INCREASING SHALE OIL RECOVERY AND CO_2 STORAGE WITH CYCLIC CO_2 ENHANCED OIL RECOVERY

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INCREASING SHALE OIL RECOVERY AND CO_2 STORAGE WITH CYCLIC CO_2 ENHANCED OIL RECOVERY

PROMOTING DOMESTIC AND INTERNATIONAL CONSENSUS ON FOSSIL ENERGY TECHNOLOGIES

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Report Outline

Disclaimer

Acknowledgements

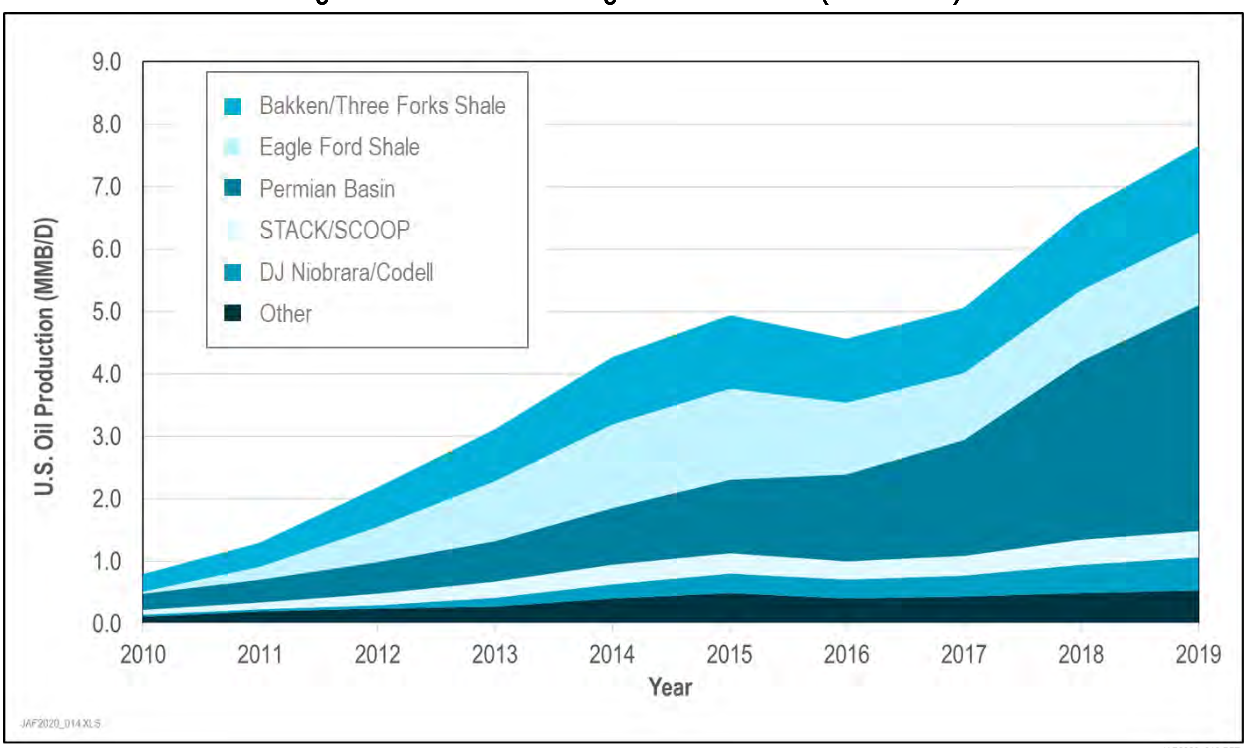
A portion of the information on resource characterization and reservoir modeling related to cyclic CO_2 EOR in shale oil basins is based on work previously prepared by Advanced Resources International, Inc. for the U.S. Department of Energy, National Energy Technology Laboratory (U.S. DOE/NETL).

Executive Summary

Introduction. The production of oil from shales and geologically similar formations (together called "tight oil") has provided major benefits to the domestic economy and the public, including: (1) substantially lower energy costs to consumers, (2) significant revitalization of domestic manufacturing and jobs, and (3) greatly improved energy security.

The growth of domestic oil production from this so called "shale oil revolution" is without precedent. Starting from a base of below one million barrels per day in 2010, "tight oil" production reached nearly 8 million barrels per day last year (2019), equal to two-thirds of total domestic oil production. Numerous basins and shale formations have contributed to this total, including the Bakken Shale of Montana and North Dakota, the Eagle Ford Shale of South Texas, and the Wolfcamp Shale in the Permian Basin of West Texas and New Mexico (Figure EX-1).

Figure EX-1. U.S. Shale/Tight Oil Production (2010-2019)



Source: Advanced Resources International Database, 2020.

The domestic shale oil resource in-place base, as defined by this USEA Study, is vast. However, only a relatively small portion – ranging from 5% to 10% -- of this vast resource in-place is recoverable with current (pressure depletion) production practices. Even modest improvements in shale oil recovery efficiency, achievable with shale enhanced oil recovery (EOR) technology, would add billions of additional barrels of domestic shale oil resources.

Study Purpose and Report. The primary objectives of the USEA Study are: (1) define the size of the "tight oil" resource in-place in four major shale basins; (2) examine how the application of CO_2 injection could lead to significantly higher extraction of the shale resource in-place; and (3) define how much CO_2 will be required and stored in these four shale basins with use of shale EOR.

The first four chapters in this report address the size and contribution we can expect from four major shale oil basins—Bakken Shale, Eagle Ford Shale, Permian/Midland Wolfcamp Shale, and Permian/Delaware Wolfcamp Shale. Chapter 5 discusses the shale assessments performed for the Appalachian Basin's Marcellus and Utica Shales. The final two chapters discuss "Shale EOR Field Tests and Projects" and "Tight Oil Recovery R&D Gaps and Topics", two key topics for guiding future DOE/NETL and industry research on shale EOR.

Study Findings. Five major findings emerge from the USEA Study.

1. The Shale Oil Resource In-place Is Massive. The in-place resource in the four major shale basins/formations evaluated by the study equals 1,315 billion barrels (Table EX-1). While this is a massive volume of oil in-place, only a small portion of this oil in-place is recoverable with current technology.

2. Successful Shale EOR Technology Would Significantly Improve Shale Oil Recovery. Timely development and application of shale EOR technology involving cyclic injection of CO_2 would notably improve shale oil recovery efficiency. This would enable 47.5 billion barrels of additional shale oil to become technically recoverable from the four basins addressed by the USEA Study (Table EX-1).

3. Use of Shale EOR Technology Would Provide New Opportunities for Geologically Storing CO_2. Applying shale EOR to the four major shale oil basins would provide space for storing 20 billion metric tons of CO_2, creating a new, large geological CO_2 storage option (Table EX-1).

Table EX-1. Incremental Oil Recovery and CO_2 Storage from Shale EOR

Shale Basin/Formation	Resource In-Place (MMB)	Incremental Oil Recovery from CO_2 EOR (MMB)	Storage of CO_2 (MMmt)
1. Williston Basin/Bakken Shale	90,820	3,760	1,510
2. South Texas/Eagle Ford Shale	139,300	7,670	1,840
3. Permian Basin			
▪ Midland Basin/Wolfcamp Shale	509,110	14,250	6,560
▪ Delaware Basin/Wolfcamp Shale	575,720	21,850	10,050
Total	**1,314,950**	**47,530**	**19,960**

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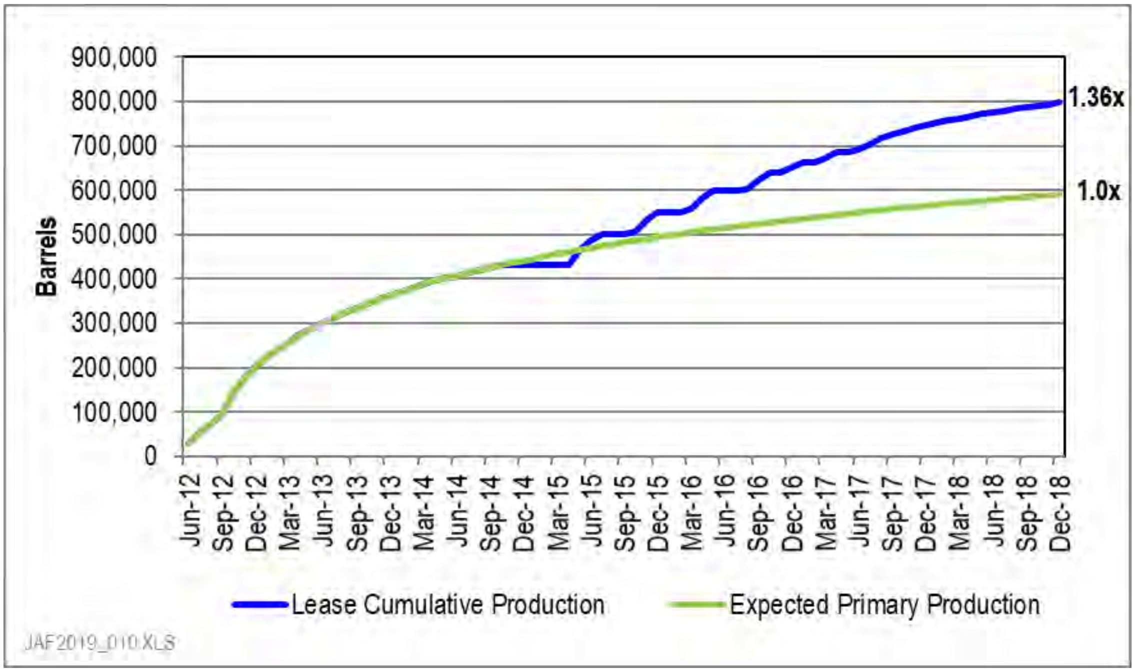
4. The Existing CO_2 EOR Field Projects Are Providing a "Path Forward" Toward More Efficient Technology and Practices. To better understand the performance of using cyclic gas EOR in shales, Advanced Resources International (ARI) evaluated the performance of the Martindale Unit 4-well cyclic gas injection field project in the Eagle Ford Shale. This project was initiated in November 2014, with data available through December 2018. ARI's estimate of a 1.36x uplift in oil recovery due to cyclic gas injection is within the range of uplift values reported by industry (Figure EX-2).

Figure EX-2. 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

5. A Robust Program of Private and Public R&D Will Be Essential for Developing Improved Oil Recovery Technology for Shales. The most challenging, highest value tight oil recovery R&D topics are introduced below and discussed more extensively in Chapter 7 of the USEA Report.

- R&D Priority #1. Defining Reservoir Conditions and Well Completion Methods Favorable for Shale Oil EOR.
- R&D Priority #2. Establishing the Relative Importance of Shale Oil Enhanced Oil Recovery (EOR) Mechanisms.
- R&D Priority #3. Improving EOR Monitoring and Diagnostic Technologies and Practices for Shale Oil.
- R&D Priority #4. Breaking the "Technology Lock" on Achieving Successful Continuous Gas Flooding EOR in Shale Oil.

- R&D Priority #5. Establishing Optimum Gas Injection Rates, Soak Times, and Production Times for Shale Oil EOR Using Cyclic Injection of Gas.

- R&D Priority #6. Conducting Fully Integrated Laboratory, Reservoir Modeling, and Field Pilot EOR Projects in Each Shale/Tight Oil Basin and Formation.

- R&D Priority #7. Establishing the Technical and Economic Attractiveness of Using CO_2, Wet Gas, Dry Gas, and Other Fluids for Cyclic Gas EOR in Various Shale/Tight Oil Formations.

Study Recommendations. The following “next steps” would greatly advance the status and knowledge base for increasing oil recovery and CO_2 storage in shales.

1. Undertake In-Depth Studies of Shale EOR Field Performance. Our initial review of shale EOR indicates that, with in-depth analyses of data at the Texas Railroad Commission and other state regulatory bodies, it will be possible to gain a more rigorous understanding of the performance of shale EOR field projects involving cyclic gas injection. This would: (1) advance the understanding of optimum field project design criteria; (2) further define the geological settings favorable for shale EOR; and (3) help design laboratory and field R&D efforts that would advance shale EOR technology.

2. Conduct Shale Oil Resource and EOR Assessments for the Remaining Shale Basins and Formations. Numerous additional shale oil basins and formations have potential for shale EOR and CO_2 storage, beyond the four basins and formations evaluated by the USEA Study. These include the Cana-Woodford Shale in the Anadarko Basin, the Niobrara Shale in the DJ Basin, and the Mowry Shale in the Powder River Basin, among others. Improved understanding of the geologic settings, resource concentrations, and other features of these shale basins/formations would help accelerate the development of shale EOR technology.

3. Establish the Economic Viability of Shale EOR. Shale EOR will need to economically compete with other oil field development opportunities for investment capital. Preliminary information, provided at high-level by EOG Resources, indicates that in geologically favorable settings, such as the Eagle Ford Shale, cyclic injection of gas for shale EOR could be an economically viable option for adding shale oil reserves and production. However, this needs to be assessed in much more detail, particularly for the other major shale oil basins.

4. Examine the Potential and Challenges of Using Continuous Rather than Cyclic CO_2 Injection for Shale EOR. So far, the field trials of continuous injection of CO_2 and other gases into shale oil reservoirs, involving separate CO_2 injection and oil production wells (as opposed to injecting CO_2 into a production well), have encountered numerous problems. Particularly notable are lack of conformance and early break-through of the injected gas. Overcoming these problems would help launch the use of continuous injection of CO_2 in shales, providing a much higher efficiency shale EOR technology with a higher capacity for storing CO_2.

Chapter 1. Bakken Shale

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1 Bakken Shale

1.1. Introduction

1.1.1 Purpose of Study

The Bakken Shale, located in North Dakota and Montana, is one of the five major shale oil basins of the U.S. It holds a vast volume of shale oil resources, estimated by this study, at 90.8 billion barrels of original oil in-place (OOIP).[1] However, with current primary (pressure depletion) oil production practices, only a modest portion of this large in-place resource is recoverable. (Our resource characterization and reservoir modeling of a representative Bakken Shale area in the center of the Bakken Shale play, the Study Area, established an estimated oil recovery efficiency of 9% of OOIP.) As such, more advanced oil recovery technologies will be needed to boost the current level of oil recovery from the Bakken Shale.

The purpose of our study is to examine the potential and impact of one such advanced oil recovery process—the use of cyclic injection of CO_2 for enhanced oil recovery from the Bakken shale.

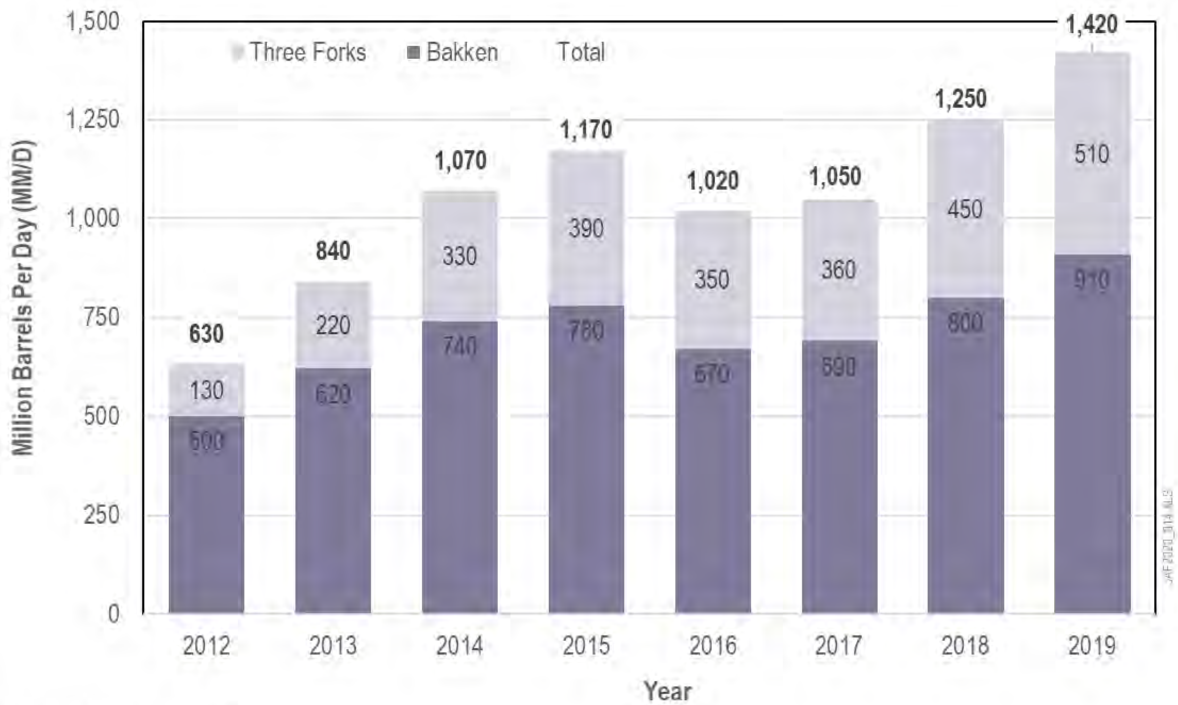
An important by-product of using cyclic injection of CO_2 for oil recovery from the Bakken shale is that a portion of the injected CO_2 remains trapped in the shale formation, providing an additional geologic site for storing CO_2.

1.1.2 Bakken Shale Well Oil Production and Completions

The Bakken Shale launched the “shale oil revolution”. Oil production from the Bakken Shale increased rapidly from a few thousand barrels per day in the early 2000s to 500,000 barrels per day in 2012, to 780,000 barrels per day in 2015, and further to 910,000 barrels per day by 2019. When adding the more recently developed Three Forks Shale, with an estimated oil production volume of 510,000 barrels per day, total shale oil production from the Willison Basin reached 1.42 million barrels per day in 2019 (Figure 1-1).

1 The resource volumes for the Bakken Shale do not include any resource volumes for the underlying Three Forks Shale.

Figure 1-1. Bakken and Three Forks Shale Oil Production*



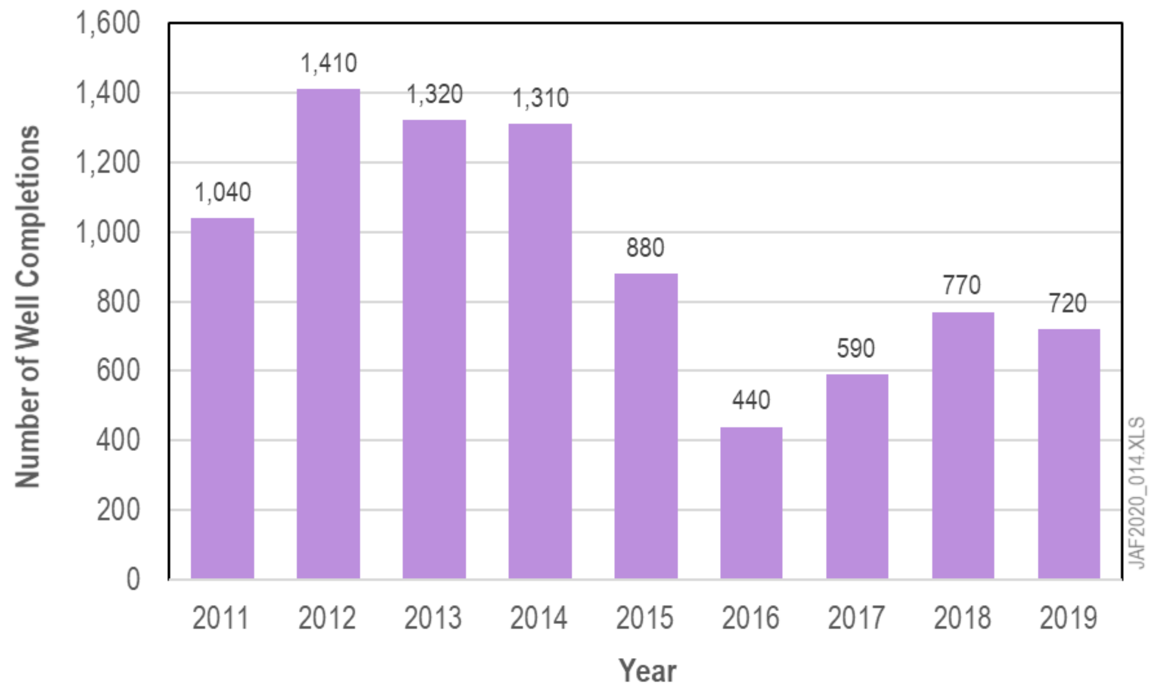
*Includes North Dakota and Montana.

Source: Advanced Resources International's Tight Oil Database, 2020; Drilling Info, 2020.

Following the drilling of vertical production wells in the late 1990's, significant pursuit of the Bakken Shale started in 2004, following the drilling and completion of 105 Hz wells. With a steady increase in rigs, Hz well completions reached a peak of 1,410 Hz wells in 2012 and remained close to this level for the next 2 years. After a drop in oil prices, Hz well completions declined to a modern-day low of 440 in 2016. Higher oil prices, along with recent improvements in well performance, supported a rebound in well completions to 770 in 2018 and 720 in 2019 (Figure 1-2).

Today, the Bakken Shale is an increasingly mature shale oil play. As such, some of the more productive areas of the Bakken Shale have become highly drilled. For example, the Nesson Anticline area of Mountrail County, North Dakota now has 2,100 well completions, consuming nearly 60% of its originally available Bakken Shale well locations in this county. As a result, much of the recent well drilling has moved to the adjoining counties of Williams, McKenzie and Dunn.

Figure 1-2. Bakken Shale Hz Well Completions, 2011-2019*



*Note that a considerable number of additional Hz wells have been completed in the underlying Three Forks Shale.

Source: Advanced Resources International's Tight Oil Database, 2020; Drilling Info, 2020.

1.1.3 Outlook for Enhanced Shale Oil Recovery

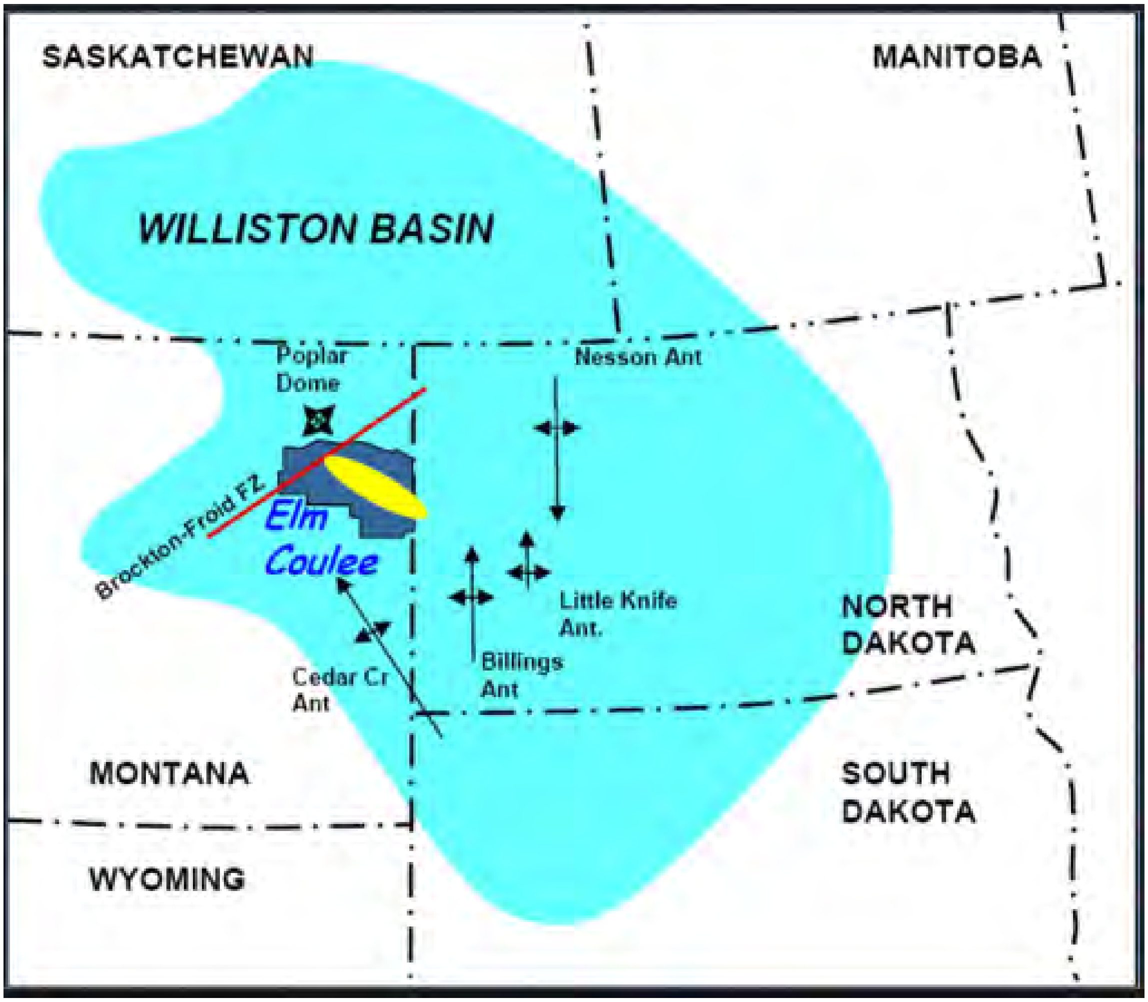
With its large numbers of rapidly depleting oil wells, the Bakken Shale is a prime candidate for using cyclic CO_2 injection for boosting oil recovery. Our assessment, as discussed in Section 1.7 of this report, is that the Bakken Shale has potential for 3,760 million barrels (MMB) of additional technically viable oil recovery and potential for storing 1,310 million metric tons (MMmt) of CO_2 from the application of cyclic CO_2 enhanced oil recovery.

1.2. Geologic Setting of the Bakken Shale

1.2.1 The Bakken Shale of the Williston Basin

The Bakken Shale extends across an 18,400 square mile (mi^2) area in the United States (U.S.) portion of the Williston Basin in North Dakota and Montana, plus considerable additional area in the Canadian portion of the Williston Basin in Saskatchewan and Manitoba (Figure 1-3). The pinch-out of the Bakken Shale interval defines the areal extent of this shale deposit. The more thermally mature, higher oil saturation area in the deeper, central portion of the Bakken Shale is the target of most interest to Bakken operators.

Figure 1-3. Williston Basin Location Map

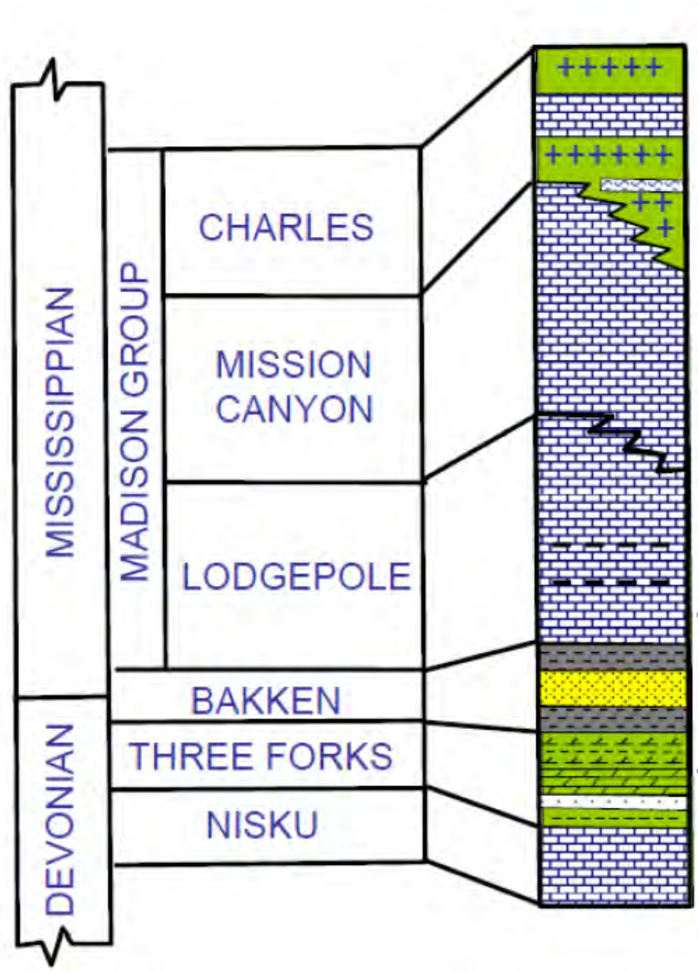


Source: Heck et al., 2004

1.2.2 Williston Basin Stratigraphic Column

The Mississippian Bakken Shale lies above the Devonian group of formations and is overlain by the Lodgepole Formation of the Madison Group (Figure 1-4).

Figure 1-4. Bakken Shale Stratigraphic Column



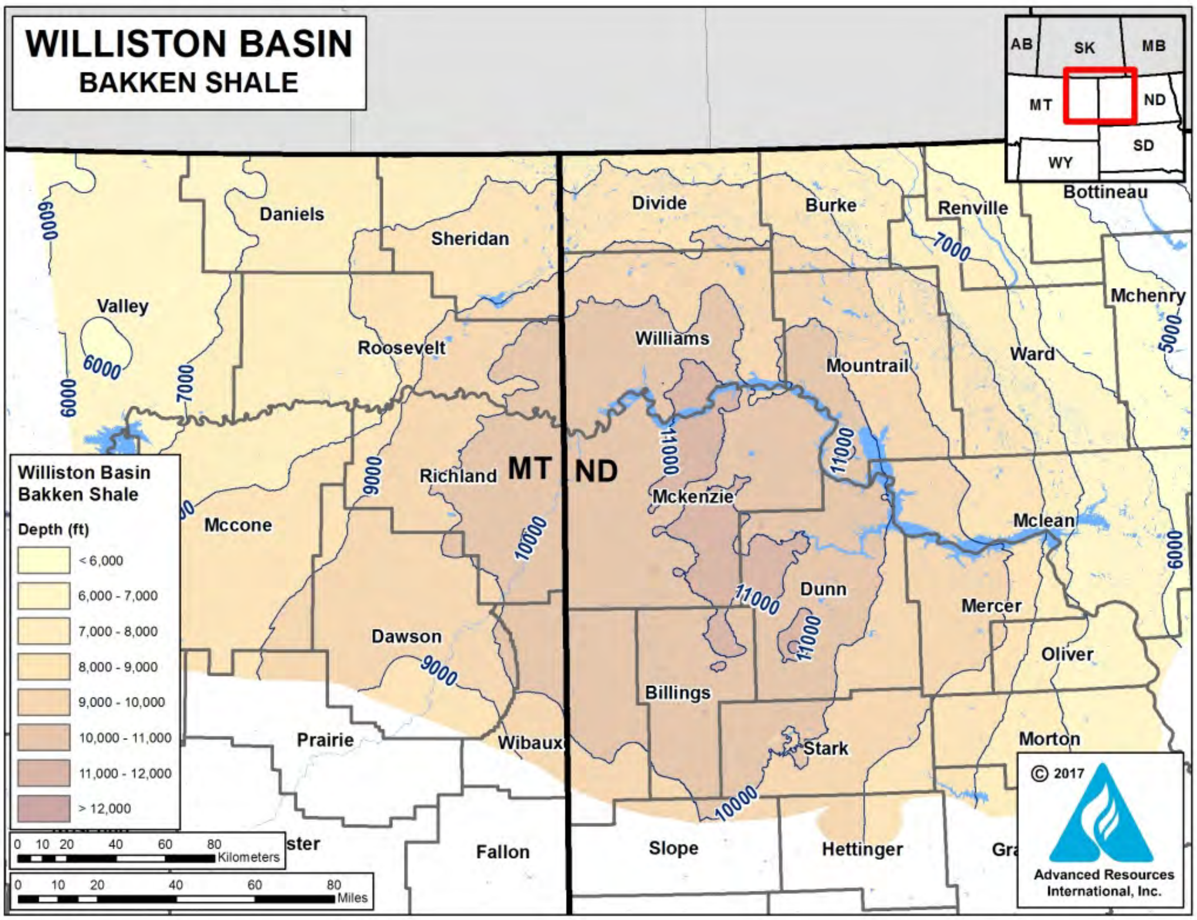
Source: Jin and Sonnenberg, 2013

Below the Bakken Shale is an equally attractive shale formation called the Three Forks Shale (not addressed in this Bakken Shale study) that has become notably active in recent years.

1.2.3 Bakken Shale Depth

From a depth of about 8,000 feet (ft) at the basin margins, the Bakken Shale reaches a depth of over 11,000 ft in the heart of the basin's hydrocarbon "kitchen", in west-central North Dakota (Figure 1-5).

Figure 1-5. Bakken Shale (Middle Member) Shale Depth

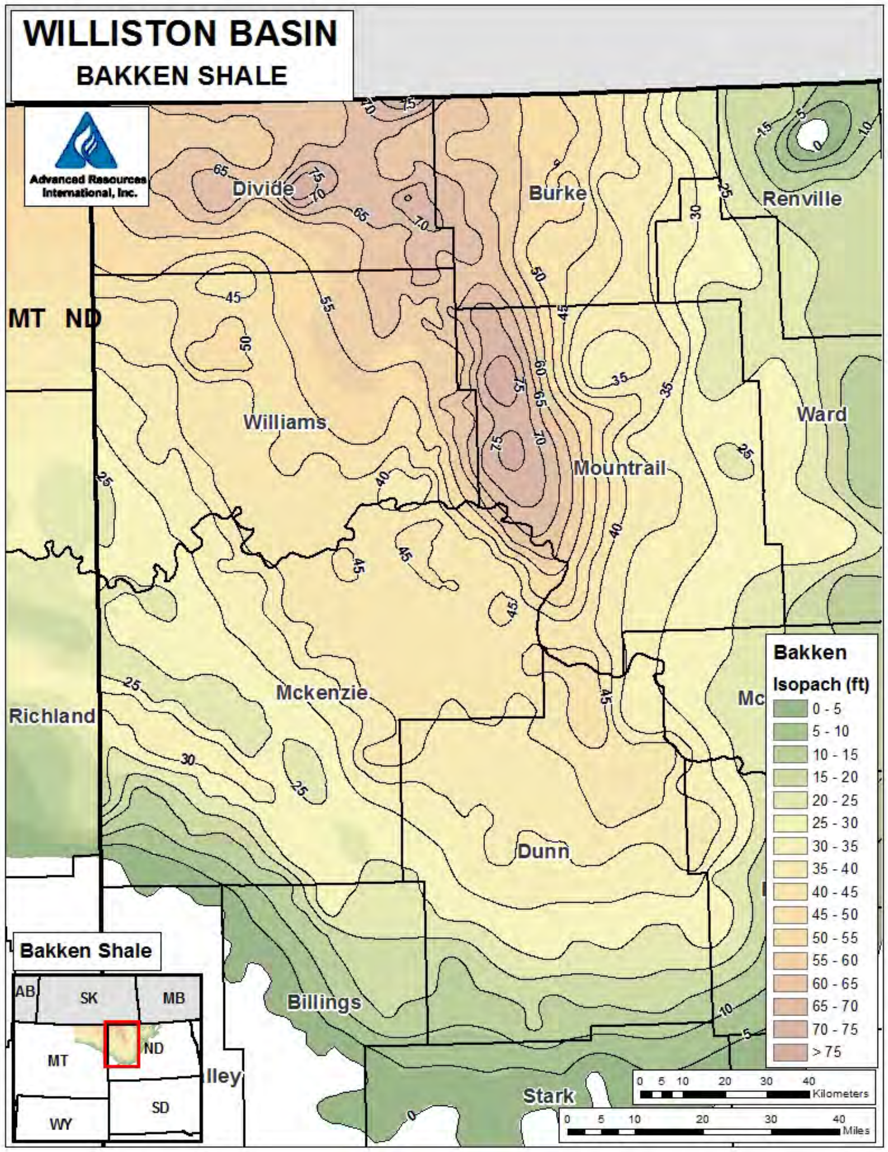


Source: Advanced Resources International, 2020.

1.2.4 Bakken Shale Isopach

The thickness of the Bakken Shale interval (including the Upper, Middle and Lower Members) ranges from less than 50 feet (ft) along the basin margin to over 150 ft in the basins center. In the actively developed areas, the Middle Bakken Shale interval generally ranges from 60 ft to 90 ft (Figure 1-6).

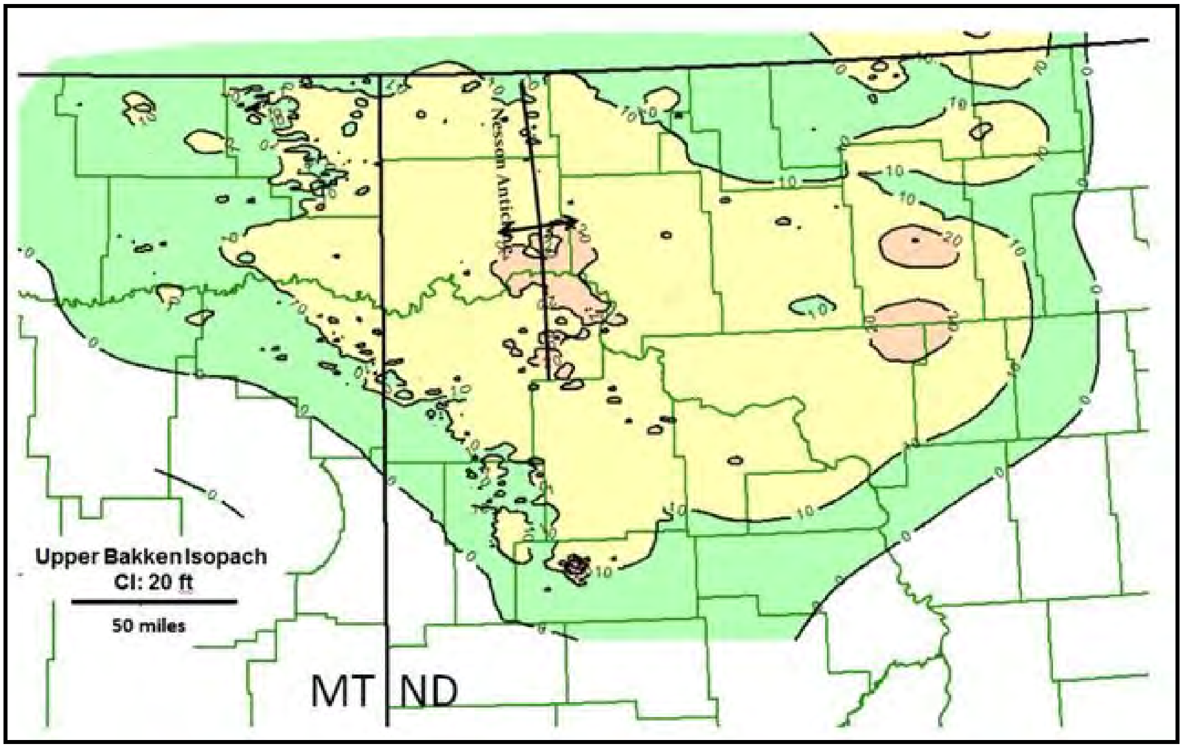
Figure 1-6. Middle Bakken Shale Gross Isopach Map



Source: Advanced Resources International, 2020.

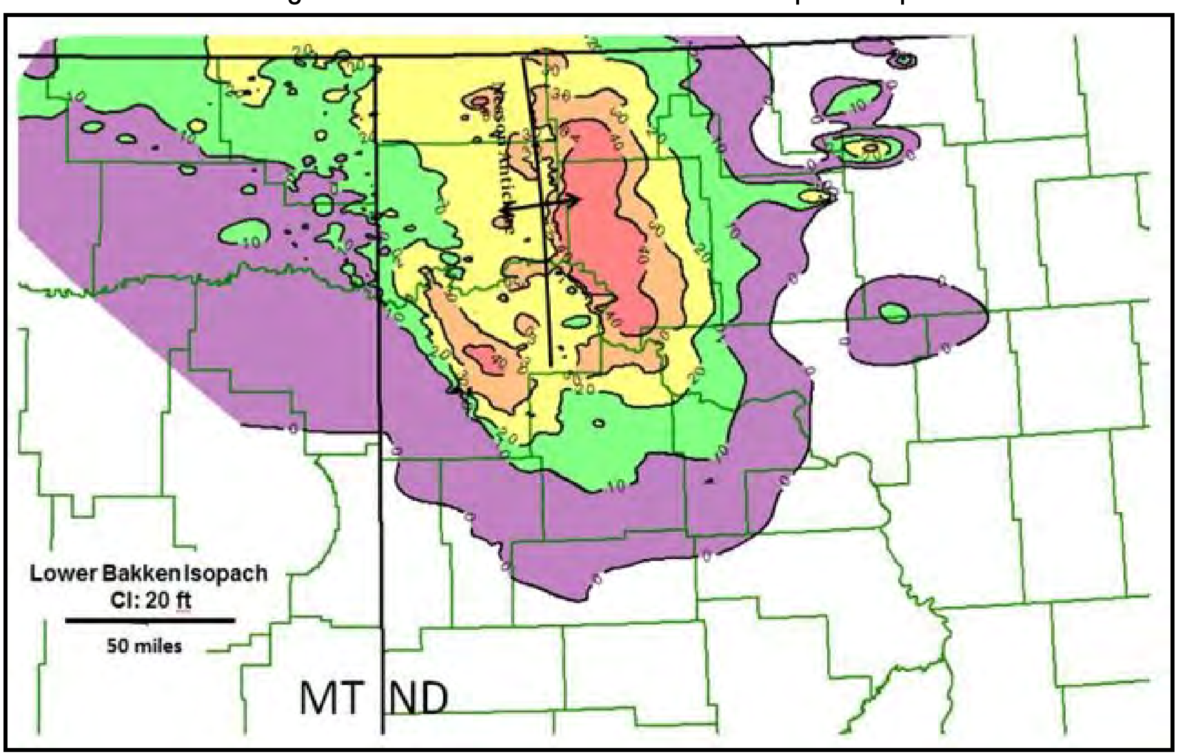
The Upper Bakken Shale Member represents a thin but consistent interval that overlies the Middle Bakken Member. The thickness of the Middle Member ranges from 5 ft to 10 ft in the basin margins of the Bakken Shale to 20 ft in the basin center of the Bakken Shale (Figure 1-7). The thickness of the Lower Bakken Shale Member ranges from 20 ft to 40 ft in the basin center of the Bakken Shale to 10 ft to 20 ft in the basin margins of the Bakken Shale (Figure 1-8). The Lower Bakken Member thins to 10 ft and less in the Montana portion of the Bakken Shale.

Figure 1-7. Upper Bakken Shale Gross Isopach Map



Source: Jin and Sonnenberg, 2013.

Figure 1-8. Lower Bakken Shale Gross Isopach Map



Source: Jin and Sonnenberg, 2013.

1.3. Establishing the Essential Reservoir Properties

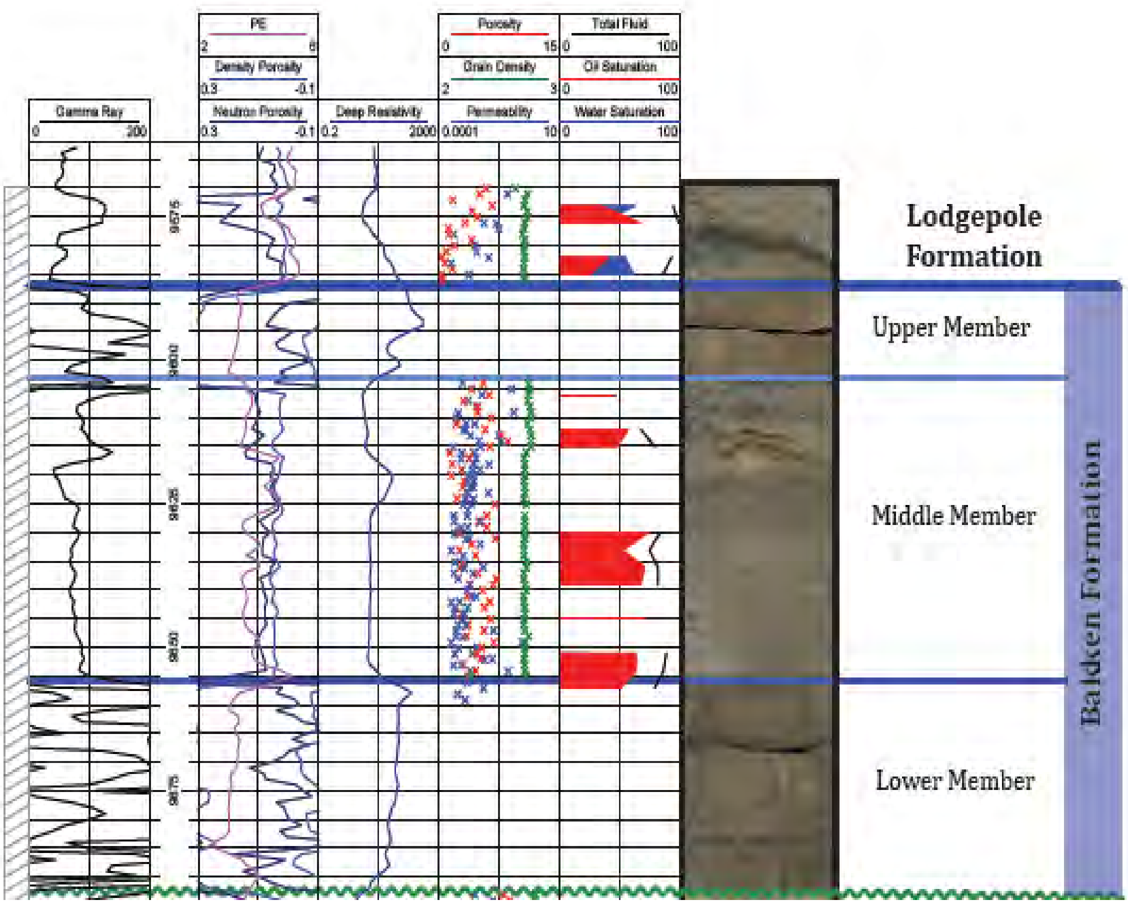
1.3.1 Bakken Shale Type Log

The Bakken Shale contains three members, as shown on well log EOG #2-11 in southern Mountrail County (Figure 1-9).

- The Upper Member consists of organic-rich, finely laminated shales deposited in a restricted marine setting.
- The Middle Member is a dolomitic siltstone to fine-grained sandstone, containing a network of microfractures.
- The Lower Member is like the Upper Member, an organic-rich shale.

Figure 1-9. Typical Bakken Well Log

EOG #2-11



Source: LeFever, et al. 2013

1.3.2 Bakken Shale Reservoir Porosity

Information on the porosity of the Bakken Shale is scarce in the technical literature, particularly for porosity values in the organic portions of the shale. Based on industry published information, the porosity of the Bakken Shale matrix ranges from 5% to 7% (Energy & Environmental Research Center (EERC), 2019a). The natural fracture system adds about 0.1% to the matrix porosity values.

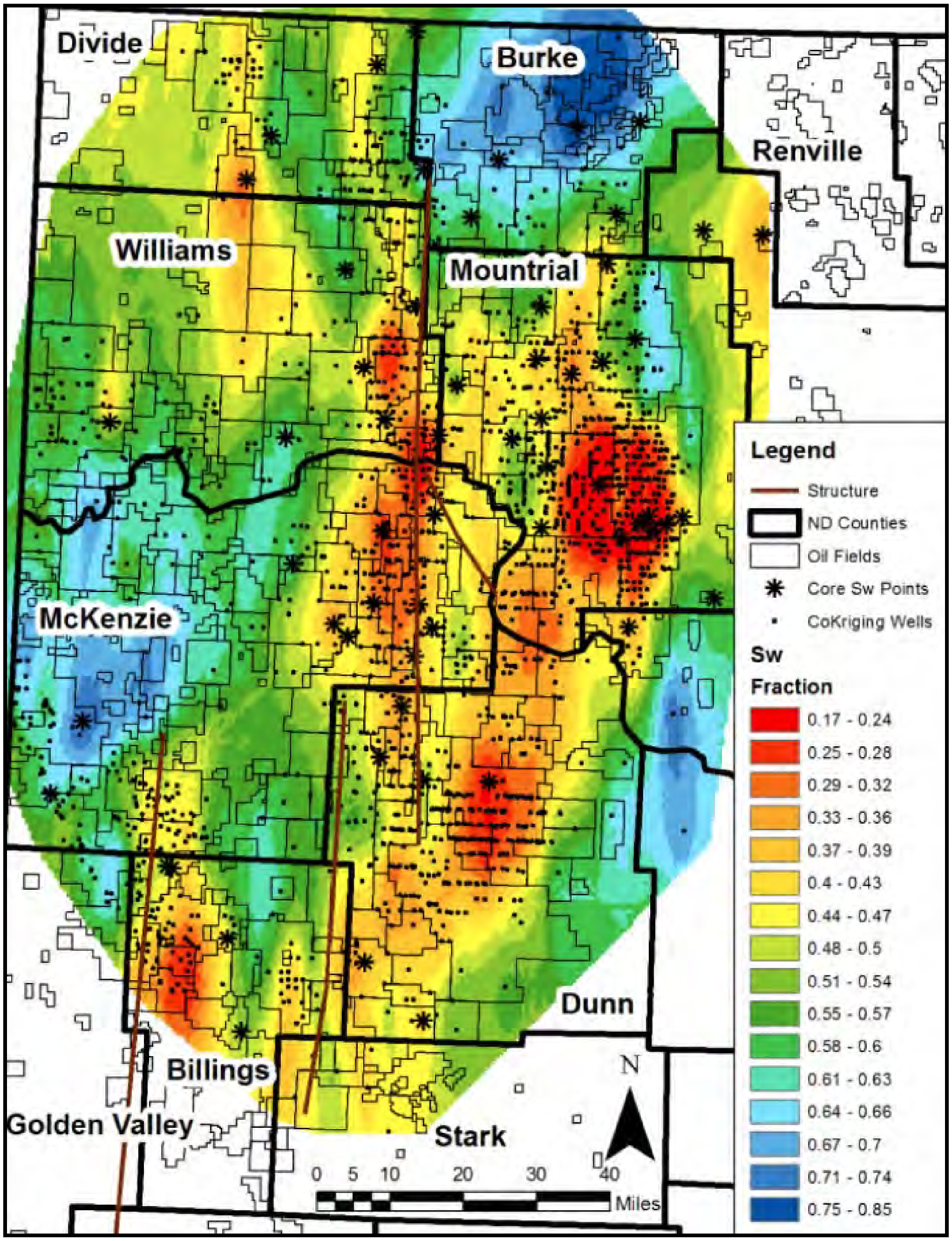
1.3.3 Bakken Shale Oil and Water Saturation

Laboratory derived information indicates that the shale in the central and southern portions of the Bakken area has an initial oil saturation of about 75% and an immobile water saturation of about 25%. However, in the two northern partitions of the Bakken area, in Divide and Burke counties, North Dakota, the shale formation has considerably higher water saturations and lower initial oil saturations that range from 40 to 55% (EERC, 2019a,b). Figure 1-10 provides regional information on the water saturation in the Bakken Shale, compiled from core data (Schmidt, 2011).

1.3.4 Bakken Shale Oil Gravity

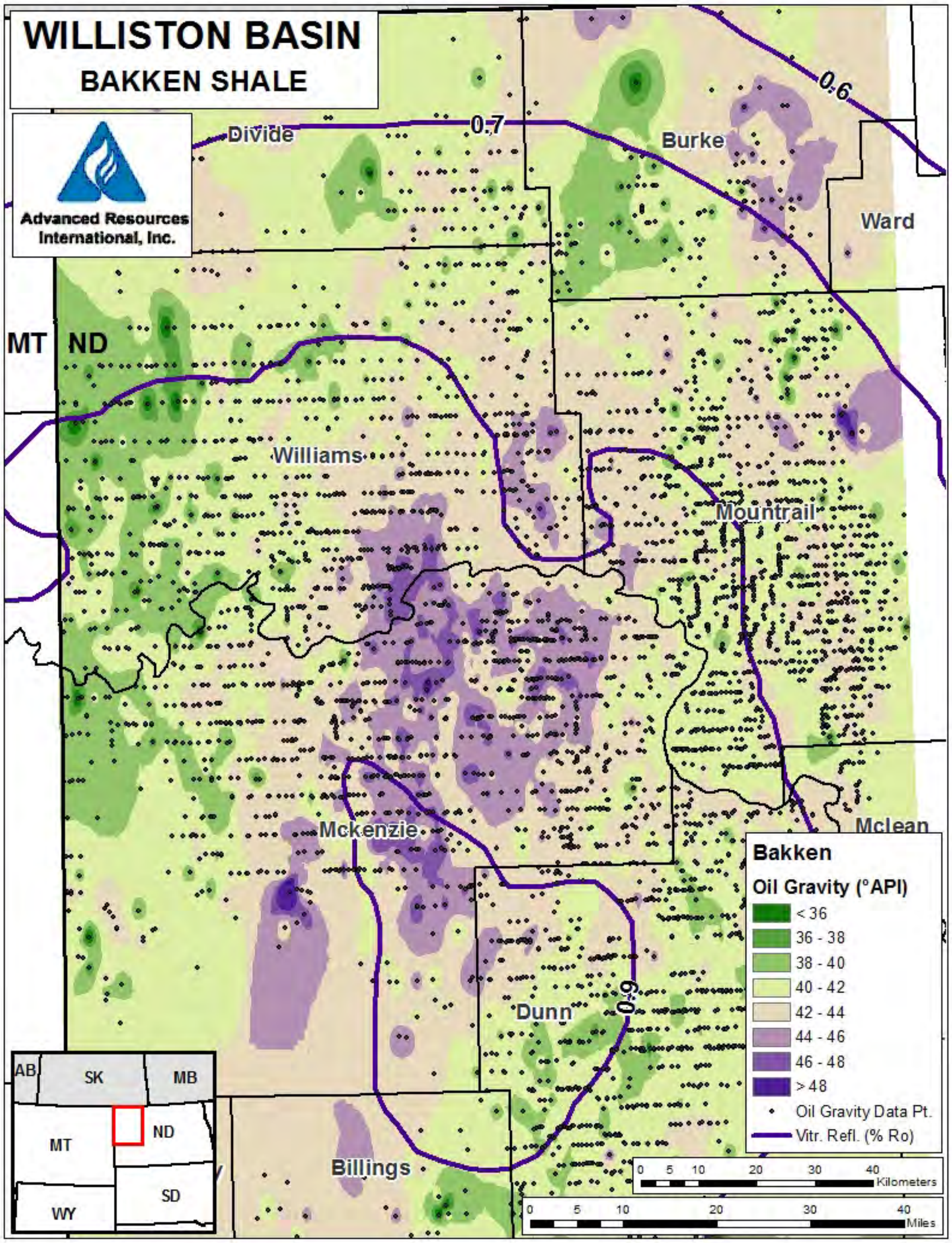
The API gravity of Bakken Shale oil ranges from 36 degrees in the thermally less mature areas to the north and west to higher API gravity values, in excess of 50 degrees, in thermally mature central McKenzie County, North Dakota (Figure 1-11).

Figure 1-10. Core Based Information on Bakken Shale Oil Saturations



Source: Schmidt, D., 2011

Figure 1-11. Bakken Shale API Gravity



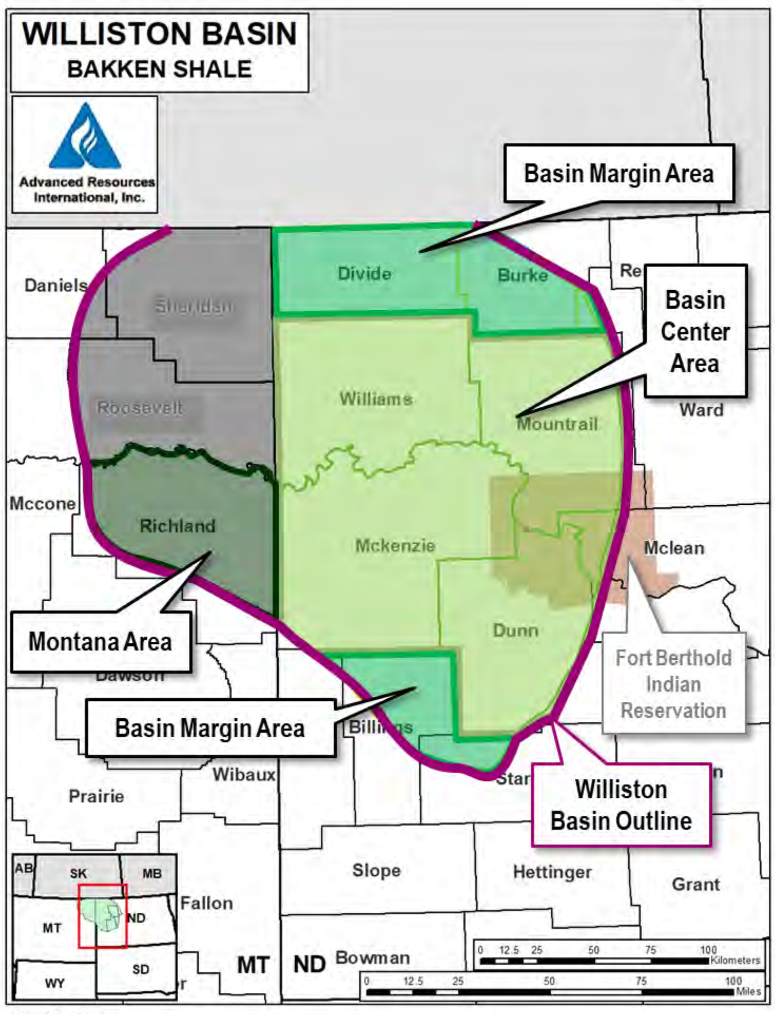
Source: Advanced Resources International, 2020.

1.4. Bakken Shale Resource Assessment

1.4.1 Assessment Methodology

The resource assessment portion of the study partitioned the Bakken Shale into Basin Center and Basin Margin areas in North Dakota with a separate partition for Montana (Figure 1-12). The study further subdivided these partitions into the various counties comprising the three larger geographic areas. For each county, the study assembled representative volumetric and other reservoir properties essential for estimating OOIP.

Figure 1-12. Outline Map of the Bakken Shale Study Area

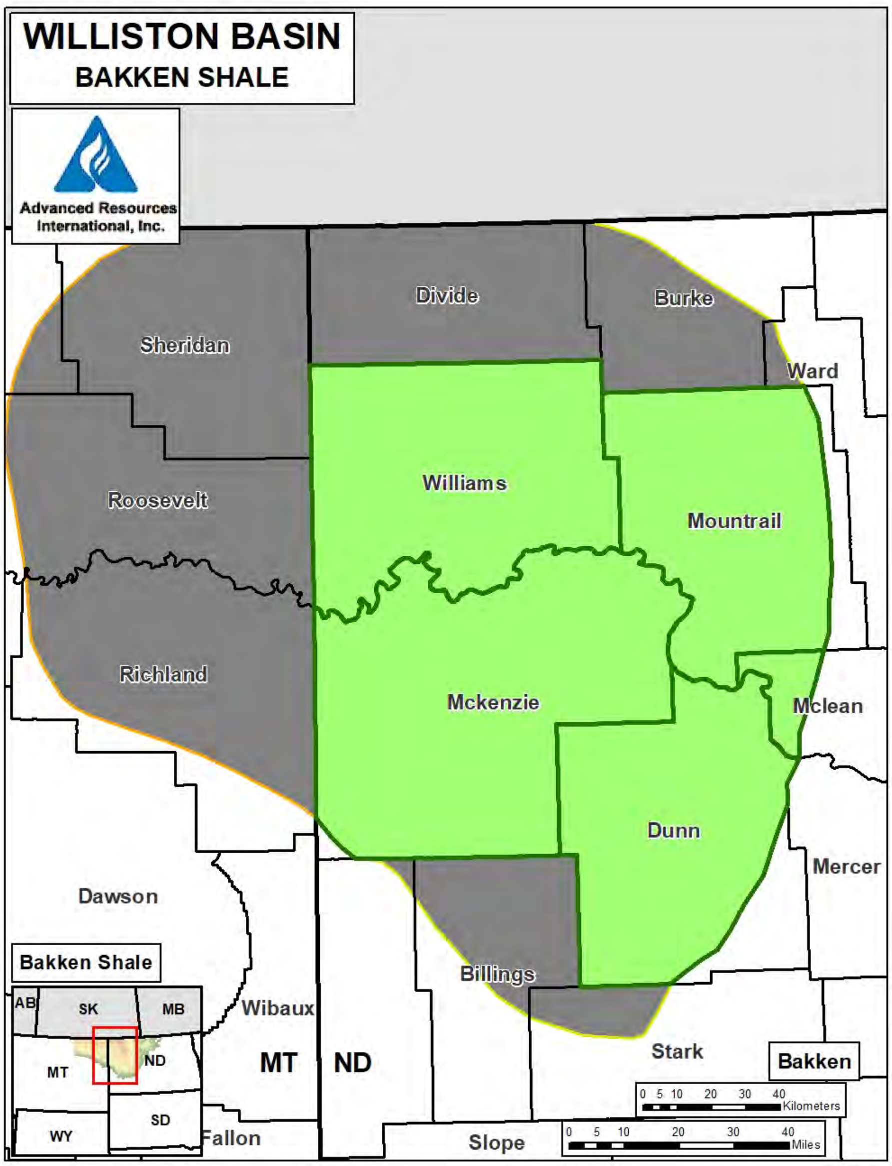


Source: Advanced Resources International, 2020.

1.5. Basin Center Shale Area

The Basin Center Shale Area of the Bakken Shale extends across 8,670 square miles (6,930 square miles, risked) in Mountrail, McKenzie, Dunn and Williams counties, North Dakota (Figure 1-13). Overall, nearly 10,000 Hz Bakken Shale oil wells have been drilled and completed in this area, as of the end of 2019. The depth of the Bakken Shale in this area ranges from about 8,000 ft on its eastern border in Mountrail County to below 12,000 ft in the center of the basin in Williams and McKenzie counties.

Figure 1-13. Outline Map of the Bakken Center Bakken Shale Area



Source: Advanced Resources International, 2020.

Table 1-1 provides the volumetric and other reservoir properties for the four counties in the Basin Center Bakken Shale Area.

Table 1-1. Reservoir Properties for Estimating OOIP, Basin Center Bakken Shale Area

Reservoir Property	Mountrail Co.	McKenzie Co.	Dunn Co.	Williams Co.
Total Area	1,890 mi^2	2,840 mi^2	1,790 mi^2	2,150 mi^2
Risked Area	1,510 mi^2	2,270 mi^2	1,430 mi^2	1,720 mi^2
Average Depth	9,750 ft	10,750 ft	10,500 ft	10,000 ft
Net Pay (Shale Unit)				
▪ Upper Bakken	10 ft	10 ft	10 ft	10 ft
▪ Middle Bakken	50 ft	40 ft	40 ft	50 ft
▪ Lower Bakken	30 ft	30 ft	20 ft	20 ft
Porosity (Shale Unit)				
▪ Upper Bakken	5.4%	5.4%	5.4%	5.4%
▪ Middle Bakken	5.2%	5.2%	5.2%	5.2%
▪ Lower Bakken	6.9%	6.9%	6.9%	6.9%
Oil Saturation	75%	75%	75%	75%
Formation Volume Factor (RB/STB)	1.8	1.8	1.8	1.8
Solution GOR (Mcf/B)	1.5	1.5	1.5	1.5

Source: Advanced Resources International, 2020.

Using the volumetric reservoir properties in Table 1-1, the OOIP for the Upper, Middle and Lower Bakken Shale in Mountrail County is 16.3 billion barrels (Table 1-2); in McKenzie County is 22.1 billion barrels (Table 1-3); in Dunn County is 11.8 billion barrels (Table 1-4); and in Williams County is 16.1 billion barrels (Table 1-5).

Table 1-2. OOIP of Bakken Shale in Mountrail County, Basin Center Shale Area

County/Interval	Risked Area (mi^2)	Resource Concentration (MMB/mi^2)	Oil/Condensate OOIP (Million Barrels)
▪ Mountrail – Upper Bakken	1,510	1,120	1,690
▪ Mountrail – Middle Bakken	1,510	5,380	8,130
▪ Mountrail – Lower Bakken	1,510	4,280	6,480
Total	1,510	10,780	16,300

Source: Advanced Resources International, 2020.

Table 1-3. OOIP of Bakken Shale in McKenzie County, Basin Center Shale Area

County/Interval	Risked Area (mi^2)	Resource Concentration (MMB/mi^2)	Oil/Condensate OOIP (Million Barrels)
▪ McKenzie – Upper Bakken	2,270	1,120	2,540
▪ McKenzie – Middle Bakken	2,270	4,300	9,780
▪ McKenzie – Lower Bakken	2,270	4,280	9,730
Total	2,270	9,700	22,050

Source: Advanced Resources International, 2020.

Table 1-4. OOIP of Bakken Shale in Dunn County, Basin Center Shale Area

County/Interval	Risked Area (mi^2)	Resource Concentration (MMB/mi^2)	Oil/Condensate OOIP (Million Barrels)
▪ Dunn – Upper Bakken	1,430	1,120	1,600
▪ Dunn – Middle Bakken	1,430	4,300	6,160
▪ Dunn – Lower Bakken	1,430	2,860	4,090
Total	1,430	8,280	11,850

Source: Advanced Resources International, 2020.

Table 1-5. OOIP of Bakken Shale in Williams County, Basin Center Shale Area

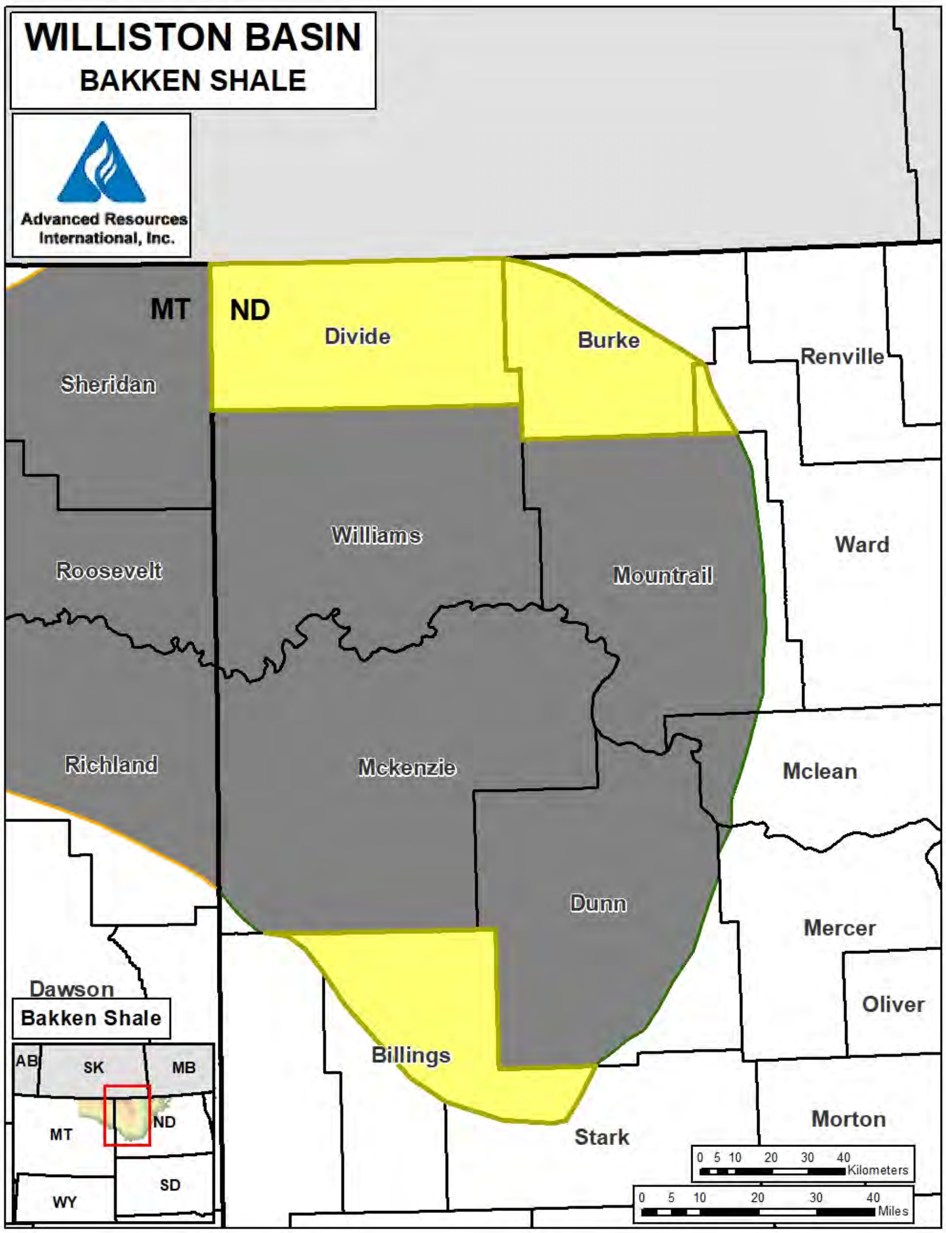
County/Interval	Risked Area (mi^2)	Resource Concentration (MMB/mi^2)	Oil/Condensate OOIP (Million Barrels)
▪ Williams – Upper Bakken	1,720	1,120	1,920
▪ Williams – Middle Bakken	1,720	5,380	9,250
▪ Williams – Lower Bakken	1,720	2,860	4,910
Total	1,720	9,360	16,080

Source: Advanced Resources International, 2020.

1.5.1 Basin Margin Shale Area

The Basin Margin Shale Area of the Bakken Shale covers 2,920 mi^2 (2,320 mi^2, risked) in Divide, Burke, Billings and Stark counties, as displayed in Figure 1-14. Only limited Hz well drilling has occurred, so far, in this shale area.

Figure 1-14. Outline Map of Basin Margin Shale Area



Source: Advanced Resources International, 2020.

Table 1-6 provides the volumetric and other reservoir properties of the three resource assessment units (counties) of the Basin Margin Bakken Shale Area.

Table 1-6. Reservoir Properties for Estimating OOIP, Basin Margin Bakken Shale Area

Reservoir Property	Divide Co.	Burke Co.	Billings-Stark Co.
Total Area	1,290 mi^2	780 mi^2	850 mi^2
Risked Area	1,030 mi^2	620 mi^2	680 mi^2
Average Depth	8,000 ft	8,000 ft	10,250 ft
Net Pay (Shale Unit)			
▪ Upper Bakken	10 ft	10 ft	5 ft
▪ Middle Bakken	65 ft	45 ft	10 ft
▪ Lower Bakken	20 ft	30 ft	5 ft
Porosity (Shale Unit)			
▪ Upper Bakken	7.0%	7.0%	5.4%
▪ Middle Bakken	7.5%	7.5%	5.2%
▪ Lower Bakken	7.0%	7.0%	6.9%
Oil Saturation	55%	40%	75%
Formation Volume Factor (RB/STB)	1.6	1.6	1.8
Solution GOR (Mcf/B)	1.3	1.3	1.5

Source: Advanced Resources International, 2020

Using the volumetric reservoir properties in Table 1-6, the OOIP in Divide County is 12.3 billion barrels (Table 1-7); in Burke County is 4.8 billion barrels (Table 1-8); and in Billings-Stark County is 1.6 billion barrels (Table 1-9).

Table 1-7. OOIP of Bakken Shale in Divide County, Basin Margin Shale Area

County/Interval	Risked Area (mi^2)	Resource Concentration (MMB/mi^2)	Oil/Condensate OOIP (Million Barrels)
▪ Divide – Upper Bakken	1,030	1,200	1,230
▪ Divide – Middle Bakken	1,030	8,320	8,590
▪ Divide – Lower Bakken	1,030	2,390	2,470
Total	1,030	11,910	12,290

Source: Advanced Resources International, 2020.

Table 1-8. OOIP of Bakken Shale in Burke County, Basin Margin Shale Area

County/Interval	Risked Area (mi^2)	Resource Concentration (MMB/mi^2)	Oil/Condensate OOIP (Million Barrels)
▪ Burke – Upper Bakken	620	870	540
▪ Burke – Middle Bakken	620	4,190	2,610
▪ Burke – Lower Bakken	620	2,610	1,630
Total	620	7,670	4,780

Source: Advanced Resources International, 2020.

Table 1-9. OOIP of Bakken Shale in Billings-Stark County, Basin Margin Shale Area

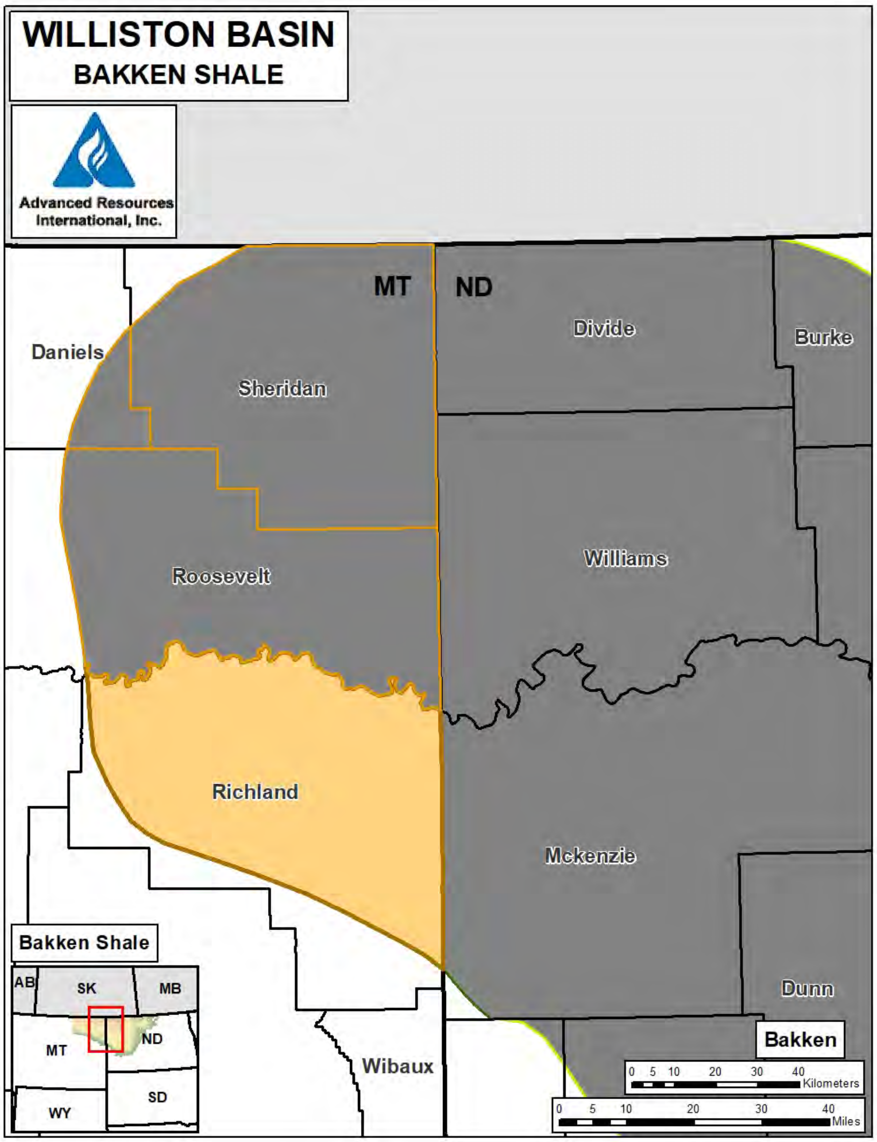
County/Interval	Risked Area (mi^2)	Resource Concentration (MMB/mi^2)	Oil/Condensate OOIP (Million Barrels)
▪ Billings-Stark – Upper Bakken	680	560	380
▪ Billings-Stark – Middle Bakken	680	1,080	730
▪ Billings-Stark – Lower Bakken	680	710	490
Total	680	2,350	1,600

Source: Advanced Resources International, 2020.

1.5.2 Montana Shale Area

The Montana Area of the Bakken Shale extends across 1,620 mi^2 (1,300 mi^2, risked) in Richland County, Montana (Figure 1-15). The study excluded Roosevelt and Sheridan counties in Montana from the Bakken Shale resource assessment due to limited development in these two counties.

Figure 1-15. Outline Map of Montana Shale Area



Source: Advanced Resources International, 2020.

Table 1-10 provides the volumetric and other reservoir properties for the Richland County resource assessment unit of the Montana Shale Area.

Table 1-10. Reservoir Properties for Estimating OOIP, Montana Bakken Shale Area

Reservoir Property	Montana
Total Area	1,620 mi^2
Risked Area	1,300 mi^2
Average Depth	9,500 ft
Net Pay (Shale Unit)	
▪ Upper Bakken	10 ft
▪ Middle Bakken	25 ft
▪ Lower Bakken	5 ft
Porosity (Shale Unit)	
▪ Upper Bakken	5.4%
▪ Middle Bakken	5.2%
▪ Lower Bakken	6.9%
Oil Saturation	75%
Formation Volume Factor (RB/STB)	1.8
Solution GOR (Mcf/B)	1.5

Source: Advanced Resources International, 2020.

Using the volumetric reservoir properties on Table 1-10, the OOIP for the Bakken Shale in Montana is 5.9 billion barrels (Table 1-11).

Table 1-11. OOIP of Bakken Shale, Montana Shale Area

County/Interval	Risked Area (mi^2)	Resource Concentration (MMB/mi^2)	Oil/Condensate OOIP (Million Barrels)
▪ Montana – Upper Bakken	1,300	1,120	1,450
▪ Montana – Middle Bakken	1,300	2,690	3,490
▪ Montana – Lower Bakken	1,300	710	930
Total	1,300	4,520	5,870

Source: Advanced Resources International, 2020.

1.5.3 Total Bakken Shale Area

Combining the OOIP estimates for the eight resource assessment units (counties) within the three geographic Bakken Shale Areas – the Basin Center Area, the Basin Margin Area, and the Montana Area – the study estimates an overall risked OOIP value for the Bakken Shale of 90.8 billion barrels (Table 1-12).

Table 1-12. Total OOIP for Bakken Shale

Shale Areas	Risked Area (mi^2)	Resource Concentration (MMB/mi^2)	Oil/Condensate OOIP (Million Barrels)
Basin Center Bakken Shale Area			
▪ Mountrail Co.	1,510	10,780	16,300
▪ McKenzie Co.	2,270	9,700	22,050
▪ Dunn Co.	1,430	8,280	11,850
▪ Williams Co.	1,720	9,360	16,080
Sub-Total			66,280
Basin Margin Bakken Shale Area			
▪ Divide Co.	1,030	11,910	12,290
▪ Burke Co.	620	7,670	4,780
▪ Billings-Stark Co.	680	2,350	1,600
Sub-Total			18,670
Montana Bakken Shale Area			
▪ Montana	1,300	4,520	5,870
Total OOIP			90,820

Source: Advanced Resources International, 2020.

1.6. Reservoir Simulation of Primary and Enhanced Oil Recovery for the Bakken Shale

1.6.1 Representative Study Area

To establish the incremental oil production from implementation of enhanced oil recovery using injection of CO_2, the study selected a representative area of the Bakken Shale in the Basin Center Shale Area, with reservoir properties shown in Table 1-13. The Study Area contains 5.2 million barrels of original oil in-place (OOIP) and 7.2 Bcf of original gas in-place (OGIP).

Table 1-13. Bakken Shale Study Area Reservoir Properties

Reservoir Properties	Units
Pattern Area	313 acres
Well Pattern Dimensions	
▪ Length	10,500 ft
▪ Width	1,300 ft
Depth (to top)	10,000 ft
Net Pay	90 ft
▪ Upper (Shale)	10 ft
▪ Middle (Carbonaceous Sands)	50 ft
▪ Lower (Shale)	30 ft
Porosity	
▪ Matrix*	5.8%
▪ Fracture	0.1%
Initial Oil Saturation	
▪ Matrix/Fracture	71.5%
Saturation Gas/Oil Ratio	1.37 Mcf/B
Formation Volume Factor	1.73 RB/STB
Initial Pressure	6,700 psia
Temperature	220^{o} F
Bubble Point	2,500 psia
Formation Compressibility	1.5 * e $^{-5}$/psi
Oil Gravity	41^{o} API

*Average for three Bakken Shale Units

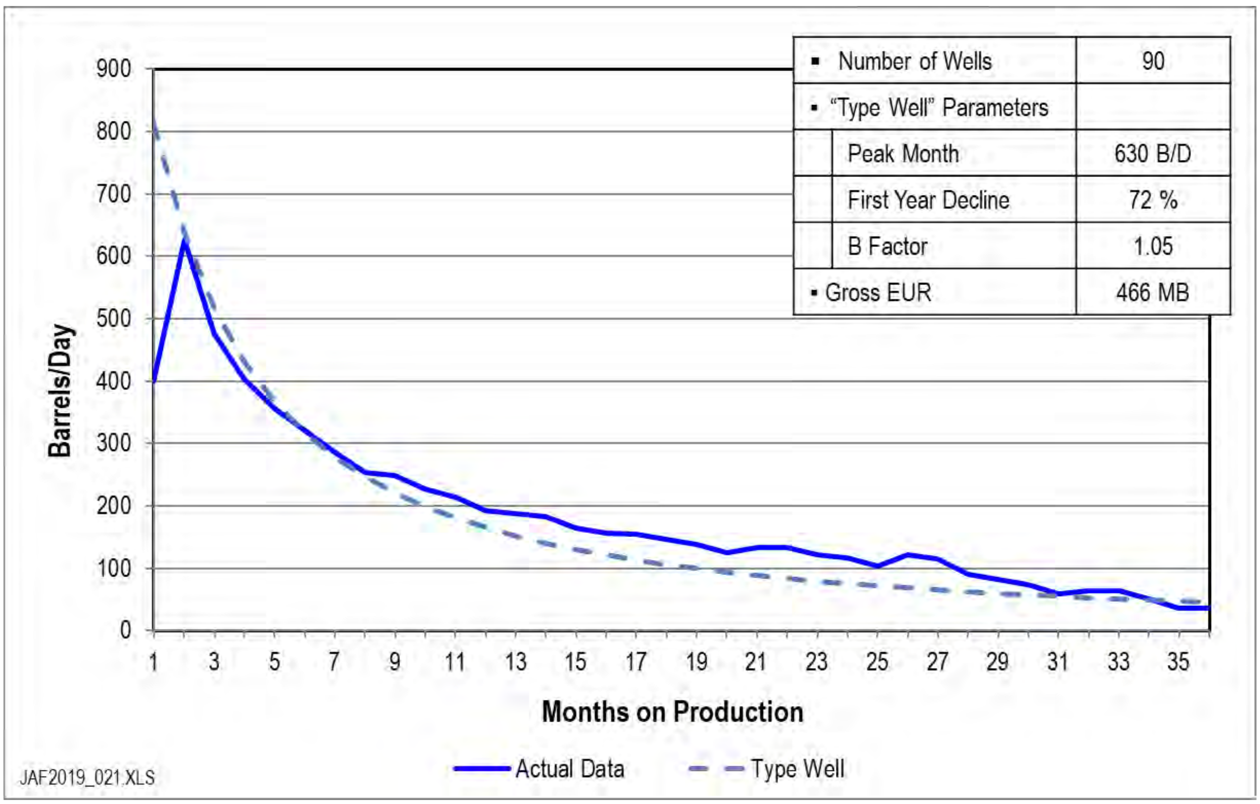
Source: EERC, 2019a; Advanced Resources International, 2020.

1.6.2 Type Well for Study Area

The Study Area well chosen for the history match is the "type well" for the Bakken Shale in Mountrail County assembled by Advanced Resources International. The "type well" represents the composite performance of 90 Hz wells drilled in 2016 and has 36 months of oil and gas production (Figure 1-16).

The well's longer term, 30-year performance of 466,000 barrels was estimated using a peak month production of 630 barrels per day (B/D), a first-year production decline of 72%, and a "b" of 1.05 for the longer-term production decline.

Figure 1-16. Study Area Type Well Oil Production

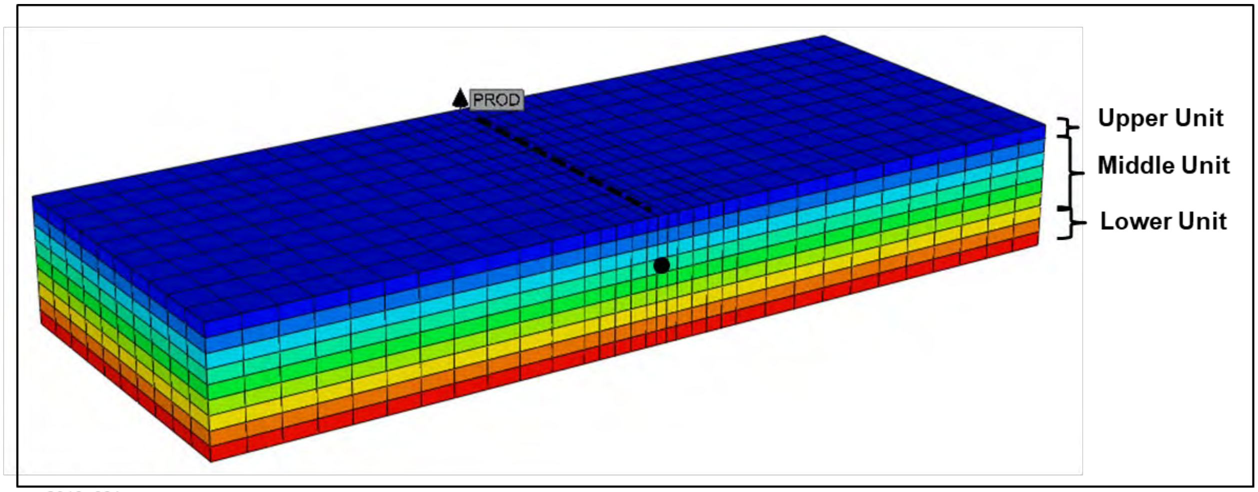


Source: Advanced Resources International, 2020.

1.6.3 Reservoir Simulation

The GEM reservoir simulator from the Computer Modeling Group was utilized for the study. GEM is a robust, fully compositional, Equation of State reservoir simulator used widely by industry for modeling the flow of three-phase, multi-component fluids through porous media. The reservoir model and grid blocks constructed to replicate the Bakken Shale geologic and reservoir setting for the Study Area well are illustrated in Figure 1-17. The reservoir property values in Table 1-13 were used to populate the reservoir model and its 2,880 grid blocks.

Figure 1-17. Reservoir Model and Grid Blocks Used for Bakken Shale Study



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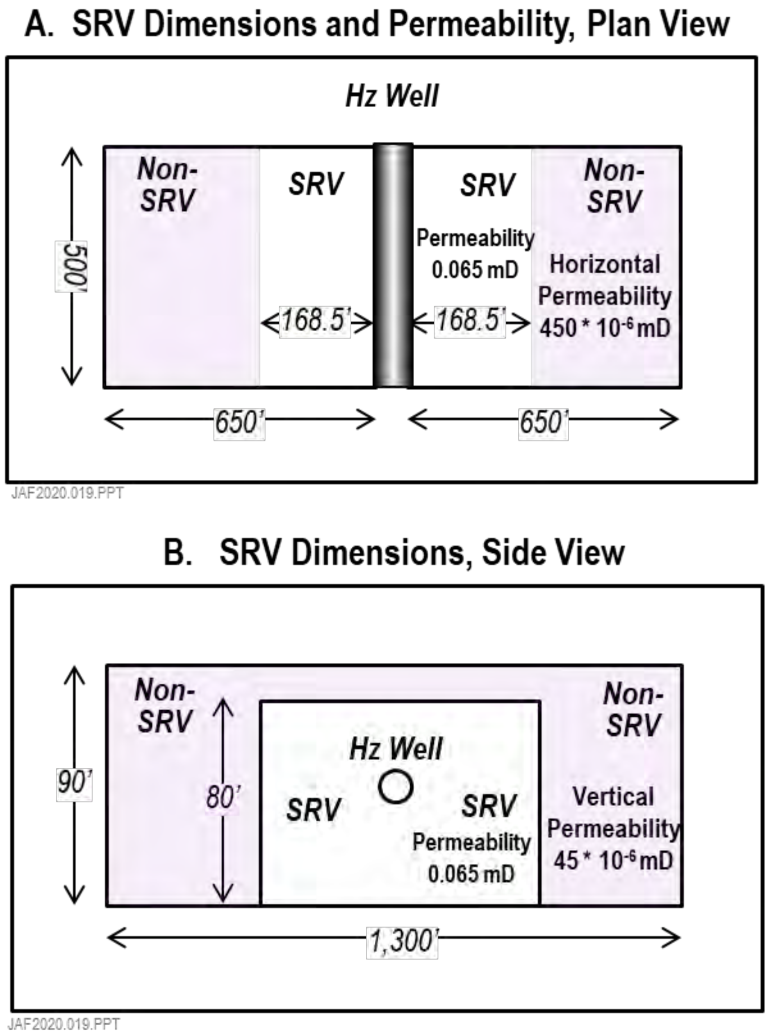
Source: Advanced Resources International, 2020.

To capture the impact of hydraulic stimulation on the performance of the horizontal well, a Stimulated Reservoir Volume (SRV) was established in the model, assuming enhanced permeability in the SRV for both the fractures and the matrix. The "segment" well lateral (1/21st of the total "type well") was assumed to be stimulated for 80% of its full length, 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. Figure 1-18 provides information on the SRV dimensions and enhanced permeability from the history match of the Bakken Shale "type well".

Figure 1-18. SRV Dimensions and Permeability Used to History Match Well Performance

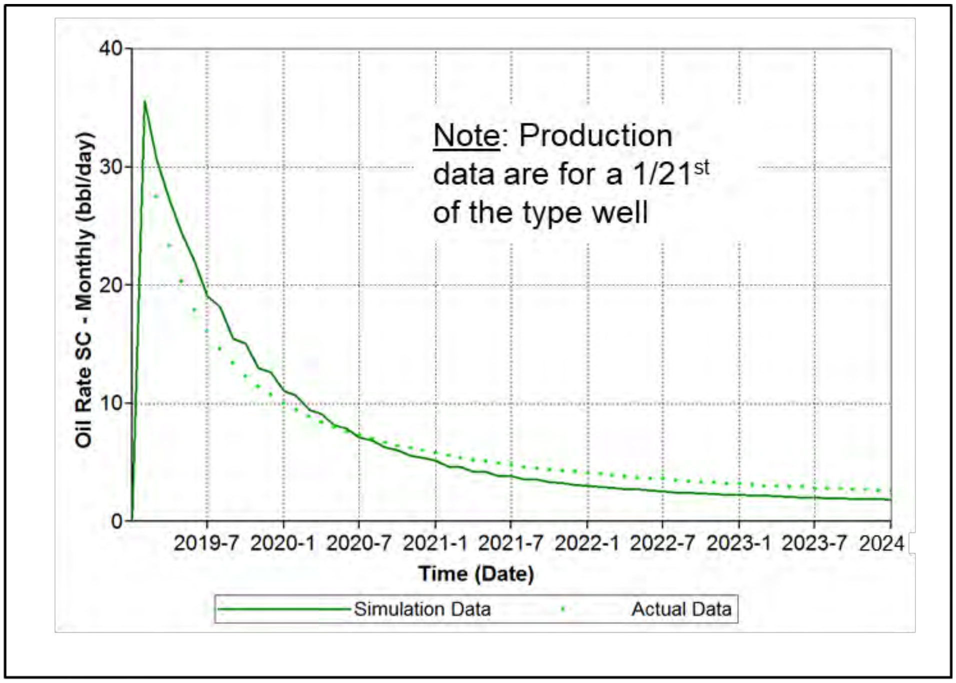


Source: Advanced Resources International, 2020.

1.6.4 History Match of Short- and Long-Term Oil Production

The reservoir properties in Table 1-13, plus the enhanced permeability values and SRV dimensions discussed above, were used to history match the Bakken Shale Study Area well, resulting in an excellent match with actual oil production data (Figures 1-19 and 1-20). With an OOIP of 5.2 million barrels and history matched oil recovery of 466,000 barrels, the primary oil recovery efficiency is 9% of OOIP.

Figure 1-19. History Match of Monthly Oil Production



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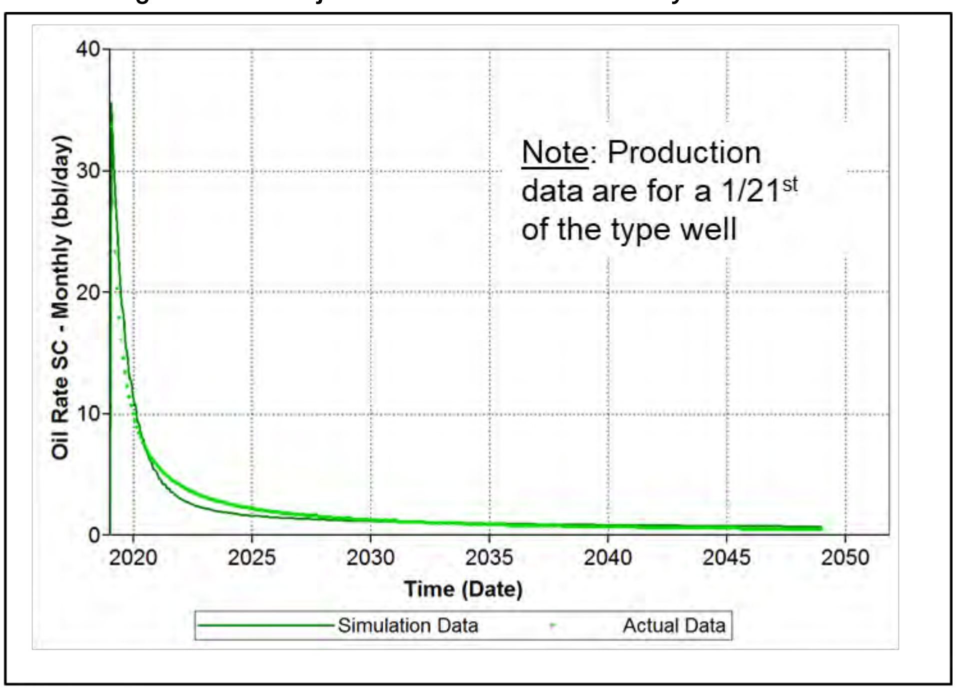
Source: Advanced Resources International, 2020.

Figure 1-20. Projection of 30 Years of Primary Production



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Source: Advanced Resources International, 2020.

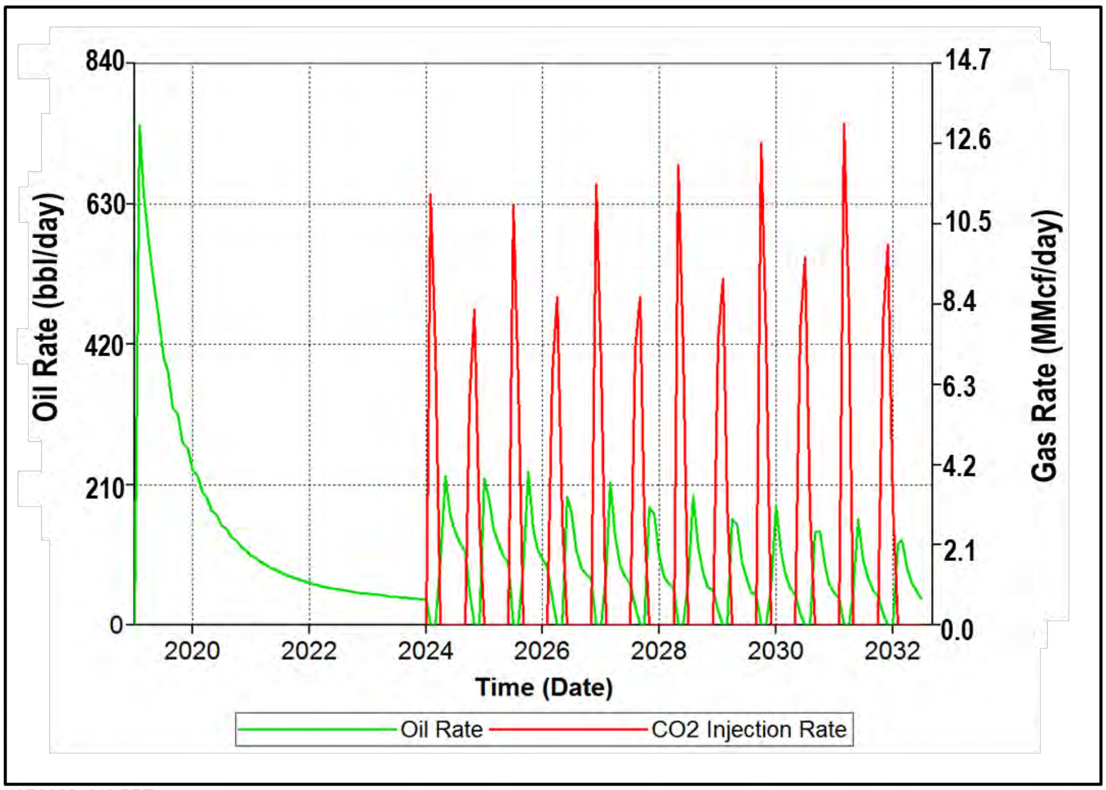
1.6.5 Performance of Cyclic CO_2 Injection

Cyclic CO_2 injection was initiated in the Study Area well after five years of primary production, after the well had produced about 60% of its estimated ultimate oil recovery using primary (pressure depletion) production.

- In cycle one, CO_2 was injected at a constant rate of 9,500 Mcfd for 2 months (BHP limit of 7,000 psia) to refill reservoir voidage and build reservoir pressure with a total of 570,000 Mcf of CO_2 injected.
- CO_2 injection was followed by a two-week soak time and then followed by six months of production.
- Eleven additional cycles of CO_2 injection, soak and production followed.

Figure 1-21 illustrates the oil production data for the first 5 years of primary oil production and from the subsequent 12 cycles (8.5 years) of cyclic CO_2 injection, soak and production from the Study Area well.

Figure 1-21. Primary Production and Enhanced Oil Recovery from Cyclic CO_2 Injection



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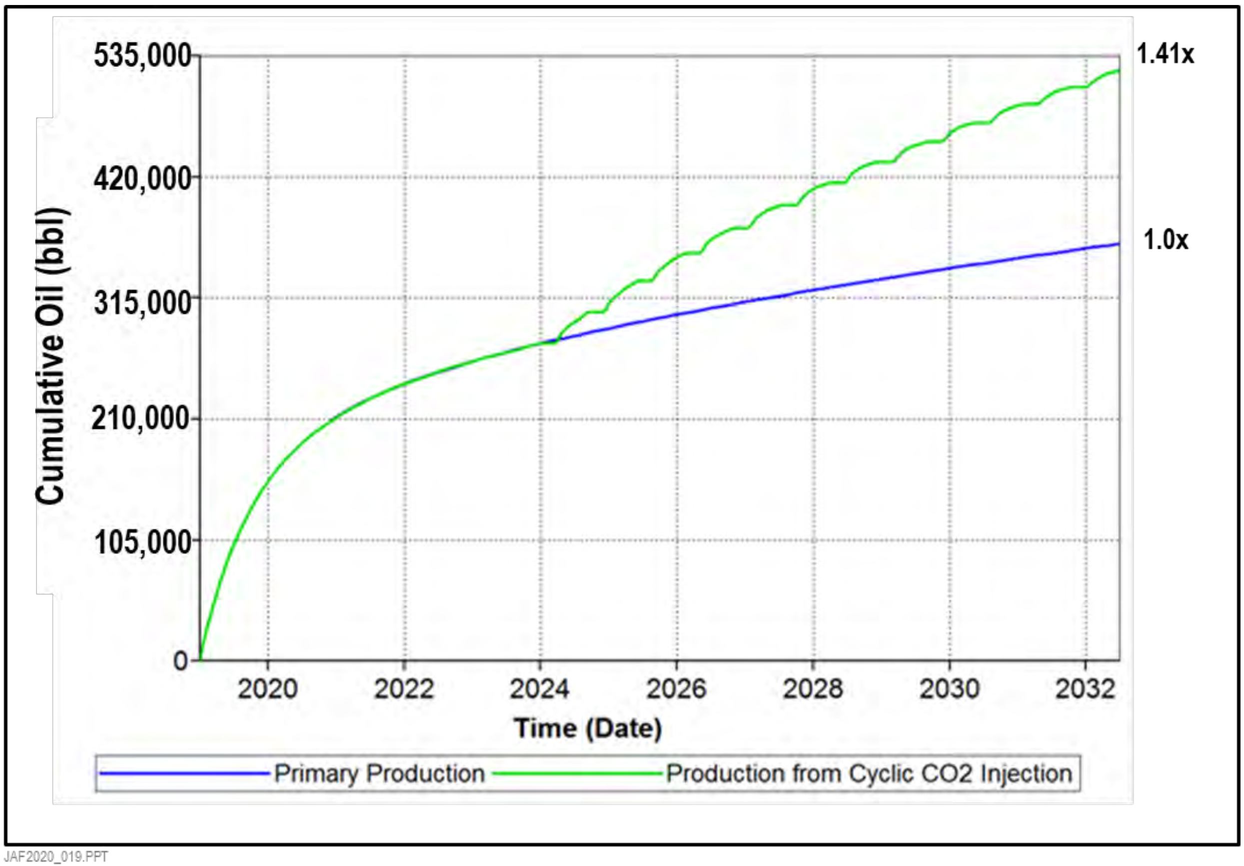
Source: Advanced Resources International, 2020.

Advanced Resources International, Inc.

The 12 cycles of CO_2 injection over 8.5 years provided 237,000 barrels of oil production, in addition to 275,000 barrels from primary oil recovery at the start of CO_2 injection, for overall oil recovery of 512,000 barrels. Continuation of primary recovery for 8.5 years would have provided 88,000 barrels of oil recovery. As such, 149,000 barrels of incremental oil recovery (237,000 barrels less 88,000 barrels) is attributable to the injection of CO_2. This 12 cycle CO_2 injection project provided a 1.41x uplift to primary oil production for the Study Area well (Figure 1-22 and Table 1-14).

Figure 1-22. Cumulative Oil Production from Primary and Cyclic CO_2 Injection



Source: Advanced Resources International, 2020.

Table 1-14. Cumulative Oil Production, CO_2 Injection and CO_2 Production: Study Area Well

	Cumulative Oil Production			Cumulative CO_2		Estimated CO_2 Storage (MMscf)
	Total (M Barrels)	Primary (M Barrels)	Incremental EOR (M Barrels)	Injection (MMscf)	Production (MMscf)	
End of 5-year primary	275	275	-	-	-	-
End of first cycle	302	288	14	570	320	250
End of 6th cycle	416	326	90	3,250	2,580	670
End of 12th cycle	512	363	149	6,930	5,940	990

Source: Advanced Resources International, 2020.

Approximately 14% (990 Mcf) of the 6,930 MMcf of CO_2 injected remained stored in the reservoir at the end of 12 cycles of CO_2 injection (Table 1-14). As such, the cyclic CO_2 project in the Bakken Shale Study Area stored 6.6 Mcf of CO_2 (0.35 metric tons of CO_2) per barrel of incremental oil recovery.

1.6.6 Increasing Shale Oil Recovery and CO_2 Storage with Cyclic CO_2 Enhanced Oil Recovery

We have combined three sources of information to estimate the volumes of additional oil recovery and CO_2 storage that would result from the application of cyclic CO_2 enhanced oil recovery to the Bakken Shale.

- Estimates of OOIP for each of the counties in the U.S. portion of the Williston Basin, provided in Section 1.4 of this report.
- Estimates of primary oil recovery from reservoir modeling and from Bakken Shale "type wells" in each county, discussed in Section 1.5 of this report.
- Estimated "uplift" to primary shale oil recovery from reservoir modeling of cyclic CO_2 enhanced oil recovery, including the calculation of volumes of CO_2 injection and storage, provided in Section 1.5 of this report.

Each Bakken Shale county was also assessed to determine if it was geologically attractive for applying cyclic CO_2 enhanced oil recovery.

1.6.7 Increased Volumes of Oil Recovery and CO_2 Storage

Basin Center Shale Area. We estimate that the application of cyclic CO_2 enhanced oil recovery to the Bakken Shale in the Basin Center Shale Area would provide 3,240 MMB of additional technically viable shale oil recovery and provide opportunities for storing 1,130 MMmt of CO_2 (Table 1-15). The incremental oil recovery from use of cyclic CO_2 ranges from 3.5% of OOIP in Williams County to 6.9% of OOIP in Dunn County.

Basin Margin Shale Area. Our assessment is that only Burke County in the Basin Margin Shale Area is favorable for application of cyclic CO_2 enhanced oil recovery. Burke County would provide 180 MMB of additional technically viable shale oil recovery and provide opportunities for storing 60 MMmt of CO_2 (Table 1-15). Given their limited well drilling, their low well performance, and their high water saturation values, Divide, Billings and Starke counties are currently deemed unfavorable for the application of cyclic CO_2 enhanced oil recovery.

Montana Shale Area. We estimate that the application of cyclic CO_2 enhanced oil recovery to the Bakken Shale in Montana (Richland County) will provide 340 MMB of additional technically viable oil recovery and provide opportunities for storing 120 MMmt of CO_2 (Table 1-15).

Total Bakken Shale Area. Applying cyclic CO_2 enhanced oil recovery to the six geologically favorable resource assessment units of the Bakken Shale can provide 3,760 MMB of additional technically viable oil recovery and space for storing 1,310 MMmt of CO_2 storage.

Table 1-15. Estimates of Incremental Oil Recovery and CO_2 Storage from Application of Cyclic CO_2 Enhanced Oil Recovery: Bakken Shale

Bakken Shale Area	OOIP	Resource Concentration	Primary Recovery Efficiency		CO_2 EOR Recovery Efficiency*	CO_2 EOR Incremental Recovery	CO_2 Storage**
	(MMB)	(MB/mi^2)	(MB/mi^2)	(% OOIP)	(% OOIP)	(MMB)	(MMmt)
1. Basin Center Shale Area							
▪ Mountrail Co.	16,300	10,780	1,220	11.3%	4.6%	760	260
▪ McKenzie Co.	22,050	9,700	1,180	12.2%	5.0%	1,100	380
▪ Dunn Co.	11,850	8,280	1,400	16.7%	6.9%	820	290
▪ Williams Co.	16,080	9,350	800	8.6%	3.5%	560	200
					Sub-Total	3,240	1,130
2. Basin Margin Shale Area							
▪ Burke Co.	4,780	7,670	700	9.1%	3.7%	180	60
3. Montana Shale Area							
▪ Montana Co.	5,860	4,520	640	14.2%	5.8%	340	120
					Bakken Shale Area Total	3,760	1,310

*Based on reservoir modeling of Bakken Shale Study Area.
**Assumes 0.35 mt of CO_2 per barrel of oil.

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Advanced Resources International, Inc.

1.7. References

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Chapter 2. Eagle Ford Shale

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2. Eagle Ford Shale

2.1 Introduction

2.1.1 Purpose of Study

The Eagle Ford Shale, located in South Texas, is one of the five major shale oil basins of the U.S. It holds a vast volume of shale oil resource, estimated by this study at 139 billion barrels of original oil in-place (OOIP). However, with current primary (pressure depletion) oil production practices, only a modest portion of this large in-place resource is recoverable. (Our resource characterization and reservoir modeling of a geologically representative area in the center of the Eagle Ford Shale play, the Study Area, established an estimated oil recovery efficiency of 8% of OOIP.) As such, more advanced oil recovery technologies will be needed to boost the current level of oil recovery from the Eagle Ford Shale.

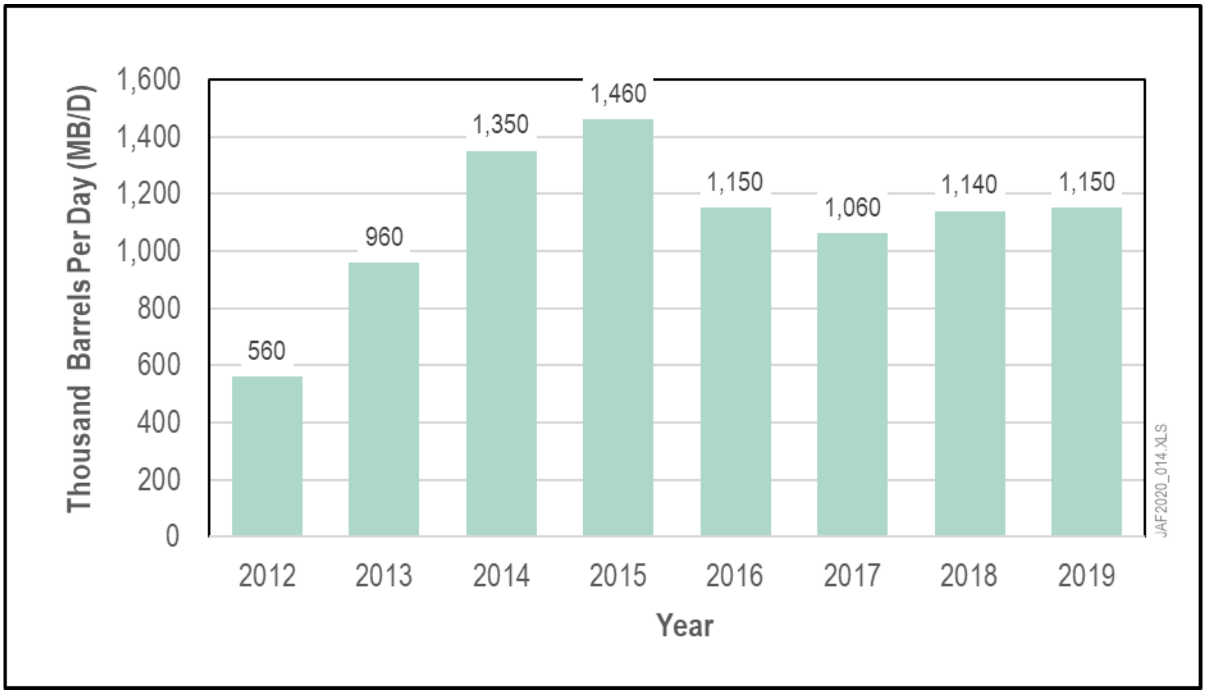
The purpose of our study is to examine the potential and impact of one such advanced oil recovery technology—the use of cyclic injection of CO_2 for enhanced oil recovery from the Eagle Ford Shale.

An important by-product of using cyclic injection of CO_2 for oil recovery in the Eagle Ford Shale is that a portion of the injected CO_2 remains trapped in the shale formation, providing an additional geologic site for storing CO_2.

2.1.2 Eagle Ford Shale Oil Production and Well Completions

Positive well performance from the Eagle Ford Shale showed that a variety of shale formations, beyond the Bakken Shale, could be economically viable resource settings, confirming the “shale oil revolution”. Oil production from the Eagle Ford Shale increased rapidly, exceeding a half million barrels per day in 2012 and climbing to nearly a million barrels per day the following year. After reaching a peak of nearly 1.5 million barrels per day in 2015, oil production from the Eagle Ford Shale has declined and stabilized at about 1.1 million barrels per day for the past four years (Figure 2-1).

Figure 2-1. Eagle Ford Shale Oil Production

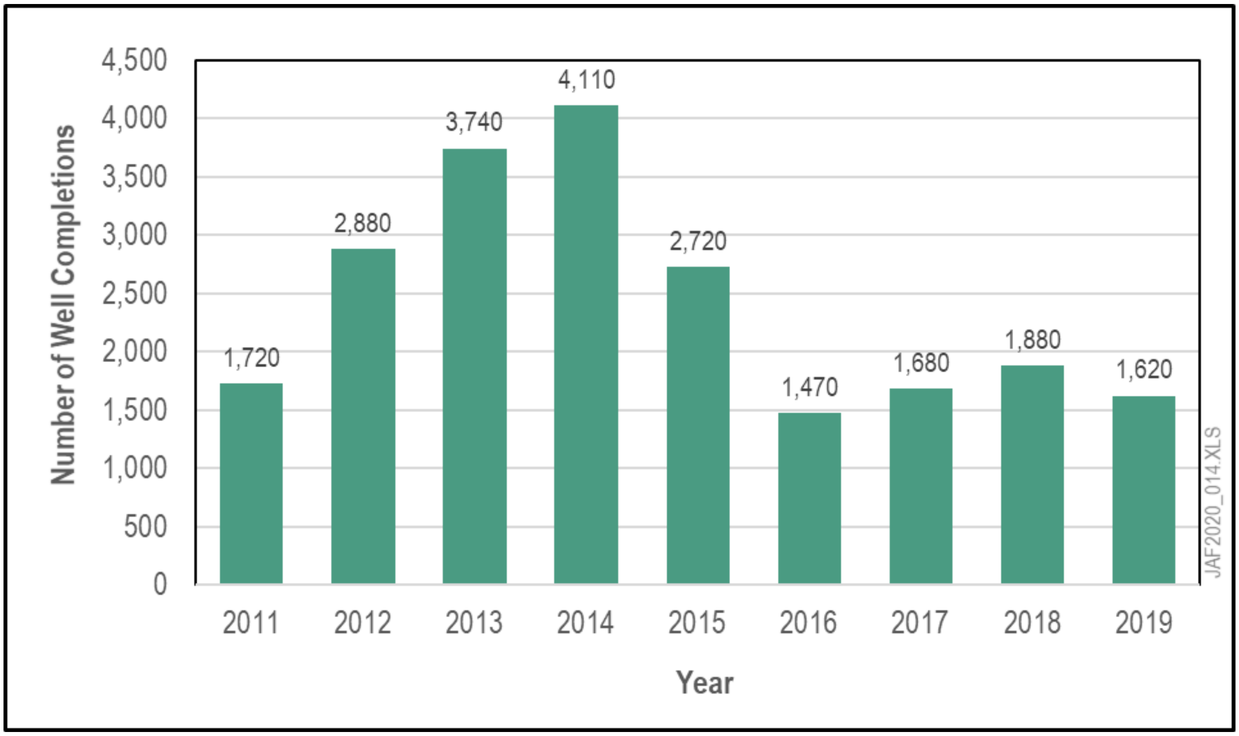


Source: Advanced Resources International's Tight Oil Database, 2020; Drilling Info, 2020.

Following the drilling of a handful of vertical shale characterization wells, significant development of the Eagle Ford Shale started in 2009 with the drilling and completion of 74 Hz wells. With increasing deployment of rigs, Hz well completions reached a peak of 4,110 in 2014. Well completions declined to 1,470 two years later, following a sharp drop in oil prices. With improving oil prices, well completions rebounded to 1,880 in 2018 declining somewhat to 1,620 in 2019 (Figure 2-2).

Today, the Eagle Ford Shale is an increasingly mature tight oil play, with nearly 18,000 Hz oil wells drilled and placed in production. As such, some of the more productive areas of the Eagle Ford Shale have become highly developed. For example, the geologically attractive Karnes Trough area, in the eastern portion of the Eagle Ford Shale oil "window", now has nearly 4,000 well completions, consuming the great bulk of the originally available well locations.

Figure 2-2. Eagle Ford Shale Hz Well Completions, 2011-2019



Source: Advanced Resources International's Tight Oil Database, 2020; Drilling Info, 2020.

2.1.3 Outlook for Enhanced Shale Oil Recovery

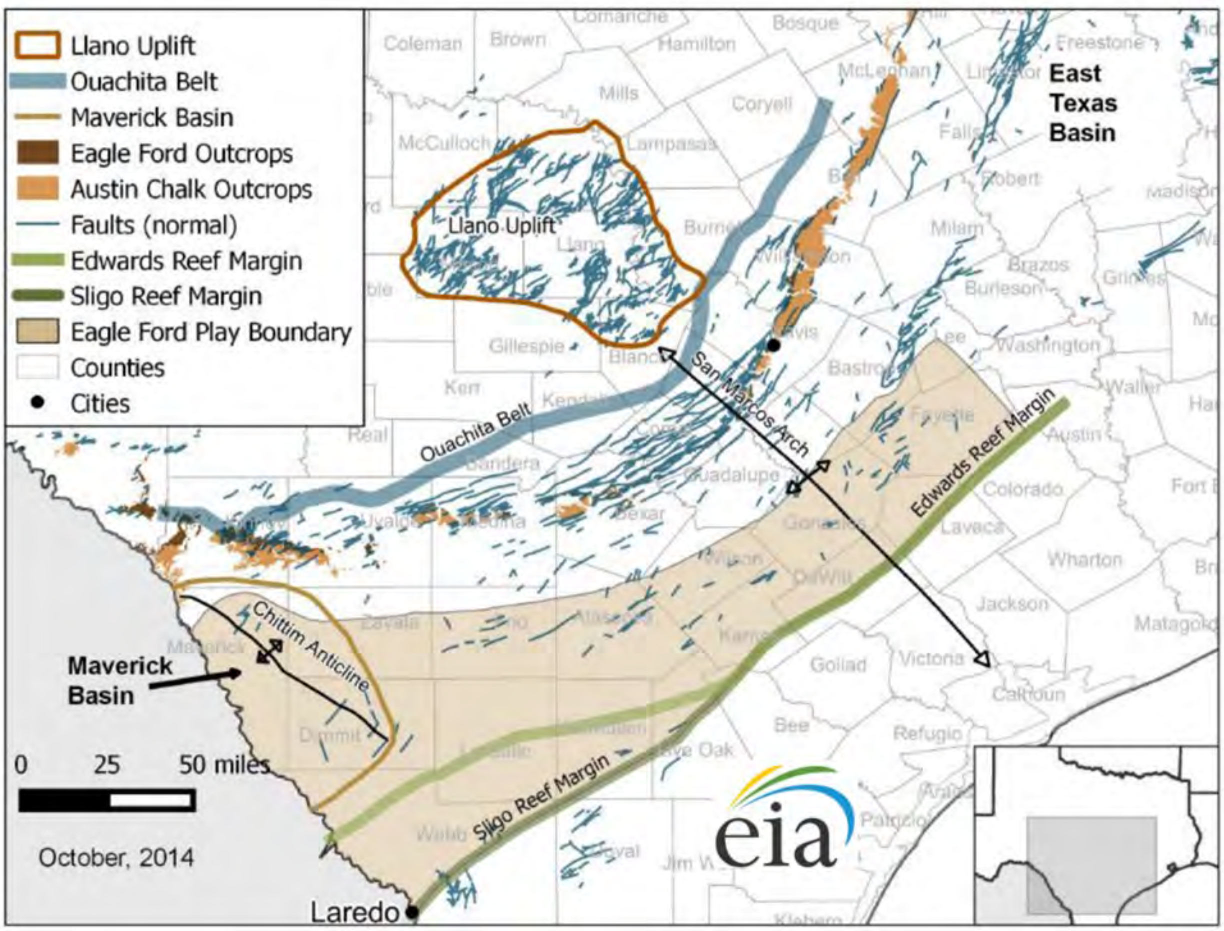
With its large numbers of mature oil wells, the Eagle Ford Shale is a prime candidate for using cyclic CO_2 injection to boost oil recovery. Our assessment, as discussed further in Section 2.7 of this report, is that the application of this technology to the Eagle Ford Shale could provide 7,670 million barrels (MMB) of additional technically viable oil recovery and space for geologically storing 1,840 million metric tons (MMmt) of CO_2.

2.2 Geologic Setting of the Eagle Ford Shale

2.2.1 Introduction

The Eagle Ford Shale, located in South Texas, extends across a 20,000 square mile area of the Western Gulf Coast Basin. The more actively developed 10,000 square mile central portion of the Eagle Ford Shale is bounded on the east by the San Marcos Arch, on the west by the Chittim Anticline, on the south by the Sligo Reef Margin, and on the north by the productive limits of the light oil play before reaching the shale outcrop near the Ouachita Belt (Figure 2-3).

Figure 2-3. Eagle Ford Shale Location Map

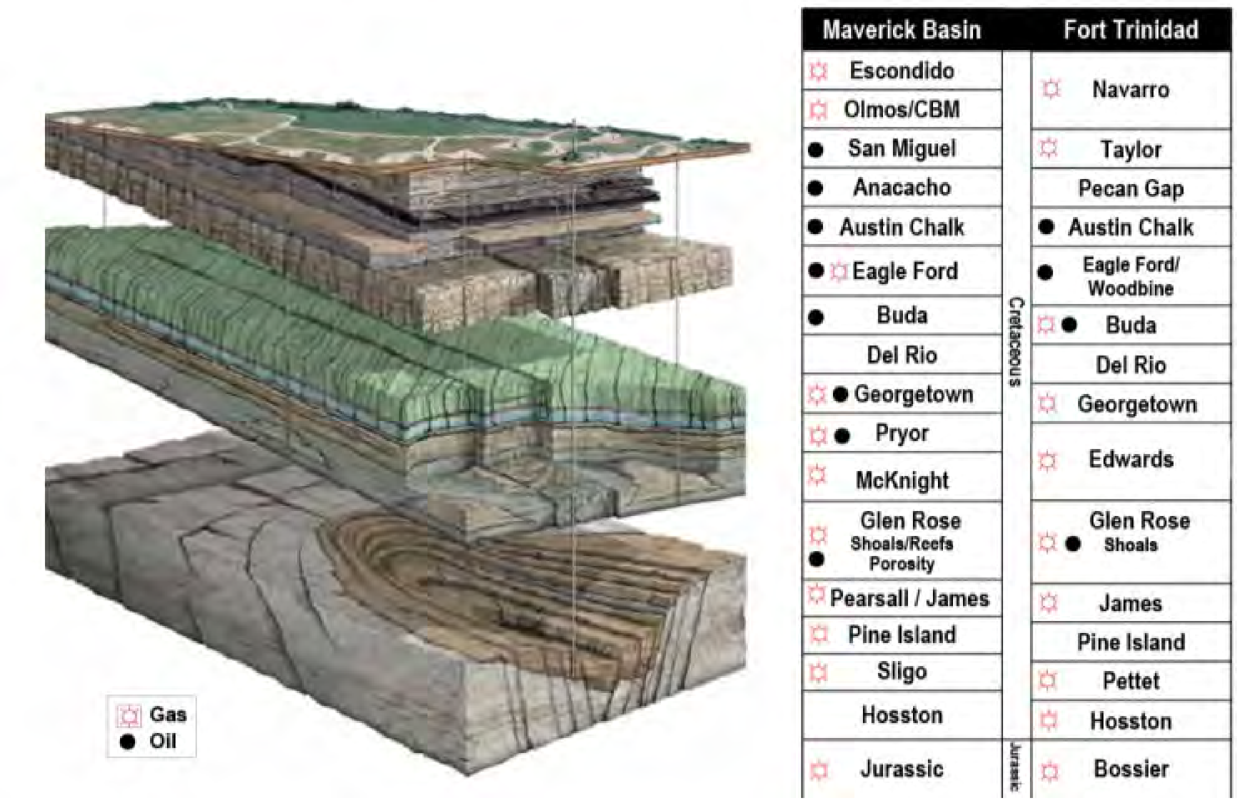


Source: U.S. Energy Information Administration, 2014

2.2.2 Eagle Ford Shale Stratigraphic Column

The Upper Cretaceous Eagle Ford Shale lies above the Buda Limestone and is overlain by the Austin Chalk, as shown in Figure 2-4 for the Maverick Basin. This area contains a stack of oil and gas producing formations, ranging from the Escondido Formation at the top of the Cretaceous section to the Sligo Formation at the base of the Cretaceous section.

Figure 2-4. Eagle Ford Shale Stratigraphic Column



Source: TXCO Resources, 2009

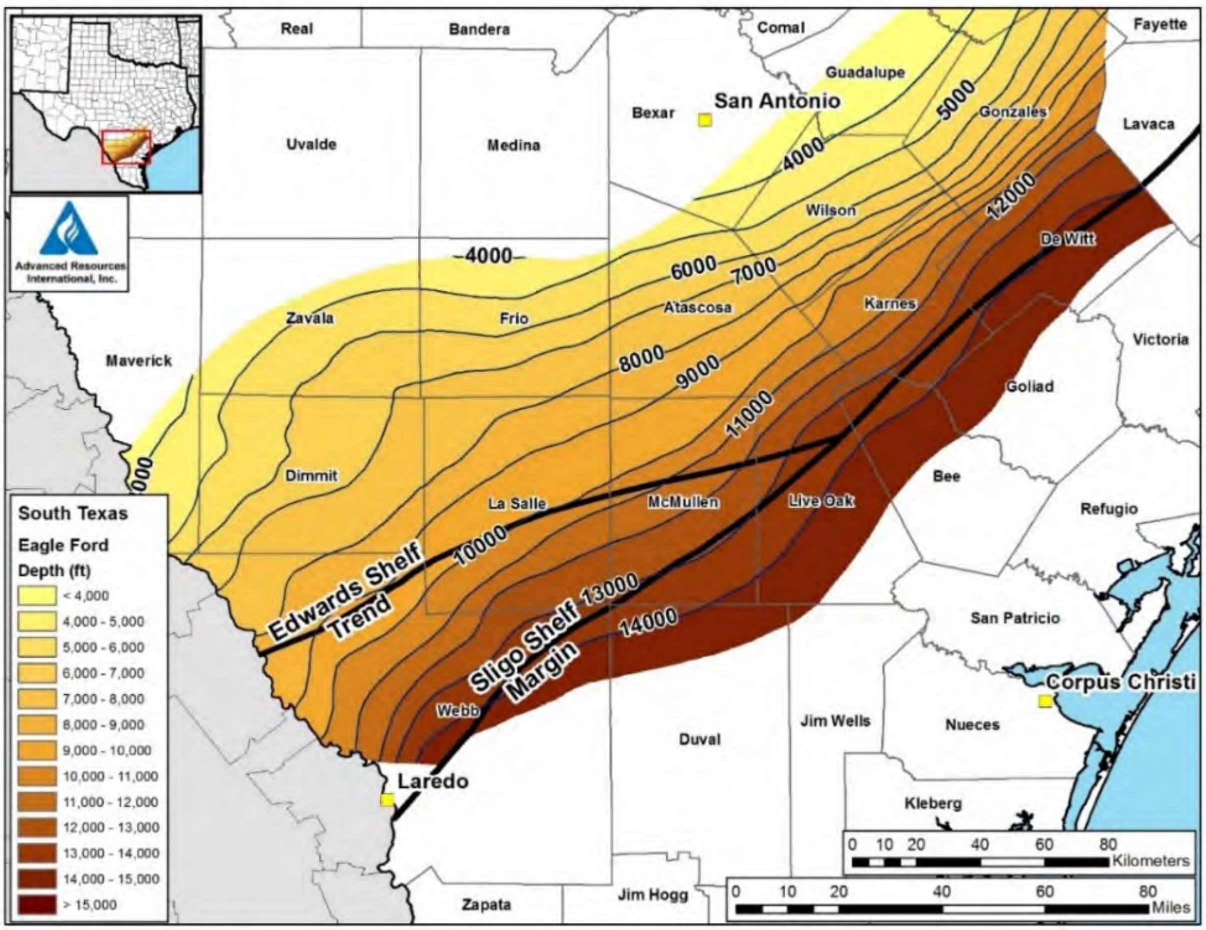
The area east of the San Marco Arch, where the Eagle Ford Shale interfingers with the Woodbine tight sand, is labeled the Eaglebine (combination of Eagle Ford and Woodbine) by industry and is not included in this Basin Study.

2.2.3 Eagle Ford Shale Assessment Area and Depth

The Eagle Ford Shale deepens progressively from less than 5,000 ft in the north to below 14,000 ft in the south, with the depth contours following a series of parallel northeast to southwest trends (Figure 2-5).

However, very few deep Eagle Ford Shale wells have been drilled in the southern, natural gas dominant area of the shale, limiting the data control points in this area. Similar lack of Eagle Ford Shale wells exists along the northern, shallow oil dominant area of the shale.

Figure 2-5. Eagle Ford Shale Depth

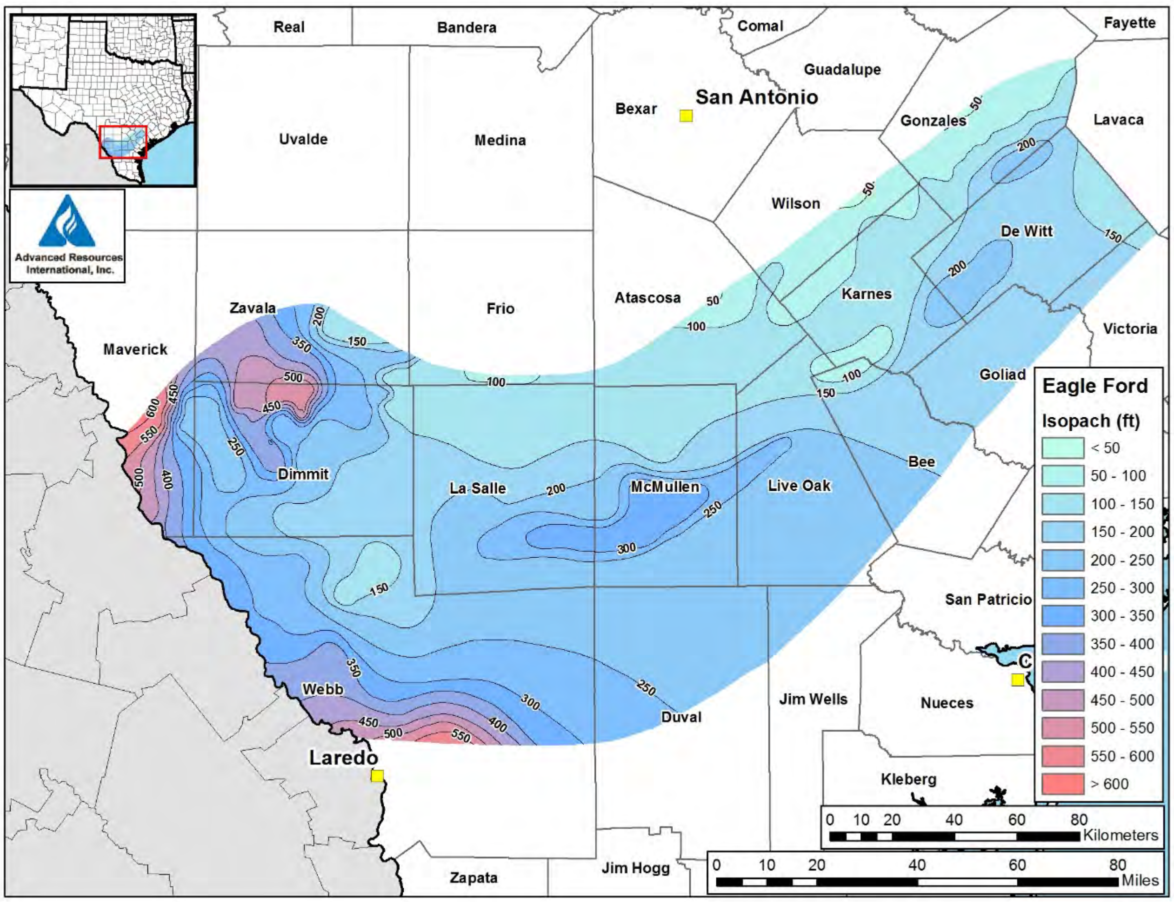


Source: Advanced Resources International, 2020.

2.2.4 Eagle Ford Shale Isopach and Interval

The thickness of the Eagle Ford Shale (Lower Shale Unit) interval ranges from 50 ft in the north to over 500 ft in selected areas in the west and south. In the actively developed areas of the Eagle Ford Shale, the shale interval ranges from 100 ft in the north to 300 ft in the west and south (Figure 2-6).

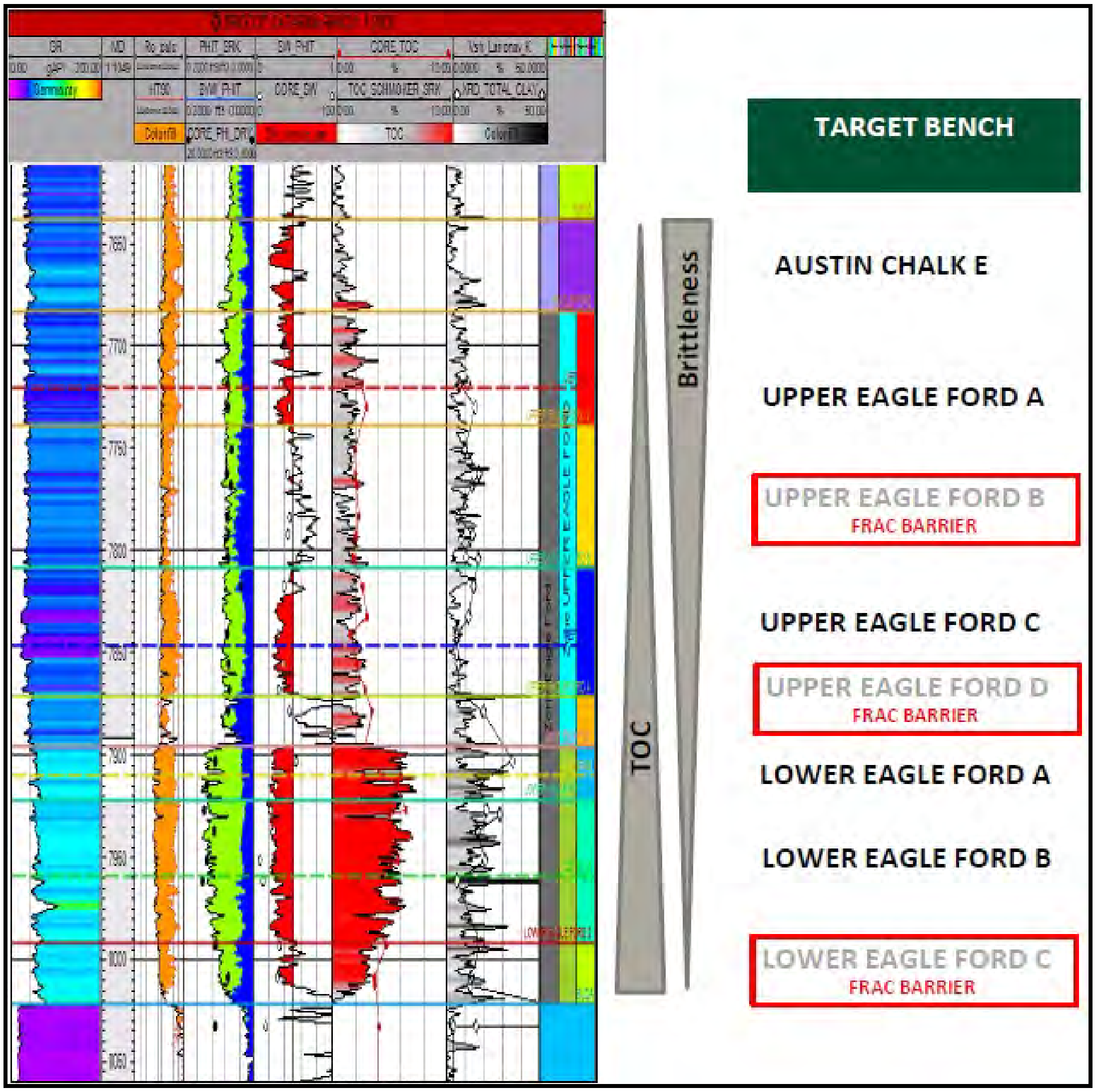
Figure 2-6. Eagle Ford Shale Lower Unit Isopach



Source: Advanced Resources International, 2020.

The Eagle Ford Shale contains an Upper Shale Unit as well as a Lower Shale Unit, separated by a dense interval that serves as a frac barrier (Figure 2-7). The Upper Unit is generally thinner than the Lower Unit and has lower Total Organic Carbon (TOC). However, the Upper Unit has brittle rock properties favorable for hydraulic stimulation. The Lower Unit has higher TOC, ranging from 4 to 5 percent (by wt), but has more ductile rock properties posing challenges to optimum hydraulic stimulation.

Figure 2-7. Upper, Middle and Lower Units of the Eagle Ford Shale



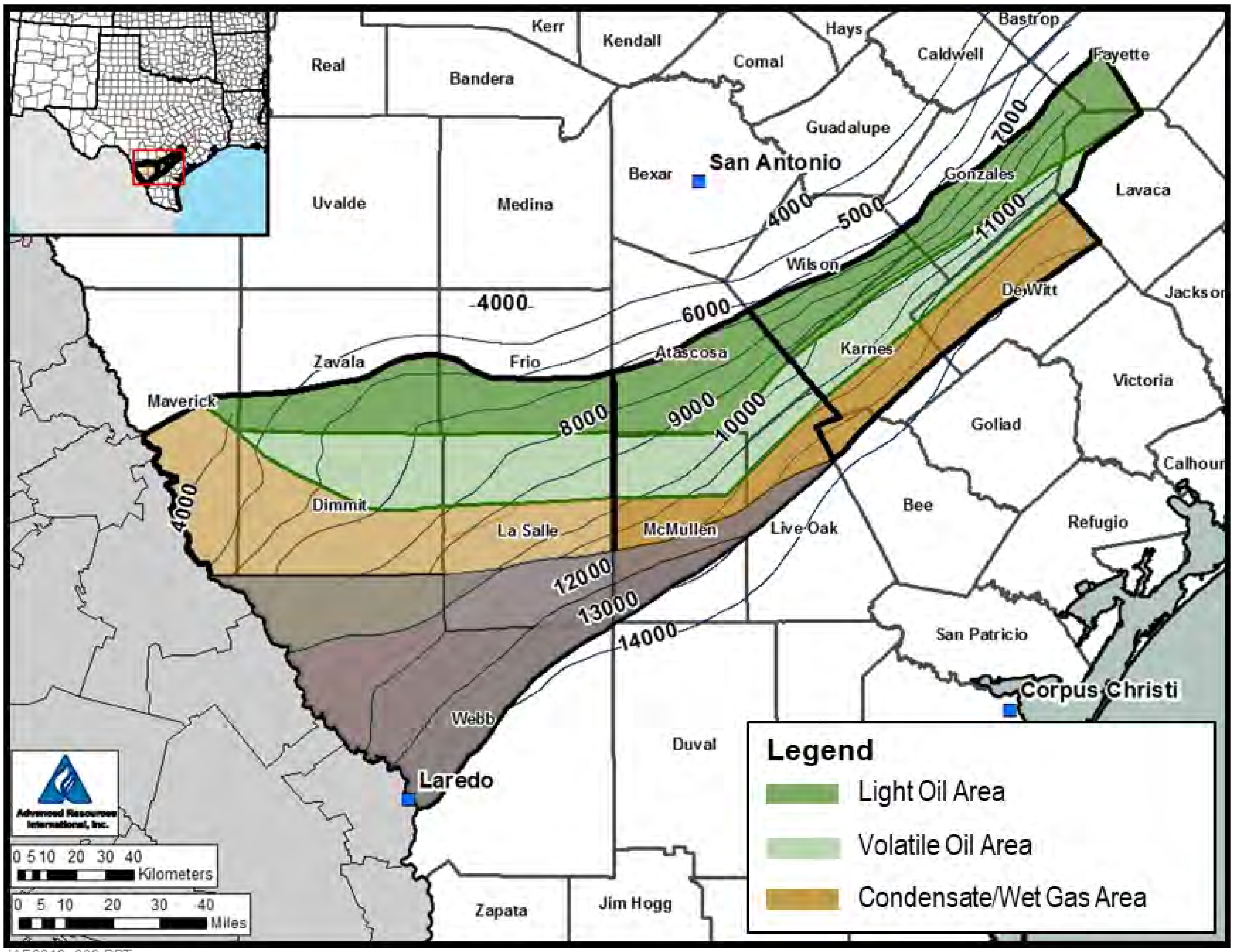
Source: Modified from Sanchez Energy, 2014

2.2.5 Oil Dominant Area

Figure 2-8 shows the location of the <u>oil dominant</u> portion of the Eagle Ford Shale, including the condensate/wet gas, volatile oil and light oil areas in the northern and eastern portions of the shale. Along with production of oil and condensate, these areas also produce significant volumes of wet associated gas.

The natural gas dominant portion of the Eagle Ford Shale, consisting of wet and dry gas areas, is in the southwestern portion of the shale, primarily in LaSalle, McMullen, and Webb counties. Some of the natural gas dominant portions of the Eagle Ford Shale also produce modest volumes of by-product condensate.

Figure 2-8. Eagle Ford Shale Oil Dominant Area



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Source: Advanced Resources International, 2020.

2.3 Establishing the Essential Reservoir Properties

2.3.1 Eagle Ford Shale Type Log

The reservoir properties of the Eagle Ford Shale vary greatly, both vertically within the Eagle Ford Shale interval and horizontally across the large shale deposition area. The information on reservoir properties for this study targets the Lower Shale Unit, the primary development target of the Eagle Ford Shale. A published log of the Sanchez Energy Wycross Unit well in northern McMullen County shows a 150 ft gross interval for the Lower Eagle Ford Shale, with a net-to-gross ratio of about 90% (Figure 2-9).

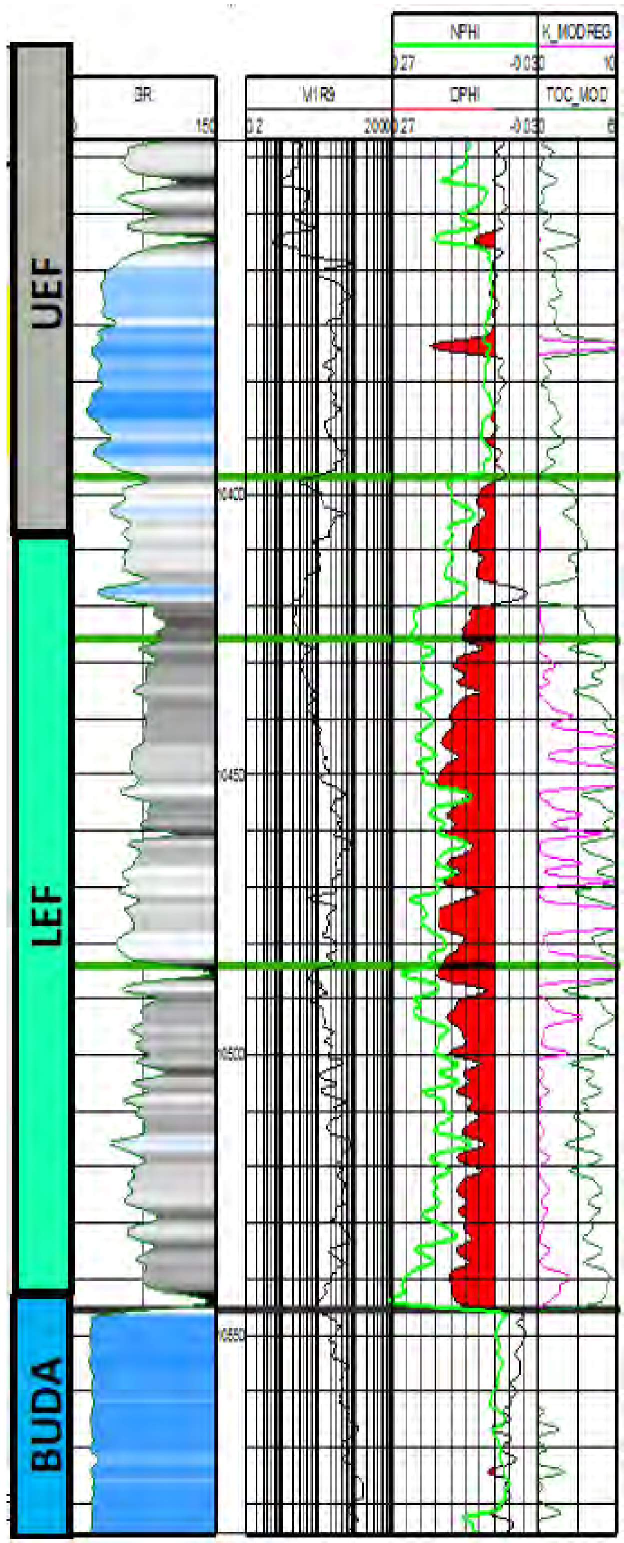
2.3.2 Eagle Ford Shale Porosity

Information on the porosity of the Eagle Ford Shale is scarce in the technical literature for specific areas of the shale. Particularly challenging is establishing the significant porosity values in the organic portions of the shale. Based on industry published information, the porosity of the Eagle Ford Shale matrix ranges from 8% to 11% in the Lower Shale Unit and from 4% to 6% in the Upper Shale Unit. The natural fracture system adds about 0.1% to the matrix porosity values.

2.3.3 Eagle Ford Shale Oil and Water Saturation

Laboratory derived information for the Eagle Ford Shale indicates that the shale, in the oil dominant area, has an initial oil saturation of about 80% and an immobile water saturation of about 20%. The initial oil saturation in the natural fracture system is estimated to be slightly higher, at about 90%. (Gala, D., and Sharma, M., 2018)

Figure 2-9. Wycross Unit Eagle Ford Shale Well Log

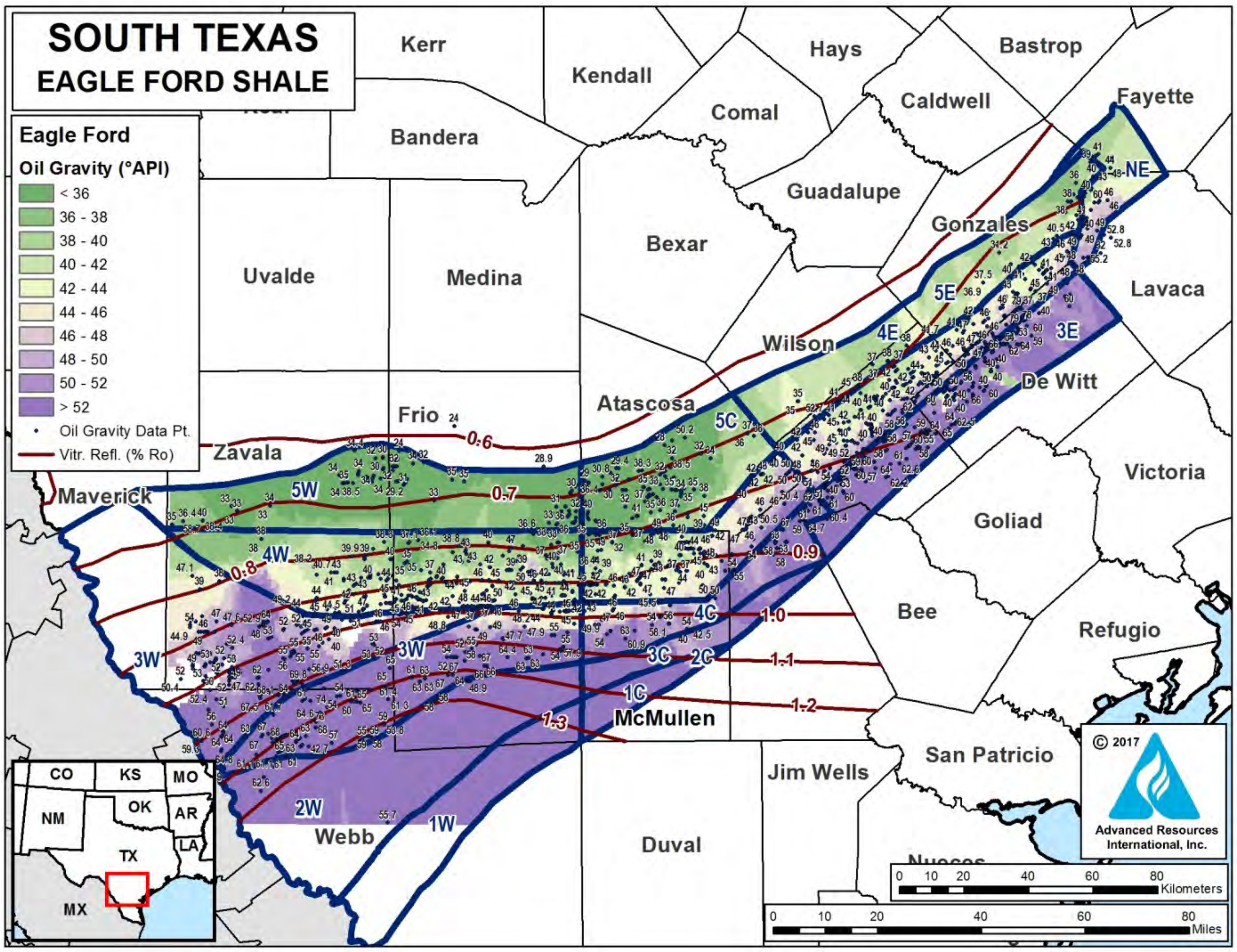


Source: Sanchez Energy, 2014.

2.3.4 Oil Gravity

The API gravity of Eagle Ford Shale liquids ranges from light oil of 36 to 42 degrees in the north (volatile and light oil windows) to higher API gravity values, in excess of 50 degrees, in the condensate/wet gas windows in the south (Figure 2-10).

Figure 2-10. Eagle Ford Shale API Gravity



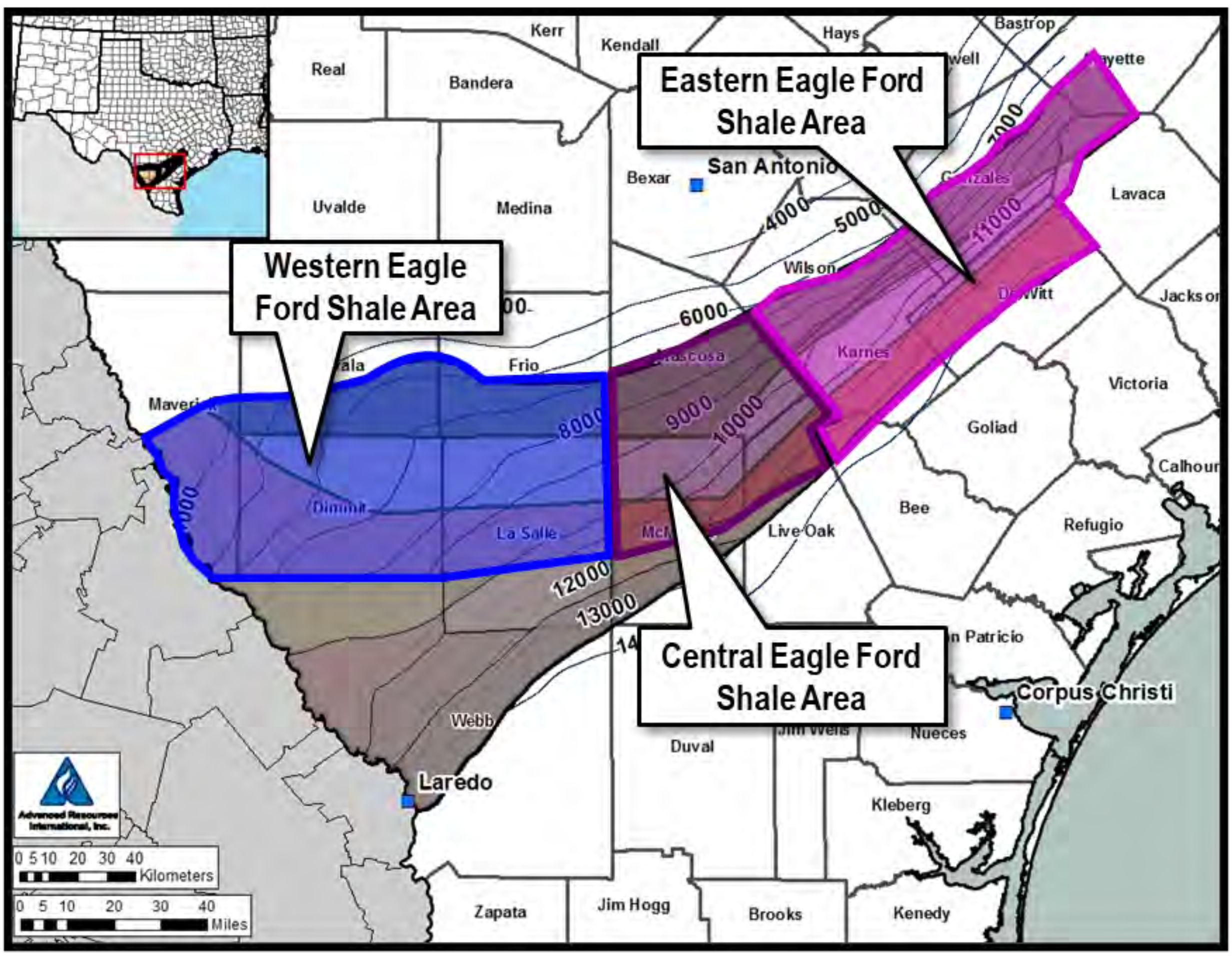
Source: Advanced Resources International using data from DrillingInfo, 2020.

2.4 Eagle Ford Shale Resource Assessment

2.4.1 Assessment Methodology

To provide some granularity to the estimates of OOIP, the resource assessment portion of the study partitioned the oil dominant portion of the Eagle Ford Shale into Eastern, Central and Western areas. The study then further subdivided each of these three geographically established areas into: (1) a condensate/wet gas area; (2) a volatile oil area; and (3) a light oil area (Figure 2-11). For each area, the study assembled representative volumetric and other reservoir properties essential for estimating OOIP.

Figure 2-11. Eagle Ford Shale Study Area Map



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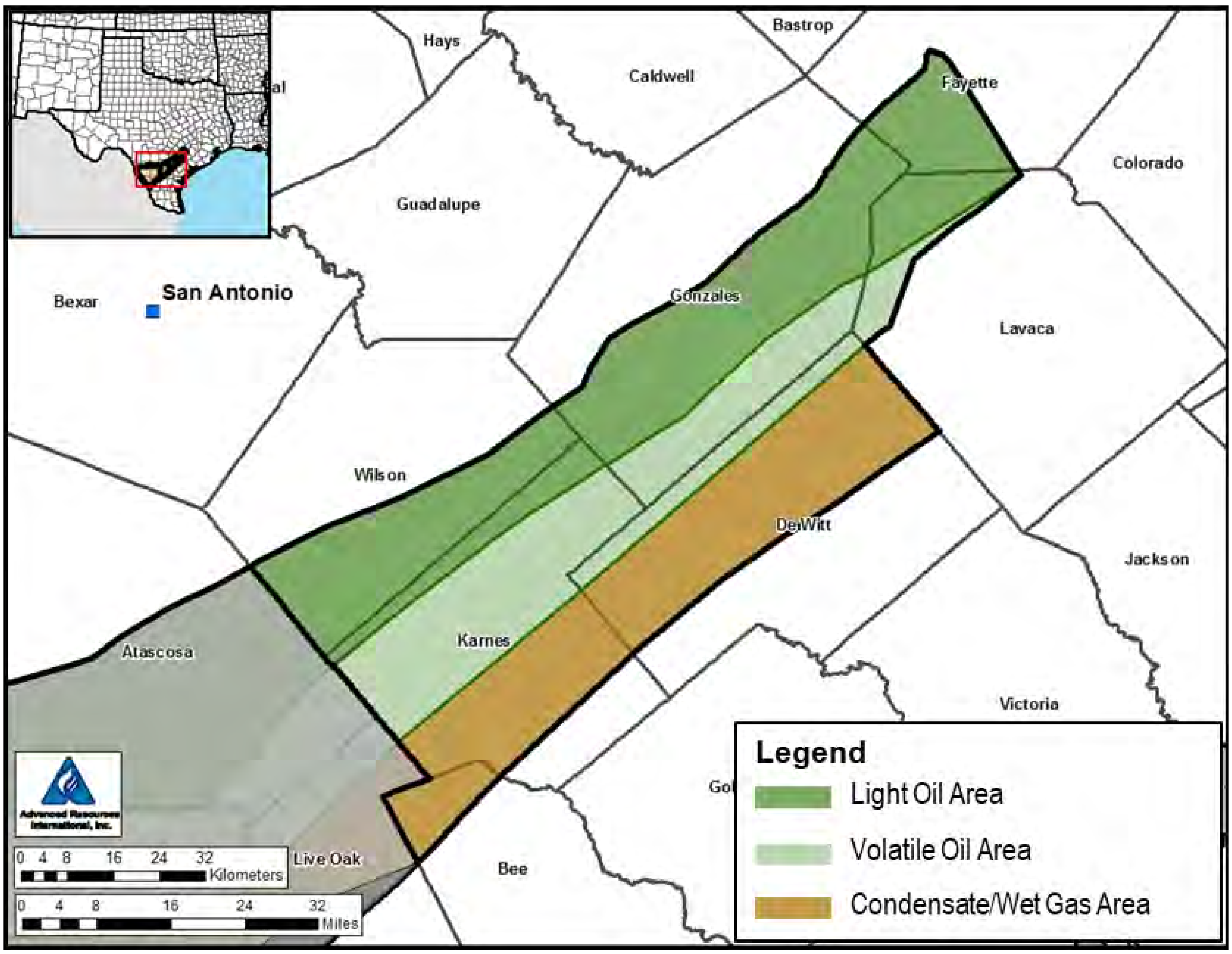
2.4.2 Eastern Eagle Ford Shale Area

The Eastern Area of the Eagle Ford Shale extends across 2,250 square miles in Karnes, DeWitt, Gonzales and Wilson counties. Portions of this area, particularly in Karnes and DeWitt counties, have seen extensive well drilling.

The Eastern Shale Area has three parallel trending hydrocarbon windows that range from a condensate (with wet gas) region in the south, a volatile oil region in the center, and a light oil region in the north (Figure 2-12).

Figure 2-12. Hydrocarbon Windows of the Eastern Eagle Ford Shale Area



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Source: Advanced Resources International, 2020.

Table 2-1 provides the key reservoir properties for the three hydrocarbon windows (resource assessment units) of the Eastern Eagle Ford Shale Area.

Table 2-1. Reservoir Properties for Estimating OOIP for the Eastern Eagle Ford Shale

Reservoir Property	Condensate/ Wet Gas Area	Volatile Oil Area	Light Oil Area
Risked Area	560 mi^2	530 mi^2	710 mi^2
Average Depth	13,000 ft	10,500 ft	9,000 ft
Net Pay (Lower Shale Unit)	150 ft	120 ft	100 ft
Porosity (Lower Shale Unit)			
▪ Matrix	10%	10%	10%
▪ Fracture	0.1%	0.1%	0.1%
Oil Saturation			
▪ Matrix	80%	80%	80%
▪ Fracture	90%	90%	90%
Formation Volume Factor (RB/STB)	2.5	1.69	1.38
Solution GOR (Mcf/B)	5.0	1.3	0.7

Source: Advanced Resources International, 2020.

Using the reservoir properties in Table 2-1, the OOIP for the Lower Shale Unit of the Eastern Eagle Ford Shale is estimated at 48.6 billion barrels (Table 2-2).

Table 2-2. OOIP of Lower Shale Unit, Eastern Eagle Ford Shale Area

Shale Areas	Risked Area (mi^2)	Resource Concentration (MMB/mi^2)	Oil/Condensate OOIP (Million Barrels)
▪ Condensate/Wet Gas	560	23.8	13,300
▪ Volatile Oil	530	28.2	14,900
▪ Light Oil	710	28.8	20,400
Total			48,600

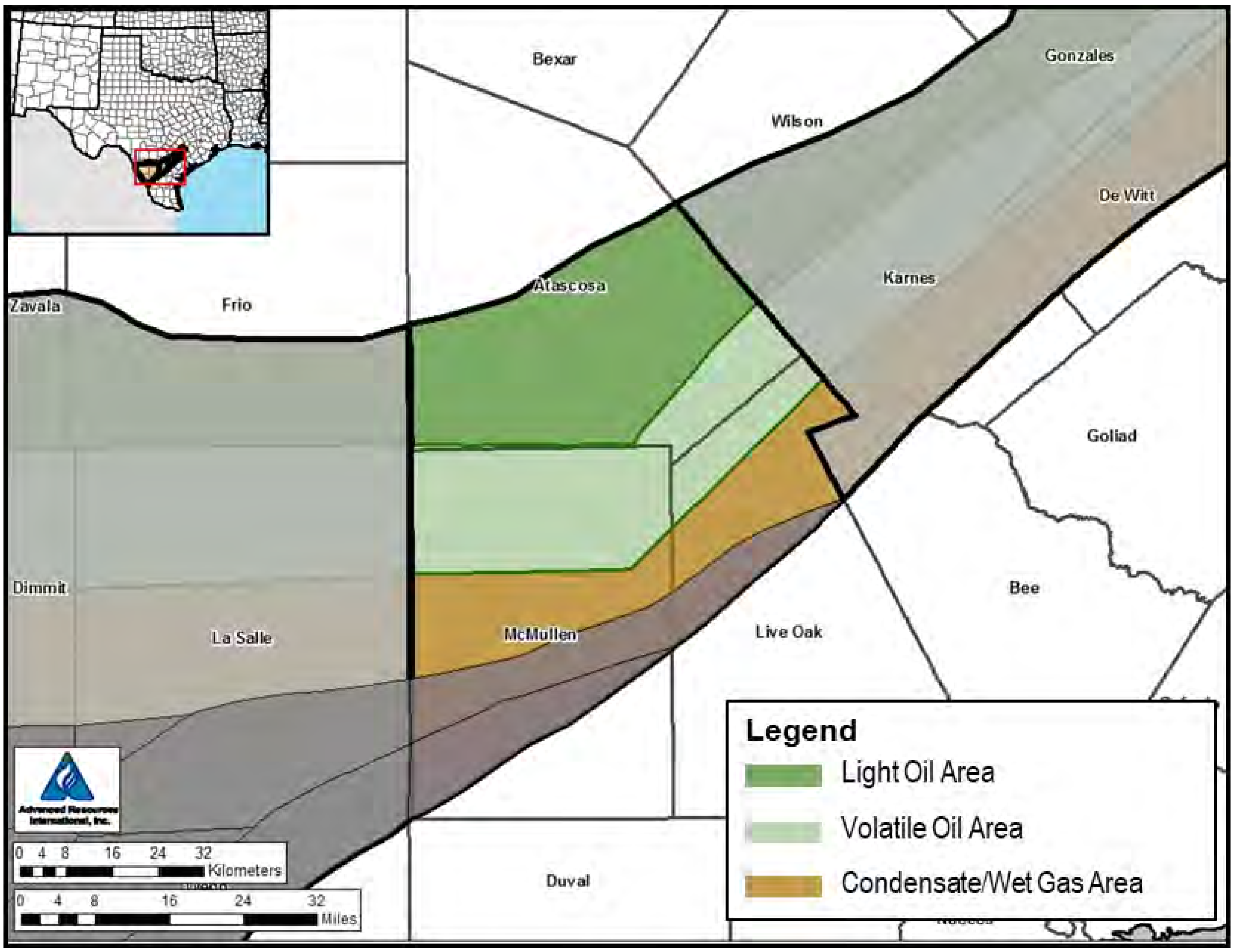
Source: Advanced Resources International, 2020.

2.4.3 Central Eagle Ford Shale Area

The Central Area of the oil dominant Eagle Ford Shale extends across 1,590 square miles, in Atascosa, Live Oak and McMullen counties.

The Central Eagle Ford Shale Area, like the Eastern Eagle Ford Shale Area, has three parallel trending hydrocarbon windows that range from condensate (with wet gas) in the south, volatile oil in the center, and light oil in the north (Figure 2-13).

Figure 2-13. Hydrocarbon Windows of the Central Eagle Ford Shale Area



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Source: Advanced Resources International, 2020.

Table 2-3 provides the key reservoir properties for the three hydrocarbon windows (resource assessment units) of the Central Eagle Ford Shale Area.

Table 2-3. Reservoir Properties for Estimating OOIP for the Central Eagle Ford Shale

Reservoir Property	Condensate/ Wet Gas Area	Volatile Oil Area	Light Oil Area
Risked Area	320 mi^2	460 mi^2	490 mi^2
Average Depth	12,000 ft	10,000 ft	8,500 ft
Net Pay (Lower Shale Unit)	150 ft	120 ft	80 ft
Porosity (Lower Shale Unit)			
▪ Matrix	10%	10%	10%
▪ Fracture	0.1%	0.1%	0.1%
Oil Saturation			
▪ Matrix	80%	80%	80%
▪ Fracture	90%	90%	90%
Formation Volume Factor (RB/STB)	2.4	1.64	1.36
Solution GOR (Mcf/B)	4.5	1.2	0.65

Source: Advanced Resources International, 2020.

Using the reservoir properties in Table 2-3, the OOIP for the Lower Shale Unit of the Central Eagle Ford Shale is estimated at 32.7 billion barrels (Table 2-4).

Table 2-4. OOIP of Lower Shale Units, Central Eagle Ford Shale Area

Risked Shale Area	Risked Area (mi^2)	Resource Concentration (MMB/mi^2)	Oil/Condensate OOIP (Million Barrels)
▪ Condensate/Wet Gas	320	24.8	7,900
▪ Volatile Oil	460	29.1	13,400
▪ Light Oil	490	23.4	11,400
Total			32,700

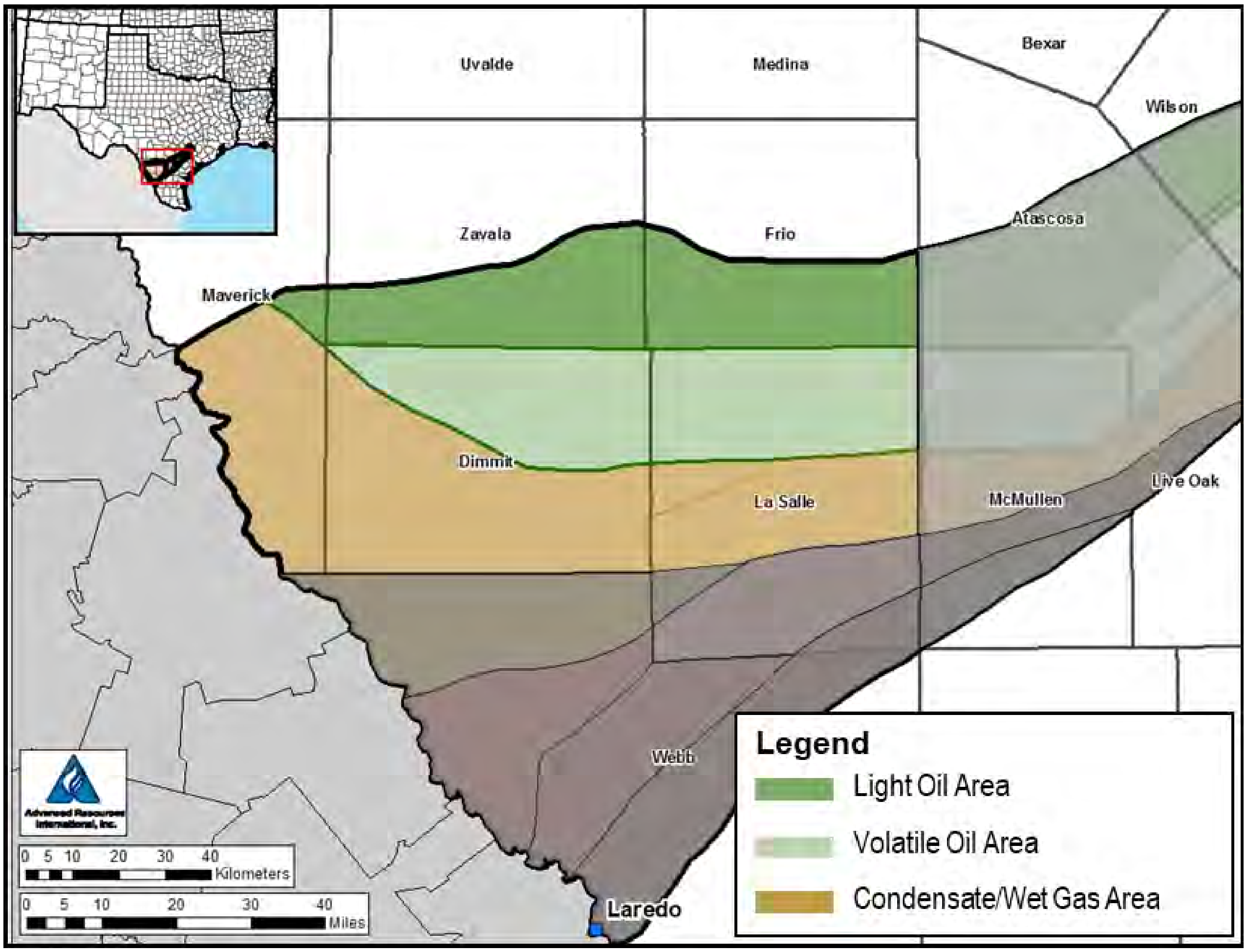
Source: Advanced Resources International, 2020.

2.4.4 Western Eagle Ford Shale Area

The Western Area of the oil dominant Eagle Ford Shale extends across 3,420 square miles, in Dimmit, LaSalle, Frio, Zavala and Maverick counties.

The Western Eagle Ford Shale Area has three parallel trending hydrocarbon windows that range from condensate (with wet gas) in the south, volatile oil in the center, and light oil in the north (Figure 2-14).

Figure 2-14. Hydrocarbon Windows of Western Eagle Ford Shale Area



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Source: Advanced Resources International, 2020.

Table 2-5 provides the key reservoir properties for the three hydrocarbon windows (resource assessment) units of the Western Eagle Ford Shale Area.

Table 2-5. Reservoir Properties for Estimating OOIP for the Western Eagle Ford Shale

Reservoir Property	Condensate/ Wet Gas Area	Volatile Oil Area	Light Oil Area
Risked Area	1,420 mi^2	849 mi^2	800 mi^2
Average Depth	8,500 ft	7,500 ft	6,500 ft
Net Pay (Lower Shale Unit)	120 ft	100 ft	80 ft
Porosity (Lower Shale Unit)			
▪ Matrix	8%	8%	8%
▪ Fracture	0.1%	0.1%	0.1%
Oil Saturation			
▪ Matrix	80%	80%	80%
▪ Fracture	90%	90%	90%
Formation Volume Factor (RB/STB)	2.1	1.58	1.33
Solution GOR (Mcf/B)	4.0	1.1	0.6

Source: Advanced Resources International, 2020.

Using the reservoir properties in Table 2-5, the OOIP for the Lower Shale Unit of the Western Eagle Ford Shale is estimated at 58.0 billion barrels (Table 2-6).

Table 2-6. OOIP of Lower Shale Unit, Western Eagle Ford Shale Area

Shale Area	Risked Area (mi^2)	Resource Concentration (MMB/mi^2)	Oil/Condensate OOIP (Million Barrels)
▪ Condensate/Wet Gas	1,420	18.2	25,800
▪ Volatile Oil	840	20.1	16,900
▪ Light Oil	800	19.1	15,300
Total			58,000

Source: Advanced Resources International, 2020.

2.4.5 OOIP for Eagle Ford Shale (Oil Dominant Areas)

The combined OOIP estimates for the nine resource assessment units (within the three geologic partitions of the Eagle Ford Shale) is a risked OOIP of 139 billion barrels.

2.5 Reservoir Simulation of Primary and Enhanced Oil Recovery from the Eagle Ford Shale

2.5.1 Representative Study Area

To estimate the incremental oil production from applying enhanced shale oil recovery using injection of CO_2, the study selected a geologically representative area in the center of the Eagle Ford Shale play, with reservoir properties shown in Table 2-7. The Study Area contains 4.6 million barrels of original oil in-place (OOIP) and 5.5 billion cubic feet (Bcf) of original gas in-place (OGIP).

Table 2-7. 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%

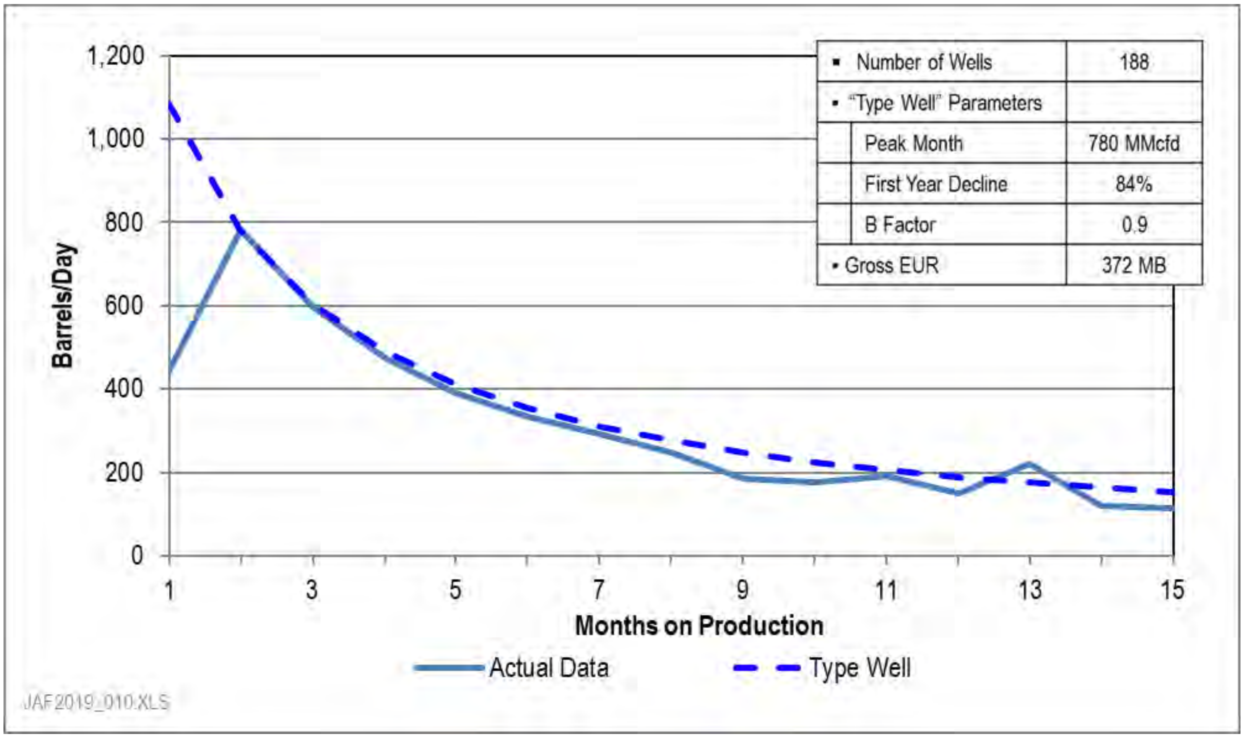
Reservoir Properties	Units
Oil Saturation	
▪ Matrix	80%
Fracture	90%
Saturation Gas/Oil Ratio	1.2 Mcf/B
Formation Volume Factor	1.64 RB/STB
Pressure	6,425 psia
Temperature	260 ^oF
Bubble Point	3,456 psia
Formation Compressibility	5 * e^{-6}/psi
Oil Gravity	43 ^oAPI

Source: Advanced Resources International, 2020.

2.5.2 Type Well for Study Area

The “type well” for the Study Area has a spacing of 8 wells per section (8 wells per 640 acres), a Hz lateral of 7,400 feet, and an estimated 30-year oil recovery of 372,000 barrels. The “type well” represents the composite performance of 188 wells drilled in 2017 and 2018 (Figure 2-15).

Figure 2-15. Study Area Type Well Oil Production

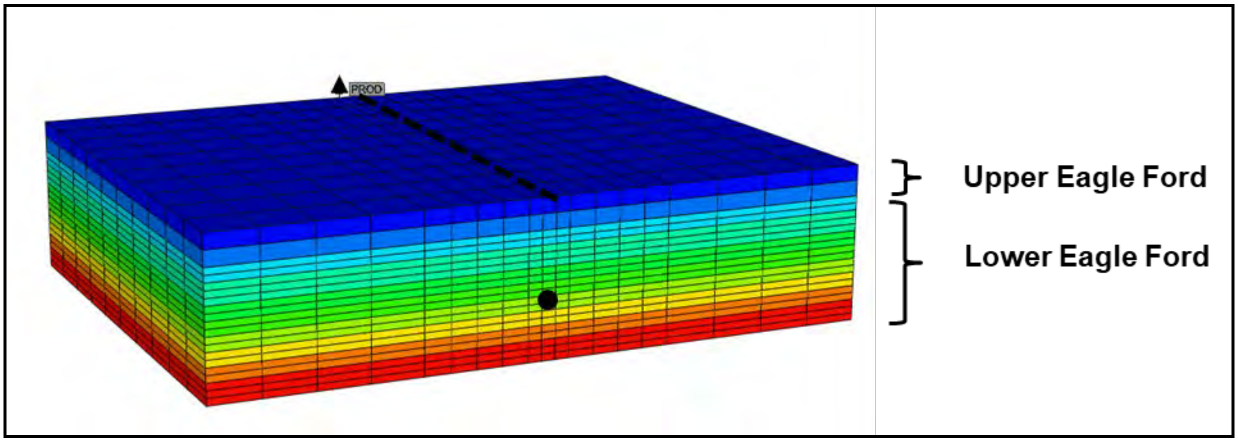


Source: Advanced Resources International, 2019.

2.5.3 Reservoir Simulation

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-component fluids through porous media. The reservoir model and grid blocks constructed to replicate the Eagle Ford Shale geologic and reservoir setting in the Study Area are illustrated in Figure 2-16. The reservoir property values provided in Table 2-7 were used to populate the reservoir model and its 3,800 grid blocks.

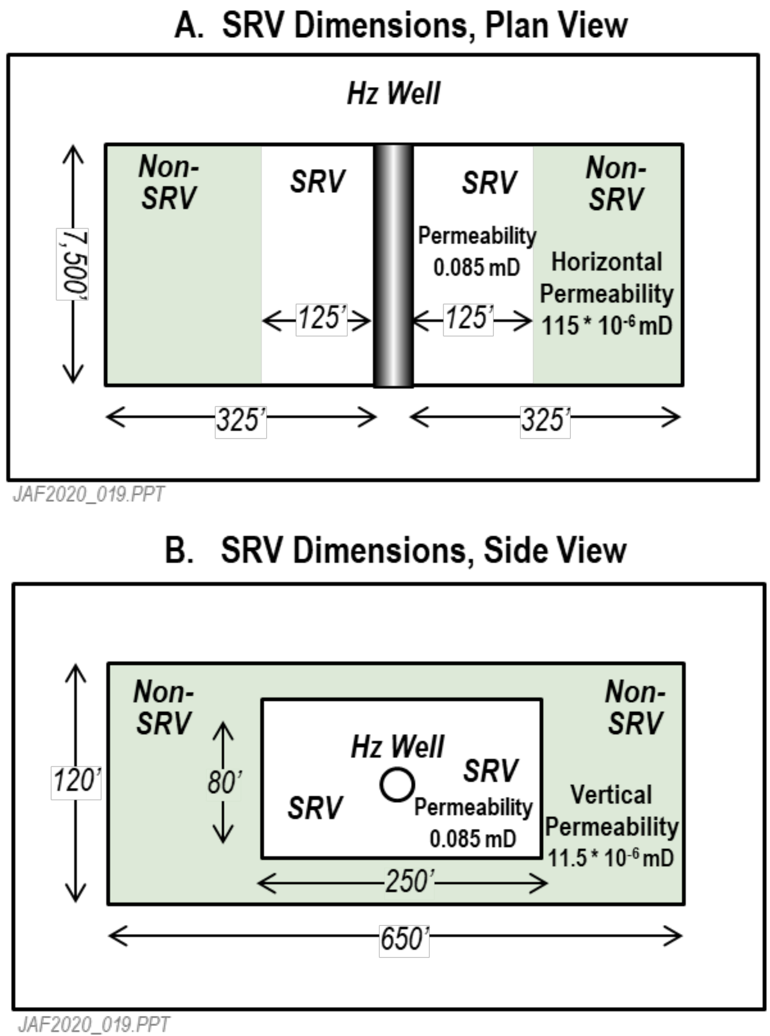
Figure 2-16. Reservoir Model and Grid Blocks Used for Eagle Ford Shale Study



Source: Advanced Resources International, 2020.

To capture the impact of hydraulic stimulation on the performance of the horizontal well, a Stimulated Reservoir Volume (SRV) was established in the model, assuming enhanced permeability in the SRV for both the fractures and the matrix. Figure 2-17 provides information on the SRV dimensions and enhanced permeability from the history match of the Bakken Shale “type well”.

Figure 2-17. SRV Dimensions and Permeability Used to History Match Well Performance.

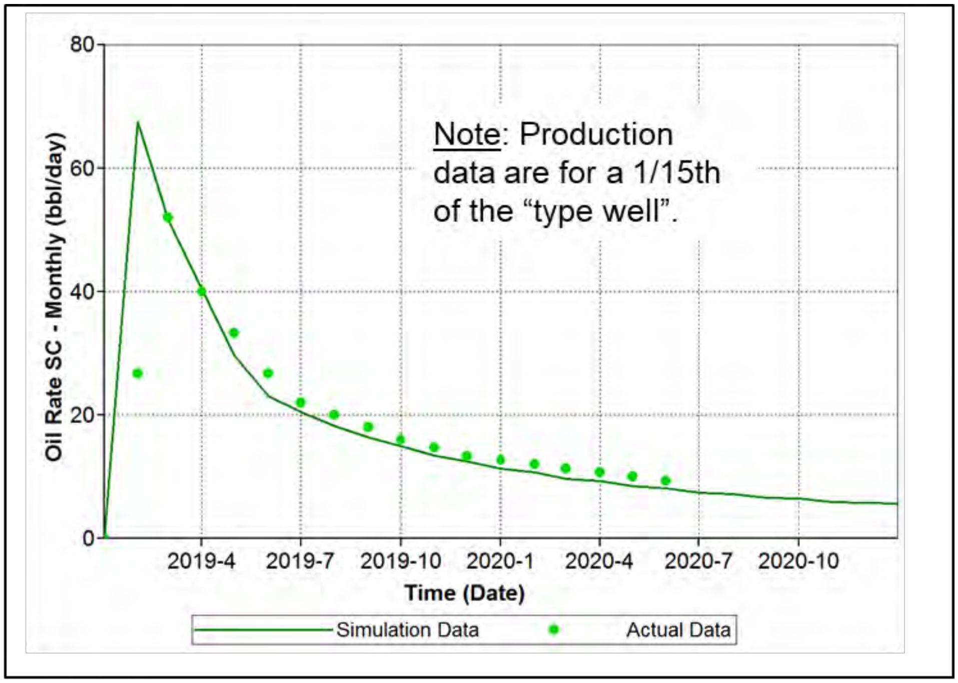


Source: Advanced Resources International, 2020.

2.5.4 History-Matching Oil and Natural Gas Production

Using the Eagle Ford Shale reservoir properties in Table 2-7 and the two key history matching parameters of stimulated reservoir volume (SRV) dimensions and enhanced permeability, reservoir simulation achieved excellent history match with the “type well” for the Study Area (Figures 2-18 and 2-19). With an OOIP of 4.6 million barrels in the well pattern area and a 30-year history matched oil recovery of 368,000 barrels, the primary oil recovery efficiency is 8% of OOIP.

Figure 2-18. History Match of Monthly Oil Production



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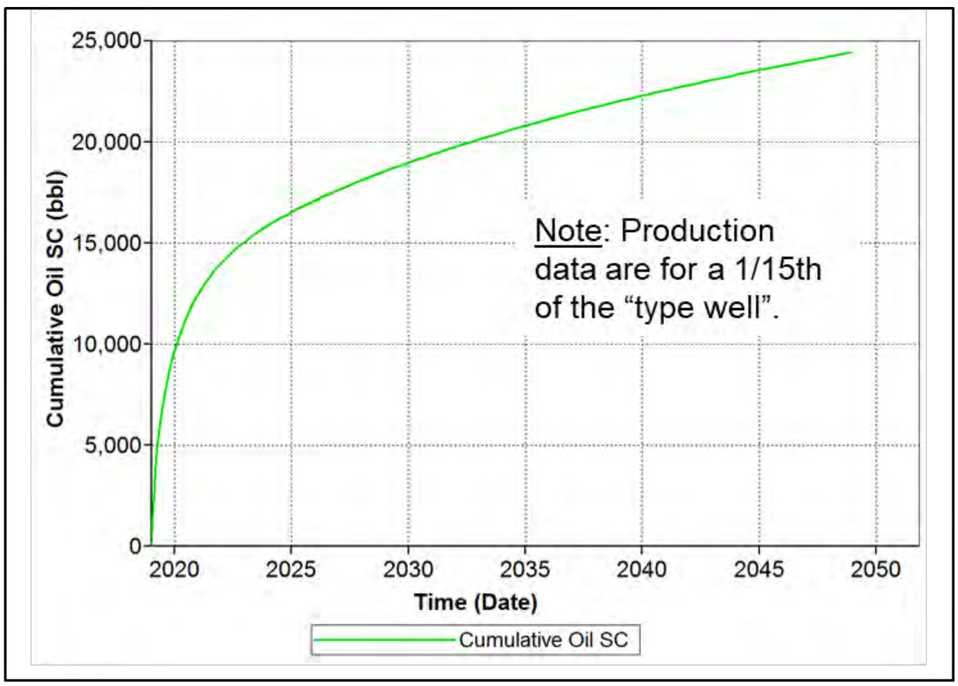
Source: Advanced Resources International, 2020.

Figure 2-19. Projection of 30 Years of Primary Production



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Source: Advanced Resources International, 2020.

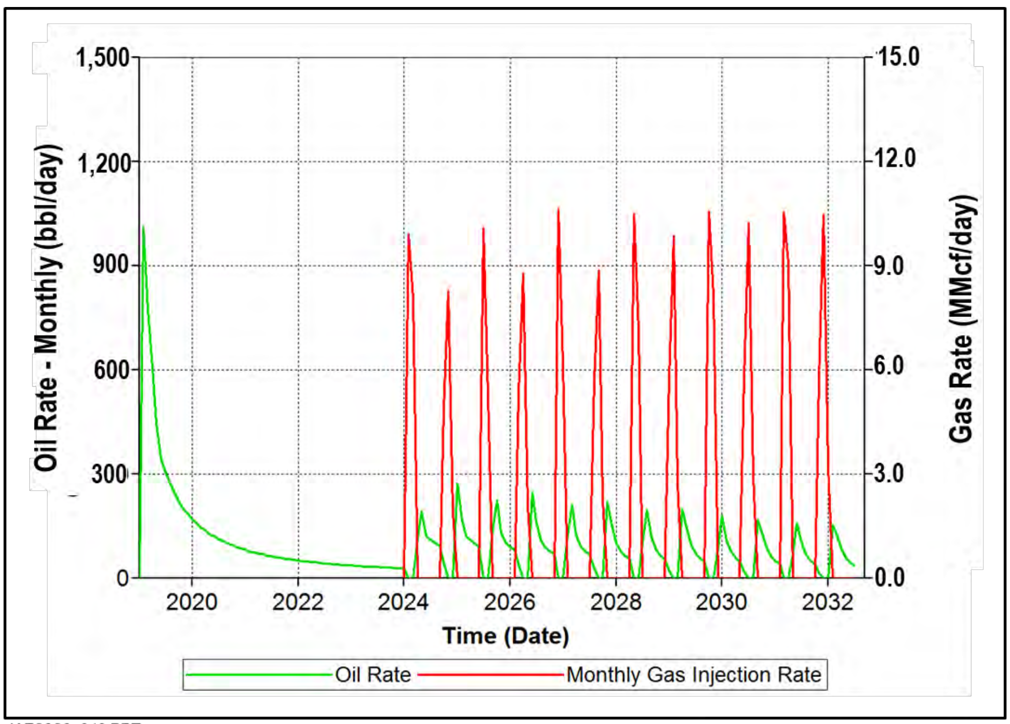
2.5.5 Performance of Cyclic CO_2 Injection

Cyclic CO_2 injection was initiated in the Study Area well after five years of primary production. At this time, the Hz well had produced 238,000 barrels, equal to about two-thirds of its estimated ultimate oil recovery (EUR).

- In cycle one, CO_2 was injected at a constant rate of 10,500 Mcfd for 2 months (with a BHP limit of 7,000 psia) to refill reservoir voidage, with a total of 540,000 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.

Figure 2-20 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.

Figure 2-20. Primary Production and Enhanced Oil Recovery from Cyclic CO_2 Injection



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Source: Advanced Resources International, 2020.

Advanced Resources International, Inc.

The 12 cycles of CO_2 injection over 8.5 years provided 245,000 barrels of oil production, in addition to 238,000 barrels at the start of CO_2 injection for overall oil recovery 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. This 12 cycle CO_2 injection project provided a 1.61x uplift to primary oil production in the Study Area well (Table 2-8).

Table 2-8. Cumulative Oil Production, CO_2 Injection and CO_2 Production: Study Area 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 CO_2 (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, 2020.

Approximately 15% (840 Mcf) of the 6,440 MMcf of CO_2 injected remained in the reservoir at the end of 12 cycles of CO_2 injection (Table 2-8). As such, the cyclic CO_2 project in the Eagle Ford Shale stored 4.5 Mcf of CO_2 (0.24 metric tons of CO_2) per barrel of incremental oil.

2.6 Increasing Shale Oil Recovery and CO_2 Storage with Cyclic CO_2 Enhanced Oil Recovery

2.6.1 Introduction

We have combined three sources of information to estimate the volumes of additional oil recovery and CO_2 storage that would result from the application of cyclic CO_2 enhanced oil recovery to the Eagle Ford Shale.

- Estimates of OOIP for each of the partitions of the Eagle Ford Shale, shown in Section 2.4 of this report.
- Estimates of primary (pressure depletion) oil recovery from reservoir modeling and from Eagle Ford Shale "type wells" in each hydrocarbon partition, discussed in Section 2.5 of this report.
- Estimated "uplift" to primary shale oil recovery from reservoir modeling of cyclic CO_2 enhanced oil recovery, including the calculation of volumes of CO_2 injection and storage, provided in Section 2.5 of this report.

Each Eagle Ford Shale partition was also assessed to determine its geologic attractiveness of applying cyclic CO_2 enhanced oil recovery.

2.6.2 Increased Volumes of Oil Recovery and CO_2 Storage

Eastern Shale Area. We estimate that the application of cyclic CO_2 enhanced oil recovery to the Eagle Ford Shale in the Eastern Shale Area would provide 2,870 MMB of additional technically viable shale oil recovery and provide opportunities to store 700 MMmt of CO_2 (Table 2-9). The incremental oil recovery efficiencies from the use of cyclic CO_2 range from 5.6% of OOIP in the Light Oil area to 6.2% of OOIP in the Condensate/Wet Gas area.

Central Shale Area. We estimate that the application of cyclic CO_2 enhanced oil recovery to the Eagle Ford Shale in the Central Shale Area will provide 1,150 MMB of additional technically viable shale oil recovery and provide opportunities to store 300 MMmt of CO_2 (Table 2-9). The incremental oil recovery efficiencies from the use of cyclic CO_2 range from 4.6% of OOIP in the Light Oil area to 4.9% in the Condensate/Wet Gas Area.

Western Shale Area. We estimate that the application of cyclic CO_2 enhanced oil recovery to the Eagle Ford Shale in the Western Area will provide 2,950 MMB of additional technically viable shale oil recovery and provide opportunities to store 360 MMmt of CO_2 (Table 2-9).

Total Eagle Ford Shale Area. Applying cyclic CO_2 enhanced oil recovery to the nine geologically favorable resource assessment units of the Eagle Ford Shale can provide 7,670 MMB of additional technically viable shale oil recovery and space for storing 1,840 MMmt of CO_2.

Table 2-9. Estimates of Incremental Oil Recovery and CO_2 Storage from the Application of Cyclic CO_2 Enhanced Oil Recovery: Eagle Ford Shale

Eagle Ford Shale Area	OOIP	Resource Concentration	Primary Recovery Efficiency		CO_2 EOR Recovery Efficiency*	CO_2 EOR Incremental Recovery	CO_2 Storage**
	(MMB)	(MB/mi^2)	(MB/mi^2)	(% OOIP)	(% OOIP)	(MMB)	(MMmt)
1. Eastern Shale Area							
▪ Condensate/Wet Gas	13,300	23,800	2,480	10.1%	6.2%	820	200
▪ Volatile Oil	14,900	28,200	2,800	9.9%	6.1%	900	220
▪ Light Oil	20,400	28,800	2,830	9.8%	6.0%	1,220	290
					Sub-Total	2,940	710
2. Central Shale Area							
▪ Condensate/Wet Gas	7,900	24,800	1,990	8.0%	4.9%	380	90
▪ Volatile Oil	13,400	29,100	2,290	7.9%	4.8%	640	150
▪ Light Oil	11,400	23,400	1,890	8.0%	4.9%	560	130
					Sub-Total	1,580	370
3. Western Shale Area							
▪ Condensate/Wet Gas	25,800	18,200	1,440	7.9%	4.8%	1,256	300
▪ Volatile Oil	16,900	20,100	1,870	9.3%	5.7%	960	230
▪ Light Oil	15,300	19,100	1,920	10.0%	6.1%	940	230
					Sub-Total	3,156	760
					Eagle Ford Shale Area Total	7,676	1,840

*Based on reservoir modeling of Eagle Ford Shale Study Area. JAF2020_014.XLS
**Assumes 0.24 mt of CO_2 per barrel of oil.

Advanced Resources International, Inc.

2.7 References

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Chapter 3. Permian (Delaware) Basin

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3. Permian (Delaware) Basin

3.1 Introduction

3.1.1 Purpose of Study

Located in the western portion of the Permian Basin of Texas and New Mexico, the Wolfcamp Shale in the Delaware Basin is the dominant shale oil formation of the U.S. It holds a vast volume of in-place resource, estimated by this study at 576 billion barrels of original oil in-place (OOIP). However, with current primary (pressure depletion) production practices, only a modest portion of this large in-place resource is recoverable. (Prior resource characterization and reservoir modeling of a geologically representative area in the Midland Basin provided an oil recovery efficiency of 5.3% of OOIP for the Wolfcamp Shale.) As such, more advanced oil recovery technologies will be needed to boost the currently low oil recovery efficiency in the Wolfcamp Shale.

The purpose of the USEA study is to examine the potential and impact of one such advanced oil recovery technology—the use of cyclic injection of CO_2 for enhanced oil recovery from the Wolfcamp Shale in the Delaware Basin.

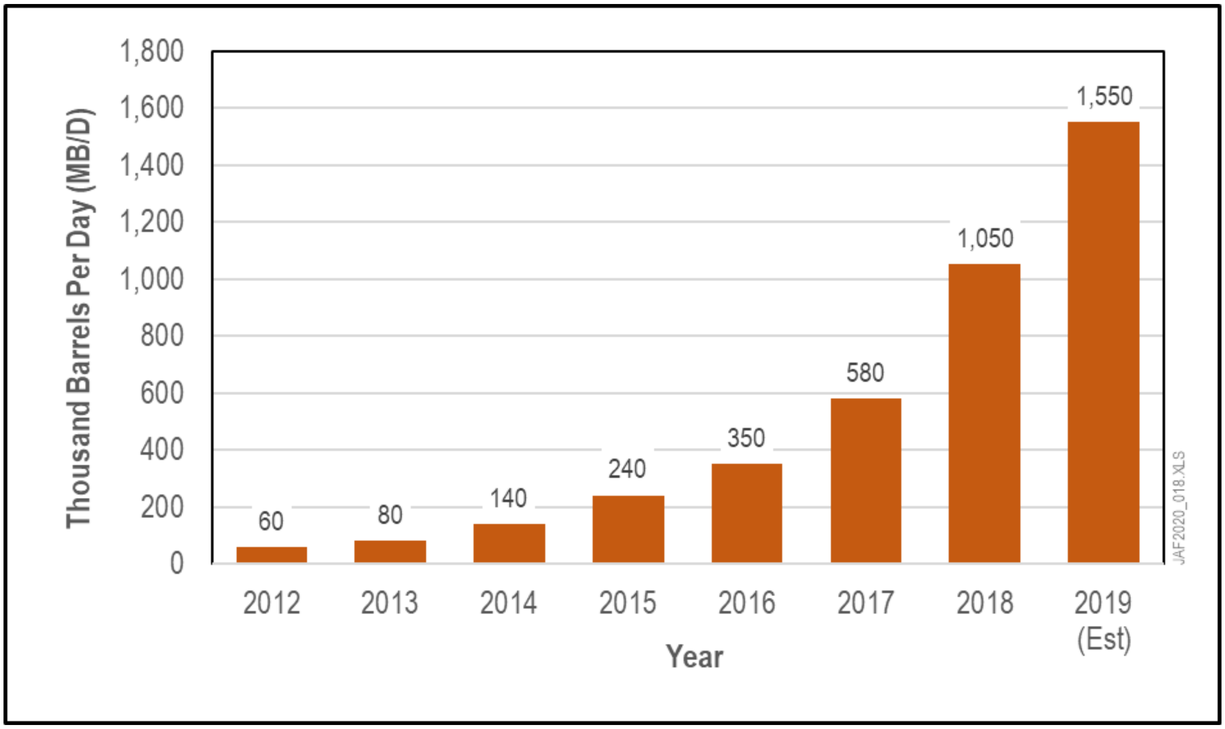
An important by-product of using cyclic injection of CO_2 for oil recovery in the Permian (Delaware Basin) Wolfcamp Shale is that a portion of the injected CO_2 remains trapped in the shale formation, providing an additional geologic site for storing CO_2.

3.1.2 Delaware Basin Shale Well Oil Production and Completions

Initially, oil production from the Delaware Basin's Wolfcamp Shale grew slowly, increasing from 60,000 barrels per day in 2012 to 240,000 barrels per day in 2015. After 2015, the growth in oil production accelerated, enabling the Delaware's Wolfcamp Shale to become the dominant "tight oil" formation in the U.S. In 2019, the Delaware Basin's Wolfcamp Shale produced 1.5 million barrels per day (MM/D) (Figure 3-1).

In addition to the Wolfcamp Shale, the Delaware Basin contains a series of shale and tight oil formations, such as the overlying Bone Spring tight sand and the Avalon Shale. In the early years, industry pursued all three of these formations. Since 2016, the Wolfcamp Shale has become the primary formation targeted by industry in the Delaware Basin, accounting for more than 75% of the basin's oil production and about 80% of the Hz wells drilled and completed in this basin in 2019.

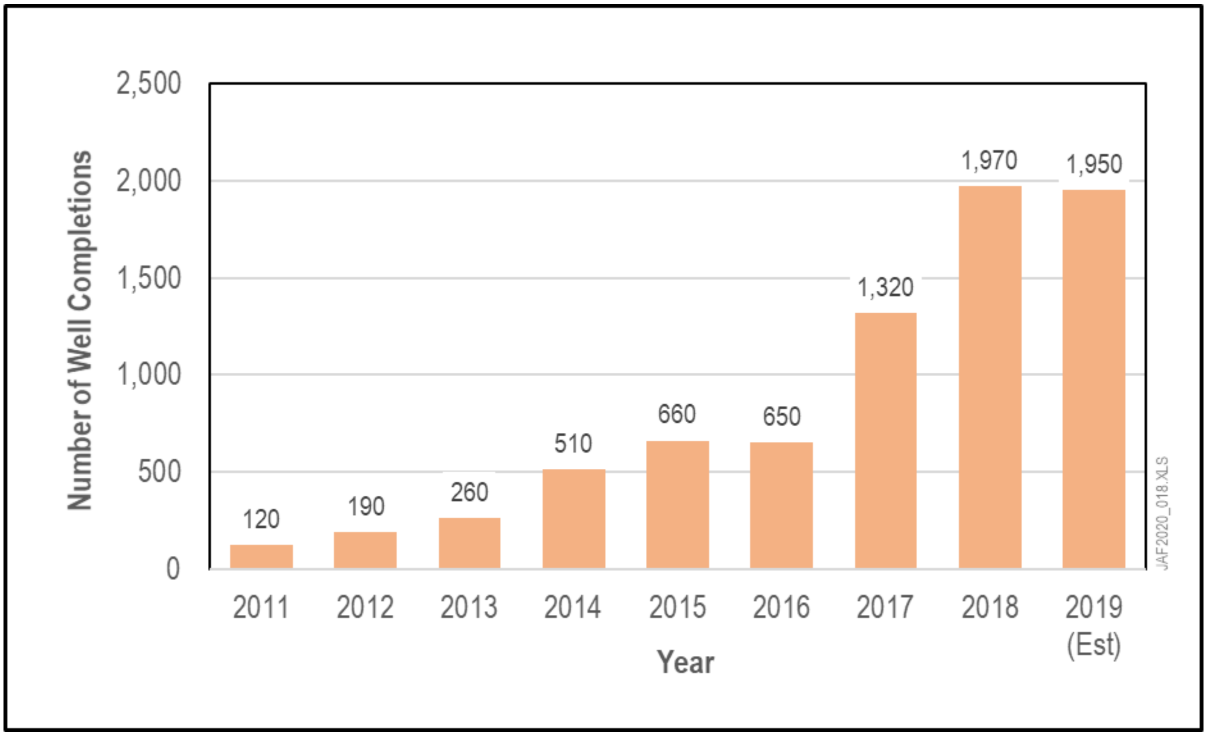
Figure 3-1. Delaware Basin Wolfcamp Shale Oil Production



Source: Advanced Resources International's Tight Oil Database, 2020; Enervus, 2020.

The initial pursuit of the Wolfcamp Shale in the Delaware Basin was with vertical wells, completed jointly in the Wolfcamp Shale and the overlying Bone Spring tight sand. These were called "Wolfbone" wells. The use of HZ wells individually targeting the Wolfcamp Shale started at commercial scale in 2011, with 120 HZ wells placed on-line and growing steadily to 660 by 2015. After a plateau in well drilling and completions in 2016, in response to the decline in oil prices, Delaware Wolfcamp Shale Hz well completions resumed their rise, doubling to over 1,320 in 2017 and further to nearly 2,000 in 2018 and 2019 (Figure 3-2).

Figure 3-2. Delaware Basin Wolfcamp Shale Hz Well Completions, 2011-2019



Source: Advanced Resources International's Tight Oil Database, 2020; Enervus, 2020.

3.1.3 Outlook for Enhanced Shale Oil Recovery

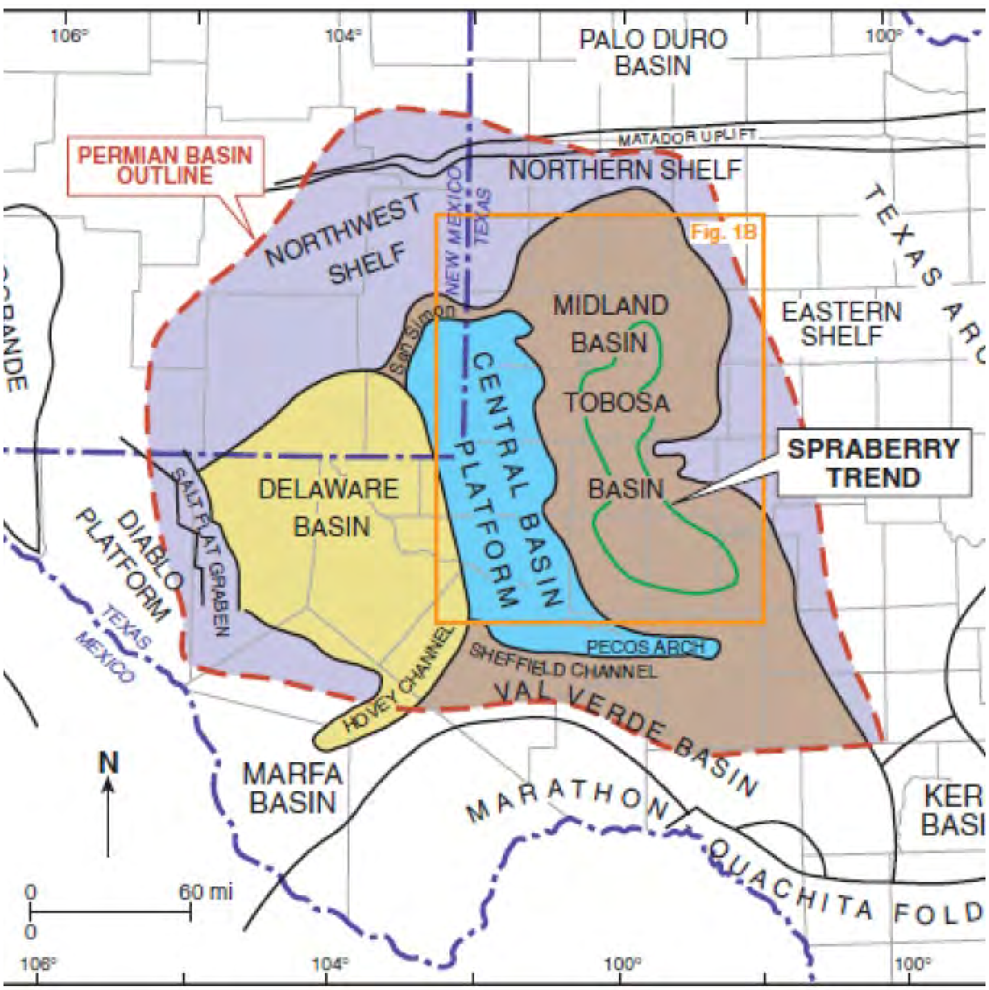
Given current relatively low primary (pressure depletion) oil recovery efficiencies, estimated at 5% to 11% of OOIP, the Wolfcamp Shale in the Delaware Basin is a prime candidate for using cyclic CO_2 injection for boosting oil recovery. Our assessment, as discussed further in Section 3.6 of this report, is that the Wolfcamp Shale in the Delaware Basin has the potential to provide 21,850 million barrels (MMB) of additional technically viable oil recovery and can provide space for geologically storing 10,050 million metric tons (MMmt) of CO_2 from the application of cyclic CO_2 enhanced oil recovery.

3.2 Geologic Setting of the Delaware Basin

3.2.1 Delaware Basin

The Permian Basin, located in West Texas and southeastern New Mexico, consists of the Midland Basin in the east, the Central Basin Platform in the center, and the Delaware Basin in the west (Figure 3-3). The Delaware Basin encompasses a 10,000 square mile area in nine counties of West Texas and New Mexico. The great majority of the tight oil development in the Delaware Basin has occurred in the center of the basin, primarily in Winkler, Loving, Ward, Reeves, and Culberson counties in Texas and Lea and Eddy counties in New Mexico.

Figure 3-3. Outline of the Permian Basin

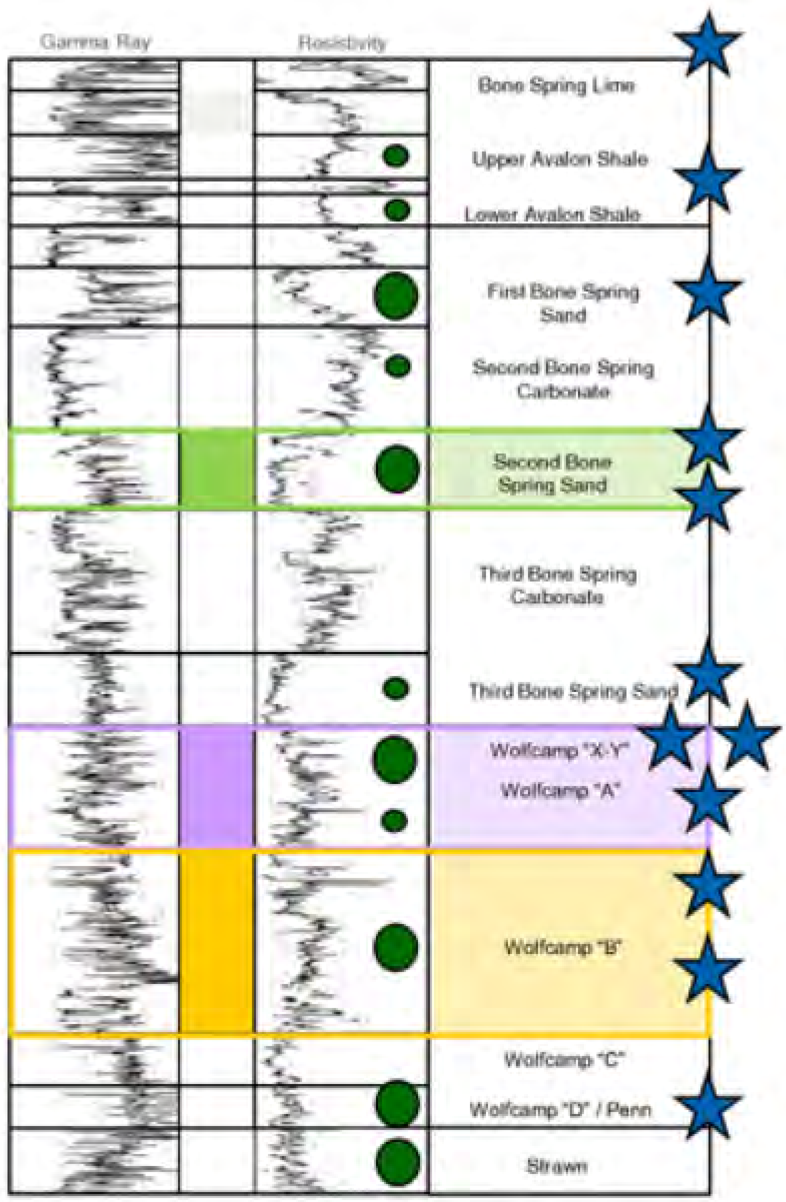


Source: Montgomery et al., 2000; Lorenz et al., 2002; Pioneer Natural Resources, 2012.

3.2.2 Delaware Basin Stratigraphic Column

The Wolfcamp Shale oil resources exist in multiple benches, in three Permian-age Wolfcamp Benches, A, B and C, as well as in the Pennsylvanian-age Wolfcamp Bench D (Figure 3-4). (The Wolfcamp Shale C and D Benches are not included in the USEA Study.)

Figure 3-4. Delaware Basin Stratigraphic Column



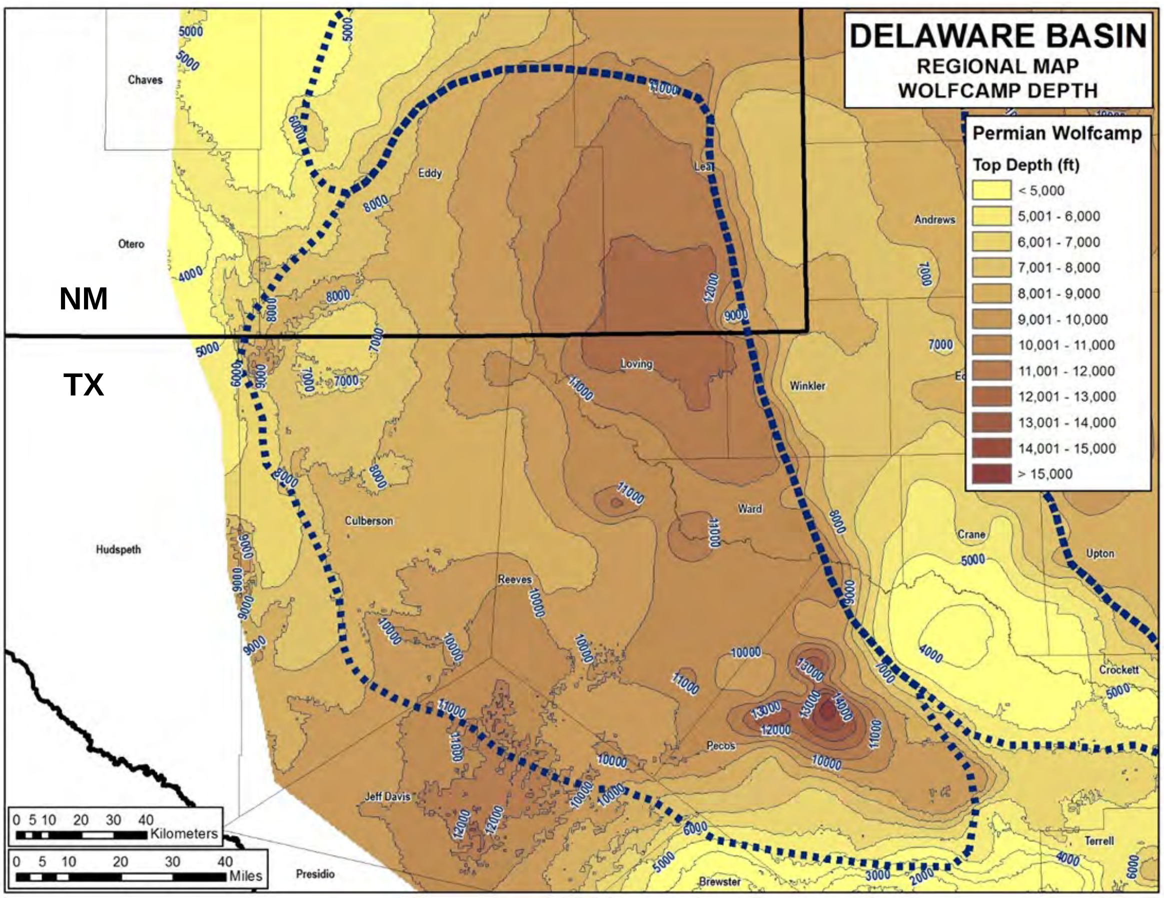
Source: Modified from Matador Resources, 2015.

3.2.3 Wolfcamp Shale Assessment Area and Depth

The Wolfcamp Shale in the Delaware Basin extends from Eddy and Lea counties in New Mexico in the north to Pecos County, Texas in the south (Figure 3-5). The area also includes the western portion of Winkler and Ward counties, as well as Loving, Reeves, and Culberson counties in Texas.

The Wolfcamp Shale formation in the Delaware Basin reaches a maximum depth of over 12,000 ft in the eastern portion of the basin in Loving, TX and Lea, NM counties, becoming shallower (<8,000 ft) in western Culberson, TX and Eddy, NM counties.

Figure 3-5. Delaware Basin Wolfcamp Shale Depth (Top of Wolfcamp A Bench)



Source: Advanced Resources International, 2020.

3.2.4 Wolfcamp Shale Isopach

The gross thickness of the Delaware Basin's Wolfcamp Shale (including Benches A, B, C, and D) ranges from 800 ft in the northwest portion of the resource assessment area to over 7,000 ft in the center of the basin (EIA, 2020).

The isopach thickness of the A Bench of the Delaware Wolfcamp Shale ranges from 100 ft along the borders of the Delaware Basin to over 700 ft in the center of the Basin in parts of Loving, TX and Lea, NM (Figure 3-6) (EIA, 2020). In the early phases of the Delaware Basin's Wolfcamp Shale development, operators pursued the thicker Upper A Bench in Loving, Winkler, and Ward counties of the basin. Since then, well drilling in the Delaware Basins has extended north into New Mexico, south into Reeves County, and west into Culberson County.

Figure 3-6. Delaware Wolfcamp Shale Gross Isopach of A Bench

Source: EIA, 2020.

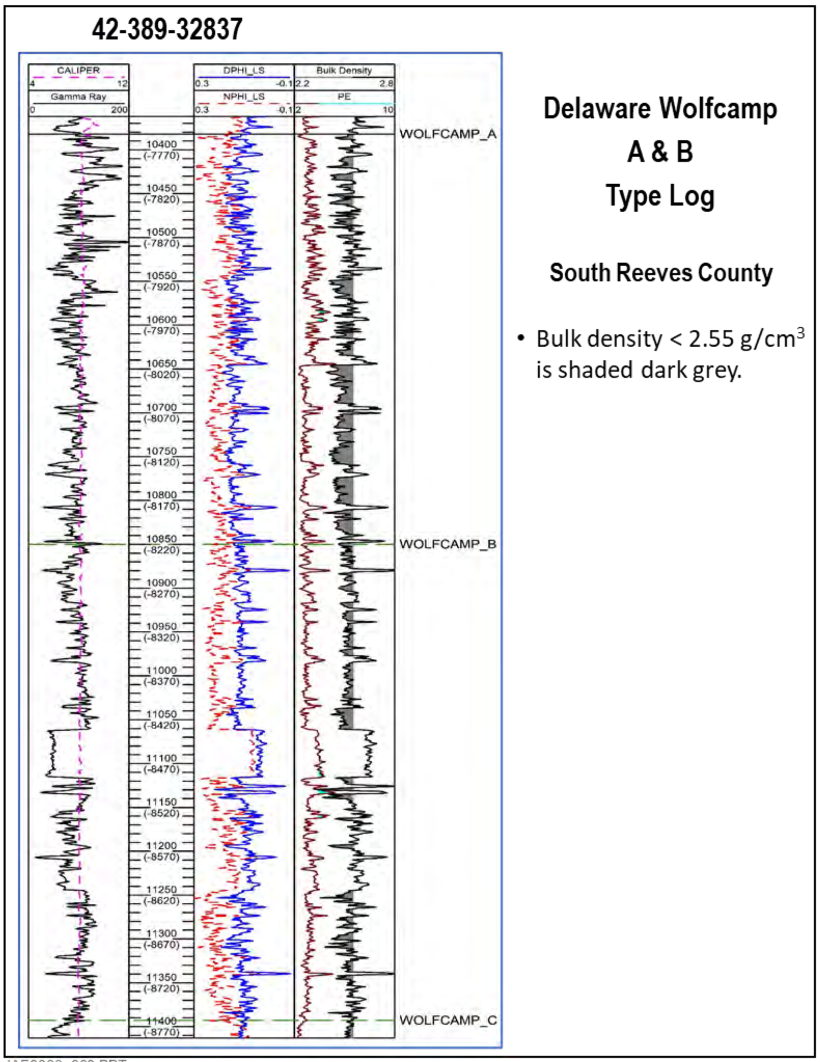
Advanced Resources International, Inc.

3.3 Establishing the Essential Reservoir Properties

3.3.1 Wolfcamp Shale Type Log

This USEA resource assessment study addresses the Lower Permian Wolfcamp Shale in the Delaware Basin and its two dominant intervals, Wolfcamp Bench A and Bench B (Figure 3-7). More recently, the Wolfcamp C and D Benches have started to be developed, particularly in the western portions of the Delaware Basin. (However, the assessment of the Wolfcamp Shale Benches C and D is beyond the scope of work set forth in the USEA Study.)

Figure 3-7. Delaware Basin Wolfcamp Shale Type Log, Reeves County



JAF2020_028.PPT

Source: Advanced Resources International, 2020.

3.3.2 Wolfcamp Shale Lithology and Thickness

Based on independent log analysis by Advanced Resources, the overall thickness of the A and B Benches of the Wolfcamp Shale is relatively uniform, ranging from 350 to 450 feet. In contrast, the lithology of the Wolfcamp Shale Benches A and B varies greatly. As illustrated in Table 3-1, shale is the dominant lithology in Loving and Reeves counties, while limestone and "mixed" are the dominant lithologies in Culberson and Eddy counties.

Table 3-1. Lithology of Wolfcamp Shale Benches, Four Delaware Basin Counties

	Shale (Thickness, ft)	Limestone (Thickness, ft)	Mixed Lithology (Thickness, ft)	Total (Thickness, ft)
1. Loving County				
▪ A Bench	323	34	114	471
▪ B Bench	286	3	77	366
2. Reeves County				
▪ A Bench	281	113	60	454
▪ B Bench	278	101	78	457
3. Culberson County				
▪ A Bench	212	96	144	452
▪ B Bench	162	14	265	441
4. Eddy County				
▪ A Bench	136	107	105	348
▪ B Bench	42	164	214	420

The thickness of the shale in each of the Wolfcamp benches was estimated using a density cut-off value of 2.55 grams per cubic centimeter (g/cm^3).

3.3.3 Wolfcamp Shale Porosity

Detailed information on the porosity of the Wolfcamp Shale is scarce. Particularly challenging is establishing the porosity values in the organic portions of the Wolfcamp Shale interval compared to the intergranular porosity in the limestone and mixed lithology portions of the Wolfcamp Shale interval.

To address this limitation on publicly available information, Advanced Resources International (ARI) undertook an independent log analysis study to establish discrete porosity values for each of the Wolfcamp Shale lithologies in each of the nine main counties in the study area. The lithology related porosity values were combined to provide a net pay-weighted average porosity value for Bench A and Bench B of the Wolfcamp Shale, as illustrated below for South Reeves County (Table 3-2).

Table 3-2. Reservoir Porosity for Wolfcamp Shale Benches, South Reeves County

Wolfcamp Bench	Shale		Limestone		Mixed Lithology		Weighted Average
	Porosity	Net Pay (ft)	Porosity	Net Pay (ft)	Porosity	Net Pay (ft)	Porosity
A	6.2%	281	6.2%	113	6.3%	60	6.2%
B	6.8%	278	4.9%	101	6.5%	78	6.3%

3.3.4 Wolfcamp Shale Oil and Water Saturation

The technical literature has only recently begun to examine and discuss the oil and water saturation values for the Wolfcamp Shale. The literature reports that the organic porosity in the shale is oil-wet and much of the inorganic (grain bounded) porosity is water-wet. As such, the organic (shale) porosity contains immobile water, estimated at 20% to 30%, while the inorganic porosity contains mobile water, estimated at 45% to 55%. Typical producing water-oil ratios range from two barrels of water per barrel of oil in the eastern part of the basin to over 5 barrels of water per barrel of oil in the western portion of the Delaware Basin.

To establish values for oil and water saturation for the Wolfcamp Shale, ARI performed detailed log analysis for a representative well in each county of the Delaware Basin. The log analysis was used to identify the three main lithologies in the Wolfcamp interval – shale, limestone and mixed. Lithology-specific oil and water saturation values were assigned to establish average oil and water saturation values for Wolfcamp Shale Bench A and Bench B in each county of the Delaware Basin, as illustrated for South Reeves County in Table 3-3.

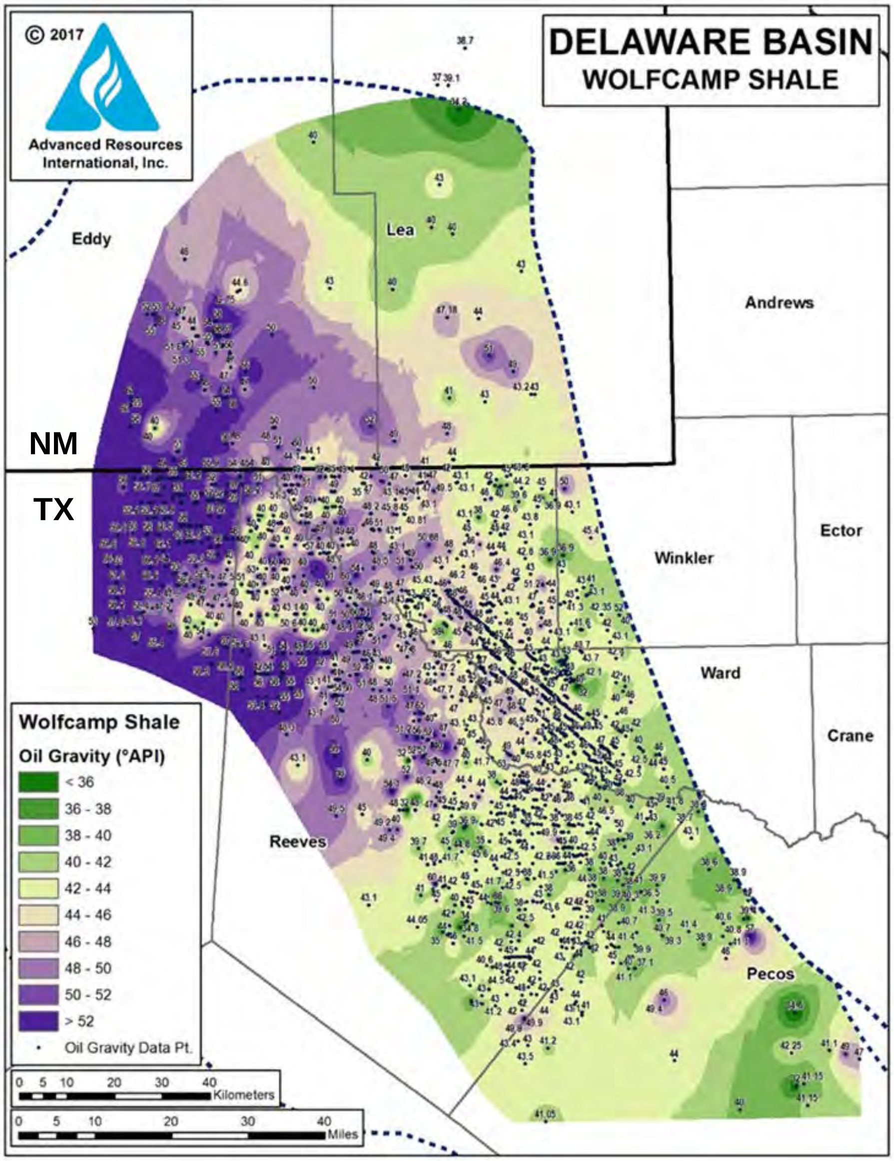
Table 3-3. Oil Saturation for the Wolfcamp Shale Benches, South Reeves County

Wolfcamp Bench	Shale			Limestone			Mixed Lithology			Weighted Average
	Porosity	Net Pay (ft)	Oil Sat.	Porosity	Net Pay (ft)	Oil Sat	Porosity	Net Pay (ft)	Oil Sat	Oil Saturation
A	6.2%	281	0.75	6.2%	113	0.50	6.3%	60	0.50	0.65
B	6.8%	278	0.75	4.9%	101	0.50	6.5%	78	0.50	0.66

3.3.5 Wolfcamp Shale Oil Gravity

The oil gravity of the Wolfcamp Shale ranges from less than 36^o API in the thermally less mature areas to the southeast of the resource assessment area to over 52^o API, in the higher maturity areas along the western edge of the Delaware Basin. The average API gravity for the Delaware Wolfcamp Shale is about 45^o API (Figure 3-8).

Figure 3-8. Wolfcamp Shale API Gravity



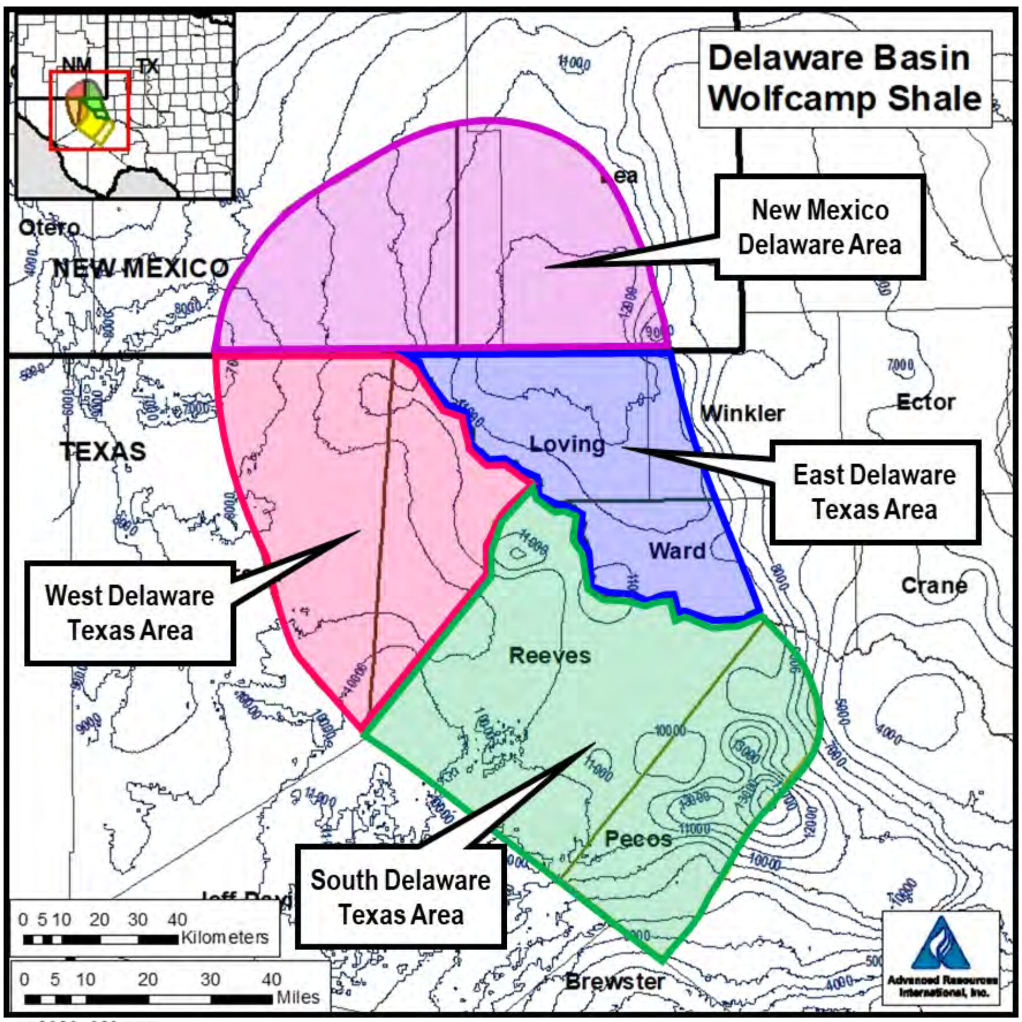
Source: Advanced Resources International, 2020.

3.4. Wolfcamp Shale Resource Assessment

3.4.1 Assessment Methodology

To provide some granularity to the estimates of OOIP, the USEA Study divided the Wolfcamp Shale in the Delaware Basin into four geologically distinct partitions – East Delaware TX Area, South Delaware TX Area, West Delaware TX Area, and New Mexico Delaware Area (Figure 3-9). Each of the four geologic partitions was further partitioned into the counties comprising the larger partition area. For each county, the study assembled representative volumetric and other reservoir properties essential for estimating the OOIP of the Wolfcamp Shale.

Figure 3-9. Four Geologic Partitions, Delaware Wolfcamp Shale

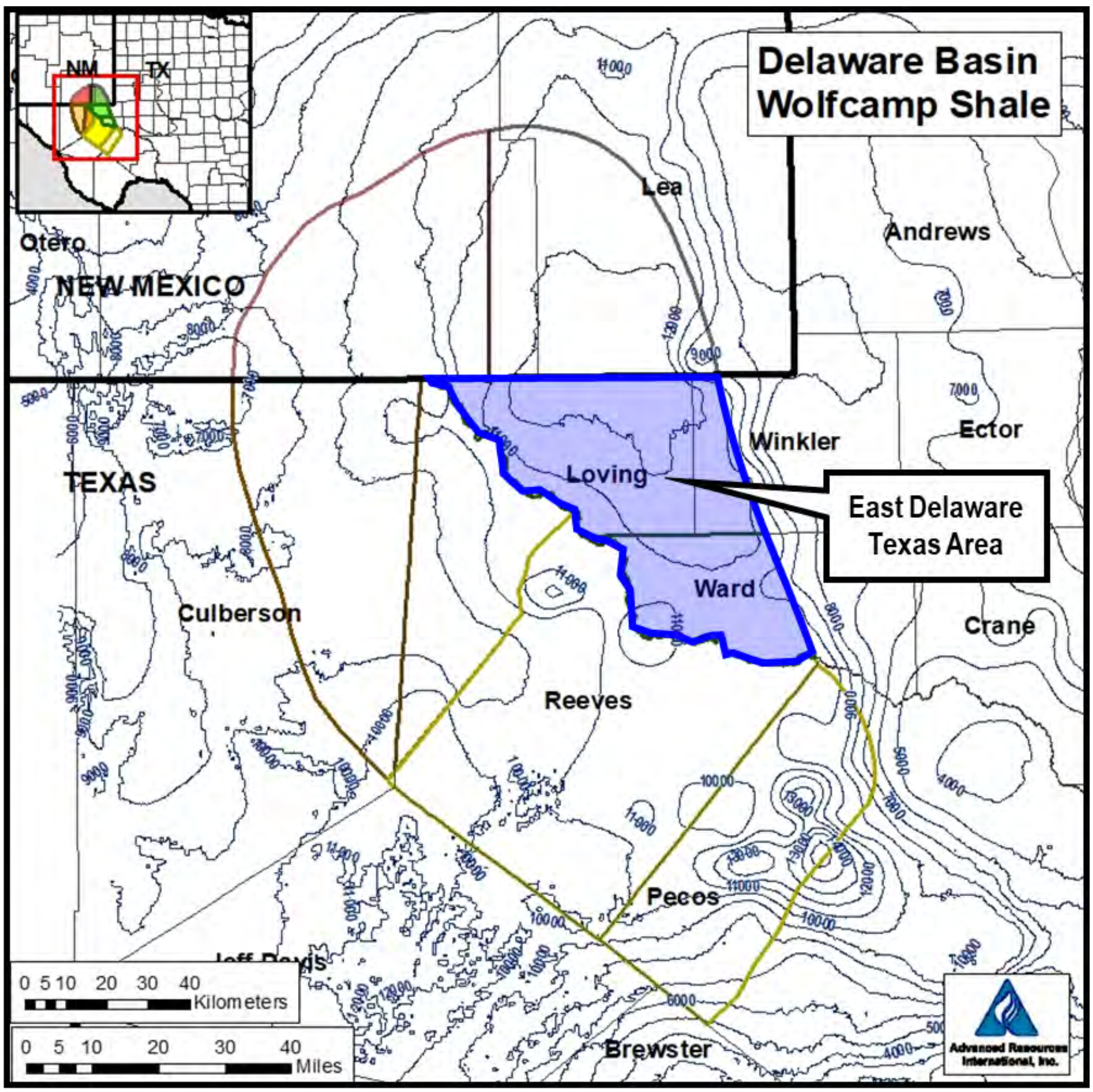


Source: Advanced Resources International, 2020.

3.4.2 East Delaware TX Shale Area

The East Delaware TX Area of the Wolfcamp Shale extends across 1,270 square miles (1,020 square miles, risked) in Loving, Winkler, and Ward counties (Figure 3-10). More than 2,300 Hz Wolfcamp Shale oil wells have been drilled and completed in the A and B Benches in this area, as of the end of 2019. The depth of the Wolfcamp Shale in the East Delaware TX Area ranges from about 10,500 ft in southeastern Ward County to over 12,000 ft in Loving County.

Figure 3-10. Outline and Depth Map of East Delaware TX Area of the Wolfcamp Shale



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Source: Advanced Resources International, 2020.

Table 3-4 provides the key reservoir properties for the Wolfcamp Shale A and B Benches in the three counties of the East Delaware TX Wolfcamp Shale Area.

Table 3-4. Reservoir Properties for Estimating OOIP, East Delaware TX Wolfcamp Shale Area

Reservoir Property	Loving Co.	Winkler Co.	Ward Co.
Total Area	680 mi^2	170 mi^2	420 mi^2
Risked Area	540 mi^2	140 mi^2	340 mi^2
Average Depth	12,000 ft	11,500 ft	11,000 ft
Net Pay			
▪ A Bench	470 ft	370 ft	490 ft
▪ B Bench	370 ft	370 ft	260 ft
Average Porosity			
▪ A Bench	6.5%	5.8%	7.0%
▪ B Bench	6.0%	5.2%	5.0%
Oil Saturation			
▪ A Bench	68%	63%	72%
▪ B Bench	70%	59%	71%
Formation Volume Factor (RB/STB)			
▪ A Bench	1.9	1.9	1.9
▪ B Bench	1.9	1.9	1.9

Source: Advanced Resources International, 2020.

Using the volumetric reservoir properties in Table 3-4, the OOIP for the Wolfcamp Shale A and B Benches in Loving County is 51.5 billion barrels (Table 3-5); in Winkler County is 8.9 billion barrels (Table 3-6); and in Ward County is 29.8 billion barrels (Table 3-7).

Table 3-5. OOIP of Wolfcamp Shale A and B Benches, Loving County

County/Interval	Risked Area (mi^2)	Resource Concentration (MB/mi^2)	Oil/Condensate OOIP (Million Barrels)
▪ Loving – A Bench	540	54,400	29,600
▪ Loving – B Bench	540	40,170	21,850
Total			51,450

Source: Advanced Resources International, 2020.

Table 3-6. OOIP of Wolfcamp Shale A and B Benches, Winkler County

County/Interval	Risked Area (mi^2)	Resource Concentration (MB/mi^2)	Oil/Condensate OOIP (Million Barrels)
▪ Winkler – A Bench	140	35,240	4,790
▪ Winkler – B Bench	140	29,830	4,060
Total			8,850

Source: Advanced Resources International, 2020.

Table 3-7. OOIP of Wolfcamp Shale A and B Benches, Ward County

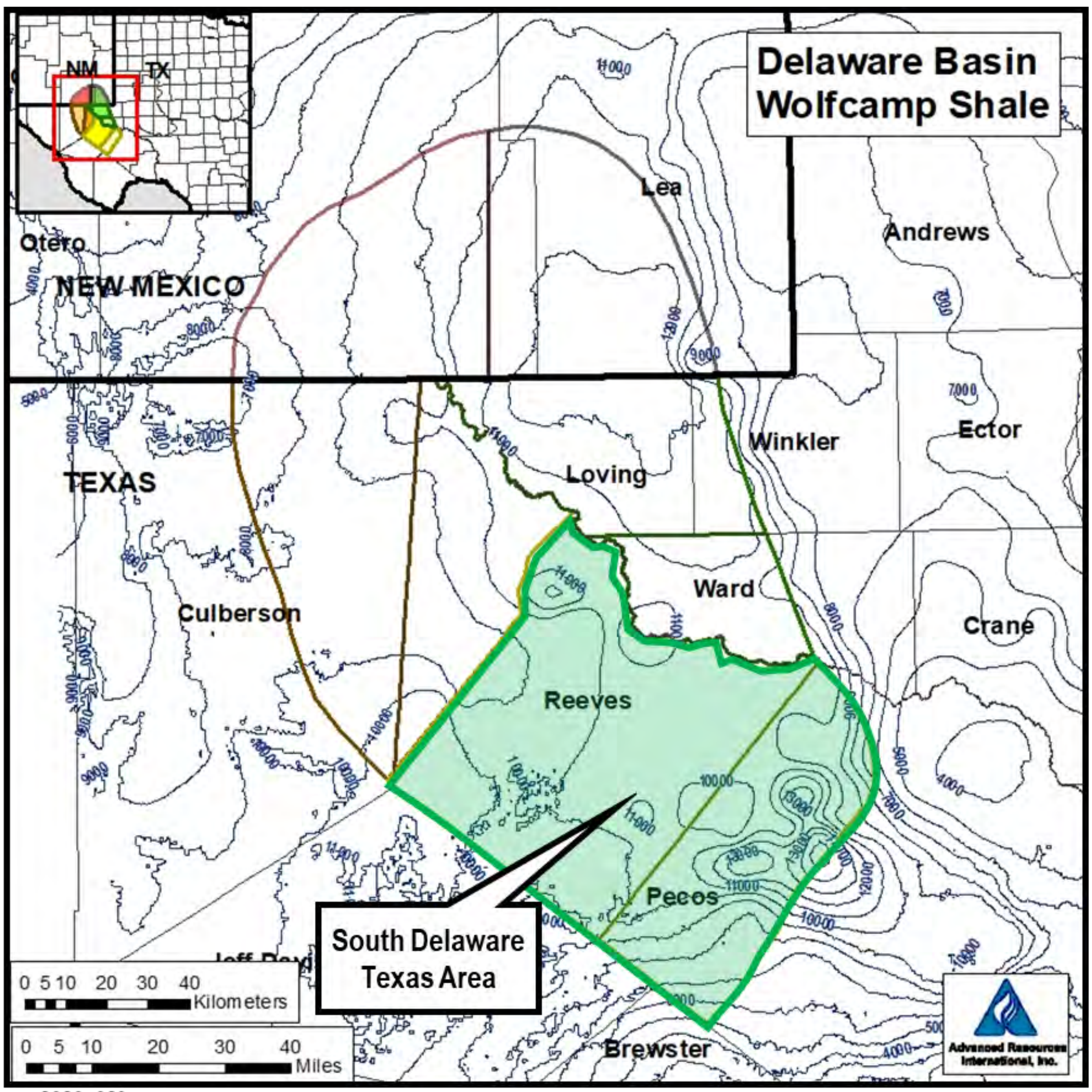
County/Interval	Risked Area (mi^2)	Resource Concentration (MB/mi^2)	Oil/Condensate OOIP (Million Barrels)
▪ Ward – A Bench	340	64,400	21,640
▪ Ward – B Bench	340	24,210	8,140
Total			29,780

Source: Advanced Resources International, 2020.

3.4.3 South Delaware TX Area Basin

The South Delaware TX Area of the Wolfcamp Shale covers 2,880 square miles (2,300 square miles, risked) in southern Reeves and Pecos counties (Figure 3-10). Over 2,100 Hz Wolfcamp Shale wells have been placed in production in Benches A and B in the South Delaware TX Area, as of the end of 2019, primarily in southern Reeves County. The depth of the Wolfcamp Shale in the South Delaware TX Area ranges from 8,500 ft in the south and east to 10,000 ft in the north (Figure 3-11).

Figure 3-11. Outline and Depth Map of South Delaware TX Wolfcamp Shale Area



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Source: Advanced Resources International, 2020.

Table 3-8 provides the key reservoir properties for the Wolfcamp Shale A and B Benches in the two counties of the South Delaware TX Wolfcamp Shale Area.

Table 3-8. Reservoir Properties for Estimating OOIP, South Delaware TX Wolfcamp Shale Area

Reservoir Property	South Reeves Co.	Pecos Co.
Total Area	1,900 mi^2	980 mi^2
Risked Area	1,520 mi^2	780 mi^2
Average Depth (top)	10,500 ft	10,200 ft
Net Pay (Shale Unit)		
▪ A Bench	450 ft	400 ft
▪ B Bench	460 ft	360 ft
Porosity (Shale Unit)		
▪ A Bench	6.2%	5.7%
▪ B Bench	6.3%	6.2%
Oil Saturation		
▪ A Bench	65%	62%
▪ B Bench	66%	54%
Formation Volume Factor (RB/STB)		
▪ A Bench	1.8	1.8
▪ B Bench	1.8	1.8

Source: Advanced Resources International, 2020.

Advanced Resources International, Inc.

Using the volumetric reservoir properties in Table 3-8, the OOIP for the Wolfcamp A and B Benches in South Reeves County is 156.4 billion barrels (Table 3-9) and in Pecos County is 56.1 billion barrels (Table 3-10).

Table 3-9. OOIP of Wolfcamp Shale A and B Benches, South Reeves County

County/Interval	Risked Area (mi^2)	Resource Concentration (MB/mi^2)	Oil/Condensate OOIP (Million Barrels)
▪ South Reeves – A Bench	1,520	50,470	76,710
▪ South Reeves – B Bench	1,520	52,420	79,670
Total			156,380

Source: Advanced Resources International, 2020.

Table 3-10. OOIP of Wolfcamp Shale A and B Benches, Pecos County

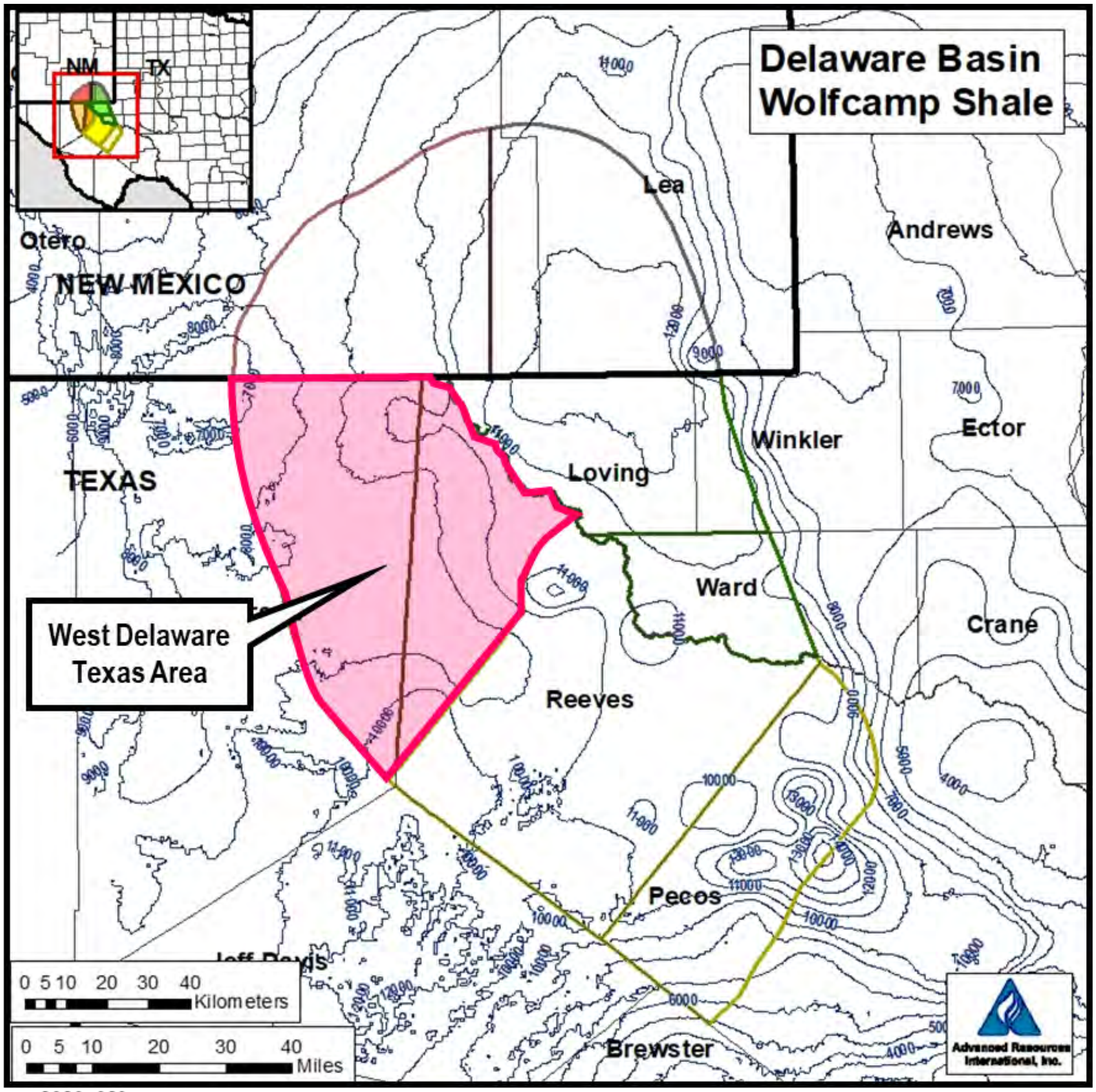
County/Interval	Risked Area (mi^2)	Resource Concentration (MB/mi^2)	Oil/Condensate OOIP (Million Barrels)
▪ Pecos – A Bench	780	38,600	30,270
▪ Pecos – B Bench	780	32,880	25,780
Total			56,050

Source: Advanced Resources International, 2020.

3.4.4 West Delaware TX Area

The West Delaware TX Area of the Wolfcamp Shale extends across 1,890 square miles (1,510 square miles, risked) in northwest (NW) Reeves and Culberson Counties (Figure 3-11). Approximately 1,250 Hz Wolfcamp Shale oil wells have been drilled and completed in Benches A and B in the West Delaware TX Area, as of the end of 2019. The depth of the Wolfcamp Shale in the West Delaware TX Area ranges from 8,000 ft in the west to nearly 10,500 ft in the east (Figure 3-12).

Figure 3-12. Outline and Depth Map of West Delaware TX Wolfcamp Shale Area



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Source: Advanced Resources International, 2020.

Table 3-11 provides the volumetric and other reservoir properties for the Wolfcamp Shale A and B Benches in NW Reeves and Culberson counties of the West Delaware TX Wolfcamp Shale Area.

Table 3-11. Reservoir Properties for Estimating OOIP, West Delaware TX Wolfcamp Shale Area

Reservoir Property	NW Reeves Co.	Culberson Co.
Total Area	740 mi^2	1,150 mi^2
Risked Area	590 mi^2	920 mi^2
Average Depth (top)	10,300 ft	9,300 ft
Net Pay (Shale Unit)		
▪ A Bench	450 ft	450 ft
▪ B Bench	550 ft	440 ft
Porosity (Shale Unit)		
▪ A Bench	6.7%	6.5%
▪ B Bench	5.8%	5.5%
Oil Saturation		
▪ A Bench	59%	59%
▪ B Bench	62%	58%
Formation Volume Factor (RB/STB)		
▪ A Bench	1.8	1.8
▪ B Bench	1.8	1.8

Source: Advanced Resources International, 2020.

Using the volumetric reservoir properties in Table 3-11, the OOIP for the Wolfcamp A and B Benches in NW Reeves County is 61.3 billion barrels (Table 3-12) and in Culberson County is 79.7 billion barrels (Table 3-13).

Table 3-12. OOIP of Wolfcamp Shale A and B Benches, NW Reeves County

County/Interval	Risked Area (mi^2)	Resource Concentration (MB/mi^2)	Oil/Condensate OOIP (Million Barrels)
▪ NW Reeves – A Bench	590	48,520	28,730
▪ NW Reeves – B Bench	590	54,950	32,530
Total			61,260

Source: Advanced Resources International, 2020.

Table 3-13. OOIP of Wolfcamp Shale A and B Benches, Culberson County

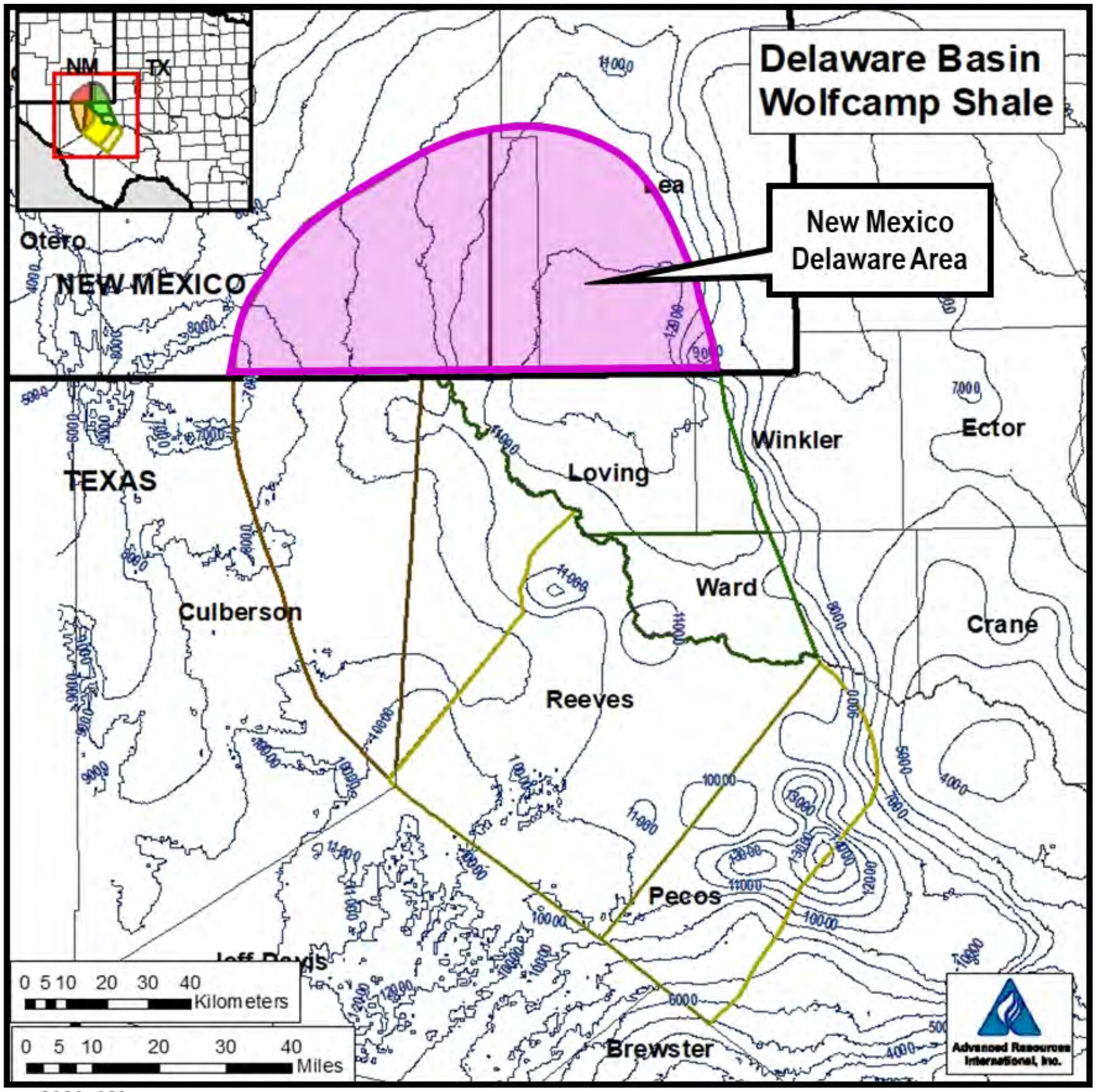
County/Interval	Risked Area (mi^2)	Resource Concentration (MB/mi^2)	Oil/Condensate OOIP (Million Barrels)
▪ Culberson – A Bench	920	47,820	43,990
▪ Culberson – B Bench	920	38,810	35,700
Total			79,690

Source: Advanced Resources International, 2020.

3.4.5 New Mexico Delaware Area

The New Mexico Delaware Area of the Wolfcamp Shale extends across 2,070 square miles (1,650 square miles, risked) in Lea and Eddy counties of New Mexico (Figure 3-12). Overall, as of the end of 2019, more than 1,100 Hz Wolfcamp Shale oil wells have been drilled and completed in Benches A and B in the New Mexico Delaware Area. The depth of the Wolfcamp Shale in the New Mexico Delaware Area ranges from 8,500 ft in the west to over 12,500 ft in the east (Figure 3-13).

Figure 3-13. Outline and Depth Map of New Mexico Delaware Area Wolfcamp Shale



JAF2020_028.PPT

Source: Advanced Resources International, 2020.

Table 3-14 provides the volumetric and other reservoir properties for the Wolfcamp Shale A and B Benches in Lea and Eddy counties of the New Mexico Delaware Wolfcamp Shale Area.

Table 3-14. Reservoir Properties for Estimating OOIP, New Mexico Delaware Wolfcamp Shale Area

Reservoir Property	Lea Co.	Eddy Co.
Total Area	1,030 mi^2	1,040 mi^2
Risked Area	820 mi^2	830 mi^2
Average Depth (top)	12,400 ft	9,800 ft
Net Pay (Shale Unit)		
▪ A Bench	460 ft	350 ft
▪ B Bench	430 ft	420 ft
Porosity (Shale Unit)		
▪ A Bench	5.8%	6.0%
▪ B Bench	5.7%	6.2%
Oil Saturation		
▪ A Bench	64%	59%
▪ B Bench	68%	52%
Formation Volume Factor (RB/STB)		
▪ A Bench	1.9	1.8
▪ B Bench	1.9	1.8

Source: Advanced Resources International, 2020.

Using the volumetric reservoir properties in Table 3-14, the OOIP for the Wolfcamp A and B Benches in Lea County is 72.9 billion barrels (Table 3-15) and in Eddy County is 59.4 billion barrels (Table 3-16).

Table 3-15. OOIP of Wolfcamp Shale A and B Benches, Lea County

County/Interval	Risked Area (mi^2)	Resource Concentration (MB/mi^2)	Oil/Condensate OOIP (Million Barrels)
▪ Lea – A Bench	820	44,720	36,850
▪ Lea – B Bench	820	43,760	36,060
Total			72,910

Source: Advanced Resources International, 2020.

Table 3-16. OOIP of Wolfcamp Shale A and B Benches, Eddy County

County/Interval	Risked Area (mi^2)	Resource Concentration (MB/mi^2)	Oil/Condensate OOIP (Million Barrels)
▪ Eddy – A Bench	830	33,980	28,270
▪ Eddy – B Bench	830	37,350	31,080
Total			59,350

Source: Advanced Resources International, 2020.

3.4.6 OOIP for Wolfcamp Shale (A and B Benches)

The combined OOIP estimates for the Delaware Basin's Wolfcamp Shale (eighteen resource assessment units within four geologic partitions) is a risked 576 billion barrels.

3.5. Estimating Primary and Enhanced Oil Recovery from the Wolfcamp Shale, Delaware Basin

3.5.1 Methodology

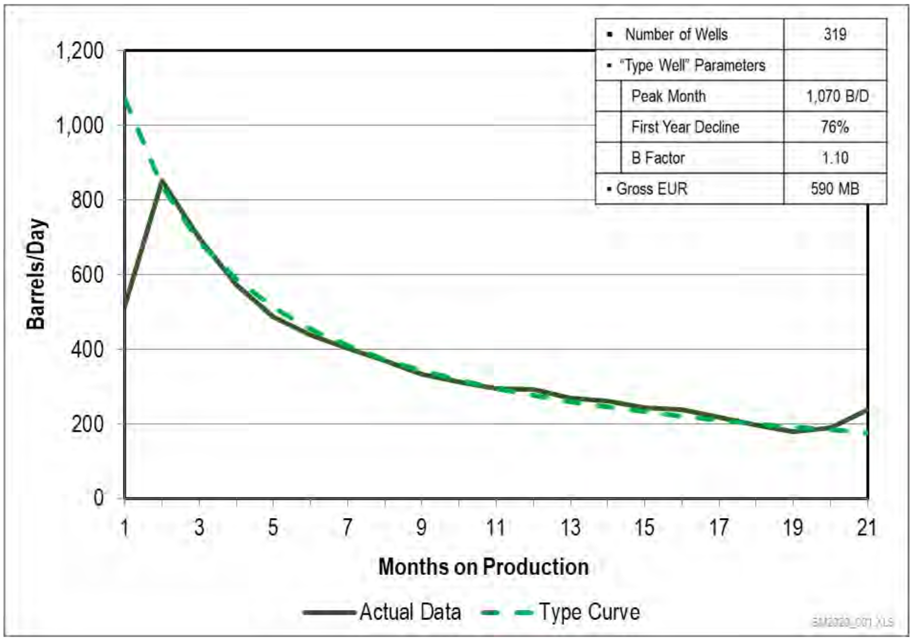
Using the OOIP values for Bench A and Bench B of the Wolfcamp Shale (as provided in Section 3.4, above), Advanced Resources determined primary (pressure depletion) oil recovery efficiency values for each of the eighteen partitions using actual oil production data and decline curve analysis, as discussed below. It then applied previous work involving reservoir modeling of the Wolfcamp Shale in the Midland Basin to estimate the "uplift' to primary oil recovery (the incremental oil recovery) due to use of cyclic injection of CO_2 in the Wolfcamp Shale of the Delaware Basin.

3.5.2 Construction of Primary Recovery "Type Wells"

Oil and water production "type wells" were completed for each of the nine counties in the Delaware Basin Wolfcamp Shale, with individual "type wells" constructed for Wolfcamp A and B Benches, as illustrated for South Reeves County, Texas.

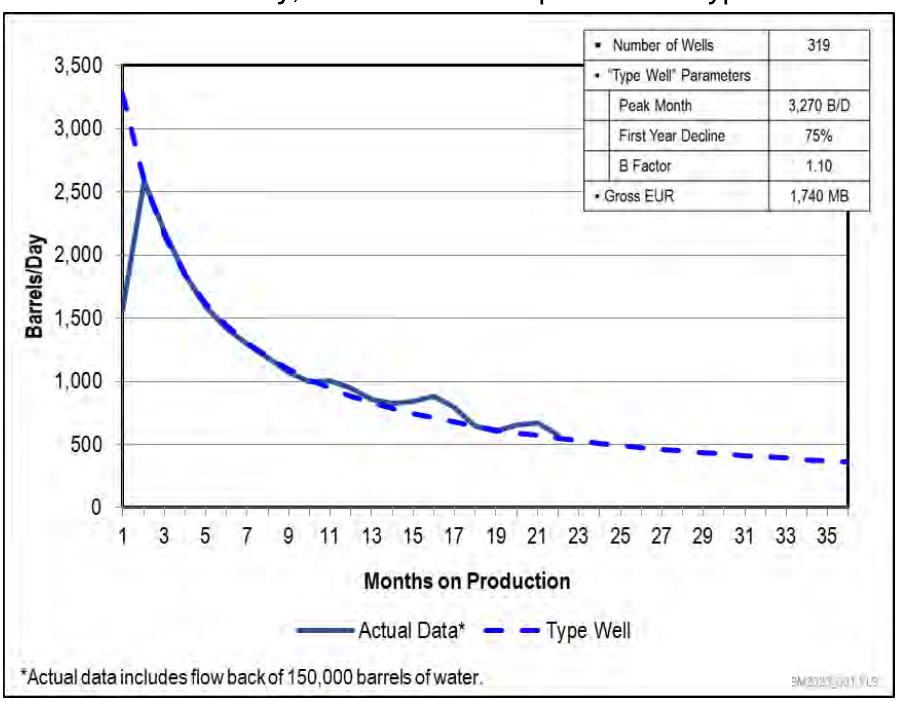
The "type oil well" in South Reeves County for the A Bench of the Wolfcamp Shale, has a spacing of 160 acres and a Hz lateral of 8,200 ft. It has an estimated 30-year ultimate recovery of 590,000 barrels of oil (Figure 3-14) and 1,740,000 barrels of water (Figure 3-15).

Figure 3-14. South Reeves County, Delaware Wolfcamp A Bench - Type Well Oil Production



Source: Advanced Resources International, 2020.

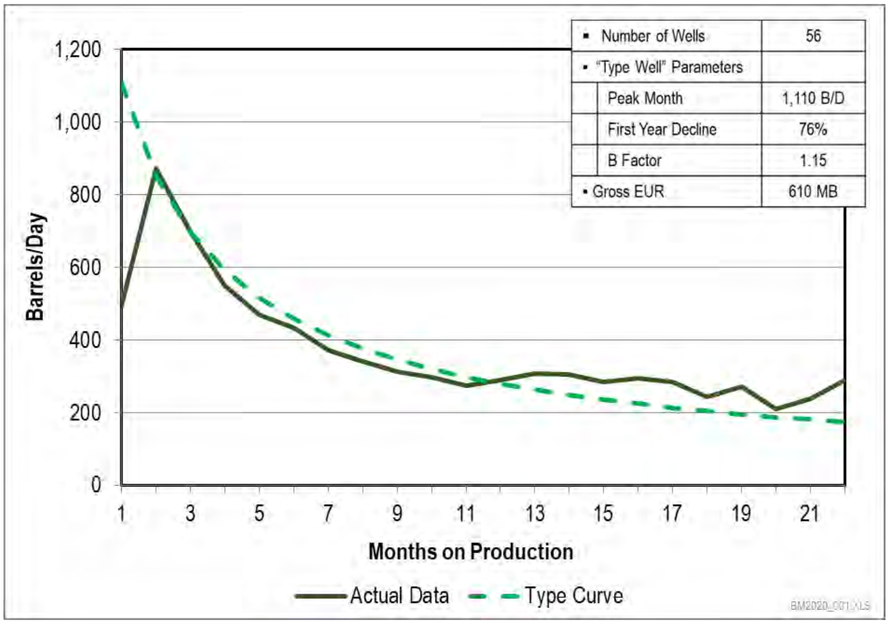
Figure 3-15. South Reeves County, Delaware Wolfcamp A Bench - Type Well Water Production



Source: Advanced Resources International, 2020.

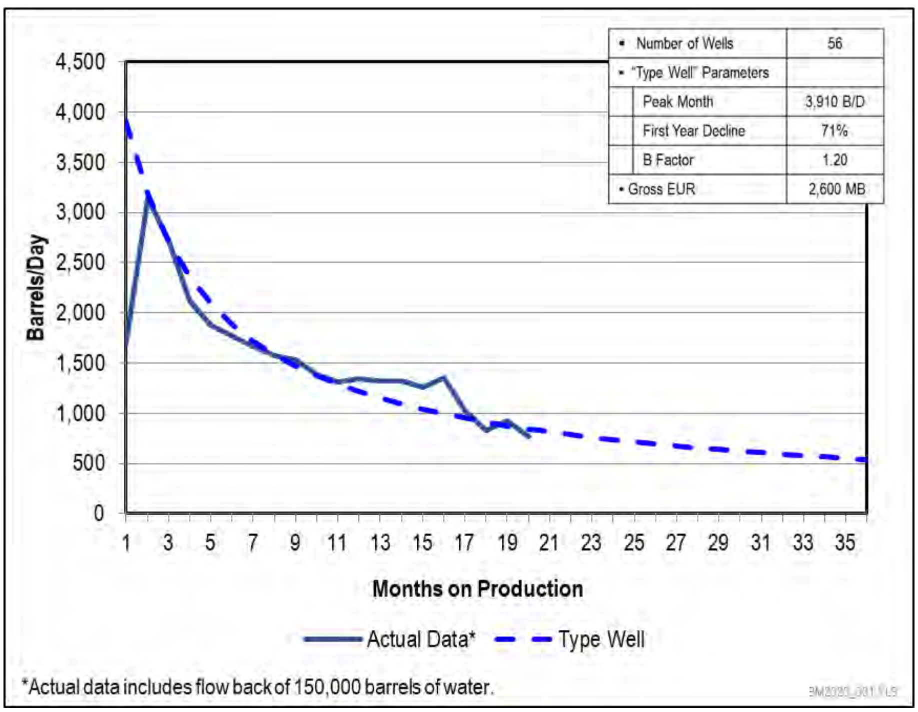
The "type oil well" in South Reeves County for the B Bench of the Wolfcamp Shale has a Hz lateral of 8,100 ft. It has an estimated 30-year recovery of 610,000 barrels of oil and 2,600,000 barrels of water (Figures 3-16 and 3-17).

Figure 3-16. South Reeves County, Delaware Wolfcamp B Bench Type Well Oil Production



Source: Advanced Resources International, 2020.

Figure 3-17. South Reeves County, Delaware Wolfcamp B Bench Type Well Water Production



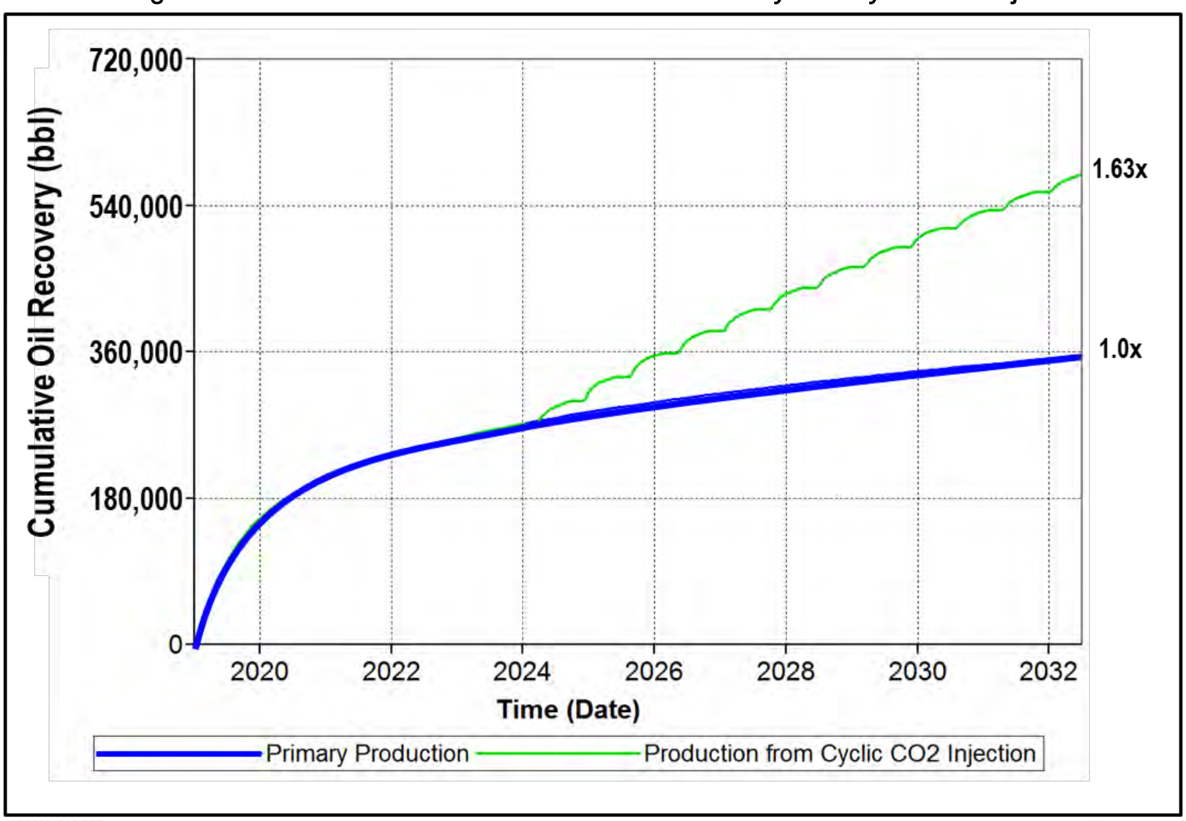
Source: Advanced Resources International, 2020.

3.5.3 Estimating Incremental Recovery from Cyclic Injection of CO_2

To establish estimates for incremental oil production from enhanced shale oil recovery using cyclic injection of CO_2 in the Delaware Wolfcamp, the USEA Study relied on the reservoir modeling of Wolfcamp Shale in the Midland Basin and assumed that the same primary recovery uplift (1.63x) will apply to the Delaware Basin's Wolfcamp Shale, as for the Midland Basin's Wolfcamp Shale (Figure 3-18).

Please refer to Section 3.5 of the Midland Wolfcamp Basin Chapter for additional information on GEM reservoir modeling and the assumptions used to calculate the oil recovery uplift from injection of CO_2 into the Wolfcamp Shale. (Future reservoir modeling of using cyclic injection of CO_2 in the Wolfcamp Shale would provide more rigorous estimates of incremental oil production from enhanced shale oil recovery from the Delaware Basin.)

Figure 3-18. Cumulative Oil Production from Primary and Cyclic CO_2 Injection



Source: Advanced Resources International, 2020.

3.5.4 Water Production from the Delaware Basin's Wolfcamp Shale

Wolfcamp Shale oil production in the Delaware Basin is accompanied by significant production of water, about 3 to 4 barrels of water per barrel of oil. To define the volume of expected water production from the Wolfcamp Shale, we examined this topic for five counties in the Delaware Basin. Table 3-17 shows that there are considerable differences in water production from the Delaware Basin, with producing water-oil ratios ranging from less than 2 in the A Bench of the Wolfcamp Shale in Lea County to over 5 in the A and B Benches of the Wolfcamp Shale in Culberson County. In general, the highest producing water-oil ratios are found in the western portion of the Delaware Basin, including Culberson, TX and Eddy, NM, while lower producing water-oil ratios are observed in the eastern portion of the basin, in Loving, TX and Lea, NM.

Table 3-17. Producing Water-Oil Ratios for Wolfcamp Shale Benches, Five Delaware Basin Counties

	Gross Oil EUR (MB)	Gross Water EUR (MB)*	Producing Water-Oil Ratio (Bbl of Water / Bbl of Oil)
1. Loving County			
▪ A Bench	730	2,090	2.9
▪ B Bench	620	1,680	2.7
2. S. Reeves County			
▪ A Bench	590	1,740	2.9
▪ B Bench	610	2,600	4.3
3. Culberson County			
▪ A Bench	680	3,620	5.3
▪ B Bench	600	3,080	5.1
4. Lea, NM			
▪ A Bench	670	1,190	1.8
▪ B Bench	470	1,100	2.3
5. Eddy, NM			
▪ A Bench	520	1,840	3.5
▪ B Bench	370	1750	4.7

* Estimated water recoveries assume that roughly 150 MB of produced water is from the flowback of injected fluid volumes.
Source: Advanced Resources International, 2020.

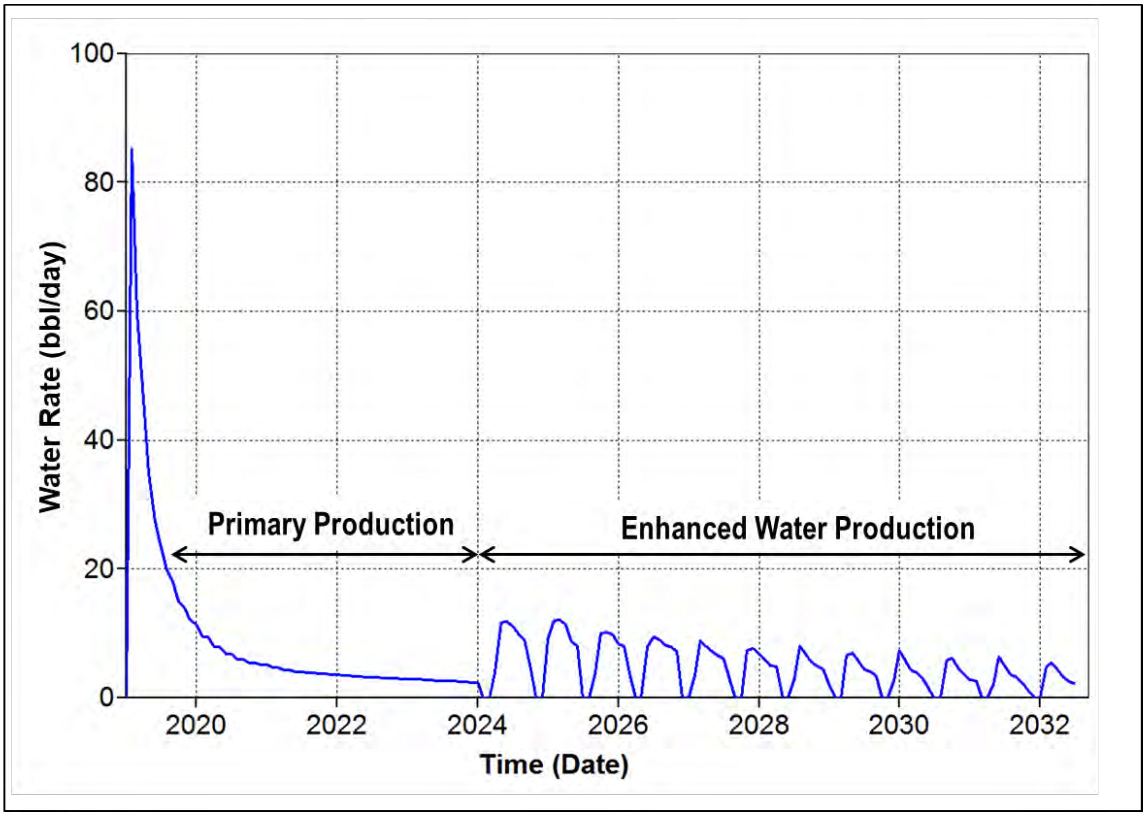
3.5.5 Water Balance and Production

The Wolfcamp Shale "type well" in South Reeves County produced 1,740,000 barrels of water in 30 years, approximately 3 barrels of produced water per barrel of produced oil, making the Wolfcamp Shale a net water source for the Delaware Basin.

- A typical hydraulic stimulation requires approximately 500,000 barrels of water injection with approximately 30% of the injected water, equal to 150,000 barrels (see Figure 3-17), produced back by the stimulated well and the remaining volumes of water retained in the shale formation.
- Adding the 1,740,000 barrels of water produced by the South Reeves County "type well" to the hydraulic stimulation flow-back water of 150,000 barrels provides total water production of 1,890,000 barrels per well, compared to use of 500,000 barrels per water per well.
- Assuming that the produced water and the hydraulic stimulation flow-back water are treated and then reused, the water balance for Wolfcamp Shale development in the Delaware Basin is highly positive.

The use of cyclic CO_2 injection also results in additional volumes of water production, as illustrated for the Wolfcamp Shale in the Midland Basin (Figure 3-19). With rigorous water treatment practices, the excess produced water could become available for agriculture and other users.

Figure 3-19. Primary and Enhanced Water Production from Cyclic CO_2 Injection: Midland Basin Wolfcamp Shale Study Area Well



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3.6. Increasing Shale Oil Recovery and CO_2 Storage with Cyclic CO_2 Enhanced Oil Recovery

3.6.1 Introduction

We have combined three sources of information to estimate the volumes of additional oil recovery and CO_2 storage that could result from the application of cyclic CO_2 enhanced oil recovery to the Wolfcamp Shale in the Delaware Basin.

- Estimates of OOIP for each of the counties in the Delaware Basin, provided in Section 3.4 of this report.
- Estimates of primary (pressure depletion) oil recovery from "type wells" in each Wolfcamp Shale Bench in each county of the Delaware Basin, as discussed in Section 3.5 of this report.
- Estimated "uplift" to primary shale oil recovery from reservoir modeling of cyclic CO_2 enhanced oil recovery for the Wolfcamp Shale in the Midland Basin, including the modeling of the volumes of CO_2 to be injected and stored.

Each Delaware Basin county addressed by this study was also evaluated to determine its geologic attractiveness for the application of cyclic CO_2 enhanced oil recovery.

3.6.2 Increased Volumes of Oil Recovery and CO_2 Storage

East Delaware TX Area. We estimate that the application of cyclic CO_2 enhanced oil recovery to the Wolfcamp Shale in the East TX Area of the Delaware Basin will provide 4,230 million barrels (MMB) of additional technically viable shale oil recovery and provide opportunities to store 1,940 million metric tons (MMmt) of CO_2 (Table 3-18). The incremental oil recovery efficiencies from use of cyclic CO_2 range from 3.2% of OOIP in Wolfcamp Shale Bench A in Ward County to 7.0% of OOIP in Wolfcamp Shale Bench B in Winkler County.

South Delaware TX Area. We estimate that the application of cyclic CO_2 enhanced oil recovery to the Wolfcamp Shale in the South TX Area of the Delaware Basin will provide 7,170 MMB of additional technically viable shale oil recovery and provide opportunities to store 3,300 MMmt of CO_2 (Table 3-18). The incremental oil recovery efficiencies from the use of cyclic CO_2 range from 3.0% of OOIP in Wolfcamp

Shale Benches A and B in South Reeves County to 4.7% of OOIP in Wolfcamp Shale Bench B in Pecos County.

West Delaware TX Area. Despite some characteristics that could make the West TX Area of the Delaware Basin a challenging setting (e.g., higher gas/oil ratios or GORs, higher API gravity/condensate, and higher producing water-oil ratios), ARI views this western area as a prospective target for the application of cyclic CO_2 enhanced oil recovery. We estimate that the application of cyclic CO_2 enhanced oil recovery to the Wolfcamp Shale in the West TX Area of the Delaware Basin will provide 5,260 MMB of additional technically viable shale oil recovery and provide opportunities to store 2,420 MMmt of CO_2 (Table 3-19). The incremental oil recovery efficiencies from the use of cyclic CO_2 range from 3.4% of OOIP in Wolfcamp Shale Bench B in NW Reeves County to 4.1% of OOIP in Wolfcamp Shale Bench A in NW Reeves County.

New Mexico Delaware Area. We estimate that the application of cyclic CO_2 enhanced oil recovery to the Wolfcamp Shale in the New Mexico Area of the Delaware Basin will provide 5,190 MMB of additional technically viable shale oil recovery and provide opportunities to store 2,390 MMmt of CO_2 (Table 3-19). The incremental oil recovery efficiencies from use of cyclic CO_2 range from 5.0% of OOIP in Wolfcamp Shale Bench A in Lea County, NM to 5.2% of OOIP in Wolfcamp Shale Bench B in Lea County, NM.

ARI does not view the Wolfcamp Shale B Bench in Eddy County in NM as a geologically attractive target for the application of cyclic CO_2 enhanced oil recovery. The Wolfcamp Shale Bench B in Eddy county has a high GOR, relatively low oil recovery per well, and a high-water saturation (48%) due to low shale thickness unit in relation to total net pay.

Total Wolfcamp Shale Area, Delaware Basin. Applying cyclic CO_2 enhanced oil recovery to the seventeen geologically favorable resource assessment units of the Wolfcamp Shale in the Delaware Basin could provide 21,850 MMB of additional technically viable shale oil recovery and space for geologically storing 10,050 MMmt of CO_2 storage (Tables 3-18 and 3-19).

Table 3-18. Estimates of Incremental Oil Recovery and CO_2 Storage from Application of Cyclic CO_2 Enhanced Oil Recovery: East TX and South TX Delaware Basin Areas of the Wolfcamp Shale

Delaware Wolfcamp Shale Area		OOIP	Resource Concentration	Primary Recovery Efficiency		CO_2 EOR Recovery Efficiency*	CO_2 EOR Incremental Recovery	CO_2 Storage**
		(MMB)	(MB/mi^2)	(MB/mi^2)	(% OOIP)	(% OOIP)	(MMB)	(MMmt)
1. East Delaware TX Area								
Loving								
▪	Bench A	29,600	54,400	3,890	7.2%	4.5%	1,330	610
▪	Bench B	21,850	40,170	3,310	8.2%	5.2%	1,140	520
Winkler								
▪	Bench A	4,790	35,240	3,890	11.0%	6.9%	330	150
▪	Bench B	4,060	29,830	3,310	11.1%	7.0%	280	130
Ward								
▪	Bench A	21,640	64,400	3,250	5.1%	3.2%	690	320
▪	Bench B	8,140	24,210	2,200	9.1%	5.7%	460	210
						Sub-Total	4,230	1,940
2. South Delaware TX Area								
South Reeves								
▪	Bench A	76,710	50,470	2,360	4.7%	3.0%	2,300	1,060
▪	Bench B	79,670	52,420	2,440	4.7%	3.0%	2,390	1,100
Pecos								
▪	Bench A	30,270	38,600	2,600	6.7%	4.2%	1,270	580
▪	Bench B	25,780	32,880	2,480	7.5%	4.7%	1,210	560
						Sub-Total	7,170	3,300
1 & 2. Sub-total							11,400	5,240

*Based on reservoir modeling of Midland Wolfcamp Shale Study Area.

**Assumes 0.46 mt of CO_2 per barrel of oil recovered.

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Table 3-19. Estimates of Incremental Oil Recovery and CO_2 Storage from Application of Cyclic CO_2 Enhanced Oil Recovery: West TX and New Mexico Delaware Areas of the Wolfcamp Shale

Delaware Wolfcamp Shale Area		OOIP	Resource Concentration	Primary Recovery Efficiency		CO_2 EOR Recovery Efficiency*	CO_2 EOR Incremental Recovery	CO_2 Storage**
		(MMB)	(MB/mi^2)	(MB/mi^2)	(% OOIP)	(% OOIP)	(MMB)	(MMmt)
3. West Delaware TX Area								
NW Reeves								
▪	Bench A	28,730	48,520	3,150	6.5%	4.1%	1,180	540
▪	Bench B	32,530	54,950	2,960	5.4%	3.4%	1,110	510
Culberson								
▪	Bench A	43,990	47,820	2,720	5.7%	3.6%	1,580	730
▪	Bench B	35,700	38,810	2,400	6.2%	3.9%	1,390	640
						Sub-Total	5,260	2,420
4 New Mexico Delaware Area								
Lea								
▪	Bench A	36,850	44,720	3,570	8.0%	5.0%	1,840	850
▪	Bench B	36,060	43,760	3,620	8.3%	5.2%	1,880	860
Eddy								
▪	Bench A	28,270	33,980	2,770	8.2%	5.2%	1,470	680
▪	Bench B***	31,080	37,350	1,970	5.3%	-	-	-
						Sub-Total	5,190	2,390
3 & 4. Sub-total							10,450	4,810
5. Total							21,850	10,050

*Based on reservoir modeling of Midland Wolfcamp Shale Study Area.

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**Assumes 0.46 mt of CO_2 per barrel of oil recovered.

***The B Bench in Eddy County was excluded due to unfavorable geologic characteristics (low shale thickness).

3.7 References

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Chapter 4. Permian (Midland) Basin

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4. Permian (Midland) Basin

4.1 Introduction

4.1.1 Purpose of Study

Located in the eastern portion of the Permian Basin of West Texas, the Wolfcamp Shale (Midland Basin) is one of the major shale oil formations of the U.S. It holds a vast volume of shale oil resource, estimated by this study at 509 billion barrels of original oil in-place (OOIP). However, with current primary (pressure depletion) oil production practices, only a modest portion of this large in-place resource is recoverable. (Our resource characterization and reservoir modeling of a geologically representative area in the center of the Wolfcamp Shale play, the Study Area, established an estimated oil recovery efficiency of 5.3% of OOIP.) As such, more advanced oil recovery technologies will be needed to boost the current level of oil recovery from the Wolfcamp Shale.

The purpose of our study is to examine the potential and impact of one such advanced oil recovery technology—the use of cyclic injection of CO_2 for enhanced oil recovery from the Wolfcamp Shale.

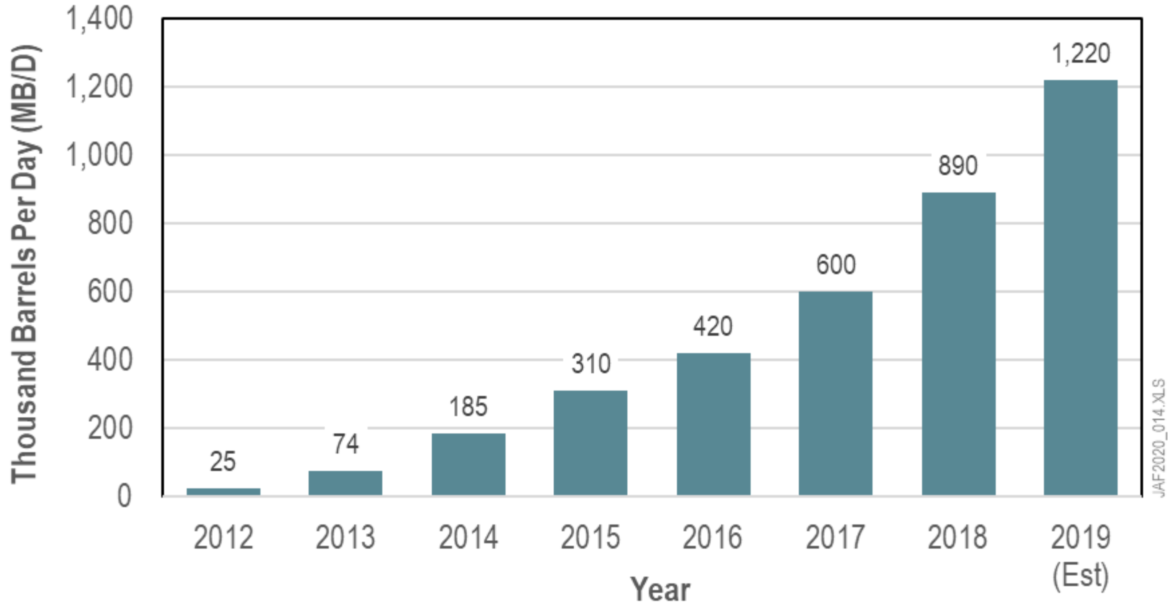
An important by-product of using cyclic injection of CO_2 for oil recovery in the Permian (Midland Basin) Wolfcamp Shale is that a portion of the injected CO_2 remains trapped in the shale formation, providing an additional geologic site for storing CO_2.

4.1.2 Midland Basin Shale Well Oil Production and Completions

Oil production from the Midland Basin's Wolfcamp Shale has grown rapidly from 25,000 barrels per day in 2012 to over 300,000 barrels per day three years later and further to over 1.2 million barrels per day (MM/D) in 2019 (Figure 4-1).

In addition to the Wolfcamp Shale, the Midland Basin contains a series of shale and tight oil formations, such as the Spraberry tight sand and the Cline Shale. However, the Wolfcamp Shale is the dominant formation being targeted in the Midland Basin, accounting for nearly 70% of the basin's oil production last year (2019) and about 80% of all horizontal (Hz) wells drilled and completed to date in this basin.

Figure 4-1. Midland Basin Wolfcamp Shale Oil Production*



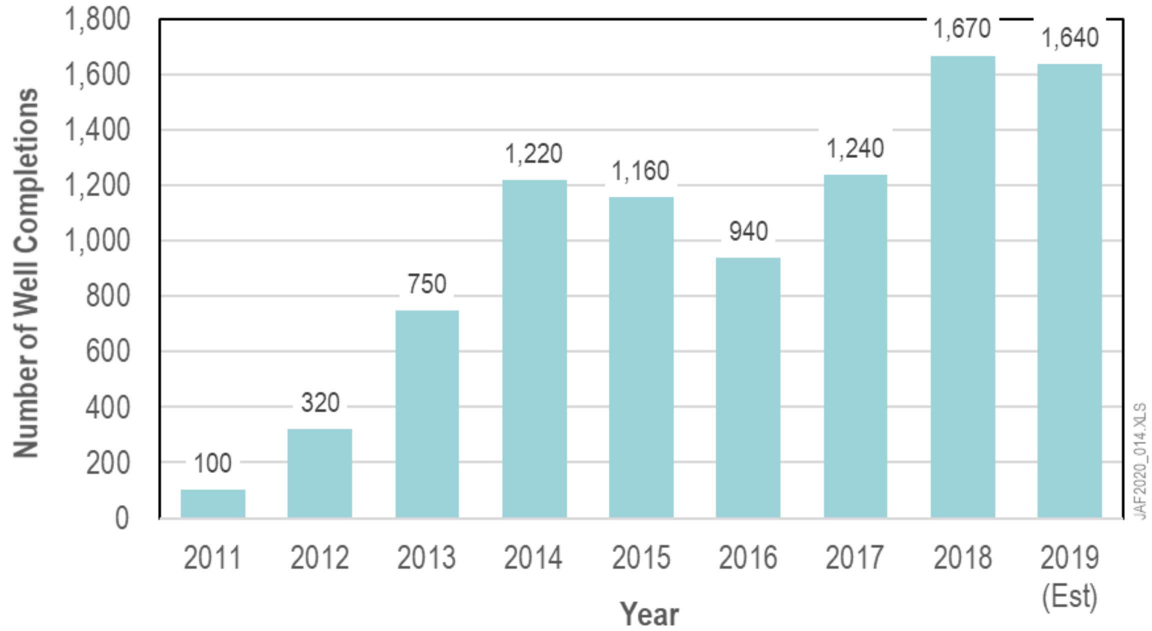
*Includes Cline Shale oil production.

Source: Advanced Resources International's Tight Oil Database, 2020; Drilling Info, 2020.

The initial pursuit of the Wolfcamp Shale in the Midland Basin was with vertical wells drilled into the Wolfcamp Shale and the overlying Spraberry tight sand, called Wolfberry wells. However, the experience from other shale oil basins, as well as the performance of pilot Hz wells, showed that long Hz wells targeting the most favorable of the Wolfcamp Shale intervals was the preferred option.

Based on these findings, operators rapidly increased their Wolfcamp Shale Hz well completions from about 100 in 2011 to a yearly average of about 1,200 in 2014 and 2015. After a decline of well drilling and completions in 2016, in response to the decline in oil prices, Wolfcamp Shale Hz well completions rebounded to over 1,240 in 2017 and to over 1,600 in 2018 and 2019 (Figure 4-2).

Figure 4-2. Midland Basin Wolfcamp Shale Hz Well Completions, 2011-2019*



*Includes Cline Shale Hz well completions.

Source: Advanced Resources International's Tight Oil Database, 2020; Drilling Info, 2020.

4.1.3 Outlook for Enhanced Shale Oil Recovery

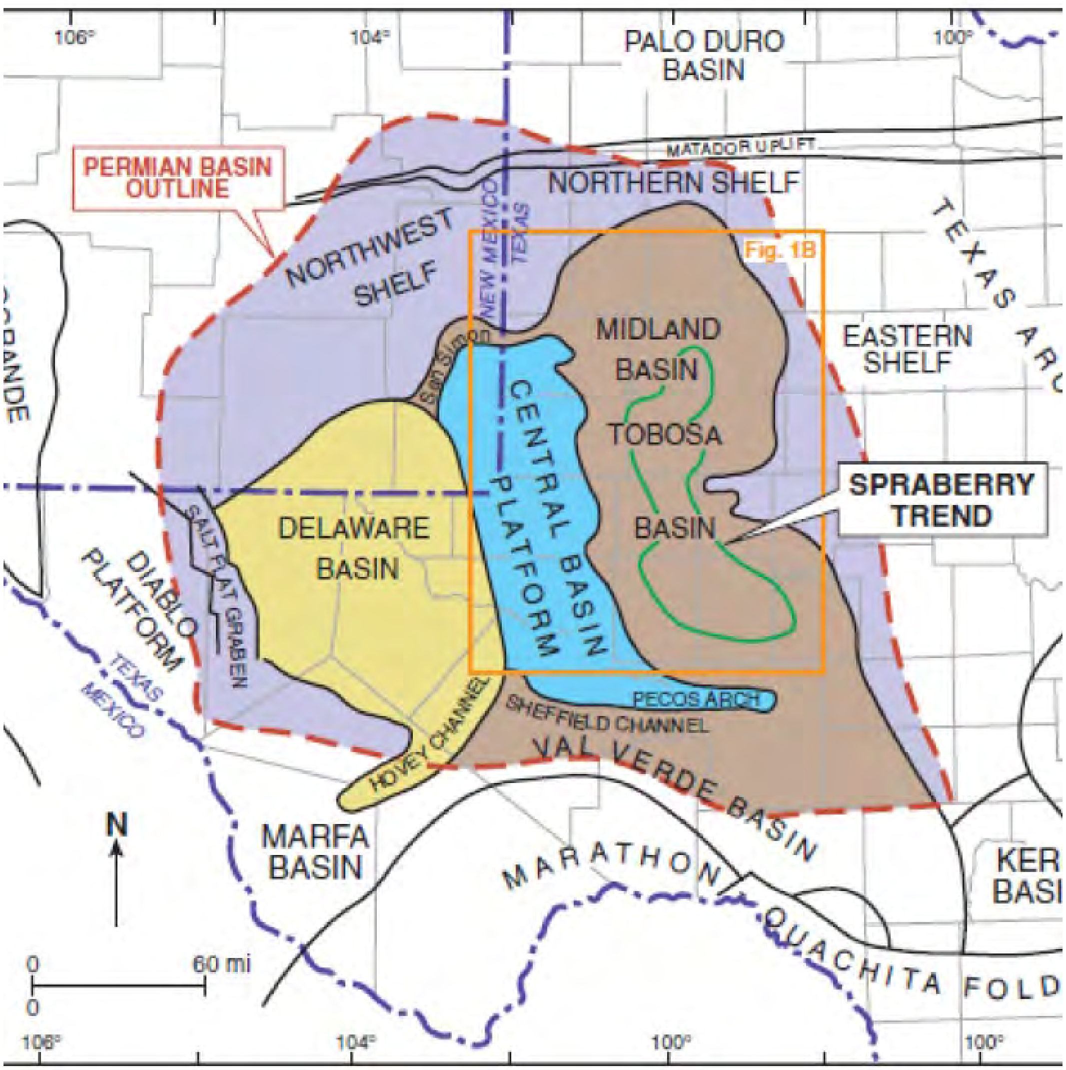
Given current relatively low primary (pressure depletion) oil recovery efficiencies, estimated at 5% to 6% of OOIP, the Wolfcamp Shale is a prime candidate for using cyclic CO_2 injection for boosting oil recovery. Our assessment, as discussed in Section 4.6 of this report, is that the Wolfcamp Shale has potential for 14,250 million barrels (MMB) of additional technically viable oil recovery and space for geologically storing 6,560 million metric tons (MMmt) of CO_2 from application of cyclic CO_2 enhanced oil recovery.

4.2 Geologic Setting of the Midland Basin

4.2.1 Midland Basin

The Permian Basin, located in West Texas and southeastern New Mexico, consists of the Midland Basin on the east, the Central Basin Platform in the center, and the Delaware Basin on the west (Figure 4-3). The Midland Basin encompasses a 13,000 square mile area in 20 counties of West Texas. The great majority of the tight oil development in the Midland Basin has occurred in the center of the basin, primarily in Martin, Midland, Upton, Howard, Glasscock, and Reagan counties.

Figure 4-3. Outline of the Permian Basin

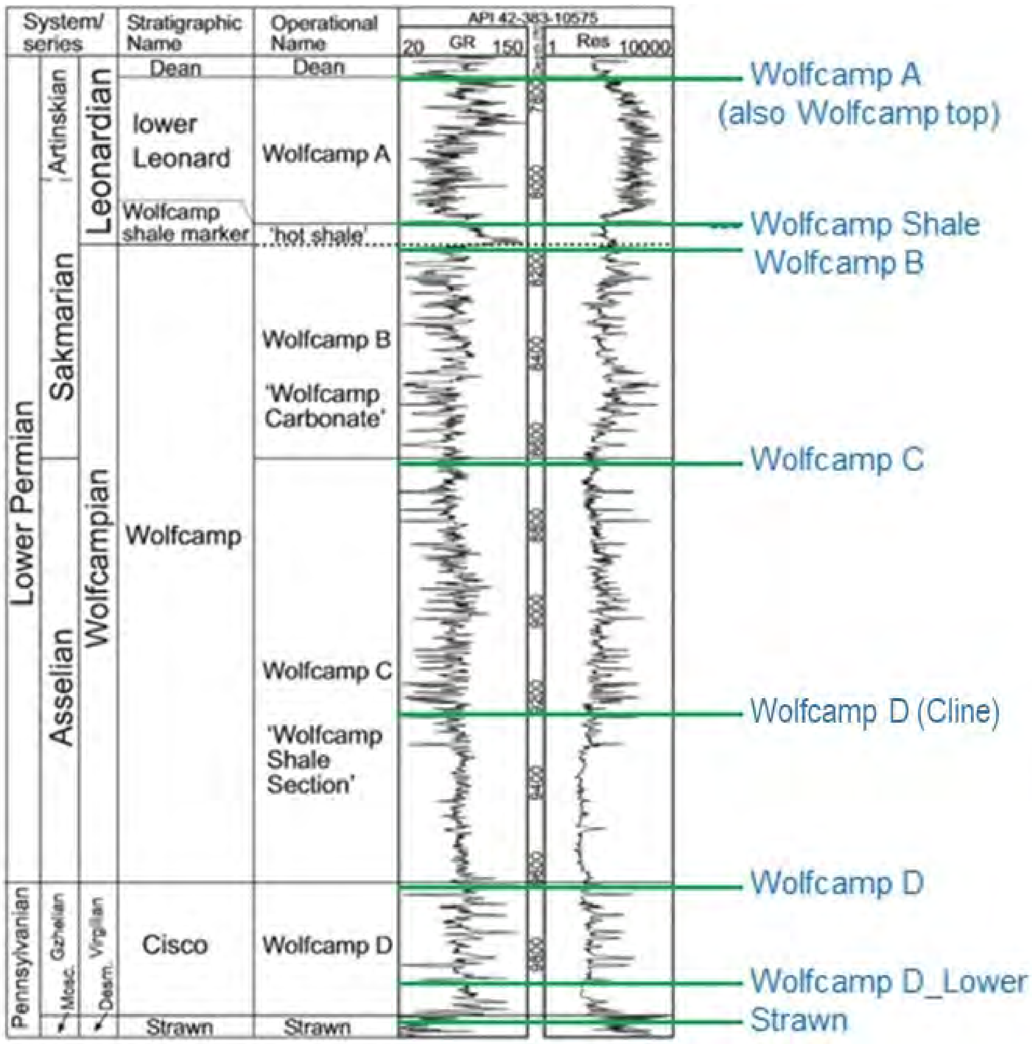


Source: Montgomery et al., 2000; Lorenz et al., 2002

4.2.2 Midland Basin Stratigraphic Column

The Lower Permian-age Wolfcamp Shale oil resources exist in multiple benches, with the Pennsylvanian-age (Cisco) Cline Shale (sometimes also called Bench D of the Wolfcamp Shale), below the Wolfcamp Shale Bench C (Figure 4-4).

Figure 4-4. Midland Basin Stratigraphic Column



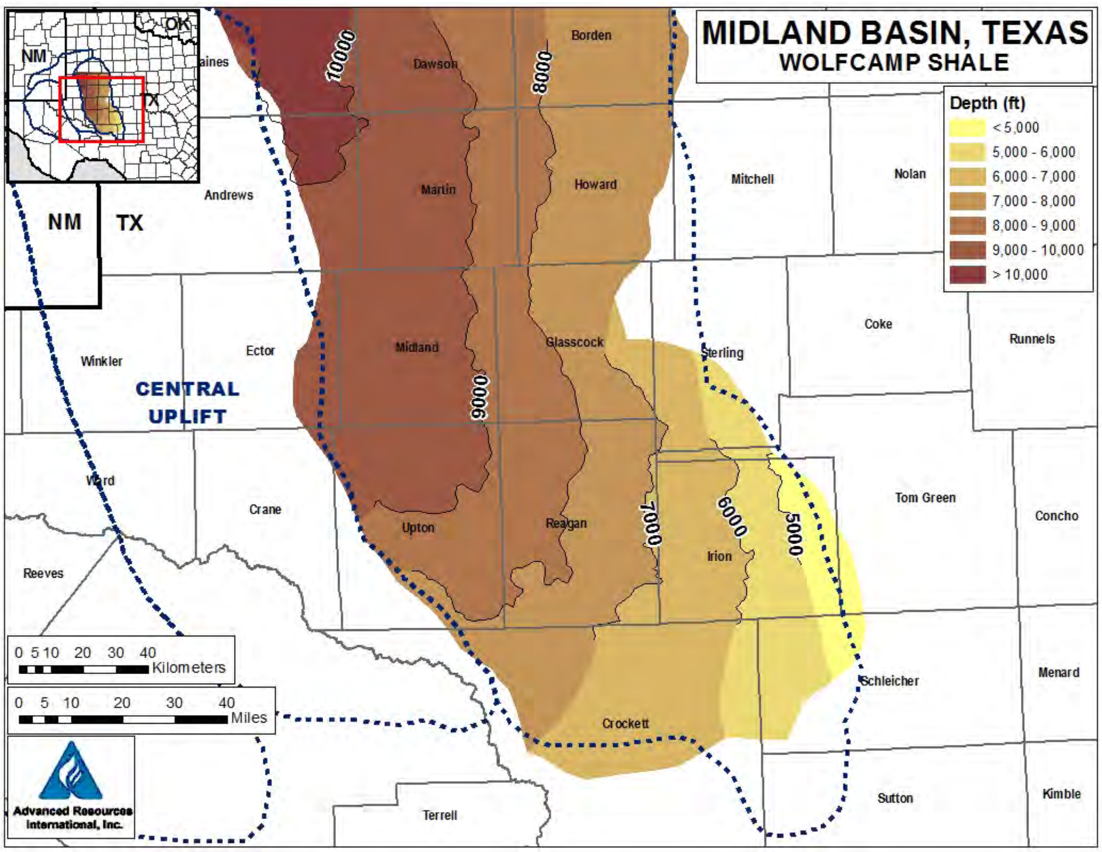
Source: Modified from Moreland, R., 2017.

4.2.3 Wolfcamp Shale Assessment Area and Depth

The Wolfcamp Shale assessment in the Midland Basin extends from Martin and Howard counties in the north to Crockett County in the south (Figure 4-5). The area also includes the eastern portion of Andrews and Ector counties, as well as Midland, Upton, Glasscock, Reagan and Irion counties in the central portion of the Midland Basin.

The Wolfcamp Shale formation reaches a maximum depth of over 10,000 ft in the basin center in Andrews and Martin counties, gradually becoming shallower (<6,000 ft) in eastern Crockett and Irion counties.

Figure 4-5. Midland Basin Wolfcamp Shale Depth (Top of Wolfcamp B Bench)



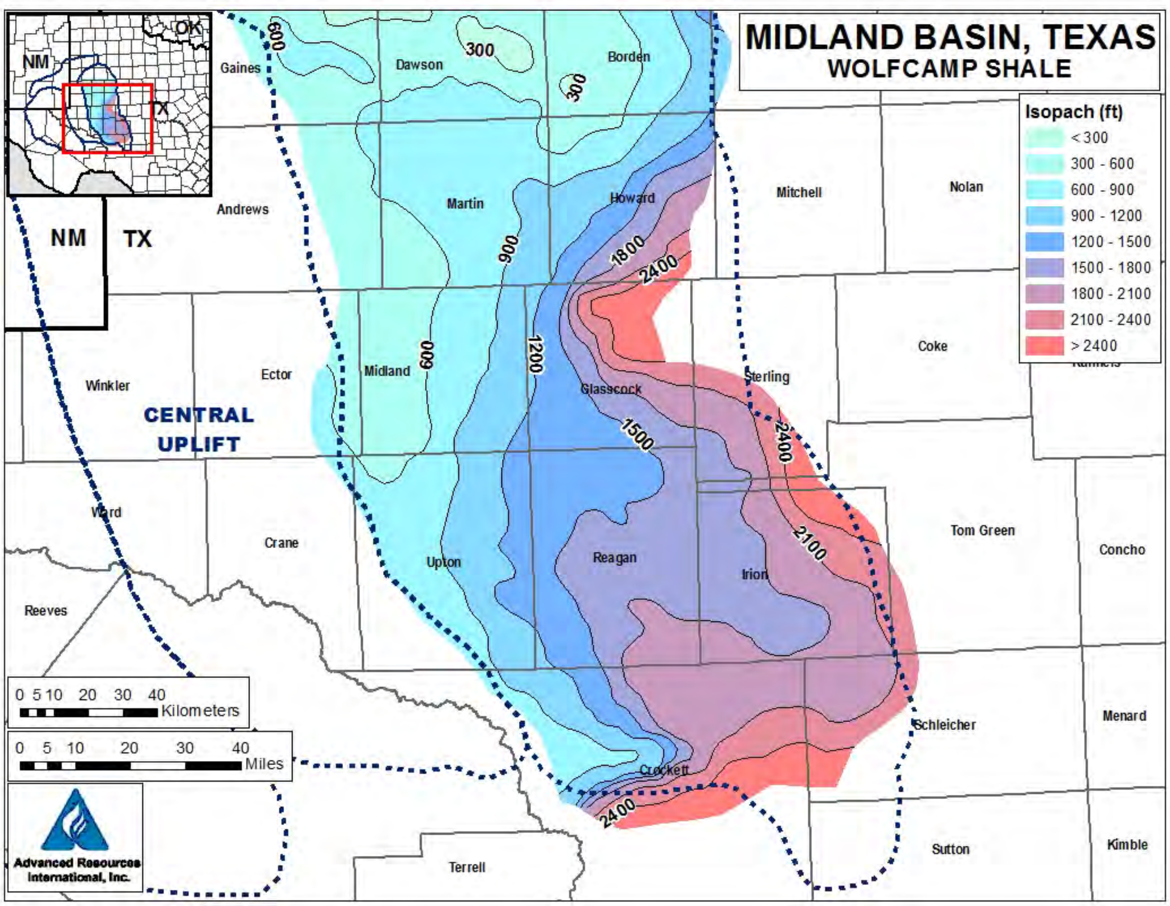
Source: Advanced Resources International, 2020.

4.2.4 Wolfcamp Shale Isopach

The gross thickness of the Midland Basin's Wolfcamp Shale interval (including Benches A, B, C and D) ranges widely from less than 600 ft in the northwest portion of the resource assessment area to over 2,000 ft in the southeast (Figure 4-6).

In the early phases of the Midland Basin's Wolfcamp Shale development, operators actively developed the thicker but shallower areas on the South. Since then, the concentration of well drilling has moved to the north and west.

Figure 4-6. Wolfcamp Shale Gross Isopach



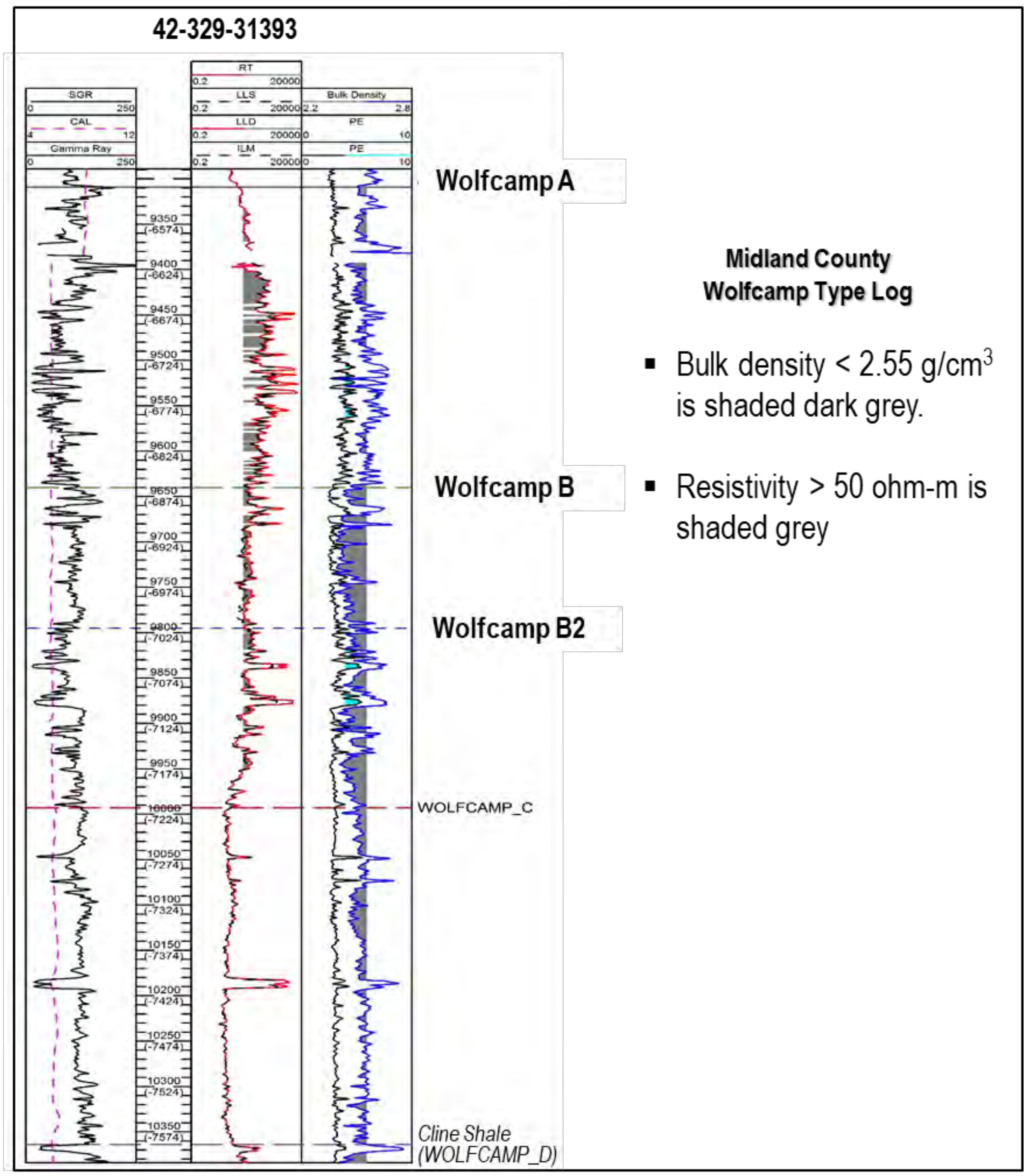
Source: Advanced Resources International, 2020.

4.3. Establishing the Essential Reservoir Properties

4.3.1 Wolfcamp Shale Type Log

This resource assessment study addresses the Lower Permian Wolfcamp Shale in the Midland Basin and two of its dominant intervals, the Wolfcamp Bench A and Bench B (Figure 4-7).

Figure 4-7. Midland Basin Wolfcamp Shale Type Log



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Source: Advanced Resources International, 2020.

4.3.2 Wolfcamp Shale Lithology and Thickness

Based on log analysis by Advanced Resources, the lithology and thickness of the two main benches comprising the Wolfcamp interval vary greatly across the Midland Basin, as illustrated on Table 4-1 for Midland, Reagan and Crockett counties.

Table 4-1. Lithology of Wolfcamp Shale Benches, Three Midland Basin Counties

	Shale (Thickness, ft)	Limestone (Thickness, ft)	Mixed Lithology (Thickness, ft)	Total (Thickness, ft)
1. Midland County				
▪ A Bench	166	57	84	307
▪ B Bench	288	29	21	338
2. Reagan County				
▪ A Bench	95	-	206	301
▪ B Bench	372	-	477	849
3. Crockett County				
▪ A Bench	153	73	80	306
▪ B Bench	204	60	379	643

The thickness of the shale in each of the Wolfcamp benches was estimated using a density cut-off value of 2.55 grams per cubic centimeter (g/cm^3), with a density cut-off value of 2.50 g/cm^3 used in Reagan County.

4.3.3 Wolfcamp Shale Porosity

Detailed information on the porosity of the Midland Basin's Wolfcamp Shale is scarce in the technical literature. Particularly challenging is establishing the porosity values in the organic portions of the Wolfcamp Shale interval compared to the intergranular porosity in the limestone and mixed lithology portions of the Wolfcamp Shale interval.

To address this limitation on publicly available information, Advanced Resources International (ARI) undertook an independent log analysis study to establish discrete porosity values for each of the Wolfcamp Shale lithologies in each of the eight main counties included in the study area. The lithology related porosity values were combined to provide a net pay-weighted average porosity value for Bench A and Bench B of the Wolfcamp Shale, as illustrated below for Midland County (Table 4-2).

Table 4-2. Reservoir Porosity for Wolfcamp Shale Benches, Midland County

Wolfcamp Bench	Shale		Limestone		Mixed Lithology		Weighted Average
	Porosity	Net Pay (ft)	Porosity	Net Pay (ft)	Porosity	Net Pay (ft)	Porosity
A	5.4%	166	6.1%	57	4.3%	84	5.2%
B	8.9%	288	6.4%	29	5.7%	21	8.5%

4.3.4 Wolfcamp Shale Oil and Water Saturation

The technical literature has only recently begun to examine and discuss the oil and water saturation values for the Wolfcamp Shale. The literature reports that the organic porosity in the shale is oil-wet and much of the inorganic (grain bounded) porosity is water-wet. As such, the organic (shale) porosity contains immobile water, estimated at 20% to 30%, while the inorganic porosity contains mobile water, estimated at 45% to 55%. Typical producing water-oil ratios range from one barrel of water per barrel of oil in the center of the basin to two barrels of water per barrel of oil in the eastern and southern basin margins (Holmes, et al., 2017; Walls and Morcote, 2015; and Walls, et al., 2017).

To establish values for oil and water saturation for the Wolfcamp Shale, ARI performed detailed log analysis for a representative well in each county of the Midland Basin. The log analysis was used to identify the three main lithologies in the Wolfcamp interval – shale, limestone and mixed. Lithology-specific oil and water saturation values were assigned to establish average oil and water saturation values for Wolfcamp Shale Bench A and Bench B in each county of the Midland Basin, as illustrated for the Midland County on Table 4-3.

Table 4-3. Oil Saturation for the Wolfcamp Shale Benches, Midland County

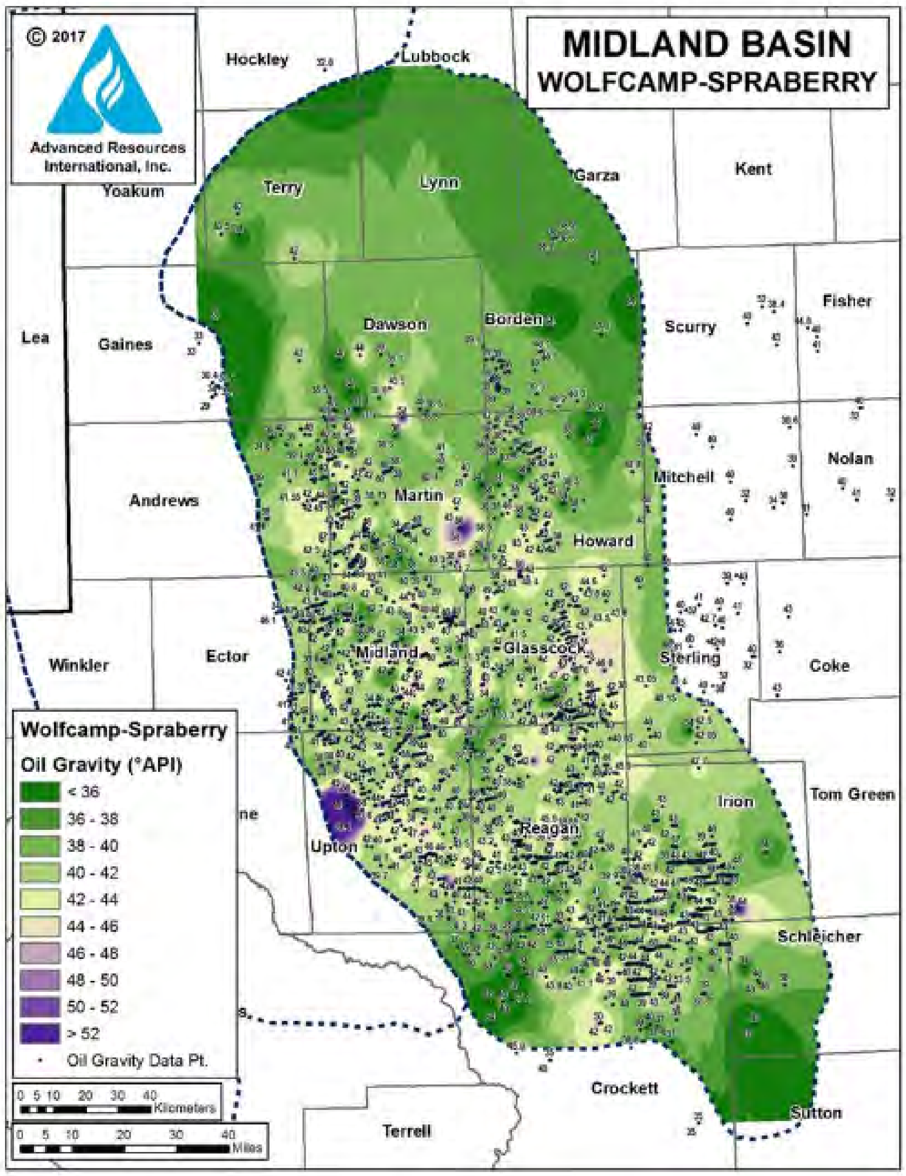
Wolfcamp Bench	Shale			Limestone			Mixed Lithology			Weighted Average
	Porosity	Net Pay (ft)	Oil Sat.	Porosity	Net Pay (ft)	Oil Sat	Porosity	Net Pay (ft)	Oil Sat	Oil Saturation
A	5.4%	166	0.75	6.1%	57	0.50	4.3%	84	0.50	0.64
B	8.9%	288	0.75	6.1%	29	0.50	5.7%	21	0.50	0.72

To provide additional information on the topics of oil and water saturation, ARI conducted a reservoir simulation-based history match of oil, gas and water saturations for a Bench B "type" well in Reagan County. This work established that a combination of a water saturation of 25% in the shale interval and a water saturation of 55% in the limestone and mixed lithology intervals provided a reasonable match with actual Wolfcamp Shale Bench B water (and oil) production in Reagan County.

4.3.5 Wolfcamp Shale Oil Gravity

The oil gravity of the Wolfcamp Shale ranges from less than 36^o API in the thermally less mature areas to the south and east of the resource assessment area to over 42^o API, in the higher maturity areas along the deeper, western edge of the Midland Basin. The average API gravity for the Wolfcamp Shales is about 40^o API (Figure 4-8).

Figure 4-8. Wolfcamp Shale API Gravity



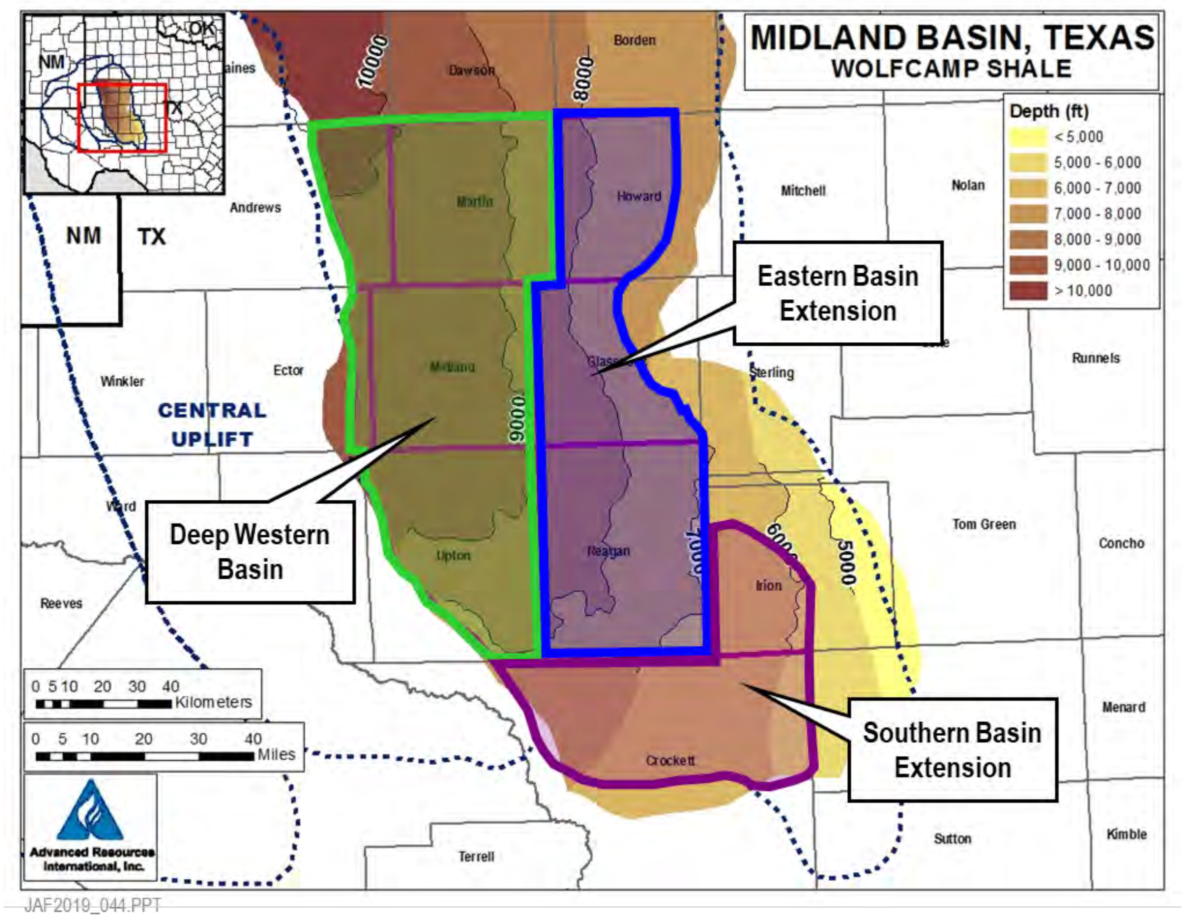
Source: Advanced Resources International, 2020.

4.4. Wolfcamp Shale Resource Assessment

4.4.1 Assessment Methodology

To provide some granularity to the estimates of OOIP, the resource assessment portion of the study divided the Wolfcamp Shale into three geologically distinct partitions – Deep Western Basin Area, Eastern Basin Extension Area, and Southern Basin Extension Area (Figure 4-9). Each of the three geologic partitions was further divided into the various counties comprising the larger partition area. For each county within a partition, the study assembled representative volumetric and other reservoir properties essential for estimating OOIP.

Figure 4-9. Three Geologic Partitions, Wolfcamp Shale Area

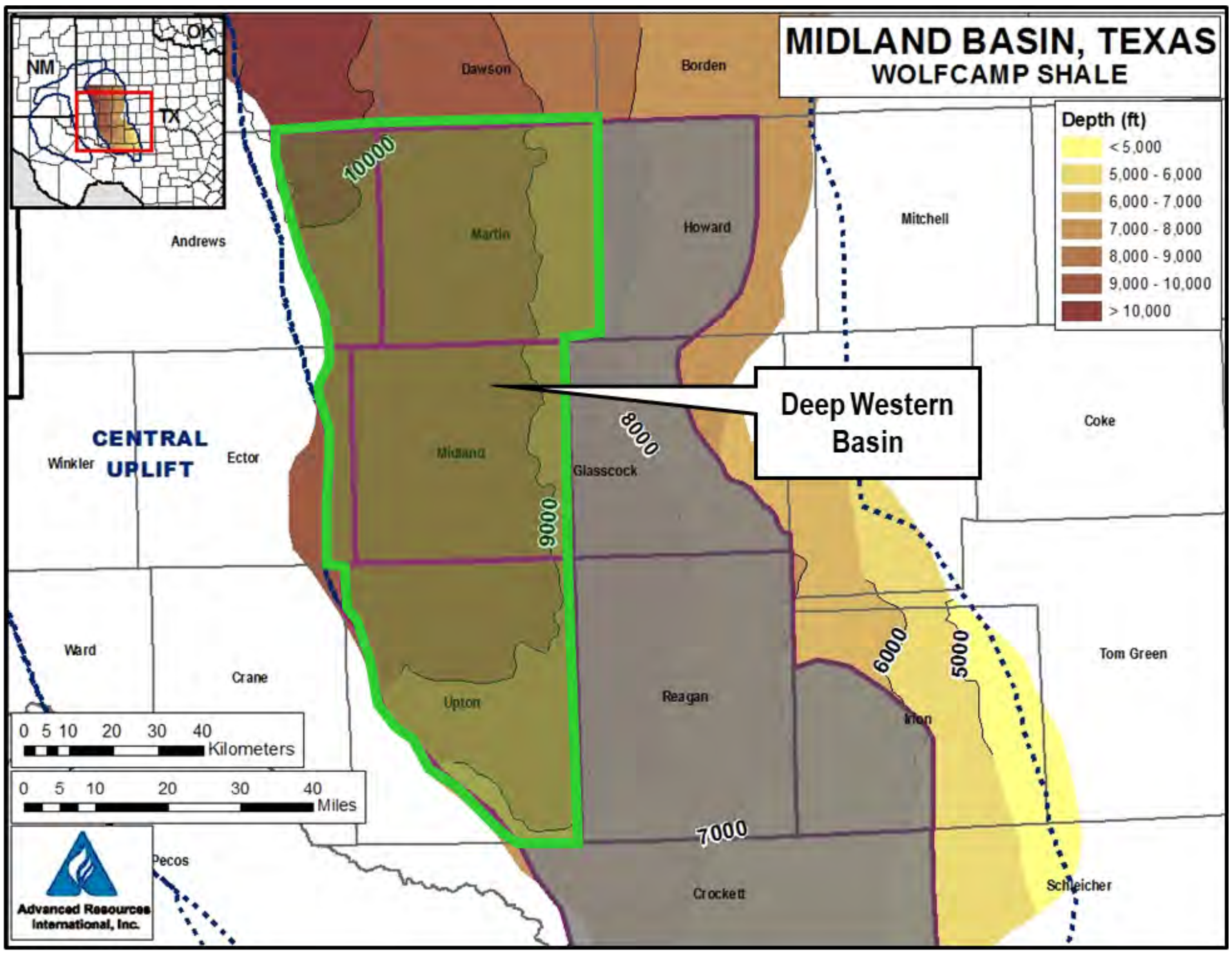


Source: Advanced Resources International, 2020.

4.4.2 Deep Western Basin Shale Area

The Deep Western Basin Area of the Wolfcamp Shale extends across 3,340 square miles (2,670 square miles, risked) in Andrews, Ector, Martin, Midland and Upton counties (Figure 4-10). Overall, about 4,000 Hz Wolfcamp Shale oil wells have been drilled and completed in the Deep Western Basin Area of the Wolfcamp Shale, as of the end of 2019. The depth of the Wolfcamp Shale in the Deep Western Basin Area ranges from about 8,500 ft on its eastern border to below 10,000 ft on the northwest in Andrews County.

Figure 4-10. Deep Western Basin Area of the Wolfcamp Shale



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Source: Advanced Resources International, 2020.

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Table 4-4 provides the key reservoir properties for the Wolfcamp Shale A and B Benches in the three counties of the Deep Western Basin Wolfcamp Shale Area.

Table 4-4. Reservoir Properties for Estimating OOIP, Deep Western Basin Wolfcamp Shale

Reservoir Property	Andrews/ Martin Cos.	Ector/ Midland Cos.	Upton Co.
Total Area	1,360 mi^2	1,030 mi^2	950 mi^2
Risked Area	1,090 mi^2	820 mi^2	760 mi^2
Average Depth	9,500 ft	9,500 ft	9,000 ft
Net Pay			
▪ A Bench	200 ft	310 ft	300 ft
▪ B Bench	260 ft	340 ft	410 ft
Average Porosity			
▪ A Bench	5.0%	5.2%	6.2%
▪ B Bench	5.8%	8.5%	4.8%
Oil Saturation			
▪ A Bench	59%	64%	55%
▪ B Bench	71%	72%	60%
Formation Volume Factor (RB/STB)			
▪ A Bench	1.42	1.42	1.42
▪ B Bench	1.47	1.47	1.47
Solution GOR (Mcf/bbl)			
▪ A Bench	0.7	0.7	0.7
▪ B Bench	0.8	0.8	0.8

Source: Advanced Resources International, 2020.

Using the volumetric reservoir properties on Table 4-4, the OOIP for the Wolfcamp Shale A and B Benches in Andrews/Martin counties is 61.8 billion barrels (Table 4-5); in Ector/Midland counties is 87.6 billion barrels (Table 4-6); and in Upton County is 57.5 billion barrels (Table 4-7).

Table 4-5. OOIP of Wolfcamp Shale A and B Benches, Andrews/Martin Counties

County/Interval	Risked Area (mi^2)	Resource Concentration (MB/mi^2)	Oil/Condensate OOIP (Million Barrels)
▪ Andrews/Martin – A Bench	1,090	20,630	22,440
▪ Andrews/Martin – B Bench	1,090	36,160	39,350
Total			61,790

Source: Advanced Resources International, 2020.

Table 4-6. OOIP of Wolfcamp Shale A and B Benches, Ector/Midland Counties

County/Interval	Risked Area (mi^2)	Resource Concentration (MB/mi^2)	Oil/Condensate OOIP (Million Barrels)
▪ Ector/Midland – A Bench	820	36,070	29,720
▪ Ector/Midland – B Bench	820	70,280	57,910
Total			87,630

Source: Advanced Resources International, 2020.

Table 4-7. OOIP of Wolfcamp Shale A and B Benches, Upton County

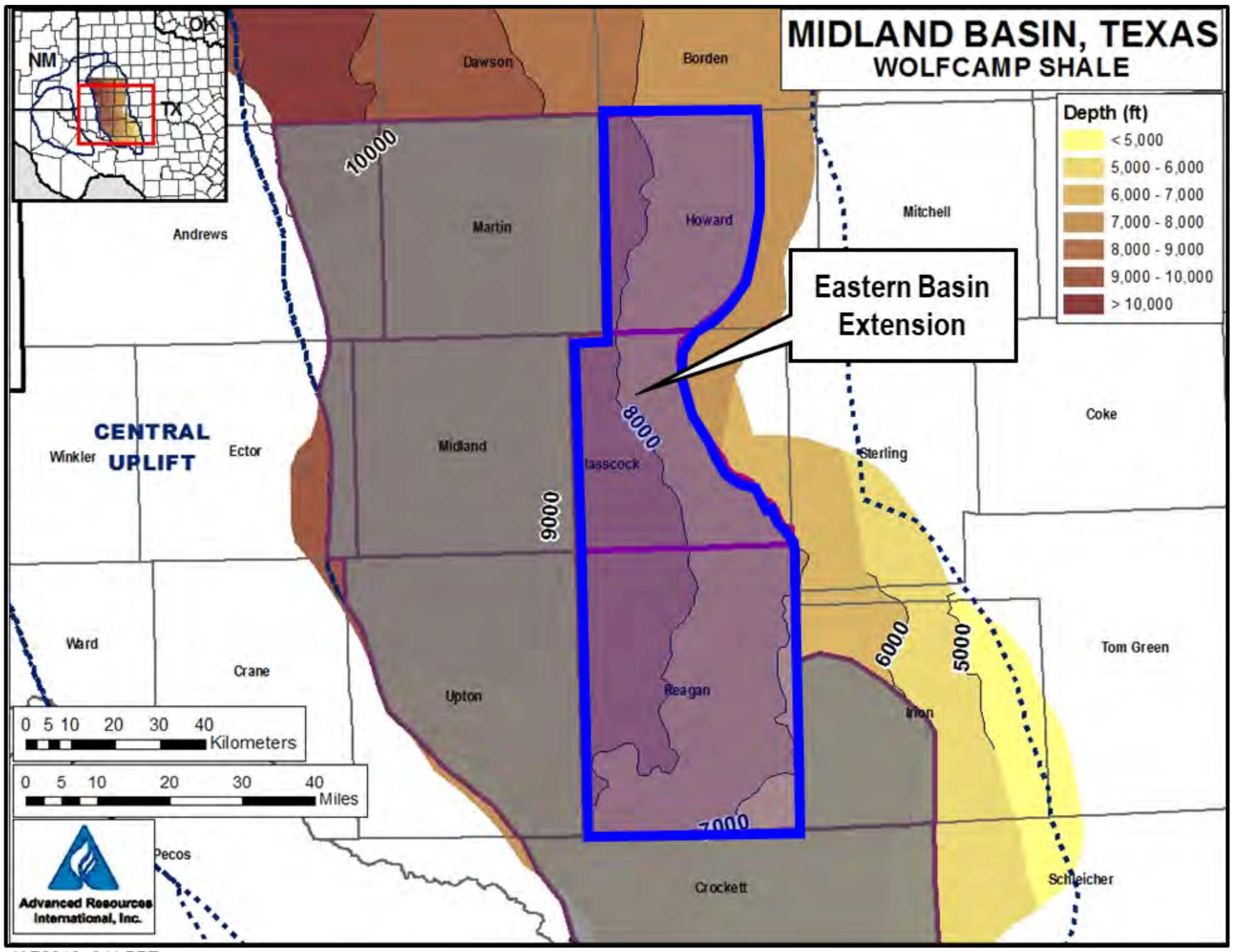
County/Interval	Risked Area (mi^2)	Resource Concentration (MB/mi^2)	Oil/Condensate OOIP (Million Barrels)
▪ Upton – A Bench	760	35,770	27,190
▪ Upton – B Bench	760	39,880	30,310
Total			57,500

Source: Advanced Resources International, 2020.

4.4.3 Eastern Basin Extension Shale Area

The Eastern Basin Extension Area of the Wolfcamp Shale covers 2,415 square miles (1,930 square miles, risked) in Howard, Glasscock and Reagan counties (Figure 4-11). Overall, about 3,000 Hz wells have been placed in production in the Eastern Basin Extension Area of the Wolfcamp Shale, as of the end of 2019. The depth of the Wolfcamp Shale in the Eastern Basin Extension Area ranges from 7,000 ft on the east to 8,500 ft on the west (Figure 4-10).

Figure 4-11. Outline and Depth Map of Eastern Basin Extension Wolfcamp Shale Area



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Source: Advanced Resources International, 2020.

Advanced Resources International, Inc.

Table 4-8 provides the key reservoir properties for the Wolfcamp Shale A and B Benches in the three counties of the Eastern Basin Extension Wolfcamp Shale Area.

Table 4-8. Reservoir Properties for Estimating OOIP, Eastern Basin Extension Wolfcamp Shale

Reservoir Property	Howard Co.	Glasscock Co.	Reagan Co.
Total Area	615 mi^2	620 mi^2	1180 mi^2
Risked Area	490 mi^2	500 mi^2	940 mi^2
Average Depth (top)	7,500 ft	7,500 ft	7,500 ft
Net Pay (Shale Unit)			
▪ A Bench	430 ft	320 ft	300 ft
▪ B Bench	510 ft	690 ft	850 ft
Porosity (Shale Unit)			
▪ A Bench	4.7%	4.6%	5.6%
▪ B Bench	5.0%	4.5%	5.6%
Oil Saturation			
▪ A Bench	59%	51%	54%
▪ B Bench	54%	53%	59%
Formation Volume Factor (RB/STB)			
▪ A Bench	1.42	1.42	1.42
▪ B Bench	1.47	1.47	1.47
Solution GOR (Mcf/bbl)			
▪ A Bench	0.7	0.7	0.7
▪ B Bench	0.8	0.8	0.8

Source: Advanced Resources International, 2020.

Using the volumetric reservoir properties in Table 4-8, the OOIP for the Wolfcamp A and B Benches in Howard County is 43.4 billion barrels (Table 4-9); in Glasscock County its 40.6 billion barrels (Table 4-10); and in Reagan County is 119.5 billion barrels (Table 4-11).

Table 4-9. OOIP of Wolfcamp Shale A and B Benches, Howard County

County/Interval	Risked Area (mi²)	Resource Concentration (MB/mi²)	Oil/Condensate OOIP (Million Barrels)
▪ Howard – A Bench	490	41,690	20,510
▪ Howard – B Bench	490	46,510	22,890
Total			43,400

Source: Advanced Resources International, 2020.

Table 4-10. OOIP of Wolfcamp Shale A and B Benches, Glasscock County

County/Interval	Risked Area (mi²)	Resource Concentration (MB/mi²)	Oil/Condensate OOIP (Million Barrels)
▪ Glasscock – A Bench	500	26,250	13,020
▪ Glasscock – B Bench	500	55,580	27,570
Total			40,590

Source: Advanced Resources International, 2020.

Table 4-11. OOIP of Wolfcamp Shale A and B Benches, Reagan County

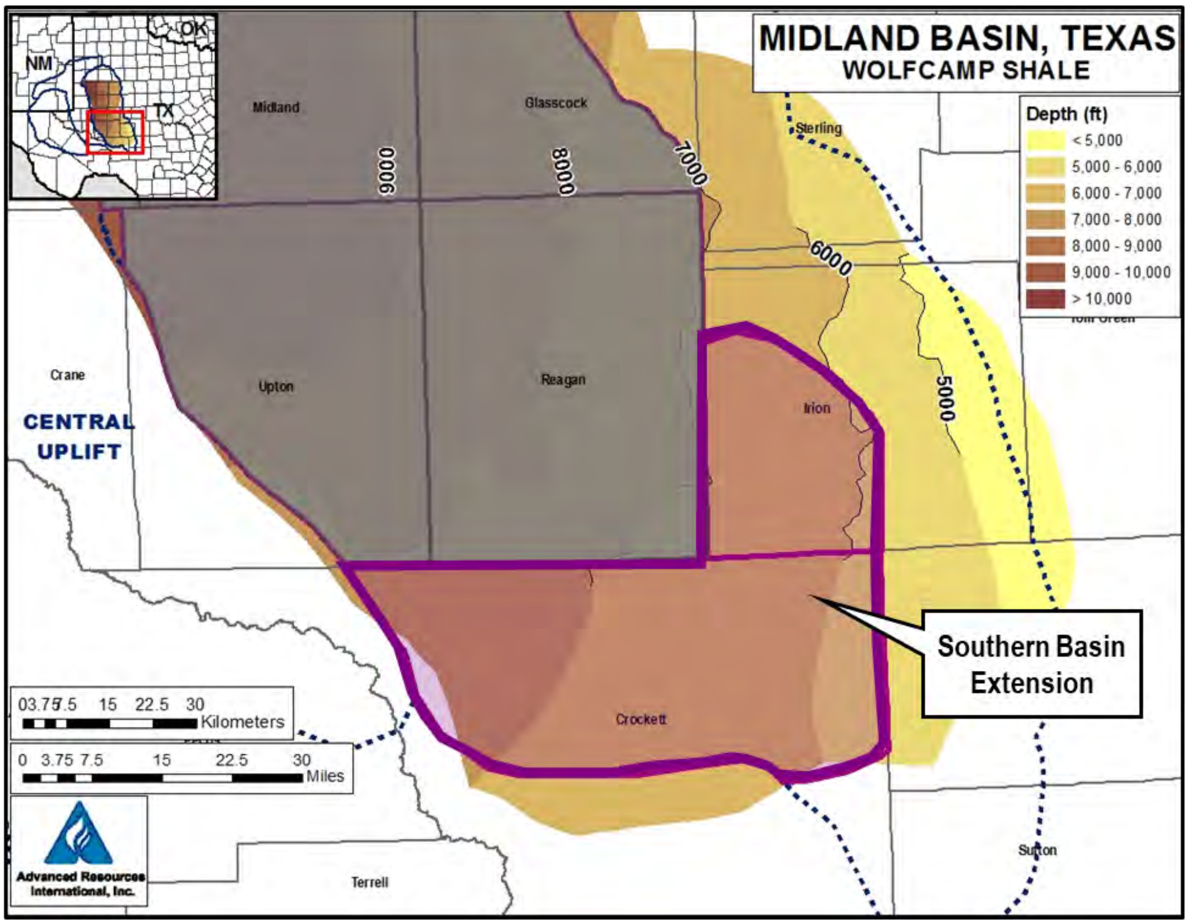
County/Interval	Risked Area (mi²)	Resource Concentration (MB/mi²)	Oil/Condensate OOIP (Million Barrels)
▪ Reagan – A Bench	940	31,720	29,940
▪ Reagan – B Bench	940	94,860	89,550
Total			119,490

Source: Advanced Resources International, 2020.

4.4.4 Southern Basin Extension Shale Area

The Southern Basin Extension Area of the Wolfcamp Shale extends across 1,550 square miles (1,240 square miles, risked) in Crockett and Irion counties (Figure 4-12). Much of this area is lightly drilled, with about 1,500 wells in production at the end of 2019. Small areas in Schleicher and Tom Green counties have been excluded due to limited activity. The depth of the Wolfcamp Shale in the Southern Basin Extension Area ranges from 5,500 ft on the east to nearly 8,000 ft on the west (Figure 4-12).

Figure 4-12. Outline and Depth Map of Southern Basin Extension Wolfcamp Shale Area



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Source: Advanced Resources International, 2020.

Table 4-12 provides the volumetric and other reservoir properties for the Wolfcamp Shale A and B Benches in Crockett and Irion counties of the Southern Basin Extension Wolfcamp Shale Area.

Table 4-12. Reservoir Properties for Estimating OOIP, Southern Basin Extension Wolfcamp Shale

Reservoir Property	Crockett Co.	Irion Co.
Total Area	1,160 mi^2	390 mi^2
Risked Area	930 mi^2	310 mi^2
Average Depth (top)	6,750 ft	6,500 ft
Net Pay (Shale Unit)		
▪ A Bench	310 ft	330 ft
▪ B Bench	640 ft	640 ft
Porosity (Shale Unit)		
▪ A Bench	5.8%	5.8%
▪ B Bench	5.5%	5.5%
Oil Saturation		
▪ A Bench	53%	54%
▪ B Bench	49%	52%
Formation Volume Factor (RB/STB)		
▪ A Bench	1.68	1.68
▪ B Bench	1.71	1.71
Solution GOR (Mcf/bbl)		
▪ A Bench	0.7	0.7
▪ B Bench	0.8	0.8

Source: Advanced Resources International, 2020.

Using the volumetric reservoir properties in Table 4-12, the OOIP for the Wolfcamp A and B Benches in Crockett County is 72.6 billion barrels (Table 4-13) and in Irion County is 26.1 billion barrels (Table 4-14).

Table 4-13. OOIP of Wolfcamp Shale A and B Benches, Crockett County

County/Interval	Risked Area (mi^2)	Resource Concentration (MB/mi^2)	Oil/Condensate OOIP (Million Barrels)
▪ Crockett – A Bench	930	28,250	26,210
▪ Crockett – B Bench	930	49,990	46,390
Total			72,600

Source: Advanced Resources International, 2020.

Table 4-14. OOIP of Wolfcamp Shale A and B Benches, Irion County

County/Interval	Risked Area (mi^2)	Resource Concentration (MB/mi^2)	Oil/Condensate OOIP (Million Barrels)
▪ Irion – A Bench	310	30,640	9,560
▪ Irion – B Bench	310	53,050	16,550
Total			26,110

Source: Advanced Resources International, 2020.

4.4.5 OOIP for Wolfcamp Shale (A and B Benches)

The OOIP estimates for the three geologic partitions of the Wolfcamp Shale in the Midland Basin—the Deep Western Basin Shale Area, the Eastern Basin Extension Shale Area, and the Southern Basin Extension Shale Area (together containing sixteen individual Wolfcamp Shale resource assessment units for Benches A and B) is a risked OOIP of 509.1 billion barrels.

4.5 Reservoir Simulation of Primary and Enhanced Oil Recovery from the Wolfcamp Shale

4.5.1 Representative Study Area

To establish the incremental oil production from implementation of enhanced shale oil recovery using injection of CO_2, the study selected a representative area of the Wolfcamp Shale in the Midland Basin. The Study Area contains 7.6 million barrels of original oil in-place (OOIP) and 6.5 billion cubic feet (Bcf) of original gas in-place (OGIP) (Table 4-15).

Table 4-15. Wolfcamp Shale Study Area Reservoir Properties

Reservoir Properties	Units
Pattern Area	180 acres
Well Pattern Dimensions	
▪ Length	9,000 ft
▪ Width	880 ft
Depth (to top)	8,000 ft
Net Pay (All units)*	290 ft
Porosity	
▪ Matrix (Avg)*	4.7%
▪ Fracture	0.1%

Reservoir Properties	Units
Initial Oil Saturation (Avg)*	
▪ Matrix/Fracture	57% / 1%
Saturation Gas/Oil Ratio	0.85 Mcf/B
Formation Volume Factor	1.42 RB/STB
Initial Pressure	4,265 psia
Temperature	159° F
Bubble Point	2,800 psia
Formation Compressibility	2.2 * e^{-5}/psi
Oil Gravity	39° API

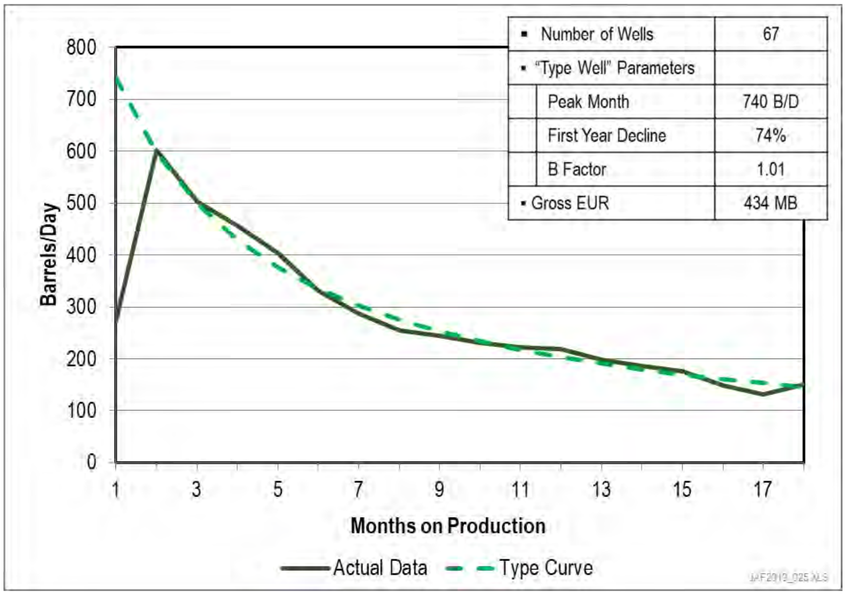
*Rock Units	Net Pay	Porosity	Oil** Saturation
Organic Shale	130	4.4%	75%
Mixed Lithology	160	5.0%	44%
Total	290	4.7%	57%
**Oil and water saturation are based on history matching of production.			

Source: Advanced Resources International, 2020.

4.5.2 Type Well for Study Area

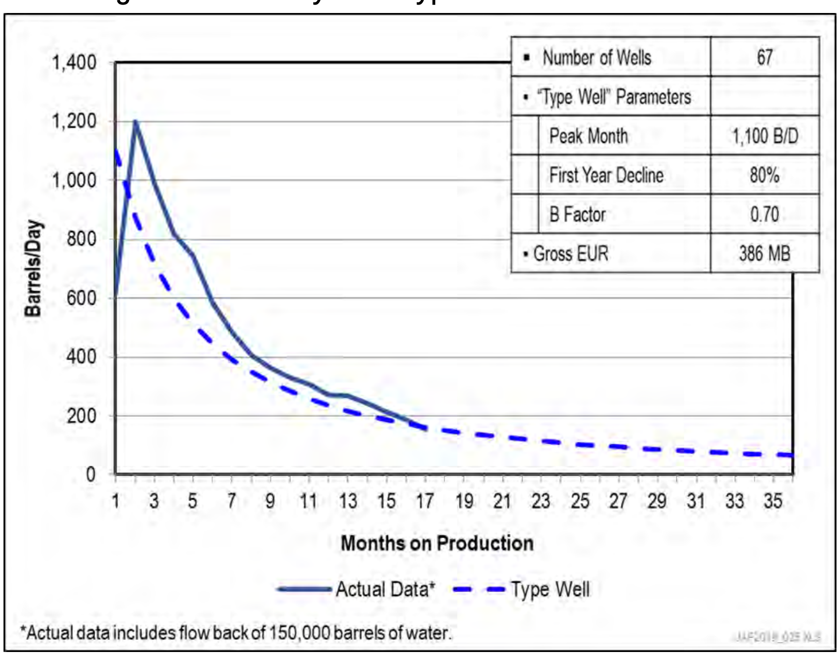
The "type oil well" in the Study Area has a spacing of 180 acres and a Hz lateral of 9,000 ft. It has an estimated 30-year recovery of 434,000 barrels of oil and 386,000 barrels of water (Figures 4-13 and 4-14).

Figure 4-13. Study Area Type Well Oil Production



Source: Advanced Resources International, 2020.

Figure 4-14. Study Area Type Well Water Production



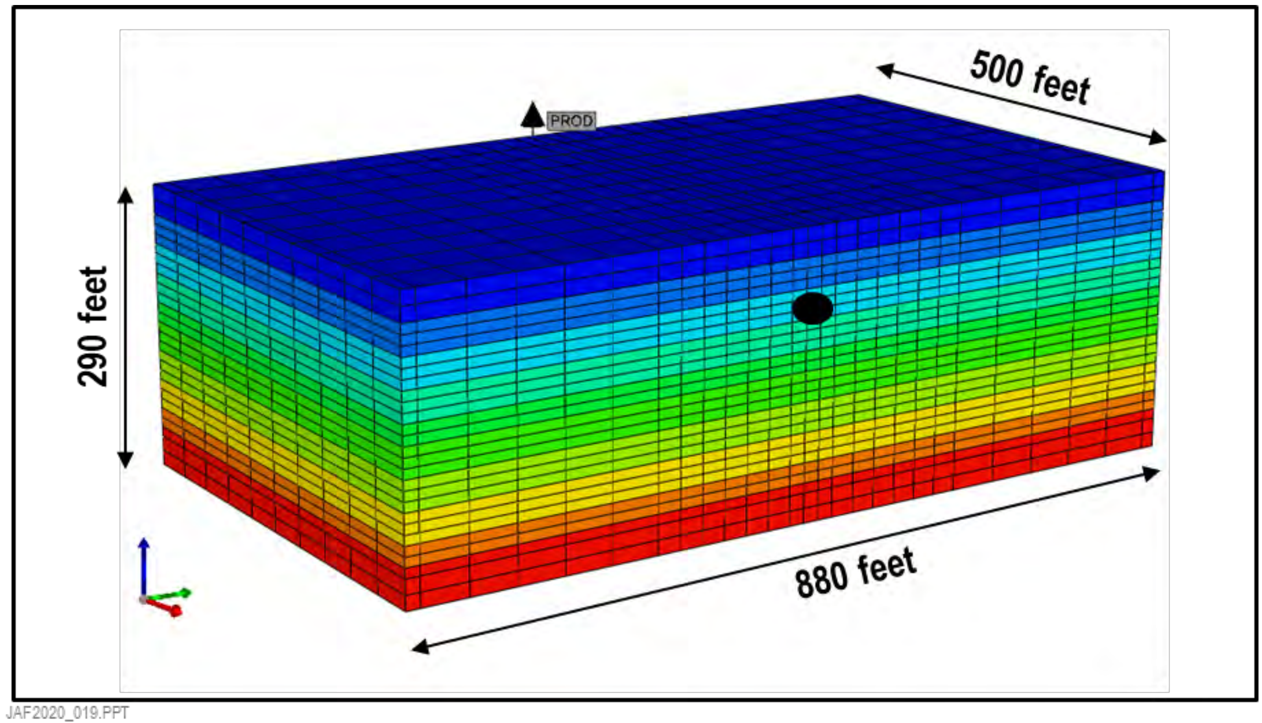
Source: Advanced Resources International, 2020.

4.5.3 Reservoir Simulation

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

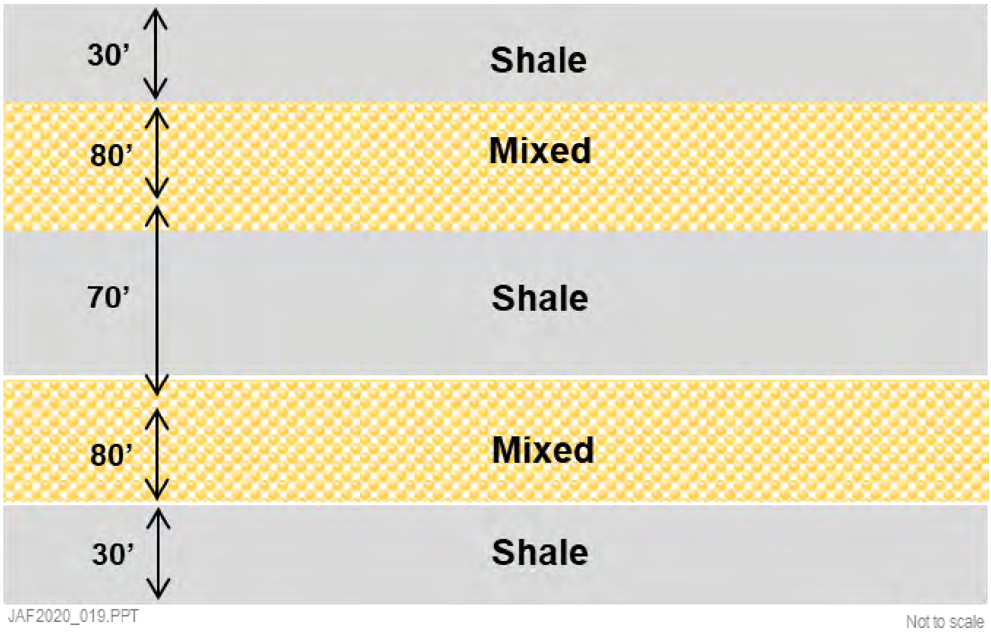
The reservoir model and grid blocks for the Wolfcamp Shale geologic and reservoir setting for the Study Area well are illustrated on Figures 4-15 and 4-16. The reservoir property values previously provided on Table 4-15 were used to populate the reservoir model and its 7,290 grid blocks.

Figure 4-15. Reservoir Model and Grid Blocks Used for Wolfcamp Shale Study



Source: Advanced Resources International, 2020.

Figure 4-16. Reservoir Model Layers to Represent Distributed Lithology



Source: Advanced Resources International, 2020.

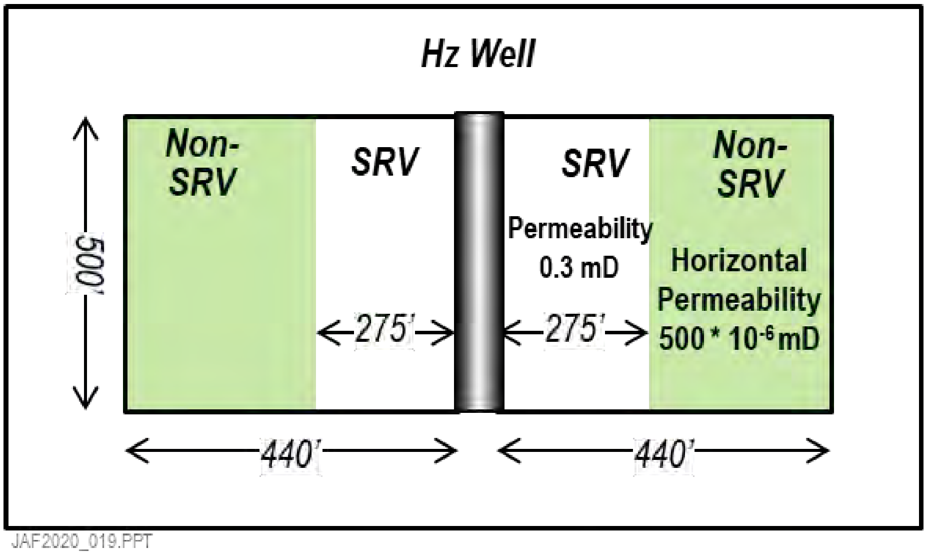
To capture the impact of the hydraulic stimulation on the performance of the horizontal well, a Simulated Reservoir Volume (SRV) was established in the model, assuming enhanced permeability in the SRV for the fracture and the matrix (Figure 4-7).

4.5.4 History-Matching Oil and Water Production

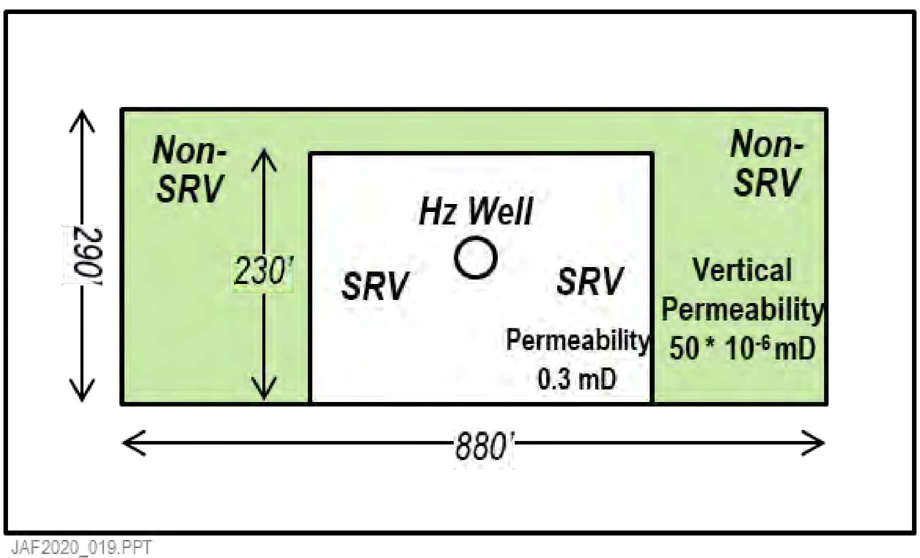
Oil Production. Using the Wolfcamp Shale reservoir properties in Table 4-15 and the two key history matching parameters of Simulated Reservoir Volume (SRV) dimensions and SRV enhanced permeability, reservoir simulation achieved an acceptable history match of both near-term and ultimate oil production with the “type well” in the Study Area (Figures 4-18 and 4-19). With an OOIP of 7.6 million barrels in the well pattern area, and a 30-year oil recovery of 402,000 barrels, the primary oil recovery efficiency is 5.3% of OOIP.

Figure 4-17. SRV Dimensions and Productivity Used to History Match Well Performance

A. SRV Dimensions and Permeability, Plan View

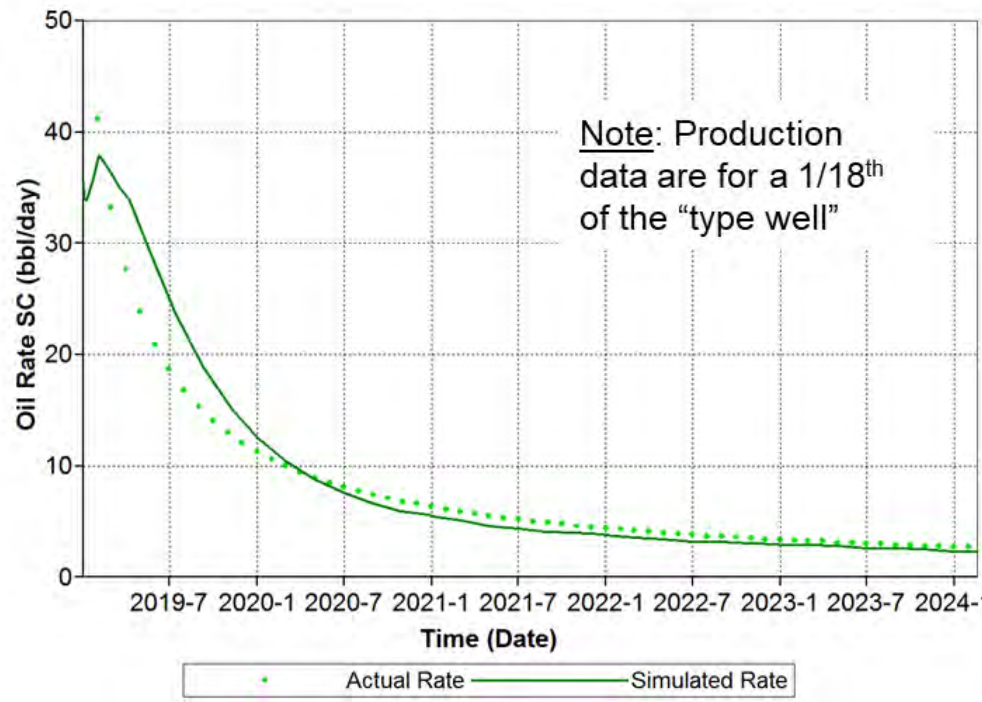


B. SRV Dimensions and Permeability, Side View



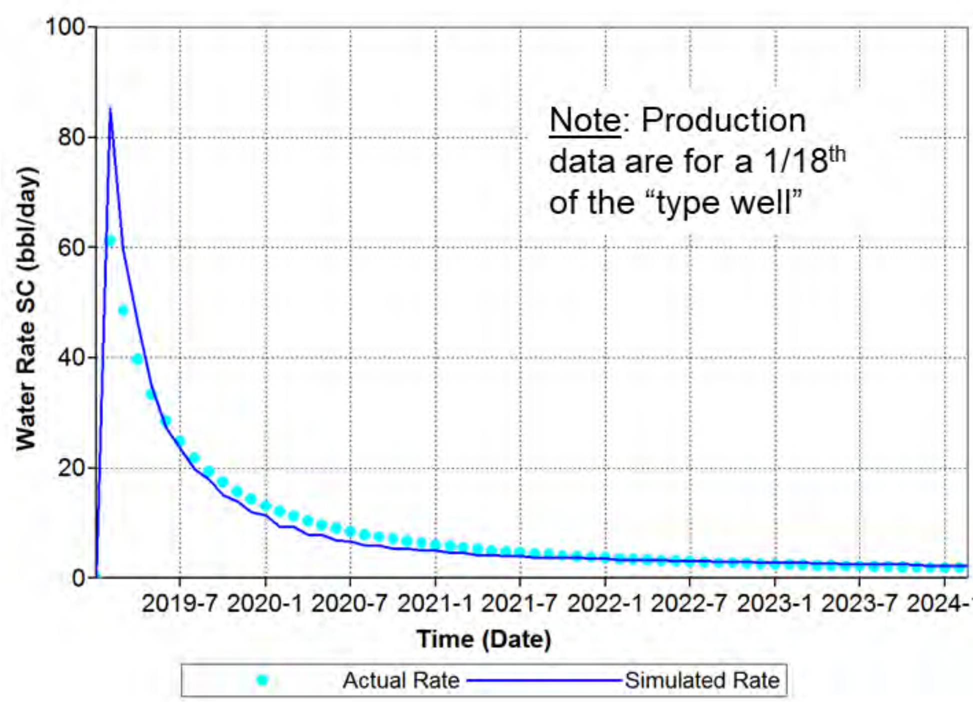
Source: Advanced Resources International, 2020.

Figure 4-18. History Match of Monthly Oil Production (5 Years)



Source: Advanced Resources International, 2020.

Figure 4-19. History Match of Annual Oil Production (30 Years)



Source: Advanced Resources International, 2020.

Water Balance and Production. Using the Wolfcamp Shale reservoir properties on Table 4-15 and the two key history matching parameters of SRV dimensions and SRV enhanced permeability, reservoir simulation achieved an excellent history match of both near-term (5 years) and long-term (30 years) water production (Table 4-16).

Table 4-16. Water Production from Actual and History Matched Study Well

Water Production Time Period	Type Well (Bbls)	History Matched Well (Bbls)
5 years	304,000	308,000
30 years	386,000	376,000

Source: Advanced Resources International, 2020.

The history matched wells produced 376,000 barrels of water in 30 years, approximately 1 barrel of produced water per barrel of produced oil. As such, the water balance for stimulating and producing Wolfcamp Shale wells in the Midland Basin is essentially neutral.

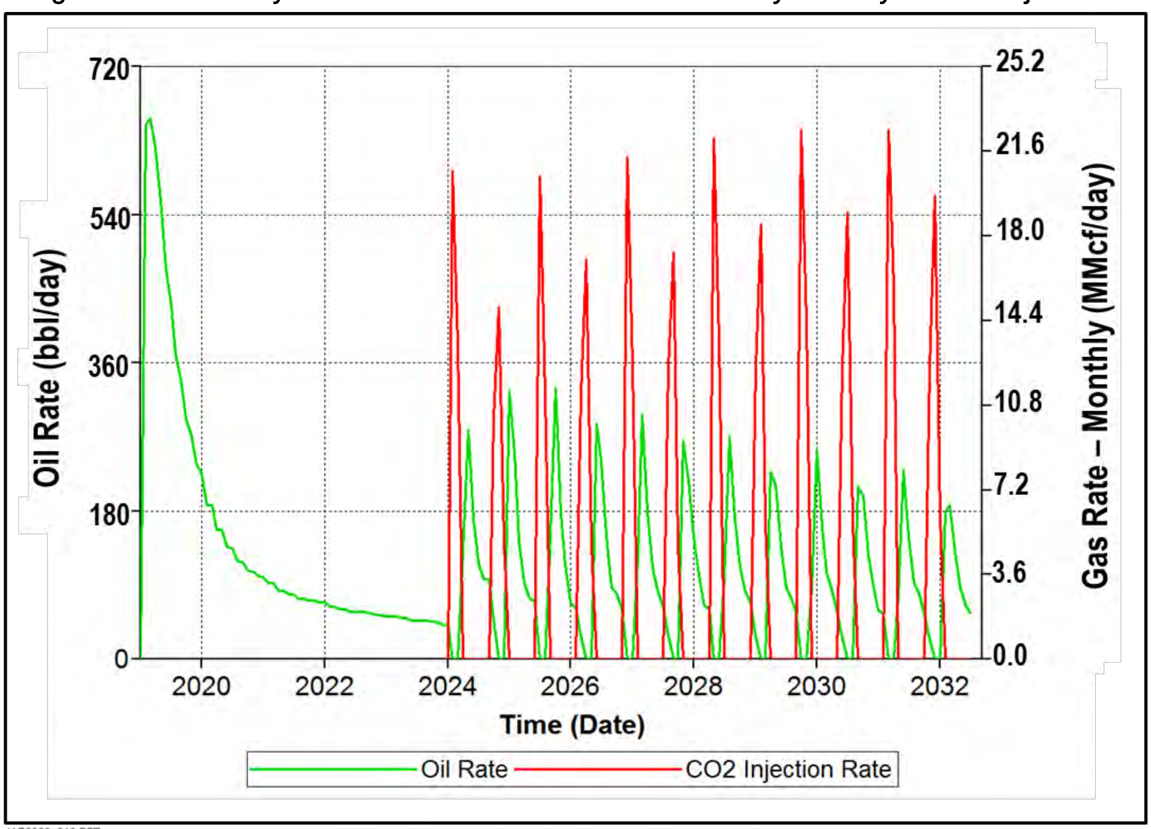
- A typical hydraulic stimulation requires approximately 500,000 barrels of water injection with approximately 30% of the injected water, equal to 150,000 barrels (see Figure 4-14), produced back by the stimulated well and the remaining volumes of water retained in the shale formation.
- Adding the 376,000 barrels of water produced by the history matched “type well” to the hydraulic stimulation flow-back water of 150,000 barrels provides total production of 526,000 barrels of water.
- Assuming both the produced water and the hydraulic stimulation flow-back water are treated and then reused, the net water use balance for the Wolfcamp Shale development in the Midland Basin is essentially neutral.

4.5.5 Performance of Cyclic CO_2 Injection

Oil Production and CO_2 Storage. Cyclic CO_2 injection was initiated using the GEM compositional simulator in the Study Area well after five years of primary production. At this time, the Hz well had produced 272,000 barrels, equal to about two-thirds of its estimated ultimate oil recovery.

- In cycle one, CO_2 was injected at a constant rate of 17,000 Mcfd for 2 months (BHP limit of 4,800 pounds per square inch absolute (psia)) to refill reservoir voidage, with a total of 1,030,000 Mcf of CO_2 injected.
- CO_2 injection was followed by a two-week soak time and then followed by six months of production.
- Eleven additional cycles of CO_2 injection, soak and production followed.
- Figure 4-20 illustrates the oil production data for the first 5 years of primary oil production and for the subsequent 12 cycles (8.5 years) of cyclic CO_2 injection, soak and production from the Study Area well.

Figure 4-20. Primary Production and Enhanced Oil Recovery from Cyclic CO_2 Injection



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Source: Advanced Resources International, 2020.

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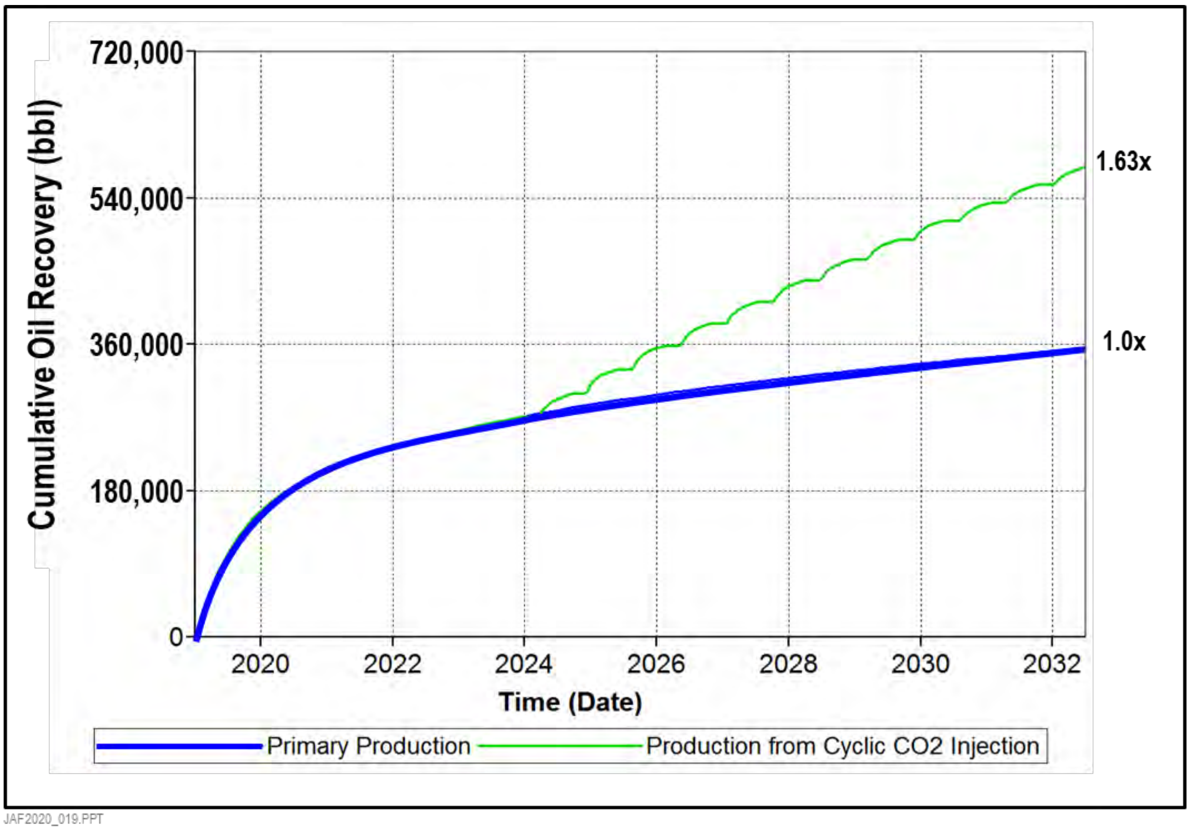
The 12 cycles of CO_2 injection over 8.5 years provided 306,000 barrels of oil production in addition to 272,000 barrels from primary oil recovery at the start of CO_2 injection, for overall oil recovery of 578,000 barrels. Continuation of primary recovery for 8.5 years would have provided 83,000 barrels of oil recovery. As such, 223,000 barrels of incremental oil recovery (306,000 barrels less 83,000 barrels) are attributable to injection of CO_2. This 12 cycle CO_2 injection project provided a 1.63x uplift to primary oil production for the Study Area well (Figure 4-21 and Table 4-17).

Figure 4-21. Cumulative Oil Production from Primary and Cyclic CO_2 Injection



Source: Advanced Resources International, 2020.

Table 4-17. Cumulative Oil Production, CO_2 Injection and CO_2 Production: Study Area Well

	Cumulative Oil Production			Cumulative CO_2		Estimated CO_2 Storage (MMscf)
	Total (M Barrels)	Primary (M Barrels)	Incremental EOR (M Barrels)	Injection (MMscf)	Production (MMscf)	
End of 5-year primary	272	272	-	-	-	-
End of first cycle	302	288	14	1,030	590	440
End of 6th cycle	416	326	90	5,990	4,700	1,220
End of 12th cycle	578	355	223	12,730	10,800	1,930

Source: Advanced Resources International, 2020.

Approximately 15% (1,930 Mcf) of the 12,730 MMcf of CO_2 injected remained stored in the reservoir at the end of 12 cycles of CO_2 injection (Table 4-17). As such, the cyclic CO_2 project in the Wolfcamp Shale Study Area stored 8.7 Mcf of CO_2 (0.46 metric tons of CO_2) per barrel of incremental oil recovery.

Water Balance and Production. The use of cyclic CO_2 injection also results in additional volumes of water production (Figure 4-22).

As shown in Table 4-18, the production of oil from cyclic CO_2 injection brings with it 234,000 barrels of incremental water at the end of 12 cycles of CO_2 injection, soak and production. This additional production of water can be treated and reused for future hydraulic stimulations. With more rigorous treatment practices, the produced water could also become available for agriculture and other users.

Figure 4-22. Primary and Enhanced Water Production from Cyclic CO_2 Injection: Study Area Well

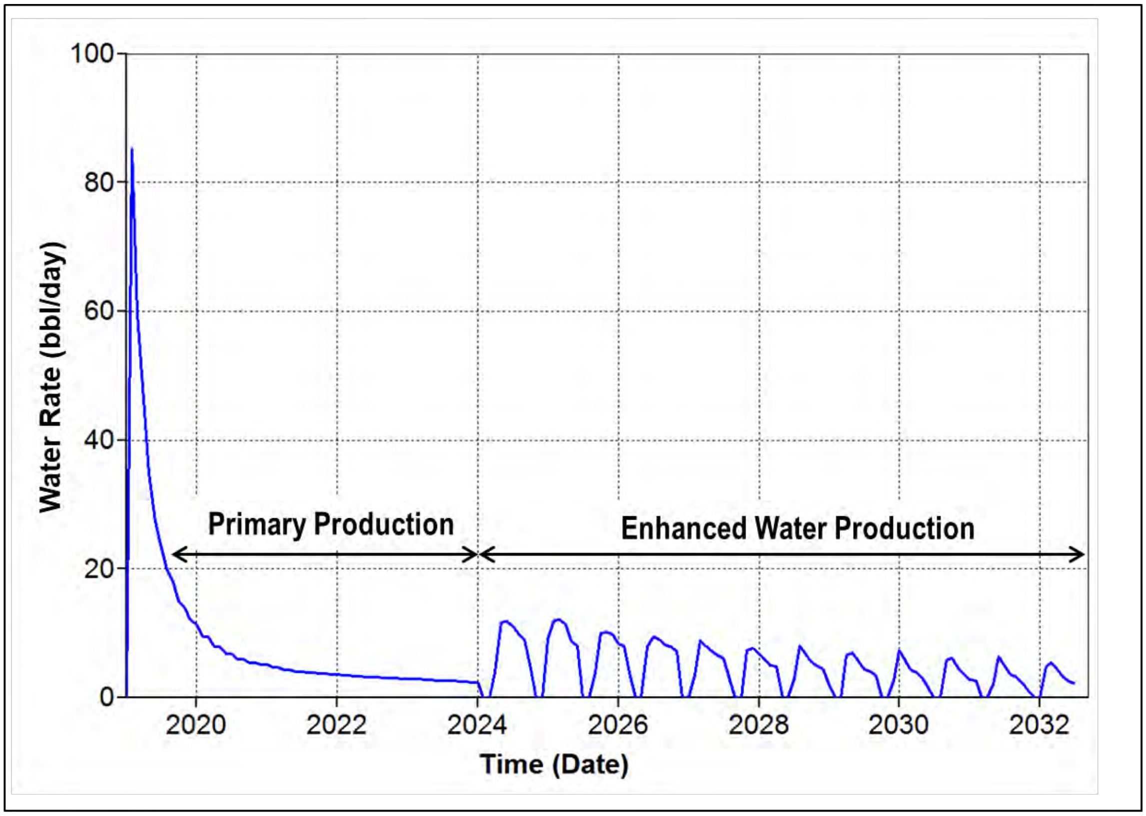


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Table 4-18. Cumulative Water Production: Total, Primary and Incremental: Study Area Well

	Cumulative Water Production		
	Total (M Barrels)	Primary (M Barrels)	Incremental (M Barrels)
End of 5-year primary	308	308	-
End of first cycle	342	318	34
End of 6th cycle	476	326	150
End of 12th cycle	566	332	234

Source: Advanced Resources International, 2020.

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4.6. Increasing Shale Oil Recovery and CO_2 Storage with Cyclic CO_2 Enhanced Oil Recovery

4.6.1 Introduction

We have combined three sources of information to estimate the volumes of additional oil recovery and CO_2 storage that could result from the application of cyclic CO_2 enhanced oil recovery to the Midland Basin.

- Estimates of OOIP for each of the counties in the Midland Basin, provided in Section 4.4 of this report.
- Estimates of primary (pressure depletion) oil recovery from reservoir modeling and from "type wells" in each Wolfcamp Shale bench in each county of the Midland Basin, discussed in Section 4.5 of this report.
- Estimated "uplift" to primary shale oil recovery from reservoir modeling of cyclic CO_2 enhanced oil recovery, including the calculation of volumes of CO_2 injection and storage, provided in Section 4.5 of this report.

Each Midland Basin county addressed by this study was also evaluated to determine its geologic attractiveness for application of cyclic CO_2 enhanced shale oil recovery.

4.6.2 Increased Volumes of Oil Recovery and CO_2 Storage

Deep Western Shale Area. We estimate that the application of cyclic CO_2 enhanced oil recovery to the Wolfcamp Shale in the Deep Western Shale Area of the Midland Basin will provide 8,640 million barrels (MMB) of additional technically viable shale oil recovery and provide opportunities to store 3,900 million metric tons (MMmt) of CO_2 (Table 4-19). The incremental oil recovery efficiencies from use of cyclic CO_2 range from 2.5% of OOIP in Wolfcamp Shale Bench B in Ector/Midland counties to 7.2% of OOIP in Wolfcamp Shale Bench A in Andrews/Martin counties.

Eastern Basin Extension Area. We estimate that the application of cyclic CO_2 enhanced oil recovery to the Wolfcamp Shale in the Eastern Basin Extension Area of the Midland Basin will provide 5,790 MMB of additional technically viable shale oil recovery and provide opportunities to store 2,660 MMmt of CO_2 (Table 4-19). The incremental oil recovery efficiencies from use of cyclic CO_2 range from 2.2% of OOIP in

Wolfcamp Shale Bench B in Reagan County to 5.1% of OOIP in Wolfcamp Shale Bench A in Glasscock County.

Southern Basin Extension Shale Area. The Southern Basin Extension Area of the Midland Basin is largely a wet gas producing area with byproduct production of oil (on a Btu produced basis).

The gas/oil ratio in this area is 10.7 Mcf/barrel in Bench A and 9.7 Mcf/barrel in Bench B of the Wolfcamp Shale. In addition, the oil recoveries per well in this higher water producing area are low.

Given that the Wolfcamp Shale in the Southern Basin Extension Area of the Midland Basin is a natural gas dominant area and has low oil recoveries per well, we do not view this area to be attractive for the application of cyclic CO_2 enhanced shale oil recovery.

Total Wolfcamp Shale Area, Midland Basin. Applying cyclic CO_2 enhanced oil recovery to the twelve geologically favorable resource assessment units of the Wolfcamp Shale in the Midland Basin could provide 14,250 MMB of additional technically viable shale oil recovery and space for geologically storing 6,560 MMmt of CO_2 storage (Table 4-19).

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Table 4-19. Estimates of Incremental Oil Recovery and CO_2 Storage from Application of Cyclic CO_2 Enhanced Oil Recovery: Midland Basin Wolfcamp Shale

Wolfcamp Shale Area		OOIP	Resource Concentration	Primary Recovery Efficiency		CO_2 EOR Recovery Efficiency*	CO_2 EOR Incremental Recovery	CO_2 Storage**
		(MMB)	(MB/mi^2)	(MB/mi^2)	(% OOIP)	(% OOIP)	(MMB)	(MMmt)
1. Deep Western Shale Area								
Andrews/Martin								
▪	Bench A	22,440	20,630	2,360	11.4%	7.2%	1,620	740
▪	Bench B	39,350	36,160	2,760	7.6%	4.8%	1,890	870
Ector/Midland								
▪	Bench A	29,720	36,070	2,800	7.8%	4.9%	1,450	670
▪	Bench B	57,910	70,280	2,760	3.9%	2.5%	1,430	660
Upton								
▪	Bench A	27,190	35,770	1,800	5.0%	3.2%	860	400
▪	Bench B	30,310	39,880	2,520	6.3%	4.0%	1,210	560
						Sub-Total	8,460	3,900
2. Eastern Basin Extension Area								
Howard								
▪	Bench A	20,510	41,690	2,400	5.8%	3.6%	740	340
▪	Bench B	22,890	46,510	2,040	4.4%	2.8%	630	290
Glasscock								
▪	Bench A	13,020	26,250	2,120	8.1%	5.1%	660	300
▪	Bench B	27,570	55,580	3,360	6.0%	3.8%	1,050	480
Reagan								
▪	Bench A	29,940	31,720	1,280	4.0%	2.5%	760	350
▪	Bench B	89,550	94,860	3,280	3.5%	2.2%	1,950	900
						Sub-Total	5,790	2,660
3. Total							14,250	6,560

*Based on reservoir modeling of Wolfcamp Shale Study Area.

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**Assumes 0.46 mt of CO_2 per barrel of oil recovered.

4.7 References

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Chapter 5. Marcellus and Utica Shale

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5 Evaluating the Viability of Using Cyclic Injection of CO_2 for Enhanced Oil Recovery from the Marcellus and Utica Shale

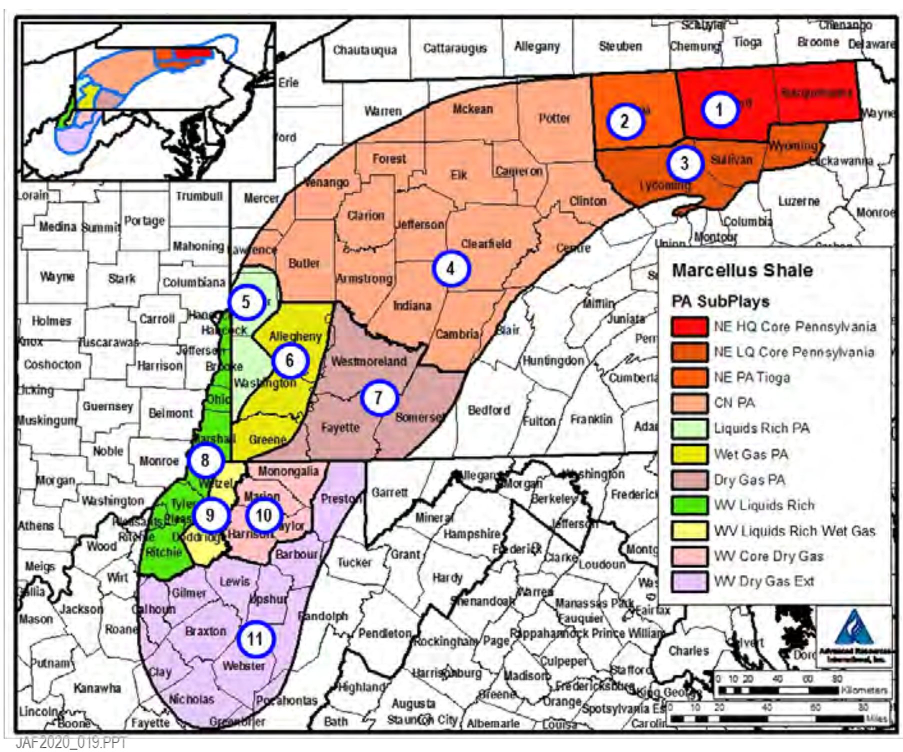
5.1 Introduction

The Scope of Work for the USEA Study included assessing the viability of using cyclic injection of CO_2 for increasing oil recovery and providing by-product storage of CO_2 in the Appalachian Basin's Marcellus and Utica shales.

5.2 Marcellus Shale

The Marcellus Shale of the Appalachian Basin extends across a 30,000 square mile area of western Pennsylvania and northern West Virginia. Our in-depth review of the Appalachian Basin shows that the Marcellus is a shale gas dominant formation with dry shale gas areas in the northern, central and southern portions of the basin and wet shale gas areas in the southwestern Pennsylvania and northern West Virginia portions of the basin (Figure 5-1).

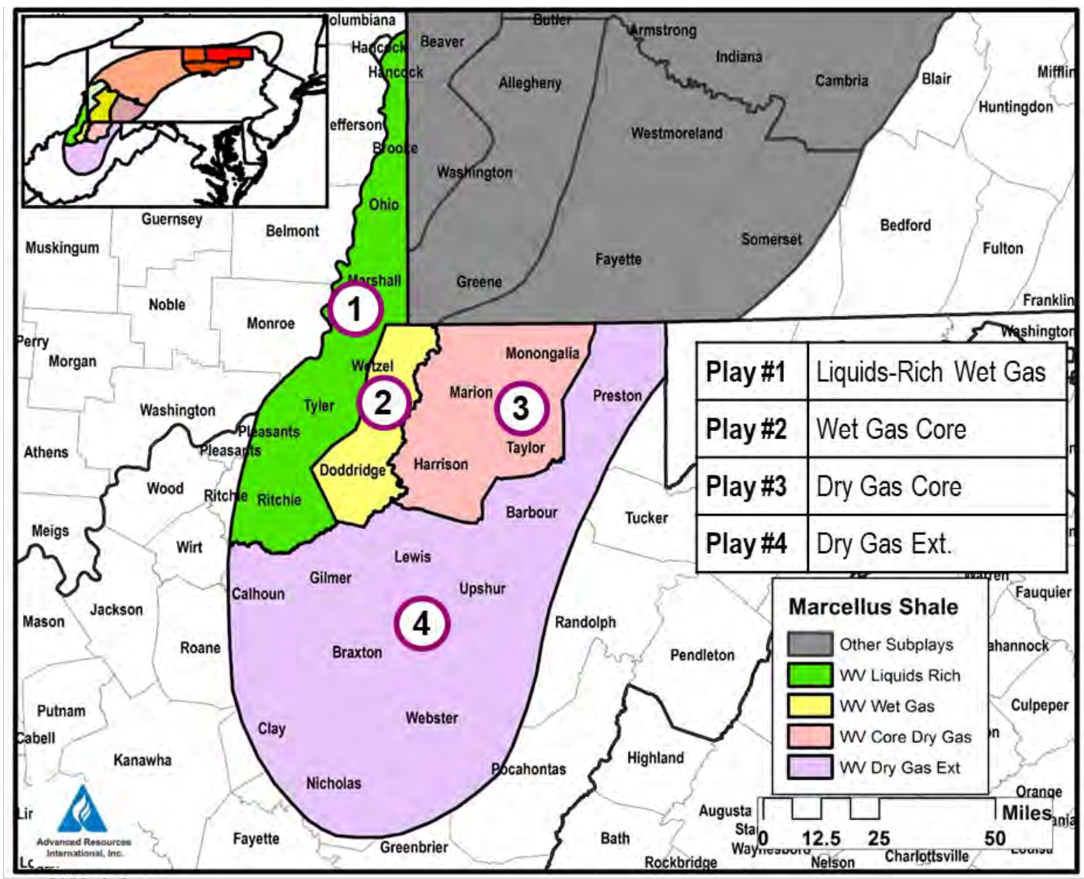
Figure 5-1. Marcellus Shale: Hydrocarbon Partitions



Source: Advanced Resources International, 2020

A modest size, 1,500-acre area of the Marcellus Shale in northwestern West Virginia produces wet gas with by-product condensate (see Play #1 on Figure 5-2). However, Marcellus Shale Play #1 (labeled liquids-rich wet gas) has a gas-oil ratio of about 109 Mcf per barrel, making this area a shale gas dominant play. With shale gas reserves estimated at about 14 Bcf per well and by-product condensate reserves estimated at only 130,000 barrels per well, injecting CO2 into this modest size Marcellus Shale play area for enhanced oil recovery is not technically or economically viable.

Figure 5-2. The Marcellus Shale of West Virginia



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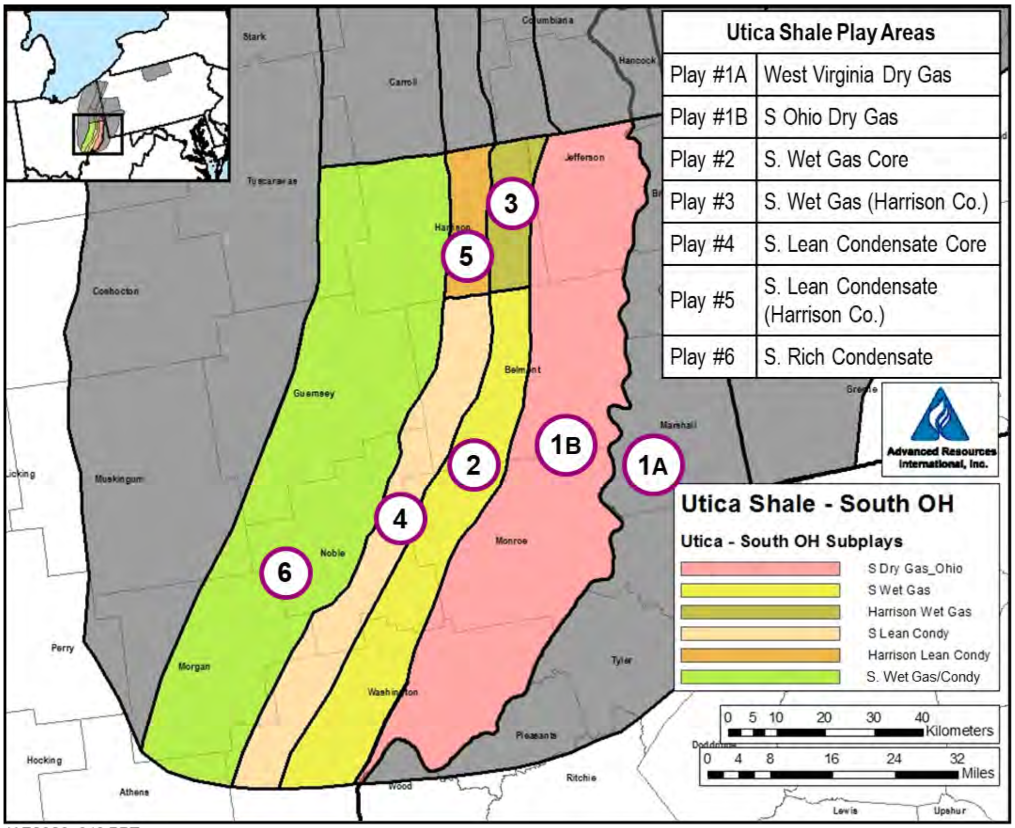
Source: Advanced Resources International, 2020

5.3 Utica Shale

The Utica Shale extends across a 12,000 square mile area of the western Appalachia Basin, primarily in east-central Ohio and northern West Virginia. The southern portion of the larger Utica Shale deposition area is the current development target by industry (Figure 5-3). Like the Marcellus Shale, the Utica Shale is also a shale gas dominant formation.

Figure 5-3. Utica Shale: SE Ohio/West Virginia Hydrocarbon "Windows" and Partitions



JAF2020_019.PPT

Source: Advanced Resources International, 2020.

A modest 1,200-acre area of the Utica Shale in the south western portion of the Utica Shale play area produces wet gas with by-product condensate (see Play #6 in Figure 1-3). However, Utica Shale Play #6, labeled Wet Gas/Condensate, has a gas-oil ratio of over 20 Mcf per barrel, making this area a shale gas dominant play and thus not viable for using cyclic CO_2 injection for enhancing shale oil recovery.

5.4 Concluding Comments

Our detailed geological assessments of the Marcellus and Utica shales shows that these two shale formations are dominantly shale gas producing formations. Injection of CO_2 into a gas dominant shale formation, while the wells still produce economically viable volumes of natural gas, results in a CO_2 contaminated shale gas stream. This will require costly separation of CO_2 from natural gas to meet pipeline specifications for natural gas sales and transport, likely not compensated by the modest potential volumes of additional condensate extraction.

Once natural gas production from the Marcellus Shale reaches an economic limit, the space created in the shale could potentially be used for storage of CO_2. However, shale gas wells typically produce for 25 to 35 years, placing this CO_2 storage option far into the future.

Chapter 6. Shale EOR Field Tests and Projects

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6. Shale EOR Field Tests and Projects

6.1 Introduction

Given the low primary (pressure depletion) oil recovery efficiencies being realized in domestic shale oil formations, considerable interest surrounds the topic-- **how could these low shale oil recovery efficiencies be improved**? One of the options being investigated by research institutions and industry involves using cyclic injection of CO_2 and other gasses to recover more of the oil in-place from shale formations.

Building on reservoir characterization, laboratory work, and reservoir simulation, industry has initiated a series of small field R&D tests and larger-scale field projects using cyclic injection of CO_2 and hydrocarbon gases for improving oil recovery from shale formations. However, publicly available information on the specific design and performance of these cyclic gas injection field tests and projects is extremely limited. As such, the data assembled, analyzed and reported by Advanced Resources Int. (ARI), as part of the USEA Study, is intended to fill a portion of this information gap.

The great majority of the cyclic gas injection field pilots and projects for enhanced oil recovery from shales have been conducted in the Eagle Ford Shale. A handful of small field tests have been conducted in the Bakken Shale, and a few announcements have been made for proposed field pilots in the Wolfcamp Shale of the Permian Basin.

Looking forward, we believe that by undertaking in-depth collection and analyses of data at the Texas Railroad Commission and other state regulatory bodies, it may be possible to gain a more rigorous understanding of the performance of shale EOR field projects involving cyclic gas injection. As such, a next logical phase of the USEA Study could entail conducting such an in-depth assessment of shale EOR Field Tests and Projects. This would provide significant value, including: (1) advancing the understanding of optimum field project design criteria; (2) further addressing the nature of geological settings favorable for shale EOR; and (3) helping design laboratory and field R&D efforts that would improve the performance of shale EOR.

6.2 Shale EOR Performance: Industry Information

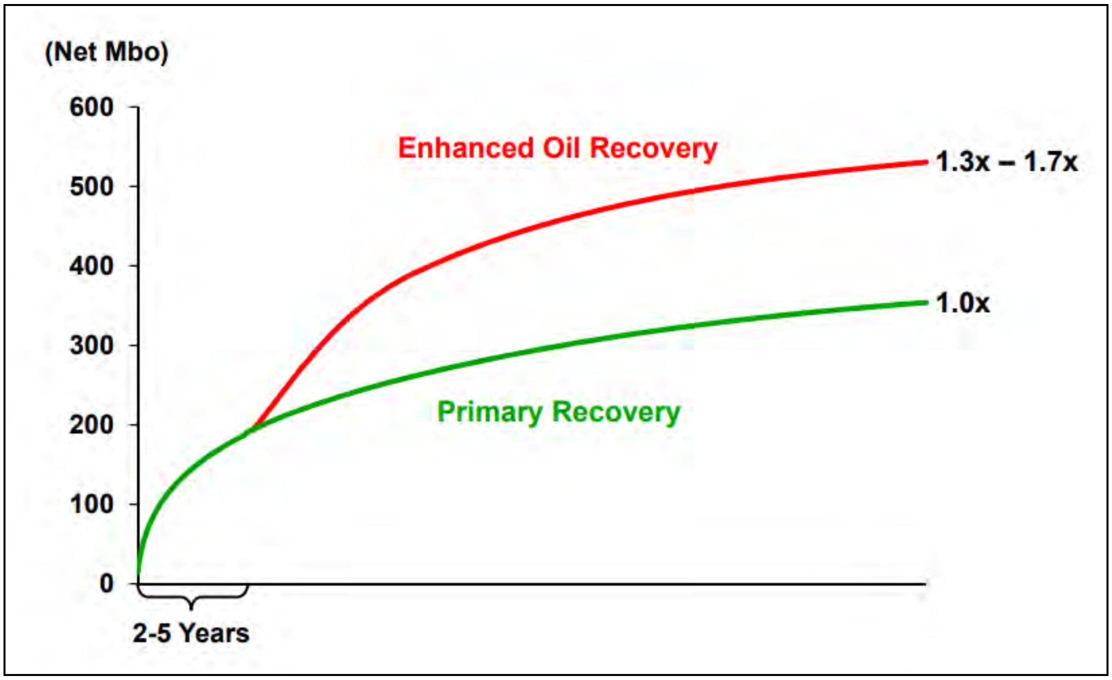
While numerous enhanced oil recovery (EOR) field tests and projects have been initiated in shale oil formations, very little information exists in the public domain on the performance of these EOR field tests and projects. This is understandable given the still early phase in the development of shale EOR technology. It is also understandable given the interest of operators for gaining a competitive advantage, having invested scarce resources in the design and execution of these EOR field tests and projects.

Fortunately, two companies, EOG Resources and Chesapeake Energy, have provided high level information on the actual or expected performance of some of their shale EOR field projects. Equally valuable is the discussion these companies have provided on critical geologic settings and project design influencing the success or failure of applying cyclic gas injection for improving oil recovery efficiency from shales.

EOG Resources' Field Projects. EOG's field tests using cyclic injection of gas for improving tight oil recovery started in 2012-2013 and involved injecting natural gas into 15 wells in various areas of the Eagle Ford Shale play. Subsequently, EOG initiated a larger, 32-well cyclic gas injection project to understand the impact of well spacing, level of primary depletion, and well completion practices on the performance of shale EOR. The company reported that they expected that their 32-well cyclic gas injection field project would add 30% to 70% to expected primary oil recovery (Figure 6-1).

In their November 2019 Investor Presentation, EOG announced that following this initial set of field projects, it converted 58 Eagle Ford Shale wells to cyclic gas EOR in 2017 and 54 Eagle Ford Shale wells to cyclic gas EOR in 2018. EOG also announced that they had achieved "strong results" from the 150 wells they had converted to cyclic gas injection EOR since the start of their program. The company also stated that it "continues to refine techniques" for further improving and optimizing the performance of this technology.

Figure 6-1. Primary versus Enhanced Oil Recovery: Eagle Ford Shale

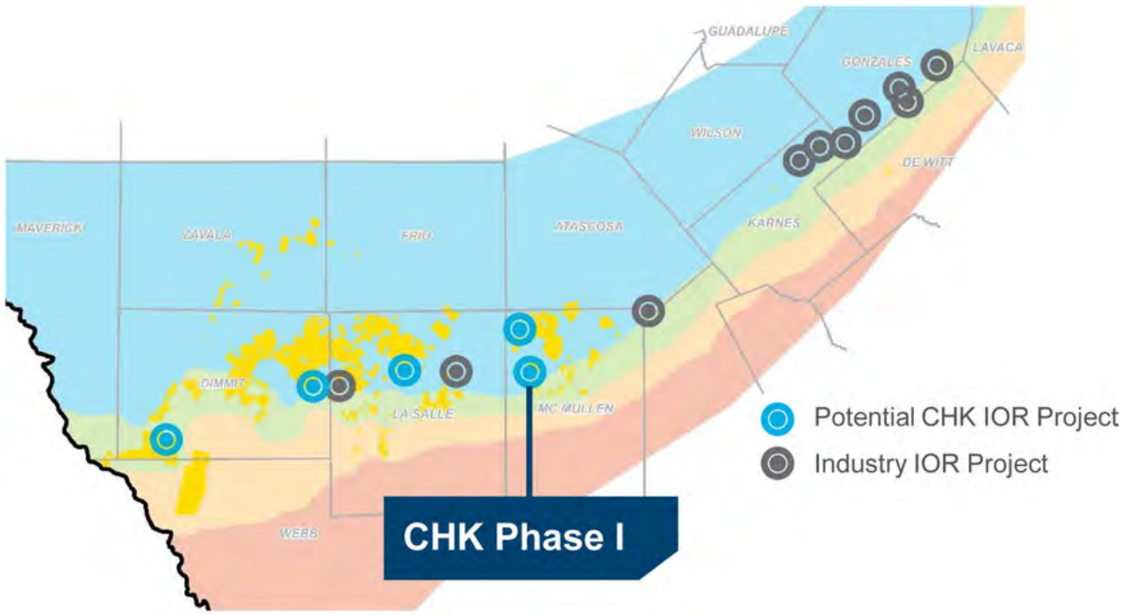


Source: EOG Resources, 2017.

In other public presentations, EOG has stated that "every shale basin is unique and what worked in one shale play may not work in others." The company stated that "geology matters, and the Eagle Ford is unique." They cautioned that how wells are drilled and completed plays a role in the technical success of the shale EOR project and that the availability of significant volumes of gas for injection is important for economic viability. Finally, EOG noted that there is a preferred "oil window" geologic setting for implementing EOR in the Eagle Ford Shale - - "not too far up-dip (in black oil areas) or too far down-dip (in wet gas/condensate areas)."

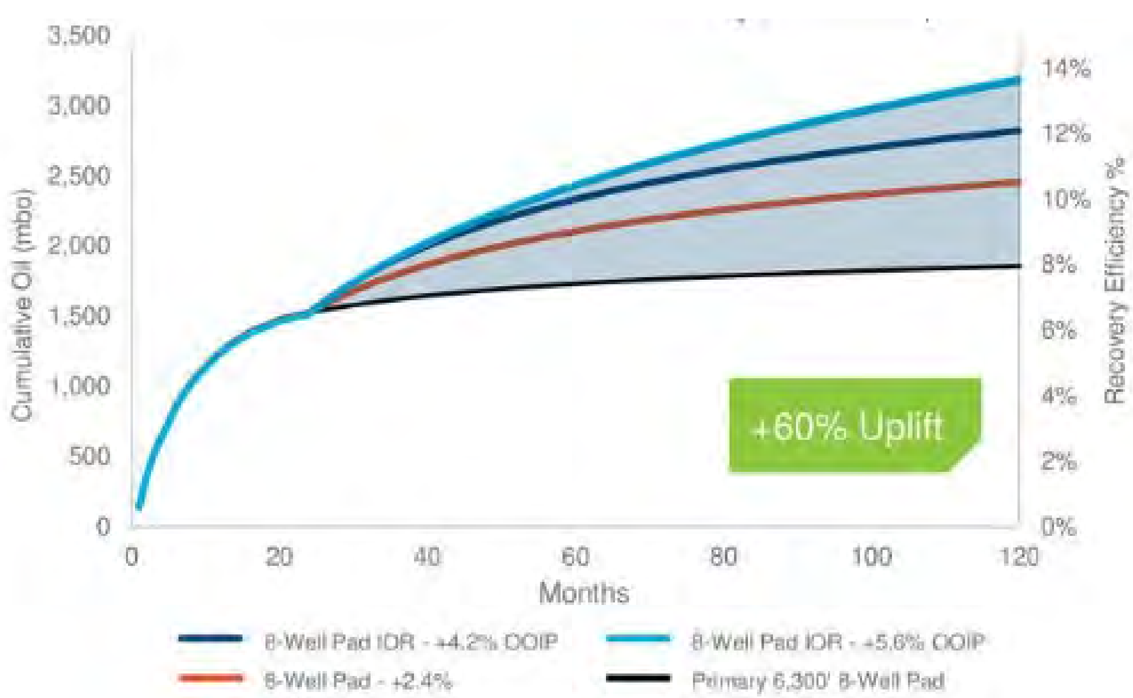
Chesapeake Energy's Proposed Field Project. In mid-2019, Chesapeake Energy announced plans for a 65-well EOR field project in the Eagle Ford Shale. The project would be located in west-central McMullen County (Figure 6-2). The company projected that Phase 1 of their shale EOR project involving cyclic gas injection would achieve a notable increase in oil recovery efficiency, an "uplift" of up to 60%, over primary production (Figure 5-3). No further information on the status or performance of Chesapeake's proposed Eagle Ford Shale EOR field project is available.

Figure 6-2. Location of Active and Planned EOR Field Projects: Eagle Ford Shale



Source: Chesapeake Energy, 2018.

Figure 6-3. Incremental Primary versus Enhanced Oil Recovery



Source: Chesapeake Energy, 2018.

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6.3 Eagle Ford Shale EOR Field Tests and Field Projects

6.3.1 Initial EOR Field Tests

Three EOR field tests, all using cyclic injection of hydrocarbon gas, were conducted in the Eagle Ford Shale between 2012 and 2015 (Table 6-1).

Table 6-1. Eagle Ford Shale EOR Field Pilots

Pilot	Year	County	# Wells in Pilot	# Wells in Lease
Steen Scruggs Unit	2012	Gonzales	1	1+
Martindale Unit	2014	La Salle	4	4
Weyburn Unit	2015	Gonzales	4	8

The first recorded cyclic gas injection field test, started in late 2012, was in one well in the Steen Scruggs Unit of the Eagle Ford Shale. This was followed in late 2014 by the Martindale Unit 4-well cyclic gas injection pilot and in early 2015 by the Weyburn 4-well cyclic gas injection project.

The Steen Scruggs Unit pilot had an increase of 250 B/D of oil production from the first cycle of gas injection, soak and production. However, no data are available for the results from any subsequent gas injection cycles. The Weyburn Unit pilot had an increase of 150 B/D of oil production from the first cycle of gas injection, soak and production and smaller volumes of oil production response from subsequent gas injection cycles. (Shale IOR LLC, 2020)

Martindale Unit Cyclic Gas Injection Pilot

To provide a more complete understanding of the performance of cyclic gas EOR in the Eagle Ford Shale, Advanced Resources International (ARI) assembled information and undertook an in-depth analysis of the performance of the Martindale Unit 4-well cyclic gas injection field pilot in LaSalle County (Table 6-1). This field pilot project was initiated in November 2014, with production data available through December 2018, as discussed below:

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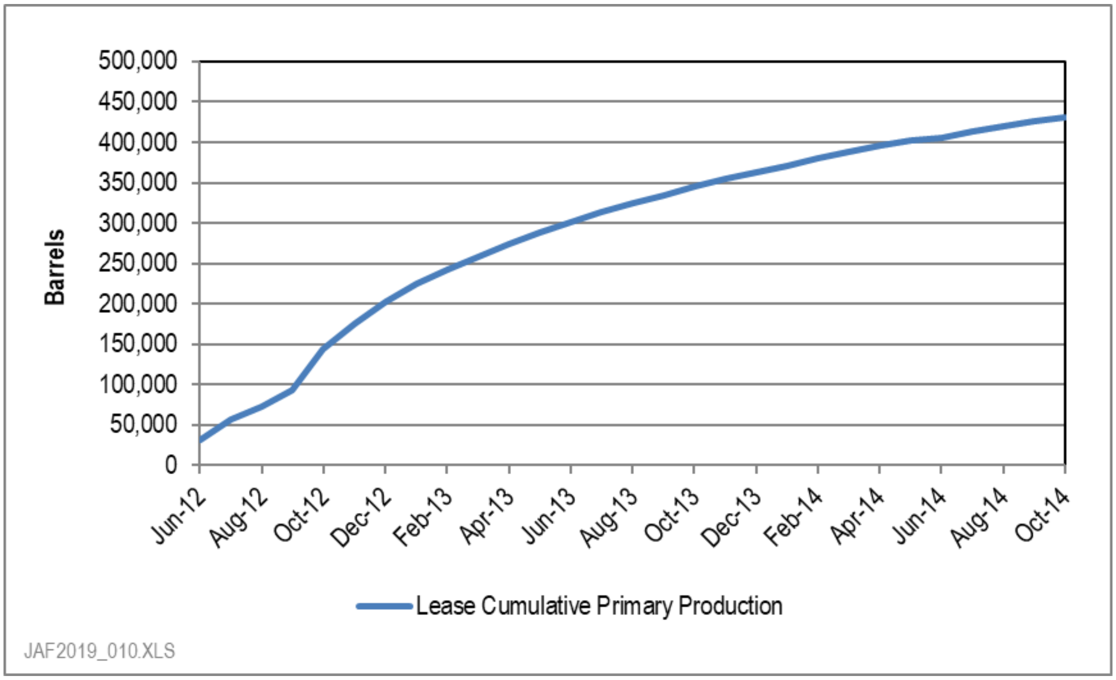
- In June 2012, two wells (3H and 4H) were drilled and placed in production at the Martindale L&C lease. In late August 2012, two additional Martindale L&C wells (1H and 2H) were completed, with first oil production reported for these wells in September 2012.

- Before the start of cyclic gas injection, these four wells had been in primary production for about 2.5 years and together had produced 430,000 barrels of oil (August 2012 to October 2014) (Figure 6-4).

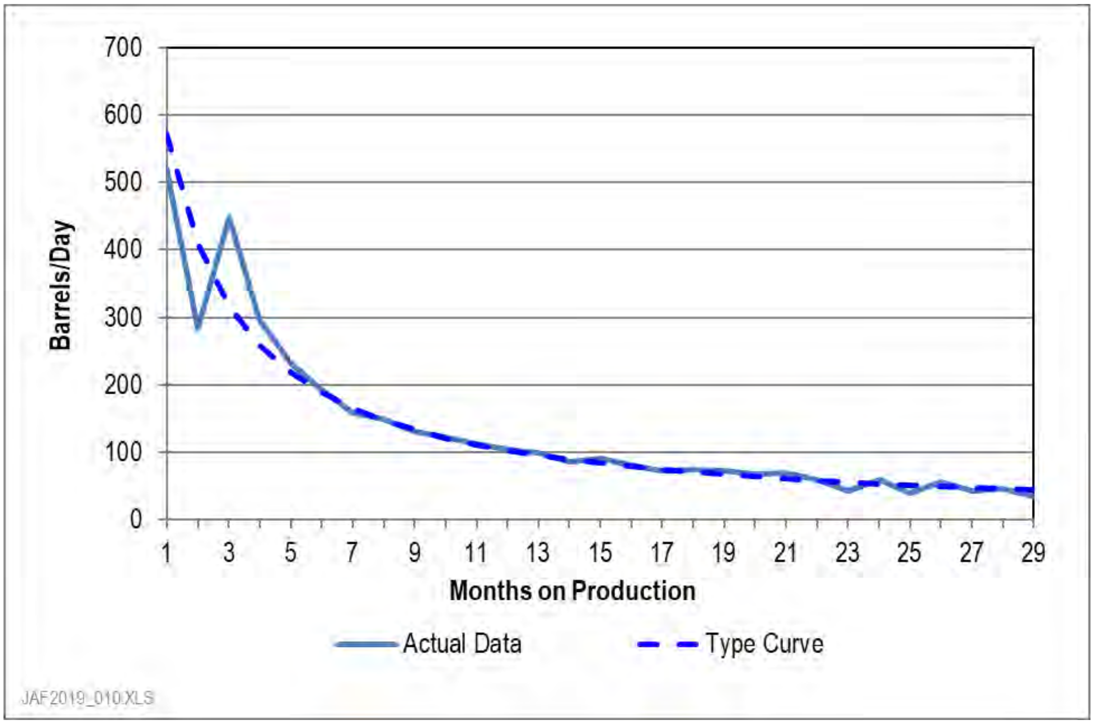
Figure 6-4. Cumulative Primary Oil Production from Four Martindale L&C Wells: June 2012 through October 2014



Source: Advanced Resources International, 2020.

- To provide a baseline for estimating longer-term oil recovery from the four-well pilot, ARI history matched the early-time performance of these wells and created a primary recovery oil production "type well" for this lease (Figure 6-5). The "type well" was used to estimate the volume of oil production that would accrue from continuation of primary production.

Figure 6-5. Primary Oil Production per Well – Martindale Unit Oil "Type Well": Data for Mid-2012 through Late 2014



Source: Advanced Resources International, 2020.

The four production wells were shut-in in November 2014 and remained shut-in through early March 2015 in preparation for and during the first cycle of gas injection and soak.

- Natural gas was injected into the four wells in March 2015 and the wells were shut in for two weeks. After brought back online in late April 2015, the wells produced at ~260 B/D of oil and remained in production for three months.

- Three more similar gas injection and soak cycles and three shorter gas injection and soak cycles followed, ending in October 2017. The oil production response was positive in each of the gas injection cycles, albeit with a declining peak in oil production during each subsequent cycle (Figure 6-6).

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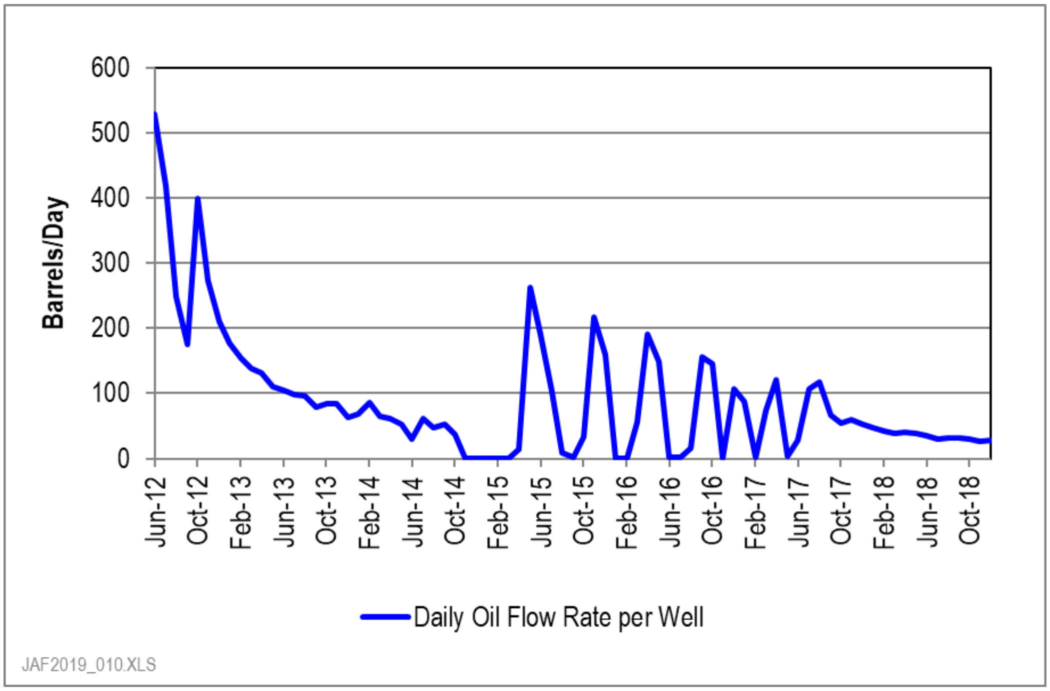
Figure 6-6. Oil Recovery from Primary and Cyclic Gas Injection – Average Martindale L&C Lease Well (August 2012 through December 2018)

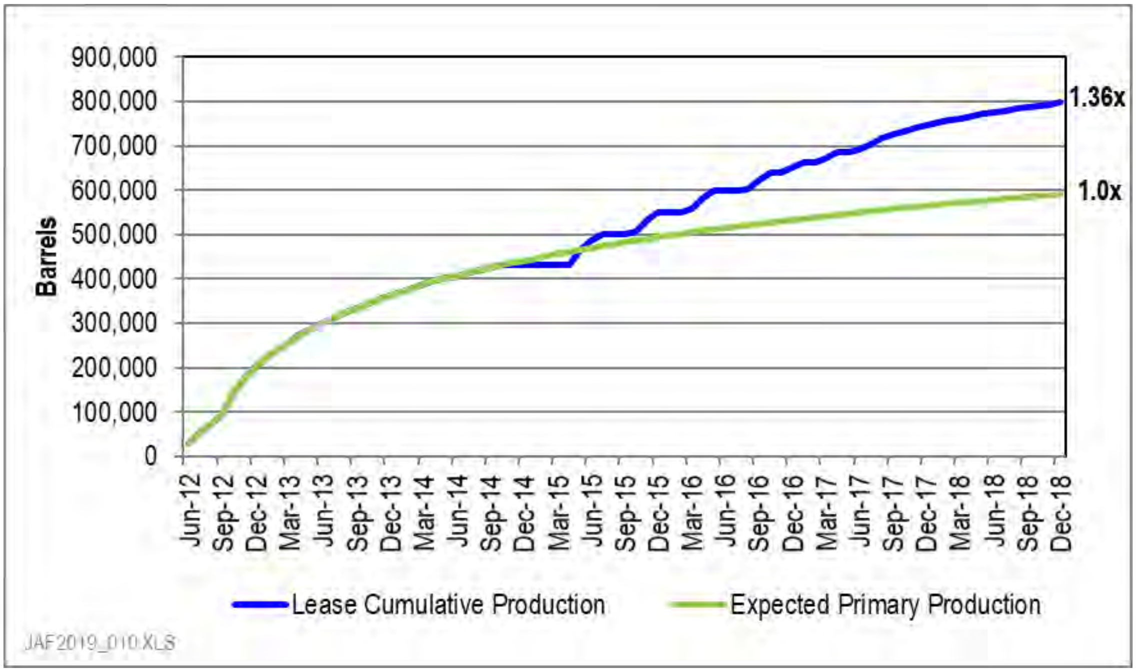


Source: Advanced Resources International, 2019

- As of the end of 2018, the four wells had been in 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% higher than the expected primary production rate of 16 barrels of oil per day, likely due to the residual effects of cyclic gas injection.

- During and following the four years of cyclic gas injection, the four Martindale L&C lease wells recovered 370,000 barrels of oil. Including the 430,000 barrels recovered prior to the start of cyclic gas injection, total oil recovery from the four well lease, from mid-2012 through end of 2018, was 800,000 barrels. With an estimated 590,000 barrels from continuation of primary recovery, the cyclic gas injection project provided 210,000 incremental barrels of oil, equal to an “uplift” of 1.36x.

Figure 6-7. 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

ARI's estimate of a 1.36x uplift in oil recovery due to cyclic gas injection from the Martindale Unit is within the range of uplift values reported by EOG Resources, shown previously in Figure 6-1.

6.3.2 Initial EOR Field Projects

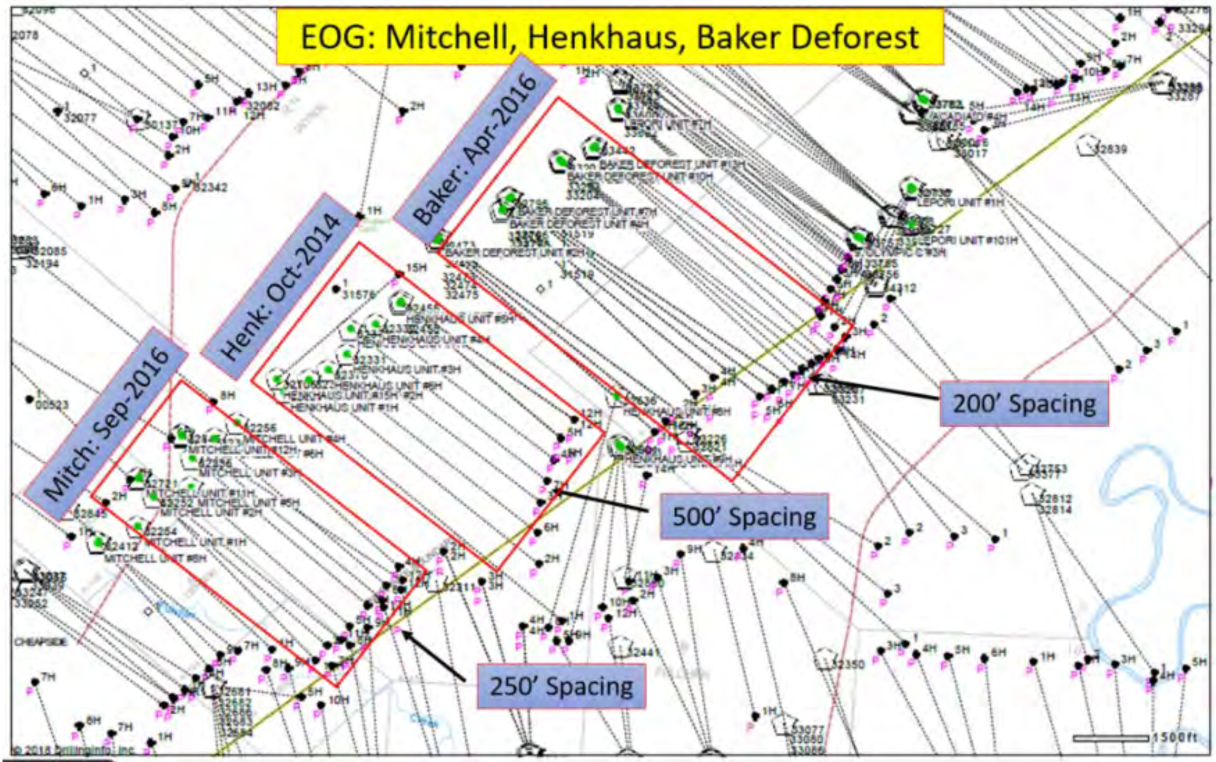
Three larger-scale cyclic gas injection EOR field projects – Henkhaus, Mitchell and Baker Deforest - were initiated by EOG Resources in the Eagle Ford Shale in 2014 and 2015 (Table 6-2 and Figure 6-8).

Table 6-2. Eagle Ford Shale EOR Field Projects

Pilot	Year	County	# Wells in Pilot	# Wells in Lease
Henkhaus	2014	Gonzales	6	14
Mitchell	2015	Gonzales	7	14
Baker Deforest	2015	Gonzales	12	14

Source: Advanced Resources International, 2019

Figure 6-8. Initial EOR Resources Eagle Ford Shale EOR Field Projects.

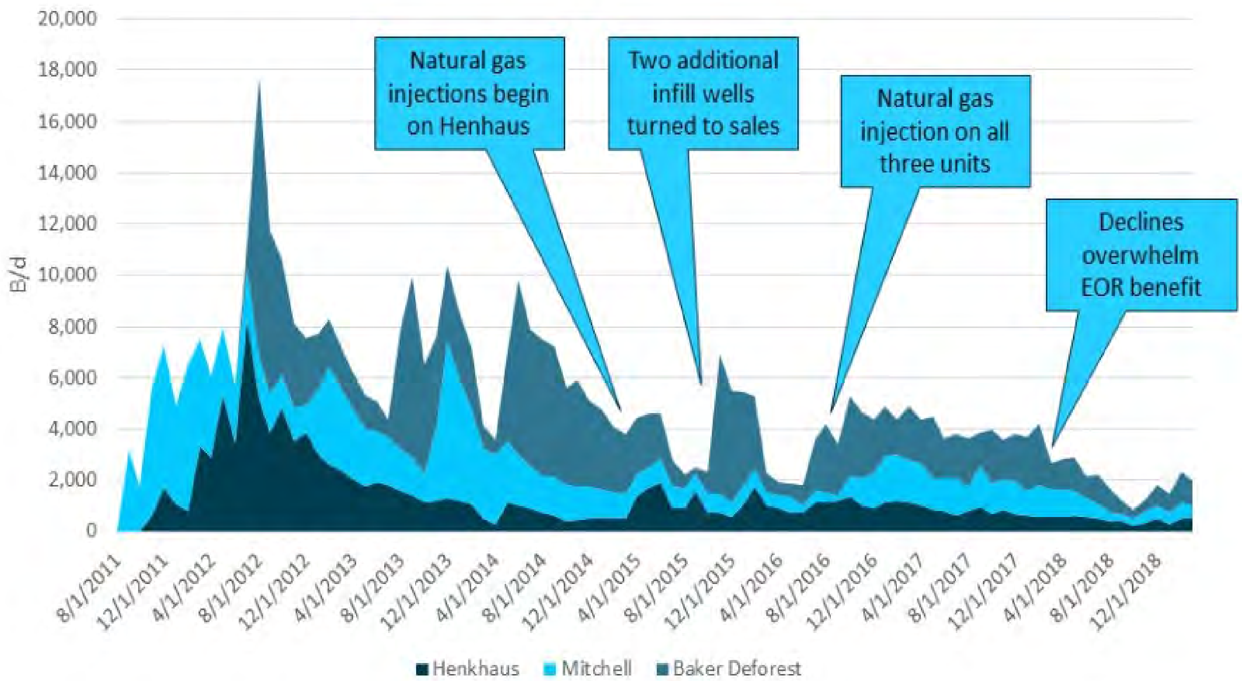


Source: Shale IOR, 2019.

Henkhaus Unit Performance. In late 2014, EOG Resources initiated cyclic field gas injection into 6 wells of the 14-well Henkhaus Unit. During the following four and a half years, November 2014 to March 2019, oil production from the Henkhaus Unit averaged 830 B/D, considerably higher than at the start of cyclic gas injection. However, only a portion of the increase in oil production was from injection of natural gas because infill wells continued to be drilled in the Henkhaus Unit during this time, impacting a more rigorous assessment of cyclic gas injection performance.

Combined Henkhaus, Mitchell and Baker Deforest Performance. Once cyclic natural gas injection was added to the Mitchell and Baker Deforest Units, combined oil production from all three units reached 5,000 B/D in late 2016, declined slowly to 4,000 B/D in late 2017, and averaged 1,600 B/D during the last six months (late 2018 to early 2019) (Figure 6-9).

Figure 6-9. EOG Shale EOR Field Projects in Eagle Ford Shale



Source: Scott, T., 2019.

6.4 Bakken Shale

6.4.1 Introduction

While cyclic gas injection for enhanced shale oil recovery (EOR) has been successful in the Eagle Ford Shale, it has performed poorly, so far, in the Bakken Shale. The technical challenge has been the inability to achieve gas containment and thus to substantially increase pressure in the shale reservoir. As a result, there has not been enough high-pressure soak time to have a positive effect on oil extraction from the shale reservoir. Even EOG Resources, with the successful projects discussed above in the Eagle Ford Shale, was unable to contain the injected gas and sufficiently raise reservoir pressure in their initial cyclic gas injection EOR field tests in the Bakken Shale. As such, the injected gas was not able to penetrate far into the reservoir matrix nor achieve mixing (or miscibility) essential for recovering the oil remaining after primary recovery.

The comment of James Sorensen, Principal Investigator for The Energy & Environmental Research Center's (EERC) U.S. Department of Energy-sponsored field R&D projects, succinctly captures the challenges of conducting cyclic gas injection EOR in the Bakken Shale:

> *". . . . past pilot scale CO_2 injection tests into horizontal, hydraulically fractured Bakken wells have shown little to no effect on oil mobilization. . .the CO_2 moves so quickly through fractures that it does not have enough time, or becomes too dispersed, to interact with stranded oil in the matrix."*

6.4.2 EOR Field Tests

Four Bakken shale gas injection field tests are reported in the technical literature. Three of the field pilots injected CO_2 and one injected enriched gas.

- Pilot Test #1, launched in 2008 in the Bakken Shale of North Dakota, involved cyclic injection of CO_2. It was successful in establishing CO_2 injectivity of 1 MMcfd for 30 days but did not achieve any increase in oil production.

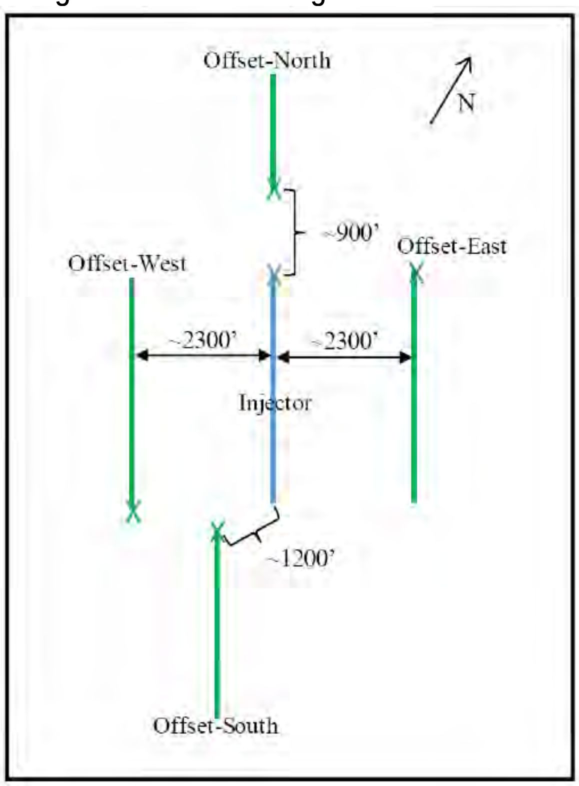
- Pilot Test #2 was launched in 2009 in the Elm Coulee field of Montana. It was successful in establishing CO_2 injectivity of 1.5 to 2 MMcfd for 45 days.

However, oil production, once the well was placed back on-line, was lower than before the start of CO_2 injection.

- Pilot Test #3, a cyclic CO_2 injection field test involving a vertical well, was conducted in 2014. A previously drilled offset horizonal production well was located about 900 feet from the vertical well. CO_2 broke through from the vertical injection well to the Hz production well in less than 24 hours, leading the operator to shut down the field test.

- Pilot Test #4, conducted in 2014, was a continuous gas flood involving one Hz injector and four Hz producers (Figure 6-10). Enriched natural gas, containing 55% methane, 10% nitrogen, and 35% C_2+ fraction, was the injection fluid. While the gas EOR flood demonstrated oil production increases in the four offset wells, the operator noted that other activities, such as stimulation and frac-hits in nearby wells, may have contributed to increased oil production. The field test was discontinued after 55 days of gas injection.

Figure 6-10. Field Design for Field Test #4



Source: Hoffman, 2016.

6.5 Wolfcamp Shale

In preparation for an announced cyclic CO_2 EOR project in the Wolfcamp Shale of the Permian Basin, the technical staff of Occidental Oil and Gas Corporation performed two important studies:

Laboratory Investigation of EOR Techniques for Organic Rich Shales in the Permian Basin, SPE 2890074-MS, Shunhua Liu, Vinay Sahni, and Jiasen Tan, (Occidental Oil and Gas) Derek Beckett, and Tuan Vo, (CoreLab). This laboratory study involved cyclic injection of miscible gases into Permian Basin shale core samples to investigate shale EOR mechanisms. PVT tests, including swelling tests and minimum miscibility pressure (MMP) measurements, were conducted for three different gases (CO_2, methane, and field produced gas). CO_2 was the most efficient solvent, with miscibility at lowest pressure. The core experiments, conducted at reservoir conditions, showed favorable results, including incremental oil recovery and favorable CO_2 utilization following seven consecutive CO_2 injection cycles. Significant oil saturation reductions were noted after several cycles of CO_2 injection, as detected by NMR (nuclear magnetic resonance) technology and confirmed by measured oil extraction.

Miscible EOR Process Assessment for Unconventional Reservoirs: Understanding Key Mechanisms for Optimal Field Test Design, URTEC-2870010-MS, Vinay Sahni and Shunhua Liu (Occidental Oil and Gas Corporation). The objective of this reservoir simulation study was to establish an optimal cyclic shale EOR design for a field test. The study addressed several shale oil recovery mechanisms, including: 1) vaporization of lighter oil components, 2) interfacial tension (IFT) reduction at pressures above the minimum miscibility pressure (MMP), and (3) molecular diffusion. The study found that the presence of hydraulic and natural fractures is important for providing a large contact area for the injected gas to penetrate the ultra-low permeability matrix. Oil recovery was found to be proportional to the mass of CO_2 injected.

In their January 2019 Investor Presentation, Occidental Petroleum Corporation stated that the company has “continued (their) progression of unconventional EOR pilots in Midland and Delaware basins using CO_2 and miscible hydrocarbon gas.”

6.6 U.S. DOE/NETL-Supported R&D

The USDOE/NETL is conducting a series of field R&D projects designed to better understand and subsequently improve the performance of shale EOR.

6.6.1 Eagle Ford Shale

The U.S. DOE/NETL is supporting the project, "Eagle Ford Shale Laboratory: A Field Study of the Stimulated Reservoir Volume, Detailed Fracture Characterization and EOR Potential." This R&D project, started in April 2018, is led by Texas A&M's Engineering Experiment Station (Prof. Dan Hill, Principal Investigator) with participation by Wild Horse Resource Development Corporation (field operator) and other firms. The R&D project is in the far northeastern portion of the Eagle Ford Shale trend in Burleson County, South Texas. One of the stated objectives of this R&D project is to conduct an EOR pilot using cyclic gas injection.

6.6.2 Bakken Shale

The U.S. DOE/NETL is supporting the project, "Advanced Characterization of Unconventional Oil and Gas Reservoirs to Enhance CO_2 Storage Resource Estimates." This R&D project, started in May 2016, is led by The Energy & Environmental Research Center (EERC) at the University of North Dakota (Bethany Kurz, Principal Investigator), with participation by Hitachi High Technologies (America). The goal of this R&D project is to develop advanced technologies for characterizing tight oil formations. A previous U.S. DOE/NETL R&D project at EERC entitled, "Improved Characterization and Modeling of Tight Oil Formations for CO_2 Enhanced Oil Recovery Potential and Storage Capacity Estimation", was started in 2014 (Dr. James Sorensen, Principal Investigator).

6.6.3 Wolfcamp Shale

In preparation for a potential shale EOR field test, the U.S. Department of Energy, National Energy Technology Laboratory, is sponsoring the project, "Hydraulic Fracturing Test Site (HFTS)" in the Midland Basin's Upper and Middle Wolfcamp Shale. GTI is the prime contractor with Mr. Jordan Ciezobka as the Principal Investigator. The HFTS is a $25 million Joint Industry Projects (JIP) research program with Laredo Petroleum providing the field test site and numerous other companies (i.e., Chevron, Conoco Phillips, Devon, and Pioneer Resources, among others) serving as JIP members. The project entails reservoir characterization using core and logs as well as a robust suite of diagnostics

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Chapter 7. Tight Oil Recovery R&D Gaps and Topics

7. Tight Oil Recovery R&D Gaps and Topics

7.1. Introduction

One of the purposes of the USEA Study is to identify critical R&D gaps and topics for improving recovery efficiency from tight/shale oil reservoirs. These R&D gaps, each representing a major technological challenge, could provide insights and opportunities for the U.S. DOE/NETL's unconventional/tight oil R&D program. The identification of high priority R&D gaps set forth below is based on an extensive review of the technical literature, an examination of the laboratory and reservoir modeling work conducted to date, and a review of the performance of R&D field tests and pilot projects targeting improved oil recovery in tight oil formations.

The nine most challenging, highest value tight oil recovery R&D topics are presented below and discussed more extensively in the following section.

- R&D Priority #1. Defining Reservoir Conditions and Well Completion Methods Favorable for Tight Oil EOR.
- R&D Priority #2. Establishing the Relative Importance of Tight Oil Enhanced Oil Recovery (EOR) Mechanisms.
- R&D Priority #3. Rigorously Characterizing and Defining the Natural and Induced Fracture Systems in Tight Oil Formations.
- R&D Priority #4. Improving EOR Monitoring and Diagnostic Technologies and Practices for Tight Oil.
- R&D Priority #5. Breaking the "Technology Lock" on Achieving Successful Continuous Gas Flooding EOR in Tight Oil.
- R&D Priority #6. Achieving Increased Reservoir Conformance Between the Injected EOR Gas and Fluid.

- R&D Priority #7. Establishing Optimum Gas Injection Rates, Soak Times, and Production Times for Tight Oil EOR Using Cyclic Injection of Gas.

- R&D Priority #8. Conducting Fully Integrated Laboratory, Reservoir Modeling, and Field Pilot EOR Projects in Each Tight Oil Basin and Formation.

- R&D Priority #9. Establishing the Technical and Economic Attractiveness of Using CO_2, Wet Gas, Dry Gas, and Other Fluids for Cyclic Gas EOR in Various Tight Oil Formations.

7.2 Discussion of R&D Priorities

While each topic is treated separately, it will require the integrated application of several of these R&D topics and technologies to achieve notable improvements in oil recovery efficiencies from tight oil formations.

R&D Priority #1. Defining Reservoir Conditions and Well Completion Methods Favorable for Tight Oil EOR.

Not all tight oil formations and reservoir settings are favorable for enhanced oil recovery (EOR). Establishing the favorable geologic and reservoir settings, such as sufficient pressure confinement and suitable hydrocarbon composition, will require a more in-depth review of the performance of tight oil EOR field pilots than has been possible so far, given the limited data published, so far, by industry. (For more information on the performance of tight oil EOR field tests and pilot projects, see companion USEA report prepared by Advanced Resources International (ARI) entitled, "Increasing Shale Oil Recovery and CO_2 Storage with Cyclic CO_2 Enhanced Oil Recovery: Shale EOR Field Tests and Projects".) A productive R&D path would be to determine to what extent changes in tight oil EOR operating practices could be modified to enable successful tight oil EOR (using cyclic gas injection) in less favorable tight oil reservoir settings.

R&D Priority #2. Establishing the Relative Importance of Tight Oil Enhanced Oil Recovery (EOR) Mechanisms.

The R&D studies to date suggest that a variety of EOR mechanisms are important for achieving more efficient oil recovery from tight oil. These include re-pressurization, miscibility, oil swelling, vaporization of light ends, and molecular diffusion, among others. Establishing the relative importance of each of these mechanisms would provide useful insights for designing an optimum EOR project for the variety of formations that comprise the domestic tight oil resource.

R&D Priority #3. Rigorously Characterizing and Defining the Natural and Induced Fracture Systems in Tight Oil Formations.

Natural fractures, enhanced by induced hydraulic fractures, provide the flow pathways and govern the extent of contact between the injected gas and the tight oil reservoir. Improved characterization of natural fracture systems can also provide insights for improving conformance of the injected gas with the reservoir.

R&D Priority #4. Improving EOR Monitoring and Diagnostic Technologies and Practices for Tight Oil.

Advanced downhole monitoring systems, that provide real-time information on the performance of the EOR project, are as essential for tight oil EOR field projects as for any other type of enhanced hydrocarbon extraction or fluid injection project. Advanced monitoring and diagnostic testing would also enable an operator to modify the EOR design as the project progresses, particularly for improving conformance between the injected gas/fluid and the reservoir.

R&D Priority #5. Breaking the "Technology Lock" on Achieving Successful Continuous Gas Flooding EOR in Tight Oil.

So far, the field trials of continuous injection of CO_2 and other gases in tight oil reservoirs, involving separate injection and production wells (as opposed to injecting cyclic CO_2 injection into a production well), have encountered numerous challenges. Particularly notable problems have been the lack of conformance and the early break-through of the injected gas. Overcoming these problems would provide a much higher efficiency EOR technology and would greatly increase the opportunities for storing CO_2 in tight oil reservoirs.

R&D Priority #6. Achieving Increased Reservoir Conformance Between the Injected EOR Gas and Fluid.

EOR performance in tight oil reservoirs, consistent with EOR performance in conventional reservoirs, is directly linked to how much of the reservoir is contacted by the EOR injection fluid or gas. As such, advanced conformance technologies and practices are essential. Therefore, the goal of achieving increased reservoir conformance and its direct link to achieving increased oil recovery efficiency, particularly for continuous (rather than cyclic) gas injection, remains a top (albeit challenging) priority topic for R&D in tight oil.

R&D Priority #7. Establishing Optimum Gas Injection Rates, Soak Times, and Production Times for EOR Using Cyclic Injection of Gas.

A great variety of gas injection rates and volumes, soak times and fluid production times are examined and discussed for cyclic gas injection in the literature. It may be that alternative cyclic gas injection designs need to be linked to specific formation properties to achieve optimum results. For example, optimum gas injection practices into the relatively permeable Bakken Shale Middle Member may be quite different than optimum gas injection practices into the much lower permeability Eagle Ford Shale Lower Unit.

R&D Priority #8. Conducting Fully Integrated Laboratory, Reservoir Modeling, and Field Pilot EOR Projects in Each Tight Oil Basin and Formation.

Given the considerable diversity of reservoir conditions encompassing the domestic tight oil resource, a series of fully integrated EOR projects (involving laboratory tests, reservoir modeling and rigorous monitoring) need to be launched in each of the major tight oil basins and formations. These integrated EOR field tests would include combining information on basic tight oil displacement mechanisms gained from laboratory studies with expected fluid flow and tight oil formation contact information gained from rigorous reservoir simulation. Most importantly, these integrated EOR field tests would entail extensive calibration of laboratory studies and reservoir simulation with feedback information gained from closely monitored field performance data.

R&D Priority #9. Establishing the Technical and Economic Attractiveness of Using CO_2, Wet Gas, Dry Gas and Other Fluids for Cyclic Gas EOR in Various Tight Oil Formations.

Prior reservoir simulation studies by Advanced Resources International in three major tight formations (Eagle Ford, Bakken and Midland Wolfcamp) showed that using cyclic injection of CO_2 provided higher improvements in tight oil recovery efficiency than using cyclic injection of dry or wet gas. However, other factors, such as the availability and the cost of the alternative injection gases and fluids, also need to be considered to establish the economic attractiveness of the alternative cyclic gas injection options for conducting EOR in tight oil formations.

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