANCE OF FIELD PROJECTS OF CYCLIC GAS INJECTION:

The most comprehensive set of field applications of cyclic gas injection for improving tight oil recovery are the projects implemented by EOG Resources in the Eagle Ford Shale. The initial field projects, started in late 2013, involved gas injection into 15 wells in various areas of the shales. In 2016, EOG Resources initiated a larger, 32-well cyclic gas injection project to assess the impact of well spacing, level of primary depletion, and well completion practices on the performance of cyclic gas injection. EOG Resources reported that the 32-well cyclic gas injection field project would add 30 to 70 percent to primary oil recovery, Exhibit 22.

Exhibit 22 Primary versus Enhanced Oil Recovery: Eagle Ford Shale.



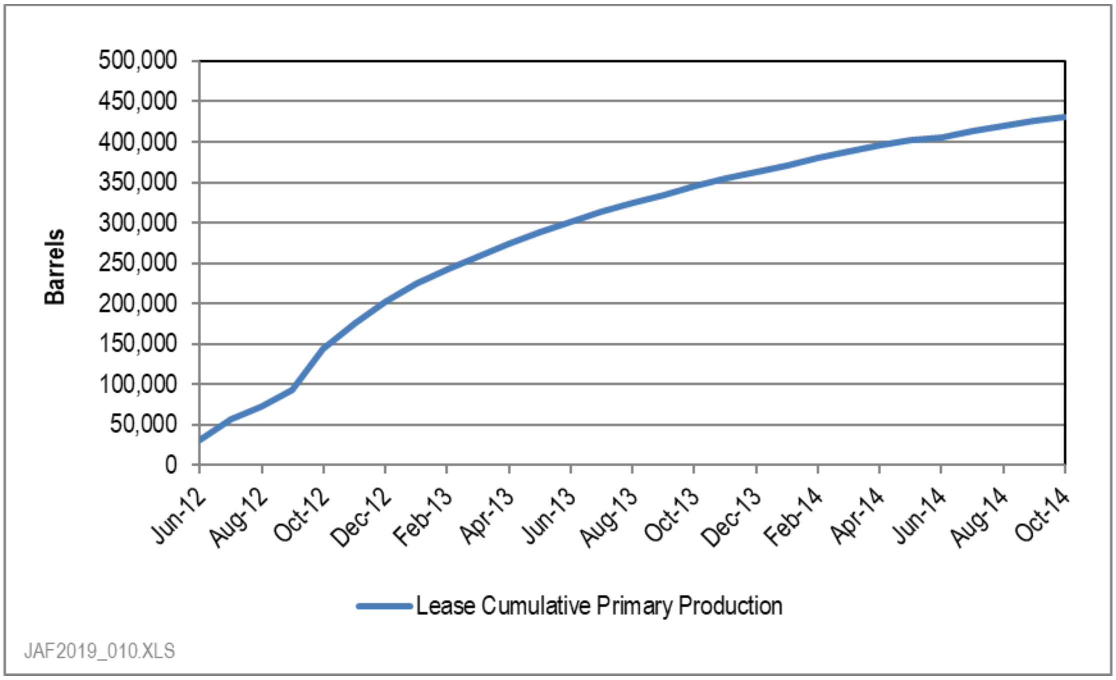
Source: EOG Resources, 2016

Except for the high-level discussion provided by EOG Resources on the performance of their cyclic gas injection field projects, little detailed information on the actual performance of cyclic gas injection exists in the technical literature for the Eagle Ford Shale or for other shale and tight oil formations.

To overcome this lack of information, Advanced Resources International (ARI) analyzed the performance of a 4-well cyclic gas injection pilot in LaSalle County, initiated in November 2014, with production data available through December 2018 from the Texas RRC:

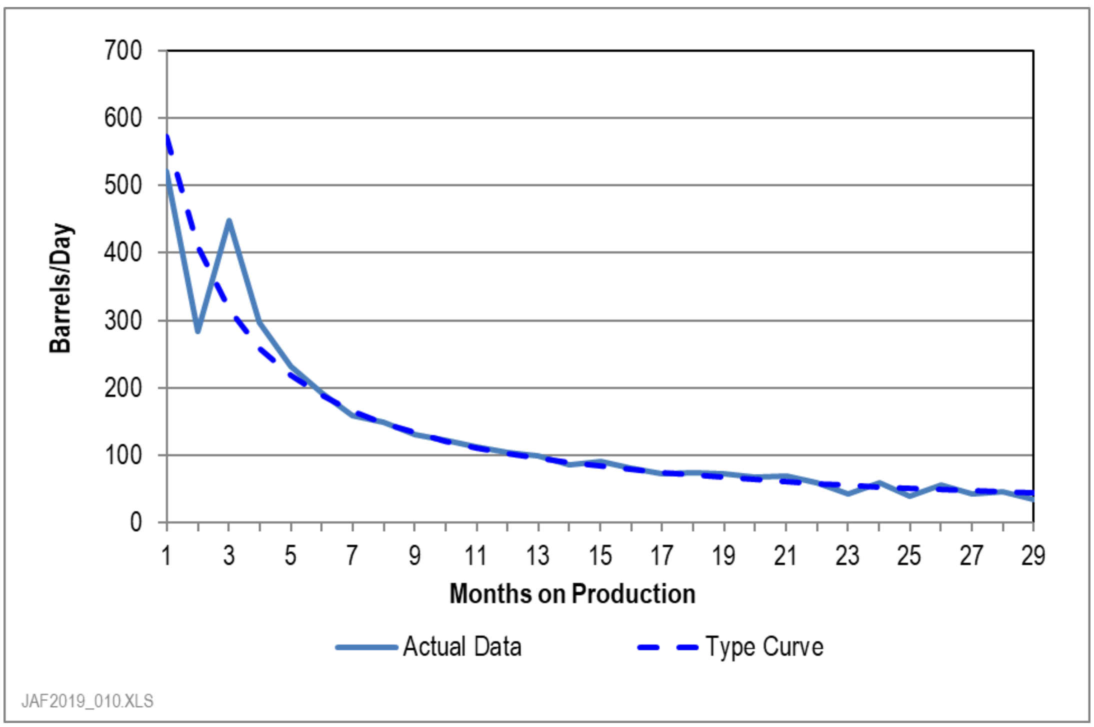
- In June 2012, two wells (3H and 4H) were drilled and placed on production at the Martindale L&C lease in LaSalle County. In late August 2012, two additional Martindale L&C wells (1H and 2H) were completed, with first oil production reported for these wells in September 2012.
- Before the start of cyclic gas injection, these four wells had been on primary production for about 2.5 years and together had produced 430,000 barrels of oil (August 2012 to October 2014), Exhibit 23.
- To provide a baseline for longer-term primary oil recovery for the four well pilot, ARI history matched the early-time performance of these wells and created primary recovery oil production "type well" for this lease, Exhibit 24. The oil production "type well" was used to evaluate oil production from continuation of primary production versus oil production from cyclic gas injection.
- The four production wells were shut-in in November 2014 and remained shut-in through March 2015 in preparation for and during the first cycle of gas injection and soak. After brought back online in late April 2015, the wells produced at ~260 B/D of oil in May 2015 and remained on production for three months.

Exhibit 23 Cumulative Primary Oil Production from Four Martindale L&C Wells: June 2012 through October 2014



Source: Advanced Resources International, 2019

Exhibit 24 Primary Oil Production per Well – Oil "Type Well": Data for Mid-2012 through Late 2014



Source: Advanced Resources International, 2019

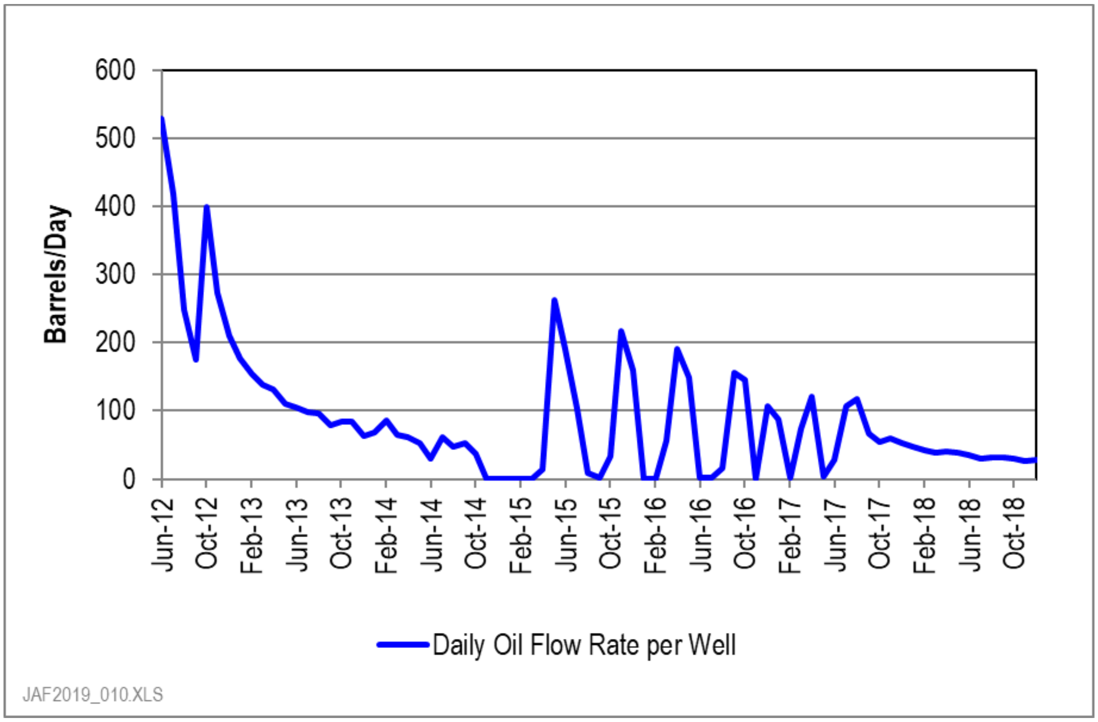
- Three more similar gas injection and soak cycles and three shorter gas injection cycles and soak followed, ending in October 2017. The oil production response was positive in each of the eight gas injection cycles, albeit with a declining peak in oil production during each subsequent cycle, Exhibit 25.
- As of the end of 2018, the four wells have been on production for 14 months since the last gas injection cycle that ended in October 2017. However, the average oil production rate from the four Martindale L&C wells was 28 barrels of oil per day in December 2018, about 80 percent higher than the expected primary production rate of 16 barrels of oil per day, likely due to the residual effects of cyclic gas injection, Exhibit 26.

During the four years of cyclic gas injection and subsequent production, the four wells at the Martindale L&C lease recovered a total of 370,000 barrels of oil, approximately 210,000 barrels more than the estimated 160,000 barrels of primary recovery during this time. Overall oil recovery from the four well lease from mid-2012 through end of 2018 was 800,000 barrels, compared to an estimated 590,000 barrels from primary alone, giving an uplift of 1.36x.

- Total Oil Recovery / Primary Oil Recovery = **Uplift**
- (430,000 + 370,000) / (430,000 + 160,000) = **1.36x**

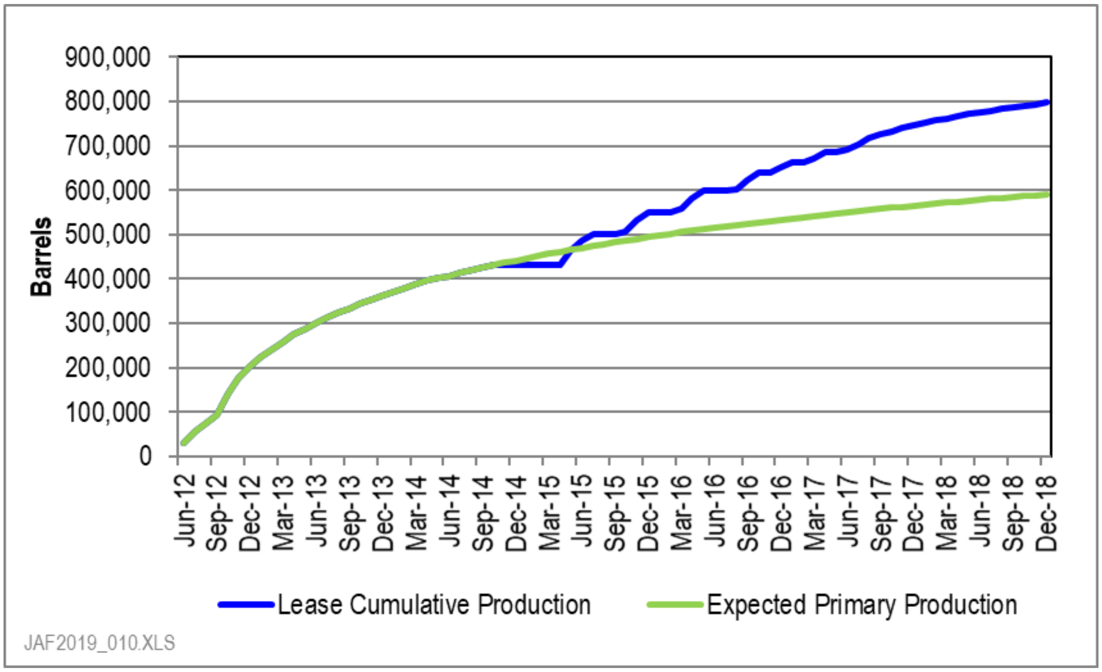
ARI's estimate of a 1.36x uplift in oil recovery due to cyclic changes in gas injection is within the range of uplift values that EOG Resources has reported (1.3x – 1.7x uplift) on its enhanced oil recovery pilots, see Exhibit 22. In addition, ARI's results are consistent with information in B.T. Hoffman's technical paper - - "Huff-N-Puff Gas Injection Pilot Projects in the Eagle Ford," SPE-189816-MS (2018) - - that provided an earlier review of this four well cyclic gas injection pilot.

Exhibit 25 Oil Recovery from Primary and Cyclic Gas Injection – Average Martindale L&C Lease Well (August 2012 through December 2018)



Source: Advanced Resources International, 2019

Exhibit 26 Cumulative Oil Recovery from Primary and Cyclic Gas Injection for Four Martindale L&C Lease Wells: June 2012 through December 2018.



Source: Advanced Resources International, 2019

9.2 Modeling of Cyclic CO_2 Injection

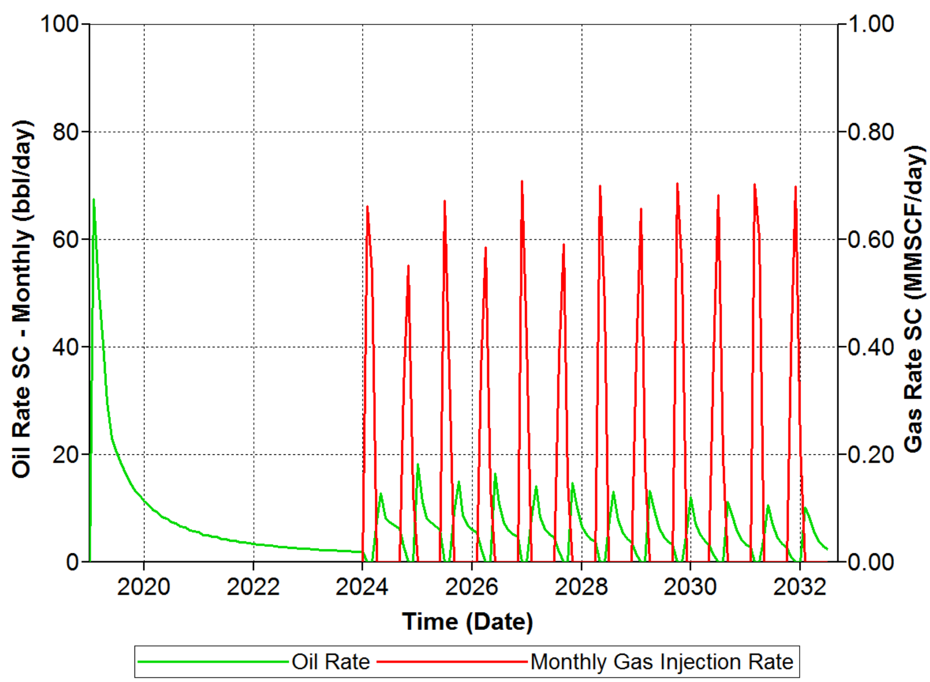
9.2.1 Cyclic CO_2 Injection

Cyclic CO_2 injection was initiated in the Study Area well after five years of primary production. At this time, the segment Hz well (1/15 of the overall horizontal well) had produced 15,900 barrels, equal to about two-thirds of its estimated oil recovery (EUR).

- In cycle one, CO_2 was injected at a constant rate of 700 Mcfd for 2 months (with a BHP limit of 7,000 psia) to refill reservoir voidage, with a total of 36,000 Mcf of CO_2 injected.
- CO_2 injection was followed by a 2 week soak time and then followed by 6 months of production.
- Eleven additional cycles of CO_2 injection, soak and production followed.

Exhibit 27 illustrates the oil production and CO_2 injection data for the five years of primary production and the subsequent twelve cycles (8.5 years) of cyclic CO_2 injection, soak and oil production from the Hz well segment (1/15 of total).

Exhibit 27 Primary Production and Enhanced Oil Recovery from Cyclic CO_2 Injection



Source: Advanced Resources International, 2019.

9.2.2 Performance of Cyclic CO_2 Injection: Reduced Hz Well Segment (500 ft)

The twelve cycles of CO_2 injection over 8.5 years provided 16,300 barrels of oil production for the reduced (1/15) Hz well segment, in addition to primary oil recovery of 15,900 barrels at the start of cyclic CO_2 injection for total oil recovery of 32,200 barrels. Continuation of primary recovery for 8.5 years would have provided 4,000 barrels of oil production during this time in addition to 15,900 barrels at the start of cyclic CO_2 injection. As such, 12,300 barrels of incremental oil recovery (16,300 barrels less 4,000 barrels) is attributable to injection of CO_2, Exhibit 28. Assuming no further injection of CO_2, this twelve cycle CO_2 injection project provided an uplift of 1.61x to primary oil production from the Study Area, Exhibit 28. Continuation of cyclic CO_2 injection for additional cycles as well as optimization of the CO_2 injection project would increase this uplift value.

Exhibit 28 Cumulative Oil Production, CO_2 Injection and CO_2 Production: Reduced Hz Well Segment

	Cumulative Oil Production		Cumulative CO2		Estimated CO2 Storage (MMscf)
	Total (Barrels)	Incremental (Barrels)	Injection (MMscf)	Production (MMscf)	
End of 5-year primary	15,900	-	-	*	-
End of first cycle	17,500	1,100	36	20	16
End of 6th cycle	23,300	7,100	200	161	39
End of 12th cycle	32,200	12,300	429	373	56

*A small volume of CO_2 (0.5 MMcf) was produced during primary production, as CO_2 is a minor constituent of the reservoir fluids (see Exhibit 10).

Source: Advanced Resources International, 2019.

A significant portion, equal to 13 percent (56 MMcf), of the 429 MMcf of CO_2 injected remained in the reservoir after the end of the 12th cycle, with higher incremental CO_2 storage during the initial CO_2 injection and production cycles and declining incremental CO_2 storage values during the later CO_2 injection and production cycles, Exhibit 28.

9.2.3 Performance of Cyclic CO_2 Injection: Full Hz Well (7,500 ft)

The twelve cycles of CO_2 injection over 8.5 years provided 245,000 barrels of oil production for the full Hz well, in addition to 238,000 barrels at the start of CO_2 injection leading to total overall oil recovery, including primary and cyclic CO_2 injection, of 483,000 barrels. Continuation of primary recovery for 8.5 years would have provided 60,000 barrels oil recovery. As such, 185,000 barrels of incremental oil recovery (245,000 barrels less 60,000 barrels) is attributable to injection of CO_2. Assuming no further cyclic injection of CO_2, this twelve cycle CO_2 injection project provided a 1.61x uplift to oil production in the Study Area well, Exhibit 29.

Exhibit 29 Cumulative Oil Production, CO_2 Injection and CO_2 Production: Full Hz Well

	Cumulative Oil Production (MBbls)		Cumulative CO_2 Injection (MMscf)	Cumulative CO_2 Production (MMscf)	Estimated CO_2 Storage (MMscf)
	Total	Incremental			
End of 5-year primary	238		-	*	-
End of first cycle	262	16	540	300	240
End of 6th cycle	380	106	3,000	2,420	590
End of 12th cycle	483	185	6,440	5,600	840

*A small volume of CO2 (0.6 MMcf) was produced during primary production, as CO_2 is a minor constituent of the reservoir fluids (see Exhibit 10).

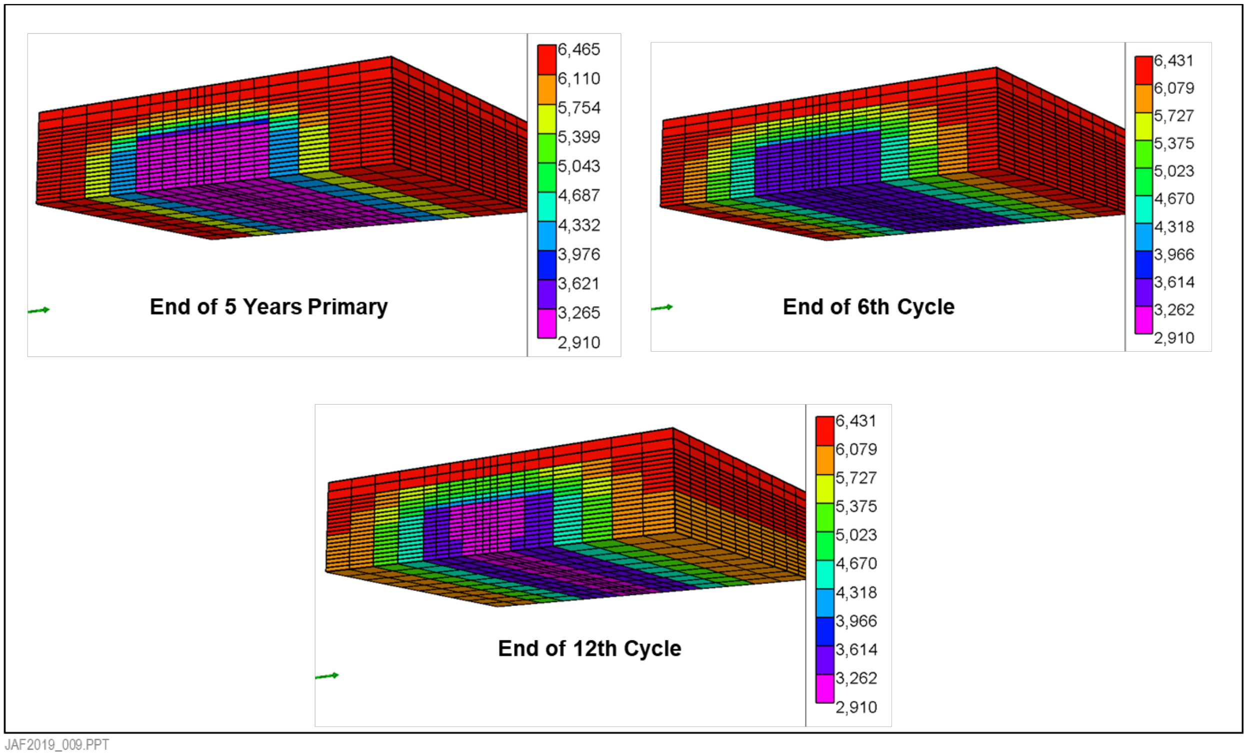
Source: Advanced Resources International, 2019.

Approximately thirteen percent (840 Mcf) of the 6,440 MMcf of CO_2 injected remained in the reservoir at the end of twelve cycles of CO_2 injection, Exhibit 29.

9.2.4 Pressure Distribution

An in-depth look at the reservoir pressure profiles at the end of primary production reveals a substantial decline in reservoir pressure for the SRV matrix as well as notable pressure declines in the non-SRV matrix blocks, Exhibit 30.

Exhibit 30 Pressure Profiles Following Primary Recovery and Cyclic CO_2 Injection



Source: Advanced Resources International, 2019.

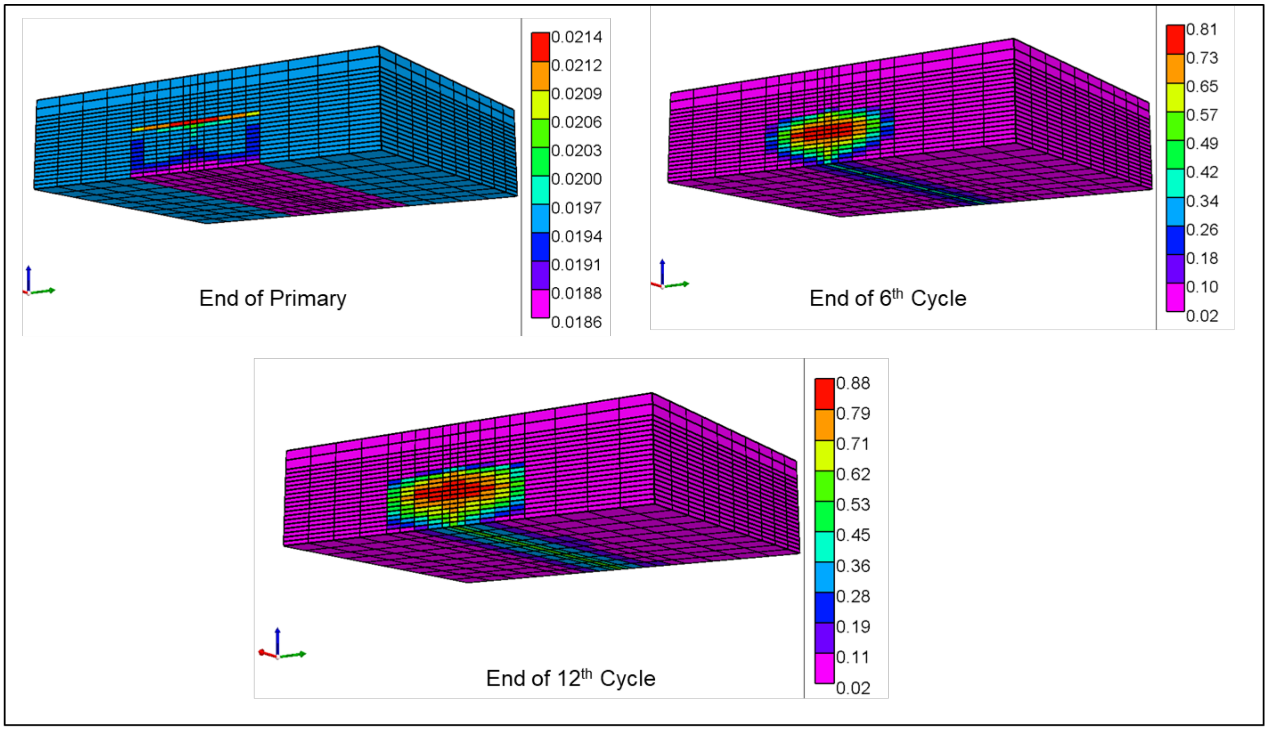
Even more noticeable pressure declines in the non-SRV matrix blocks are evident at the end of 6 cycles of CO_2 injection and 12 cycles of CO_2 injection, Exhibit 30.

9.2.5 CO_2 Distribution and Storage

Examining the CO_2 saturation in the reservoir – at the end of six and twelve cycles of CO_2 injection and fluid production – provides valuable information on the efficiency of CO_2 distribution in the SRV matrix as well as information on the volumes of CO_2 storage, Exhibit 31.

- At the end of six cycles of CO_2 injection and fluid production, CO_2 saturation in the SRV matrix reached 60 to 80 percent near the Hz well declining to 20 to 30 percent at the edges of the SRV.
- At the end of twelve cycles of CO_2 injection and fluid production, CO_2 saturation in the SRV matrix reached 80 to 90 percent near the Hz well, declining to 40 to 60 percent at the edges of the SRV.

Exhibit 31 CO_2 Saturation Profiles Following Cyclic CO_2 Injection



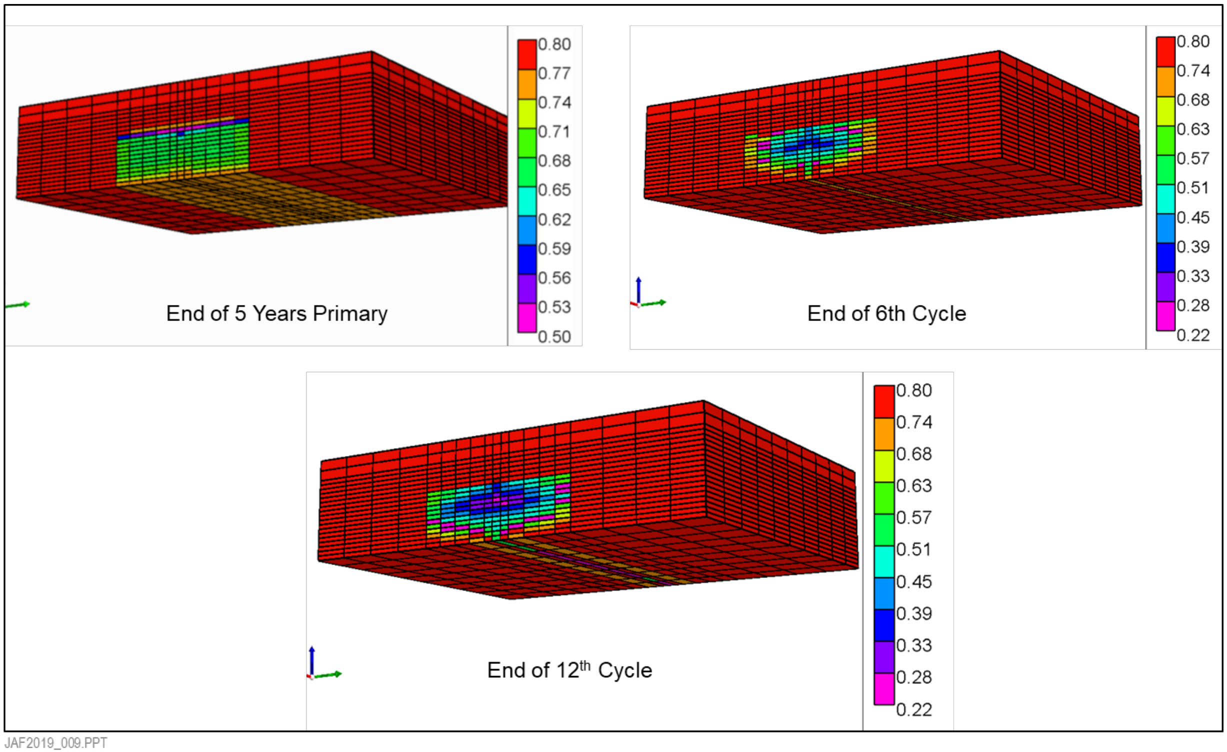
JAF2019_009.PPT

Source: Advanced Resources International, 2019.

9.2.6 Sources of Oil Recovery

To understand the sources of oil recovery, the Reservoir Simulation Study examined the contribution of the SRV and the non-SRV areas of the segment Hz well pattern to oil recovery, Exhibit 32. The analysis showed that the dominant source of oil production is from the SRV, although in the longer-term the non-SRV areas contribute small volumes of oil production.

Exhibit 32 Matrix Oil Saturation Within and Outside SRV



Source: Advanced Resources International, 2019.

The oil saturation profile shows that after 5 years of primary recovery, the oil saturation in the SRV matrix cell blocks has been reduced from 80 percent to about 70 percent. A similar examination of the oil saturation profile after 12 cycles of CO_2 injection shows that the oil saturation in the SRV has been reduced from about 70 percent at the end of primary recovery to about 60 percent. Only very limited reductions in oil saturation are noted in reservoir grid blocks above or beyond the SRV.

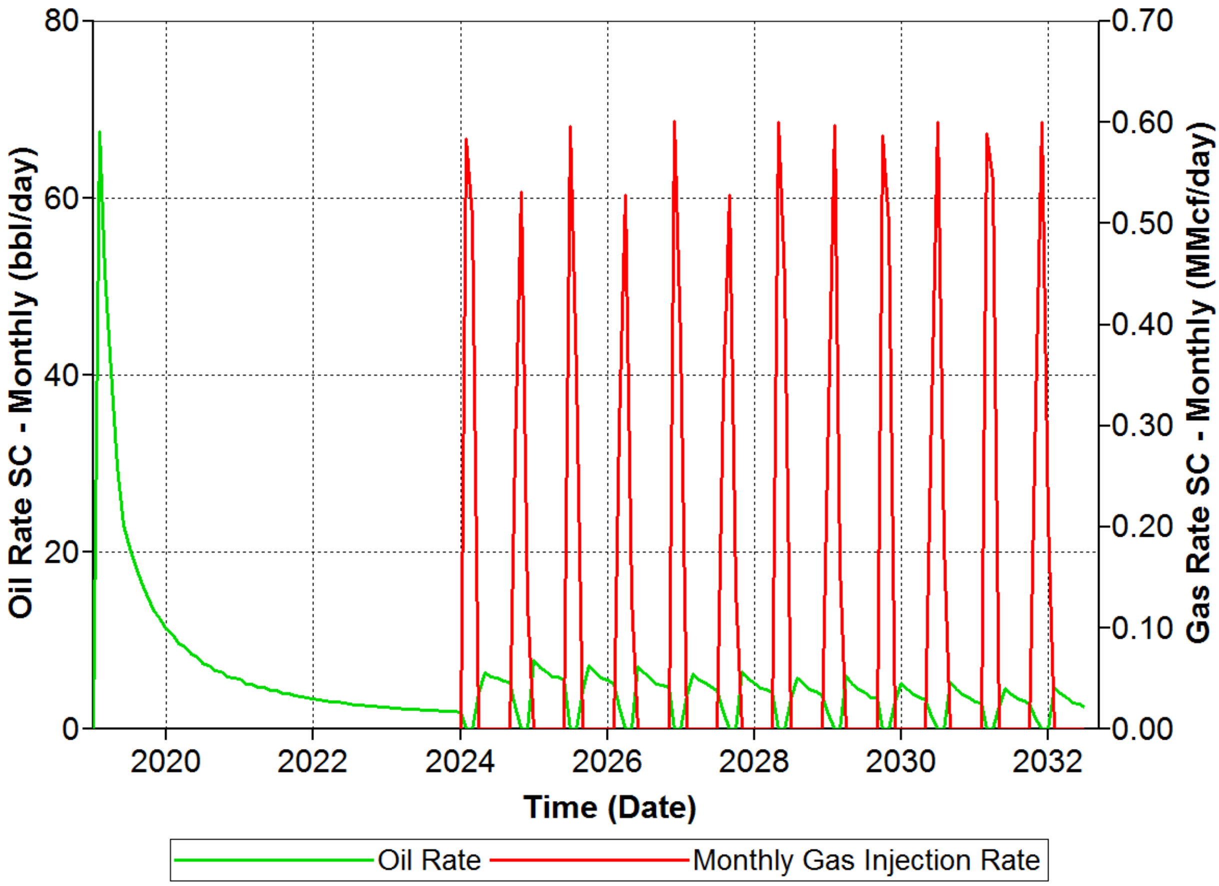
9.3 Performance of Cyclic CO_2 Versus Cyclic Natural Gas Injection

The reservoir simulation study next examined the expected performance of using cyclic natural gas injection. The first run involved cyclic injection of dry gas (100% C_1), representative of cyclic gas injection in some of industry's field projects. The second run involved cyclic injection of wet gas (80% C_1, 14% C_2, 4% C_3, and 2% C_4), typical of the wet gas produced from the Study Area.

9.3.1 Dry Gas Injection

Similar to injection of CO_2, cyclic dry gas was injected into the Study Area well after five years of primary production. Exhibit 33 illustrates the 12 cycles of oil dry gas injection and oil production.

Exhibit 33 Primary Production and Enhanced Oil Recovery from Cyclic Dry Gas Injection



Source: Advanced Resources International, 2019.

The cyclic injection of dry gas provided notably lower incremental oil recovery than the cyclic injection of CO_2, as shown on Exhibit 37, comparing use of CO_2 over use of dry gas injection. Even so, injection of twelve cycles of dry gas provided an uplift of 1.34x in oil production compared to continuation of primary recovery.

Exhibit 34 Cumulative Oil Production: Cyclic CO_2 Injection versus Cyclic Dry Gas Injection (Hz Well Segment)

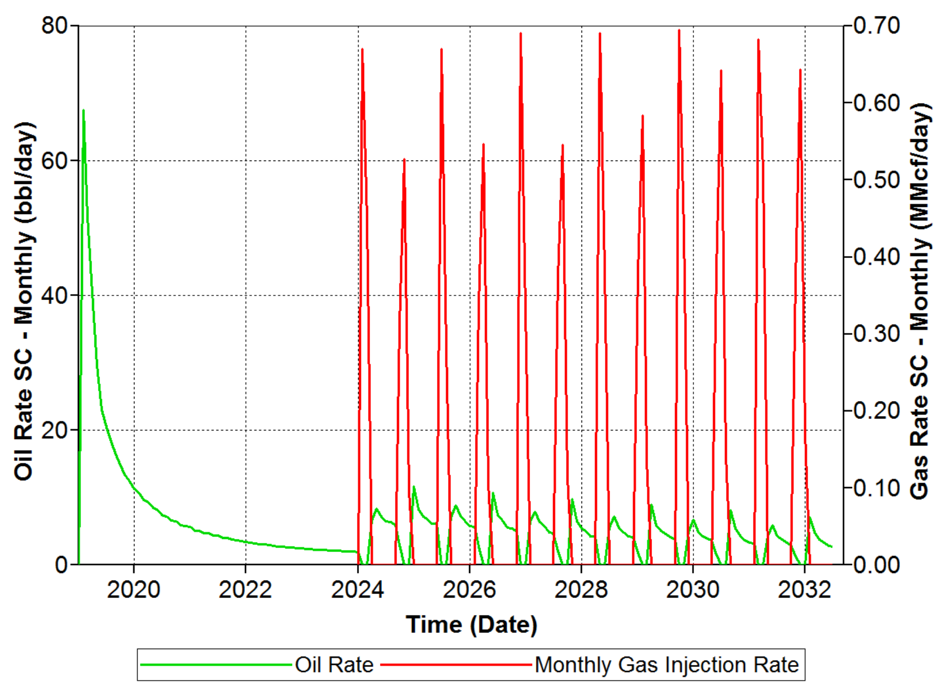
	Cumulative Oil Production Using CO_2		Cumulative Oil Production Using Dry Gas	
	Total (Barrels)	Incremental (Barrels)	Total (Barrels)	Incremental (Barrels)
End of 5-year primary	15,900	-	15,900	-
End of first cycle	17,500	1,100	17,000	600
End of 6th cycle	25,300	7,100	22,200	4,000
End of 12th cycle	32,200	12,300	26,700	6,800

Source: Advanced Resources International, 2019.

9.3.2 Wet Gas Injection

Similar to injection of dry gas, cyclic wet gas was injected into the Study Area well after five years of primary production. Exhibit 35 illustrates the 12 cycles of wet gas injection and oil production.

Exhibit 35 Primary Production and Enhanced Oil Recovery from Cyclic Wet Gas Injection



Source: Advanced Resources International, 2019.

The cyclic injection of wet gas provides somewhat more incremental oil recovery than use of dry gas, but still less incremental oil recovery than use of CO_2., as shown on Exhibit 36. Injection of twelve cycles of wet gas provided an uplift of 1.45x in oil production compared to continuation of primary recovery.

Exhibit 36 Cumulative Oil Production: Cyclic CO_2 Injection versus Cyclic Wet Gas Injection (Hz Well Segment)

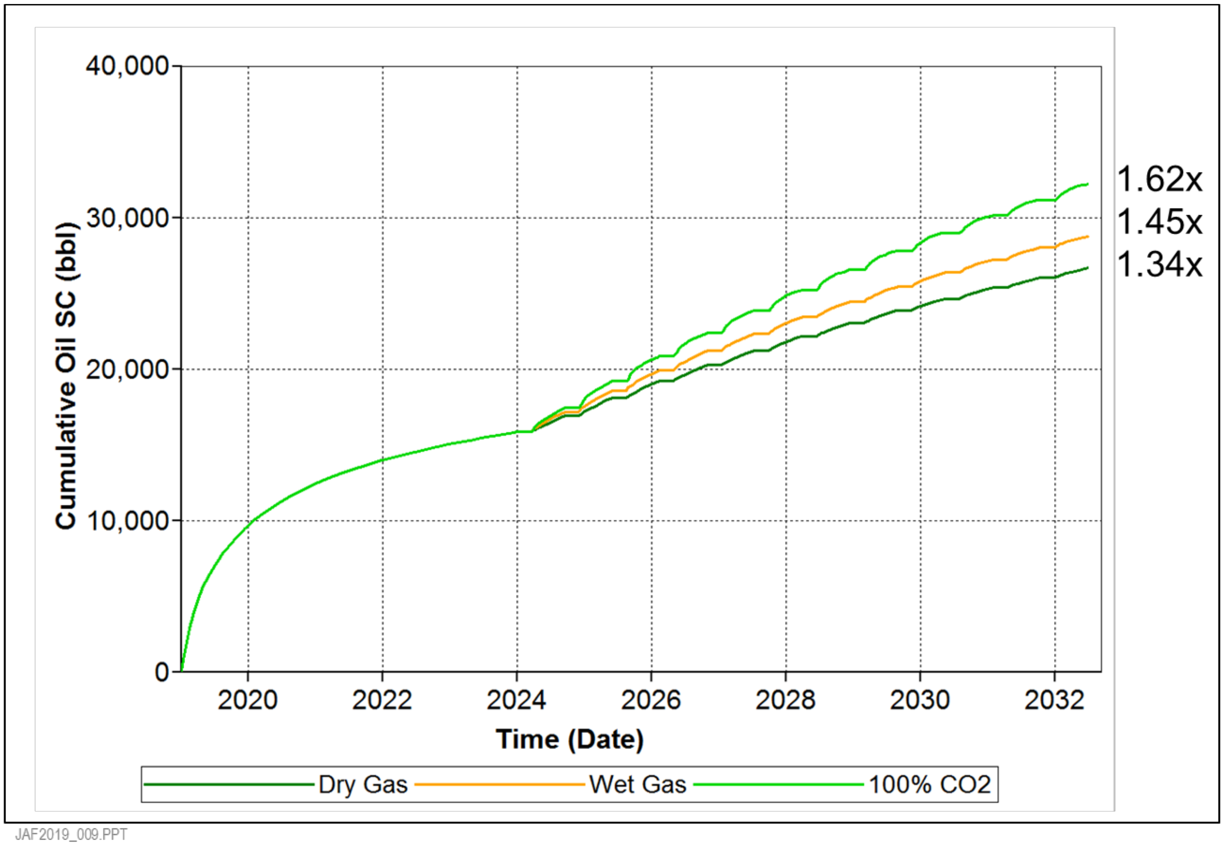
	Cumulative Oil Production Using CO_2		**Cumulative Oil Production Using Wet Gas**	
	Total (Barrels)	**Incremental (Barrels)**	**Total (Barrels)**	**Incremental (Barrels)**
End of 5-year primary	15,900	-	15,900	-
End of first cycle	17,500	1,100	17,200	800
End of 6th cycle	25,300	7,100	23,500	4,300
End of 12th cycle	32,200	12,300	28,800	7,900

Source: Advanced Resources International, 2019.

9.3.3 Comparison of Cyclic CO_2, Dry Gas and Wet Gas Injection

Reservoir simulation for the Study Area well, shows that cyclic injection of CO_2 provides an uplift of 1.62x in oil production over continuation of primary recovery, compared to uplifts of 1.34x for cyclic dry gas injection and 1.45 for cyclic wet gas injection, Exhibit 37.

Exhibit 37 Comparison of Cyclic CO_2, Cyclic Dry Gas and Cyclic Wet Gas Injection (Hz Well Segment)



Source: Advanced Resources International, 2019.

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