White Paper

Benefits of U.S. DOE/NETL Investments in Tight Oil R&D/Technology

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Enhanced Oil Recovery in Unconventional Reservoirs

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BENEFITS OF U.S. DOE/NETL INVESTMENTS IN TIGHT OIL R&D/TECHNOLOGY

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EXECUTIVE SUMMARY

The purpose of this "White Paper" is to evaluate the benefits of U.S. DOE/NETL investments in tight oil R&D and technology compared to continuation of industry's "business as usual."

While the U.S. has a large tight oil resource base, estimated at 653 billion barrels of original oil in-place (OOIP) in the three major tight oil formations appraised to date, only a small portion, 5 to 9 percent, of this OOIP is recoverable with current (pressure depletion) practices. As such, improving the recovery efficiency of the domestic tight oil resource with advanced technology, such as cyclic injection of CO_2 and natural gas, would add considerable value.

An analysis of using cyclic gas injection for enhanced tight oil recovery (in three major tight oil formations) shows that it would provide considerable "uplift," improvement to primary recovery of tight oil. This would, in turn, provide 14.1 to 24.6 billion barrels of incremental tight oil production over continuation of industry's "business as usual" practices.

The benefits to this additional tight oil production would be considerable, as discussed more fully in the White Paper.

- Assuming an equal allocation of the incremental oil production and benefits between the U.S. DOE/NETL and industry, the benefits of U.S. DOE/NETL's R&D investments in tight oil R&D/technology would include: (1) incremental GDP of $956 to $1,638 billion; (2) additional 3.87 to 6.63 million job-years, over 25 years (additional annual jobs of 154,000 to 265,000); and (3) increased state and federal tax revenues.

- Additional benefits from the U.S. DOE/NETL R&D investments would accrue from acceleration in the wide-scale deployment of advanced tight oil recovery.

INTRODUCTION

The White Paper begins with a look at the current status of tight oil development and production. It then provides a summary of the size of the tight oil resource in-place (in three major tight oil formations evaluated by the U.S. DOE/NETL sponsored Basin Studies – Eagle Ford Shale, Bakken Shale and Midland Basin/Wolfcamp Shale) and discusses how tight oil well performance in these three basins has improved over time. However, even with the notable past improvements in well performance, recovery efficiencies of the tight oil resource remain low, 5 to 9 percent of the original oil in-place (OOIP), in the three tight oil formation noted above.

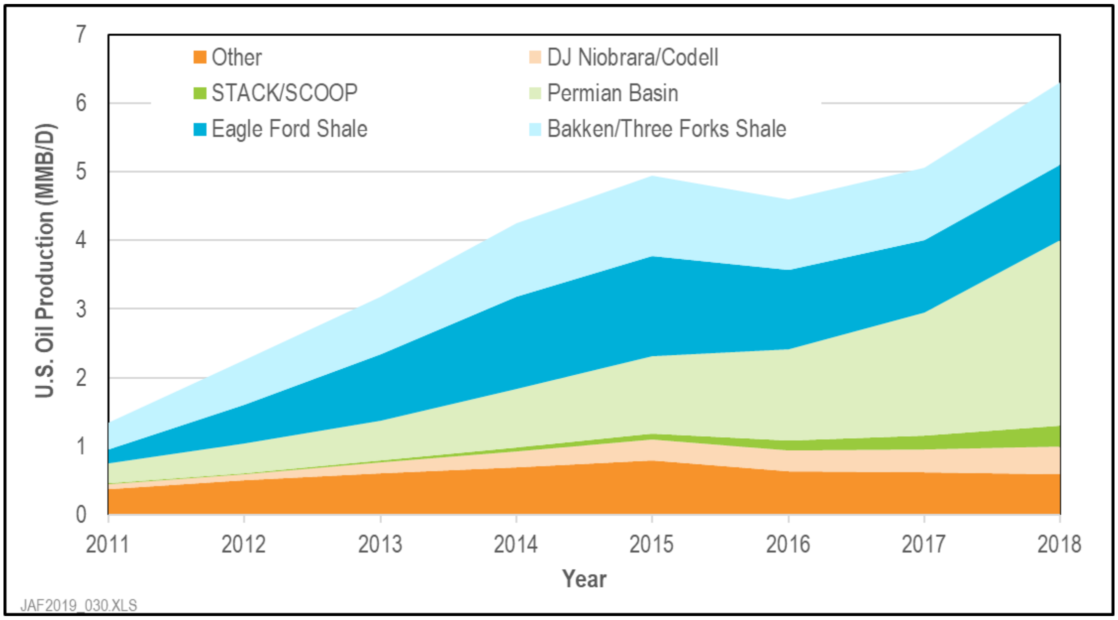
The White Paper then discusses that, as the tight oil plays mature, the historically achieved improvements in well performance will no longer be able to be maintained, requiring pursuit of more advanced tight oil recovery practices and technology. For this, the White Paper takes a preliminary look at the next potential step for improving tight oil recovery efficiency -- the cyclic injection of gas for enhanced tight oil recovery.

The report concludes with a discussion and preliminary quantification of the benefits of U.S. DOE/NETL investments in tight oil R&D and technology development.

TIGHT OIL DEVELOPMENT AND PRODUCTION

Modest volumes of tight oil have been produced in the U.S. for some time, using vertical wells drilled into tight sand oil formations such as the Spraberry in West Texas. However, it was the pursuit of the Bakken Shale (Williston Basin) with long horizontal wells that launched the modern tight oil era. With growth in the Bakken and the emergence of the Eagle Ford Shale, tight oil production reached the one million barrels per day threshold in 2011, increasing further to 6.4 million barrels of oil per day (60% of domestic oil production) in 2018, Figure 1.

Figure 1: U.S. Tight Oil Production (2011-2018).



Source: Advanced Resources International's Tight Oil Database, 2018; Drilling Info, 2018.

The latest Energy Information Administration's (EIA's) Annual Energy Outlook (2019) projects that tight oil production (Reference Case) will peak at about 10 million barrels per day (about three-quarters of domestic oil production) in the 2030-2035 time period and then enter into decline. (In the Low Oil Price Case, the peak and decline of tight oil production occur about a decade earlier). As such, there would be considerable value from accelerating the development of advanced tight oil recovery technologies that would help counter EIA's projected decline in both tight oil and overall domestic oil production.

THE TIGHT OIL RESOURCE BASE

While the tight oil resource has become the dominant source of domestic oil production, considerable uncertainty surrounds the size and ultimate recoverability of this diverse oil resource. In addition, most of the published resource estimates provide only high-level information, without including the detailed geologic and reservoir properties essential for understanding the nature and distribution of this resource.

To overcome this limitation and provide more rigorous estimates of the tight oil resource, the U.S. DOE/NETL-sponsored three Basin Studies that assembled detailed geological and reservoir data essential for estimating original oil in-place for three major tight oil basins -- Eagle Ford Shale in South Texas, Bakken Shale in the Williston Basin of North Dakota, and Wolfcamp

Shale in the Midland/Permian Basin of West Texas. The studies involved construction of geological maps, independent analyses of well logs, compilation of data from the technical literature and industry publications, and use of site-specific reservoir information from the DOE/NETL-sponsored field research laboratories.

The Basin Studies established that in-place resource in the three tight oil formations is large, equal to 653 billion barrels, Table 1.

Table 1: Tight Oil Resource In-Place, Three Major Shale Formations

Shale Formation	Risked Assessment Area (mi^2)	OOIP (BBbls)
Midland/S. Texas Basin(1) Eagle Ford Shale	6,130	139.3
Williston Basin(2) Bakken Shale	10,560	90.8
Midland Basin/Wolfcamp Shale(3) (Benches A and B)	5,840	422.9
Total	**22,530**	**653.0**

1. Eagle Ford Shale Basin Study, April 2019.
2. Bakken Shale Basin Study, June 2019.
3. Permian/Midland Basin Wolfcamp Shale Study, August 2019.

Source: Advanced Resources International, 2019.

Additional in-place tight oil resources, beyond those defined by the three Basin Studies, exist in other basins and formations such as the Anadarko's Cana-Woodford and Meramec; the DJ's Niobrara and Codell; the extensive stack of tight oil sands and shales in the Powder River Basin; and the numerous shale and tight sand oil formations in the Permian Basin. Full documentation of the domestic tight oil could show a resource base approaching 2,000 million barrels.

HISTORICAL CHANGES IN TIGHT OIL WELL PERFORMANCE

More rigorous understanding of the geological settings and reservoir properties of tight oil, along with more aggressive well drilling and completion practices, have been the driving force behind improving tight oil well performance. Table 2 presents the changes in well performance for three major U.S. tight oil formations during the five-year period between 2013 and 2018.

Table 2: Changes in Tight Oil Well Performance

Tight Oil Basin/Formation	Oil/Condensate EURs (MB per well)		Changes in Well Performance
	2013	2018	2013 to 2018
Williston Basin Bakken Shale	470	590	+26%
Eagle Ford Shale Oil Dominant Areas	340	370	+9%
Permian/Midland Basin Wolfcamp Shale	390	550	+41%

Source: Advanced Resources International's Tight Oil Database, 2018; Drilling Info, 2018.

Several observations can be gleaned from the data on changes in tight oil well performance.

- In general, tight oil well performance improves with time as "best well completion practices" become more widely used in a basin.
- However, once the "sweet spot" areas of a tight oil formation become mature (over 50 percent developed), well performance can begin to decline, as illustrated by the decline in well performance for the notably mature Karnes Trough area of the Eagle Ford Shale, Table 3.

Table 3: Recent Changes in Eagle Ford Shale Well Performance

Tight Oil Play Areas	Well Performance (EUR, MB)			Average Lateral Length (ft)		
	2016	2018	% Change	2016	2018	% Change
Eagle Ford Shale Oil Dominant Areas	340	370	+9%	6,300	7,000	+11%
Karnes Trough	430	420	(2%)	4,800	5,300	+10%

Source: Advanced Resources International's Tight Oil Database 2018; DrillingInfo, 2018.

When examining the changes in tight oil well performance, it is important to also examine the changes in Hz well lateral lengths. A longer Hz well lateral, that enables a well to contact and drain a larger area, can provide higher recoveries per well but not necessarily provide higher recovery efficiencies of the tight oil resource in-place. The information on Table 3 shows that the more recent improvement in well performance between 2016 and 2018 for the Oil Dominant Area of the Eagle Ford Shale was due to increases in the length of Hz well laterals. However, a similar increase in the length of Hz well laterals was not sufficient to preclude a decline in well performance in the more highly drilled Karnes Trough area of the Eagle Ford Shale.

CURRENT TIGHT OIL RECOVERY EFFICIENCIES

Event with the notable improvements in well performance, tight oil efficiencies remain low – ranging from 5.3 percent to 8.8 percent of the original oil in-place for the three shale formations addressed by the Basin Studies. As such, only an estimated 41.7 billion barrels of tight oil is recoverable with current primary recovery (pressure depletion) methods, leaving behind a massive 611 billion barrels of tight oil, Table 4.

Table 4: Current Tight Oil Recovery Efficiencies: Three Tight Oil Formations

Shale Formation	OOIP (BBbls)	Primary Recovery Efficiency (% OOIP)	Primary Recoverable Resource (B Bbls)	Remaining Resource (B Bbls)
Eagle Ford Shale	139.3	8.1 (1)	11.3	128.0
Bakken Shale	90.8	8.8 (2)	8.0	82.8
Midland/Wolfcamp Shale (Benches A and B)	422.9	5.3 (3)	22.4	400.5
Totals	**653.0**		**41.7**	**611.3**

1. Reservoir Simulation of Enhanced Tight Oil Recovery: Eagle Ford Shale, April 2019.
2. Reservoir Simulation of Enhanced Tight Oil Recovery: Bakken Shale Basin, June 2019.
3. Reservoir Simulation of Enhanced Tight Oil Recovery: Permian/Midland Basin Wolfcamp Shale, August 2019.

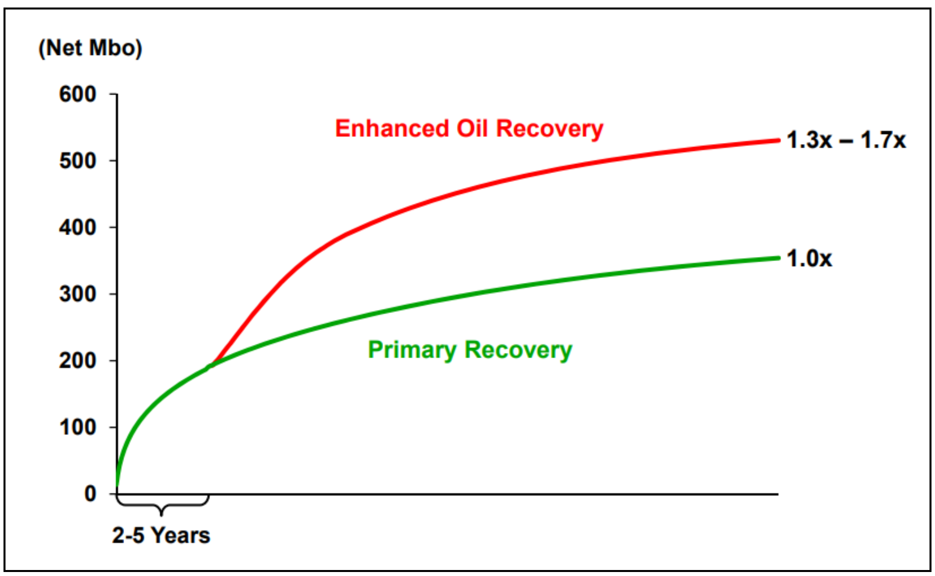
Source: Advanced Resources International, 2019

In addition, the past history of improving well performance may no longer be able to be maintained, with well performance actually beginning to decline in mature tight oil basins such as the Eagle Ford Shale. This argues that other, more advanced technologies and practices for improving well performance and oil recovery efficiencies will be required.

USING CYCLIC GAS INJECTION FOR IMPROVING TIGHT OIL RECOVERY EFFICIENCY

One of the advanced technologies for improving tight oil recovery involves the injection of gas into maturing tight oil formations. The most comprehensive set of field applications of cyclic gas injection are the projects implemented by EOG Resources in the Eagle Ford Shale. EOG has reported that cyclic gas injection could provide a 1.3x to 1.7x uplift to primary oil recovery, Figure 2. However, little information on the actual field performance of EOG's cyclic gas injection projects in tight oil formations exists in the literature.

Figure 2: Primary versus Enhanced Oil Recovery: Eagle Ford Shale

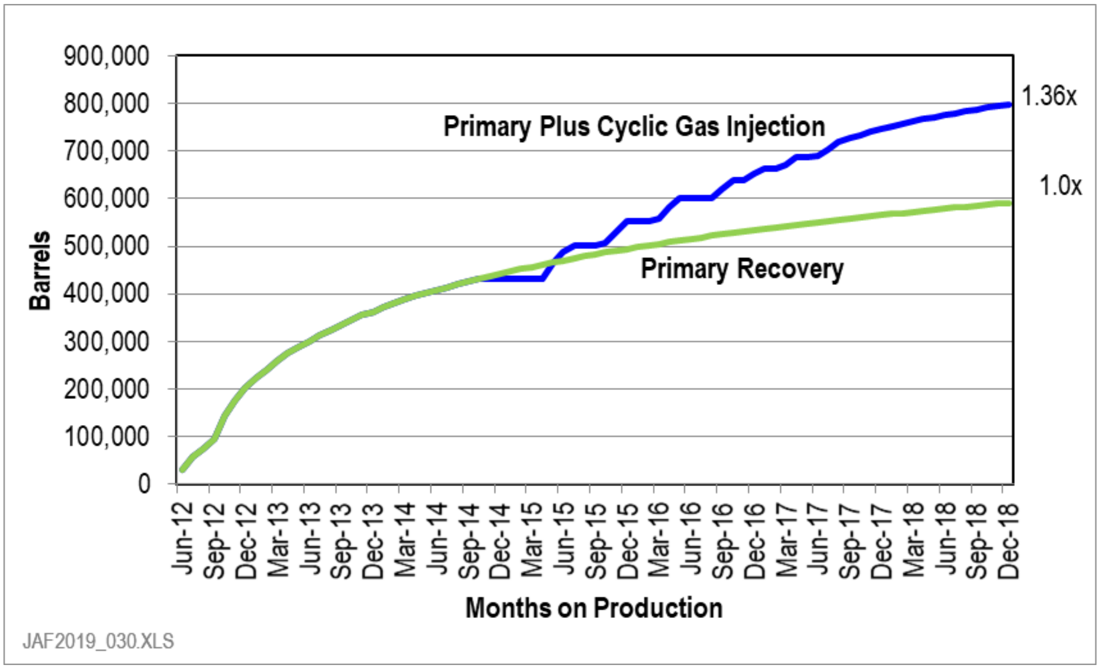


Source: EOG, 2017.

To overcome this lack of information, Advanced Resources International (ARI) analyzed the performance of the Martindale L&C 4-well cyclic gas injection pilot in LaSalle County, Texas initiated by EOG in November 2014, with production data assembled from the Texas Railroad

Commission. Our analysis shows the 1.36x uplift in oil recovery by the Martindale L&C project due to cyclic gas injection is within the range of uplift values reported by EOG, Figure 3.

Figure 3: Cumulative Oil Recovery from Primary and Cyclic Natural Gas Injection for Four Martindale L&C Lease Wells



Source: Advanced Resources International, 2019.

EVALUATING THE VIABILITY OF CYCLIC GAS ENHANCED TIGHT OIL RECOVERY

To better understand the viability and performance of cyclic gas injection for improving tight oil recovery, the U.S. DOE/NETL sponsored a series of reservoir simulation studies for tight oil formations. The results from the evaluation of the expected performance of cyclic gas injection in tight oil formations are provided below. (Attachment A provides additional details on the evaluation of cyclic gas injection in the Eagle Ford Shale.)

The studies found that cyclic injection of gas (CO_2, dry gas and wet gas) into shale oil formations, under appropriate geologic and reservoir conditions, can appreciably improve oil recovery efficiency, compared to continued use of primary (pressure depletion) production methods.

Table 5 provides data that shows cyclic injection of CO_2 can increase primary oil recovery from the Eagle Ford Shale, the Bakken Shale and the Midland Wolfcamp Shale (Bench B) by "uplifts" of 1.41x to 1.63x.

Table 5: Uplift in Tight Oil Recovery From Cyclic Injection of CO_2

Shale Formation	Study Area OOIP (MBbls)	13.5 Years of Primary Recovery (MBbls)	Incremental Due to CO_2 Injection	
			(MBbls)	"Uplift"
Eagle Ford Shale	4,620	298	185	1.61x
Bakken Shale	5,240	363	149	1.41x
Midland/Wolfcamp Shale (Bench B)	7,630	355	223	1.63x

Source: Advanced Resources International, 2019.

Table 6 provides data that show cyclic injection of dry and wet gas can also increase primary oil recovery from the Eagle Ford Shale by "uplifts" of 1.34x to 1.40x, from the Bakken Shale by "uplifts" of 1.11x to 1.19x, and from the Midland/Wolfcamp Shale (Bench B) by "uplifts" of 1.42x to 1.48x.

Table 6: Uplift Tight Oil Recovery from Cyclic CO_2, Wet Gas and Dry Gas Injection

Shale Formation	OOIP (MB)	13.5 Years of Primary Recovery (MB)	Incremental Due to Gas Injection					
			CO_2		Dry Gas		Wet Gas	
			(MB)	"Uplift"	(MB)	"Uplift"	(MB)	"Uplift"
Eagle Ford Shale	4,620	298	185	1.61x	102	1.34x	119	1.40x
Bakken Shale	5,240	363	149	1.41x	40	1.11x	69	1.19x
Midland/ Wolfcamp Shale (Bench B)	7,630	355	223	1.63x	149	1.42x	169	1.48x

Source: Advanced Resources International, 2019.

Based on the reservoir simulation studies, applying cyclic gas injection to the large "left behind" tight oil resource target of 611 billion barrels could provide 14.1 to 24.6 billion barrels of additional technically recoverable tight oil, Table 7. These incremental oil recovery values are used below to provide a preliminary estimate of the benefits of investing in R&D and pursing technology for improving tight oil recovery.

Table 7: Incremental Tight Oil Recovery from Cyclic Injection of Gas

Shale Formation	OOIP (BBbls)	Primary Recovery Efficiency (% OOIP)	Primary Recoverable Resource (B Bbls)	"Uplift" From Cyclic Gas Injection*	Enhanced Recoverable Resource (B Bbs)
Eagle Ford Shale	139.3	8.1	11.3	1.34x to 1.62x	3.8 to 6.9
Bakken Shale	90.8	8.8	8.0	1.11x to 1.41x	0.9 to 3.6
Midland/Wolfcamp Shale (Benches A and B)	422.9	5.3	22.4	1.42x to 1.63x	9.4 to 14.1
Totals	**653.0**		**41.7**		**14.1 to 24.6**

*Range reflects uplifts from cyclic dry gas and cyclic CO_2 injection.

Source: Advanced Resources International, 2019.

BENEFITS OF U.S. DOE/NETL INVESTMENTS IN TIGHT OIL R&D/ TECHNOLOGY

Two types of benefits will stem from U.S. DOE/NETL investments in tight oil R&D and technology development compared to continuation of industry "business as usual."

- The first benefit is the acceleration of the time by when advanced tight oil recovery technology becomes widely applied in the field.
- The second benefit stems from the additional R&D investments, beyond industry's current "business as usual" R&D investments, increasing the probability of successful development and deployment of advanced tight oil recovery technology.

Benefits of Acceleration. Earlier sections of the report discuss that accelerating the availability of additional tight oil production would have considerable value, particularly once domestic tight oil production enters into decline. The materials below provide a quantitative estimate of the value of such accelerated development and deployment.

We start with the assumption that industry's "business as usual" investments in R&D will result in advanced tight oil recovery technology becoming widely deployed in Year 2035, consistent with historical time lags between technology development and its wide-scale application in the field.

Introduction of U.S. DOE/NETL R&D investment would accelerate the time to wide-scale deployment of this technology by five to 10 years, given the emphasis by U.S. DOE/NETL on making public the results of its sponsored R&D and transferring technology industry wide. Based on information provided above, we assume that use of advanced tight oil recovery technology adds 14.1 to 24.6 billion barrels of recoverable oil. We also assume that this volume of additional tight oil is produced over 25 years and that the value of time (discount rate) is 5 percent per year. Using these assumptions and the expected acceleration of technology deployment, due to U.S. DOE/NETL R&D investment of 5 to 10 years, we can establish a quantitative estimate of benefits.

Using a traditional time value discount model, the benefits of U.S. DOE/NETL R&D investments for accelerating the wide-scale deployment of advanced tight oil recovery technology is an incremental 1.4 to 2.5 billion "time-value" barrels ($190 to $340 billion of additional GDP) for 5 years of acceleration to 3.2 to 5.7 billion "time-value" barrels ($440 to $780 billion of additional GDP) for 10 years of acceleration, Table 8.

As important, this additional tight oil production would become available in the crucial Year 2025 to Year 2035 time period when the U.S. EIA Annual Energy Outlook projects tight oil production, as well as overall domestic oil production, will enter into decline.

Table 8: Value of Accelerating Wide-Scale Deployment of Advanced Tight Oil Recovery Technology

	Business As Usual	U.S. DOE/NETL R&D Investment	
		5 Years of Acceleration	10 Years of Acceleration
Start Date for Wide Scale Deployment	2035	2030	2025
Ultimate Impact	14.1 to 24.6 B Bbls	14.1 to 24.6 B Bbls	14.1 to 24.6 B Bbls
Pace of Deployment	25 Yrs	25 Yrs	25 Yrs
Annual Impact	0.56 to 0.98 B Bbls	0.56 to 0.98 B Bbls	0.56 to 0.98 Bbls
Cumulative Time Discounted Value (@ 5% Discount Rate)*	5.1 to 8.9 B Bbls	6.5 to 11.4 B Bbls	8.3 to 14.6 B bls
Incremental Benefit ▪ "Time Value" Barrels ▪ GDP (@$65/B)		1.4 to 2.5 B Bbls $190 to $340 Billion	3.2 to 5.7 B Bbls $440 to $780 Billion

*With Year 2025 set as the starting point.

Source: Advanced Resources International, 2019.

Benefits of Additional R&D Investment. As discussed above, it is relatively straightforward to establish the overall impact (and benefits) of advanced tight oil recovery technology. However, there is no simple way to allocate the joint benefits that result from investments in R&D by both U.S. DOE/NETL and industry. One such attempt was undertaken by a National Academy of Sciences study that took a retrospective look at the impact of R&D investments in advanced energy technologies (including unconventional gas) by U.S. DOE/NETL and industry. This study entailed about two years of work and required substantial input from U.S. DOE staff and industry experts.

An alternative method for allocating the contribution of two parties (U.S. DOE/NETL and industry) toward the development of a joint product is to establish the size of their respective R&D investments for the next ten years. One could then use these two cumulation R&D investment values to allocate the 14.1 to 24.6 billion barrels of additional recoverable tight oil resulting from wide-scale application of advanced tight oil recovery technology.

Assuming a sufficiently robust U.S. DOE/NETL R&D technology program for tight oil, funded on the order of $100 to $200 million per year, one might equally allocate the joint benefits to U.S. DOE/NETL and industry. This would lead to assigning approximately 7 to 12 billion barrels of benefits to the U.S. DOE/NETL R&D program. This would provide the following aggregate benefits (assuming an oil price of $65 per barrel): an incremental GDP of $956 to $1,638 billion; an additional 3.87 to 6.63 million job-years, over 25 years (annual jobs of 154,000 to 265,000) and increased state and federal tax revenue.

SUMMARY OF FINDINGS

The above information shows that significant incremental benefits would accrue from U.S. DOE/NETL investments in tight oil R&D/technology compared to continuation of industry "business as usual."

- First, the acceleration of wide-scale application of advanced technology, leading to additional tight oil production, would occur in the crucial Year 2025 to 2035 time frame when domestic tight oil production is projected to enter decline.

- Second, the time value of accelerating tight oil reserves and production would provide an additional $190 to $780 billion "time value" dollars of GDP.

- Third, the likelihood of successful development and application of advanced tight oil recovery technology would increase due to U.S. DOE/NETL's R&D investments.

- Finally, the U.S. DOE/NETL share of the impact (benefits) of joint U.S. DOE/NETL and industry R&D investments would be estimated using the relative size of the R&D investments made by the two parties. Assuming an equal allocation of benefits, U.S. DOE/NETL's R&D investments would lead to an incremental GDP of $960 to $1,640 billion, an additional 3.87 to 6.63 million job-years, as well as increased state and federal tax revenues.

Attachment A
Reservoir Modeling of Cyclic Gas Injection in the Eagle Ford Shale

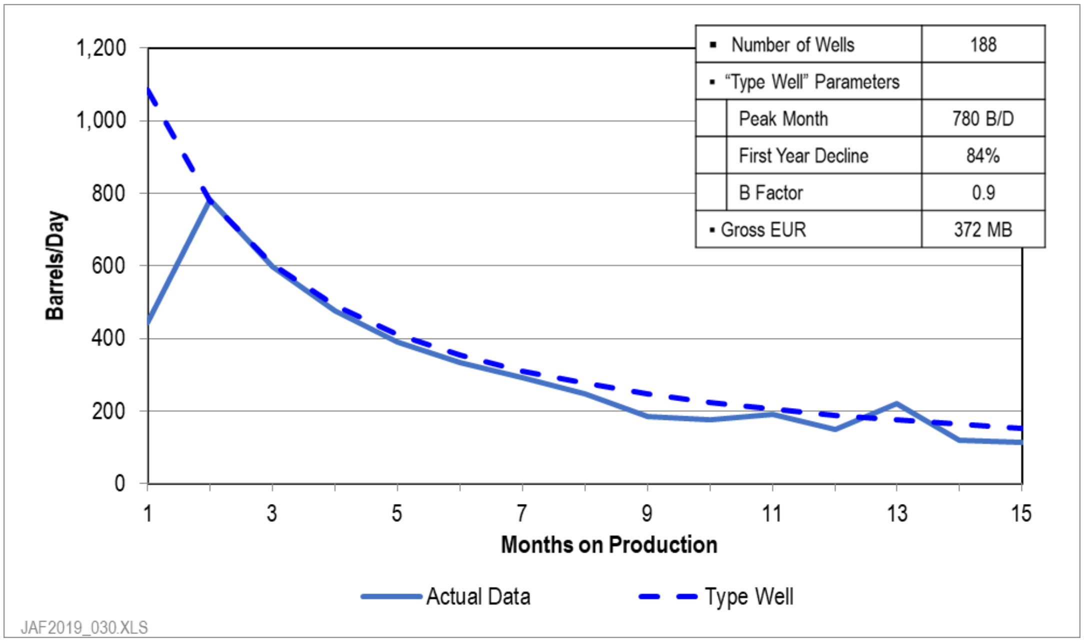
Attachment A provides additional details on one of the U.S. DOE/NETL sponsored reservoir simulation studies (conducted by Advanced Resources International) that evaluated the performance of cyclic gas injection for improving oil recovery from the Eagle Ford Shale.

The reservoir modeling study started by selecting and defining a representative Eagle Ford Shale area well. Next, the study used history matching of past well performance to confirm reservoir properties, establish the size of the stimulated reservoir volume (SRV), and estimate the boost in matrix permeabilities from application of hydraulic stimulation. Finally, the reservoir modeling study examined how much cyclic injection of gas (CO_2, wet gas and dry gas) would improve oil recovery efficiency compared to continuation of primary (pressure depletion) production.

Defining a Representative Study Area Well. The Eagle Ford Shale Study Area “type well,” used to evaluate the performance of cyclic gas injection, represents the composite performance of 188 Hz wells drilled in 2017 and early 2018 in the central portion of the Eagle Ford Shale, Figure A-1. The “type well” in the Study Area has a spacing of 8 wells per section and a Hz lateral of 7,400 feet. It has an estimated 30-year oil recovery of 372,000 barrels, an OOIP of 4.62 million barrels, and an OGIP of 5.54 Bcf.

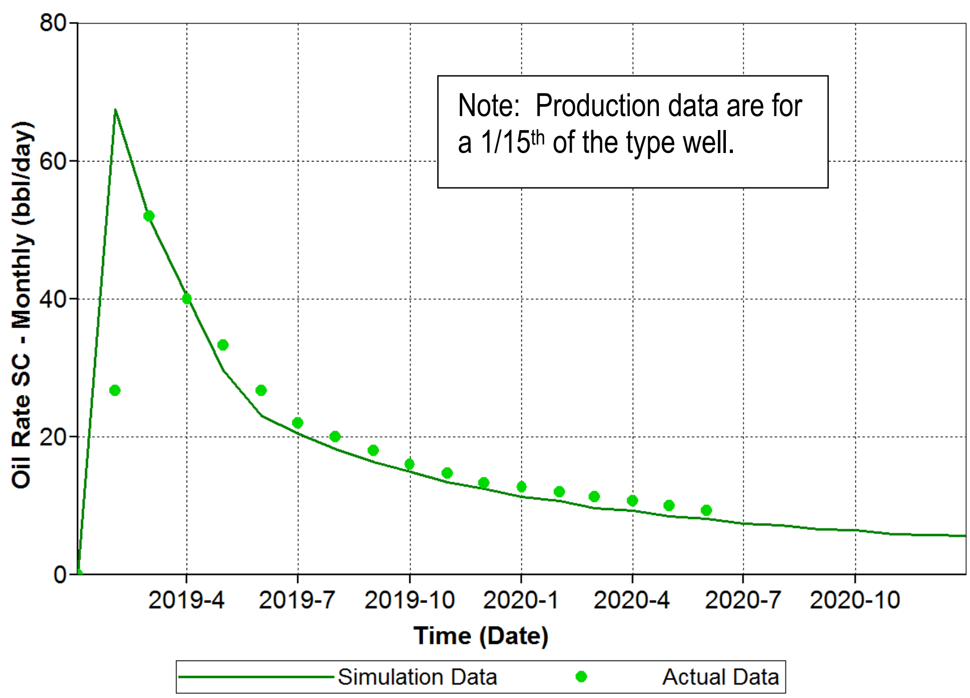
History Matching of Well Performance. Reservoir modeling, using a compositional, finite-difference reservoir model (GEM), achieved an excellent history match for oil (and gas) production, Figure A-2. This history match used the reservoir properties shown in Table A-1 and the key history matching properties of stimulated reservoir volume (SRV), Figure A-3, and post-stimulation permeability, Table A-2.

Figure A-1: Study Area "Type Well" Oil Production



Source: Advanced Resources International, 2019.

Figure A-2: History Match of Monthly Oil Production



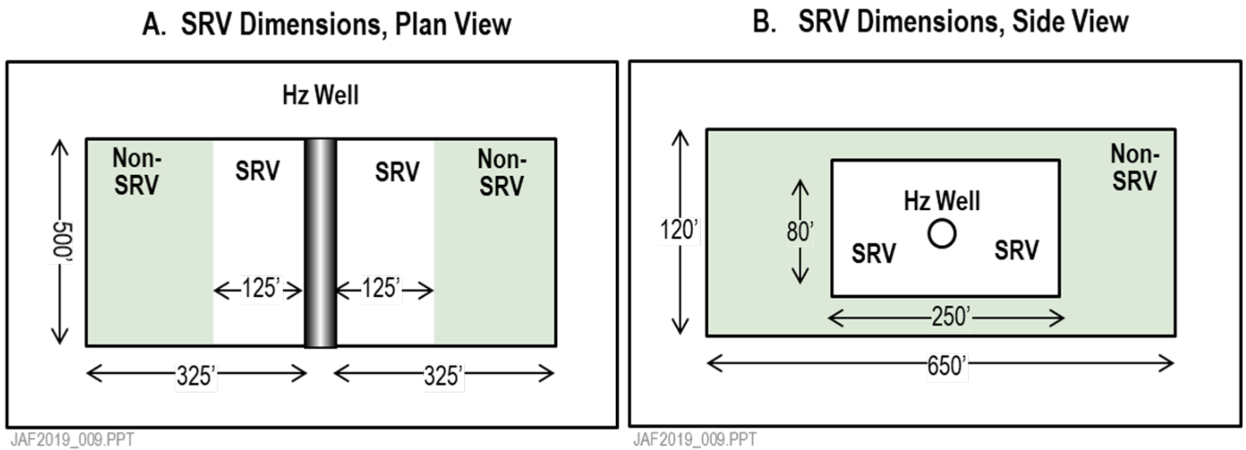
Source: Advanced Resources International, 2019.

Table A-1: Lower Eagle Ford Shale Study Area Reservoir Properties

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

Source: Advanced Resources International, 2019.

Figure A-3: Stimulation Reservoir Volume (SRV) Dimensions Used for History Match



Source: Advanced Resources International, 2019.

Table A-2: Permeability Values Used for History Match

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

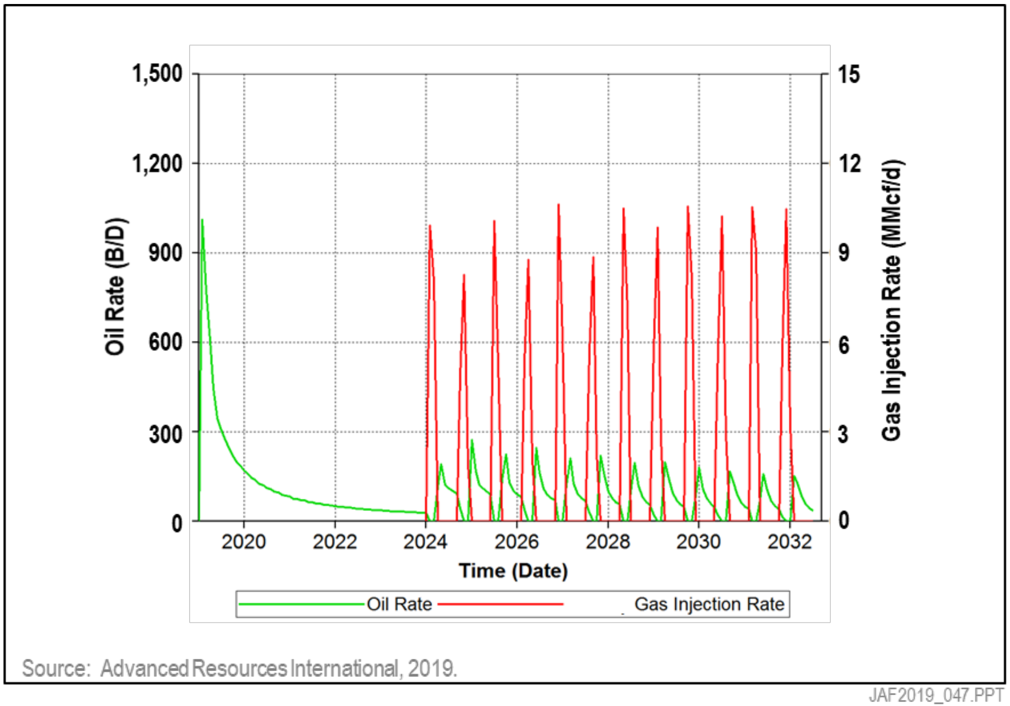
Source: Advanced Resources International, 2019.

Modeling 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) from primary production.

- In cycle one, CO_2 was injected at a constant rate of about 10 MMcfd for 2 months (with a BHP limit of 7,000 psia) to refill reservoir voidage and raise pressure.
- 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 A-4 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 Study Area well.

Figure A-4: Cyclic CO_2 Injection in Study Area Well



Source: Advanced Resources International, 2019.

Performance of Cyclic CO_2 Injection. The twelve cycles of CO_2 injection (over 8.5 years) provided 245,000 barrels of oil production for the Study Area well, in addition to 238,000 barrels at the start of CO_2 injection. Subtracting continuation of primary recovery (for 8.5 years) of 60,000 barrels, provides incremental oil recovery due to cyclic CO_2 injection of 185,000 barrels. This twelve cycle CO_2 injection project provided a <u>1.62x</u> uplift to oil production compared to continuation of primary recovery by the Study Area well, Table 5. Approximately thirteen percent (840 Mcf) of the 6,440 MMcf of CO_2 injected remained in the reservoir at the end of twelve cycles of CO_2 injection, Table A-5.

Table A-5: Cumulative Oil Production, CO_2 Injection and CO_2 Production

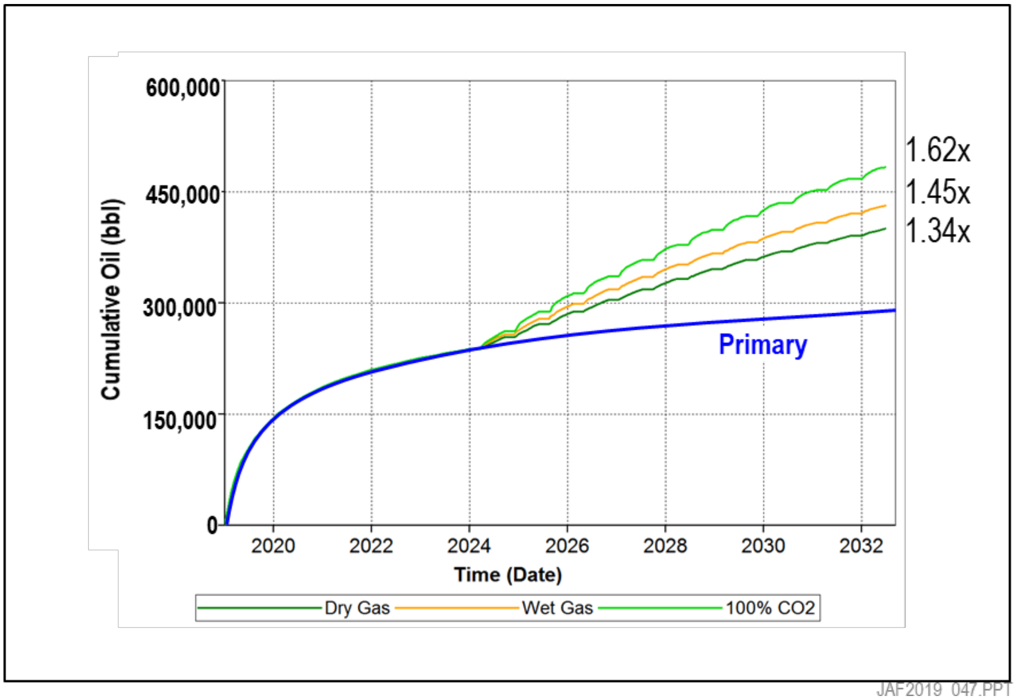
	Cumulative Oil Production				Cumulative CO_2 Injection (MMscf)	Cumulative CO_2 Production (MMscf)*	Estimated CO_2 Storage (MMscf)
	Total (MBbls)	Primary (MBbls)	Incremental				
			(MBbls)	Uplift			
End of 5-year primary	238	238	-	-	-	*	-
End of 6th cycle	380	274	106	-	3,000	2,420	590
End of 12th cycle	483	298	185	1.62x	6,440	5,600	840

*The produced CO_2 is reinjected into the reservoir.

Source: Advanced Resources International, 2019.

Performance of Cyclic Natural Gas Injection. The reservoir simulation study next examined the expected performance of using cyclic wet and dry natural gas injection. The first run involved cyclic injection of dry gas (100% C1), representative of cyclic gas injection in some of industry's field projects. The second run involved cyclic injection of wet gas (80% C1, 14% C2, 4% C3, and 2% C4), typical of the wet gas produced from the Study Area. Reservoir simulation for the Study Area well, showed that cyclic injection of natural gas provides uplifts of 1.34x for cyclic dry gas injection and 1.45x for cyclic wet gas injection, Figure A-5.

Figure A-5: Comparison of Cyclic CO_2, Dry Gas and Wet Gas Injection (Full Hz Well)



Source: Advanced Resources International, 2019.